OLSON, BZDOK & HOWARD

August 21, 2019

Ms. Barbara Kunkle
Acting Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-Filing

RE: MPSC Case No. U-20471

Dear Ms. Kunkle:

The following is attached for paperless electronic filing:

Direct Testimony of Michael Milligan on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club

Exhibits MEC-64 through MEC-74

Proof of Service

Sincerely,

Digitally signed by Christopher M. Bzdok
DN: cn=Christopher M. Bzdok, email=chris@envlaw.com, c=US
Date: 2019.08.21 16:17:45 -04'00'

Christopher M. Bzdok
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xc: Parties to Case No. U-20471

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.	Case No. U-20471 ALJ Sally L. Wallace

DIRECT TESTIMONY OF MICHAEL MILLIGAN

**ON BEHALF OF MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL,
AND SIERRA CLUB**

August 21, 2019

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position, and business address for the record.

A. My name is Michael Milligan. I am Principal at Milligan Grid Solutions, Inc. My business address is 9584 W 89th Ave., Westminster, CO 80021.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club.

Q. Please summarize your qualifications and work experience

A. I retired from the National Renewable Energy Laboratory (NREL) in 2017, where I was Principal Researcher in the Power Systems Engineering Center. I am now an independent power system consultant and Principal at Milligan Grid Solutions, Inc. I have more than 33 years' experience in power systems planning, and wind/solar power integration, and have authored and/or coauthored more than 220 technical articles, book chapters, and reports.

For many years, I was a significant contributor to the International Energy Agency Task 25 Research Group: Large-scale Integration of Wind Energy. My work at NREL influenced the formation of the Energy Imbalance Market[1] that is currently operating in the Western

[1] Western Energy Imbalance Market, https://www.westerneim.com/pages/default.aspx.

Interconnection of the U.S., and the Pilot Project on 5-Minute Scheduling in India[2] that is currently underway. I have led or participated in numerous industry committees including:

- Integrating Variable Generation Task Force and Essential Reliability Services Task Force at the North American Electric Reliability Corporation (NERC)
- Lead for Power System Integration and Transmission Task Force for the U.S. Department of Energy's Wind Vision[3]
- Lead for Power System Integration and Transmission Task Force for the U.S. Department of Energy's Hydro Power Vision[4]
- Numerous committees at the Western Electricity Coordinating Council (WECC)
- Wind and Solar Power Coordinating Committee, IEEE Power and Energy Society

Q. Have you previously testified before this Commission?

A. Yes, I sponsored rebuttal testimony in Consumers Energy's Integrated Resource Plan (IRP) proceeding, Case No. U-20165. I have also provided expert testimony before the Colorado Public Utility Commission on several occasions.

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2 New Delhi Central Electricity Regulatory Commission, Petition No. 07/SM/2018 (Suo-Motu), July 16, 2018, Order, available at http://www.cercind.gov.in/2018/orders/08.pdf.

3 United States Department of Energy Office of Energy Efficiency & Renewable Energy, *Wind Vision: A New Era for Wind Power in the United States*, available at https://www.energy.gov/eere/wind/maps/wind-vision.

4 United States Department of Energy Office of Energy Efficiency & Renewable Energy, *A New Vision for United States Hydropower*, available at https://www.energy.gov/eere/water/new-vision-united-states-hydropower.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

MEC-64	Resumé of Michael Milligan, Ph.D.
MEC-65	Milligan *et al*, Advancing System Flexibility for High Penetration Renewable Integration.
MEC-66	Milligan and Kirby, Utilizing Load Response for Wind and Solar Integration and Power System Reliability.
MEC-67	Denholm *et al*, The Role of Energy Storage with Renewable Electricity Generation.
MEC-68	Discovery response ELPCDE-9.76d.
MEC-69	Discovery response MECNRDCSCDE-5.25.
MEC-70	Minnesota Renewable Energy Integration and Transmission Study.
MEC-71	King *et al*, Operating Reserve Reductions from a Proposed Energy Imbalance Market with Wind and Solar Generation.
MEC-72	Milligan, Sources of Grid Reliability Services.
MEC-73	Milligan *et al*, Alternatives No More: Wind and Solar Power are Mainstays of a Clean, Reliable, Affordable Grid.
MEC-74	Compilation of Storage proposed in Integrated Resource Plans.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address certain aspects of the direct testimony of DTE Electric Company witness Judy W. Chang of the Brattle Group, and the report she co-authored and sponsored as Exhibit A-47. I will refer to Exhibit A-47 as the Brattle report.

Q. Please summarize your conclusions.

A. Based on witness Chang's testimony and the Brattle report, it appears that unreasonably conservative and speculative assumptions are driving their analysis. These assumptions are crucial to the report's conclusions, and I believe that, with more accurate and reasonable assumptions, the report would have found the Michigan power system in 2031 and 2040 to be not nearly as fragile as witness Chang claims it to be.

The Brattle report and witness Chang's testimony raise concerns about the potential ability of DTE's system to handle the increased penetration of clean energy expected by 2031 and 2040. Two of the main concerns referenced are ramping requirements and the Capacity Import Limit, or CIL. The CIL is a MISO construct representing a limit on the ability of MISO Zone 7 (most of lower Michigan) to import power from the broader MISO grid. The CIL is important because as long as there is a CIL, DTE will assert that it is limited in its ability to rely on the broader MISO grid.

The Brattle report models a future system that leans heavily on Ludington pumped storage and increased demand response. The Brattle report does not make definitive projections or make any attempt to quantify potential risks to the future power system, but instead raises a number of hypothetical scenarios that could possibly result in increased risk on a time horizon that extends to 2040. This future system does not "break" but the implication is that the system may be fragile and there "could be" risks, which are not clearly articulated. As one example of a hypothetical risk, witness Chang states at page 5 that "Zone 7's CIL could potentially decline…." At face value, this can be viewed as a risk; however, no effort is made to determine its likelihood. As will be seen below, the concern regarding CIL decline is not reasonable based on other evidence.

In this testimony I also highlight several incorrect assumptions made by Brattle in their report, along with additional concerns regarding the Chang testimony:

- MISO's assertion that the CIL will in fact increase, contrary to witness Chang's testimony.
- The level of CIL will have only a minor impact on ramping.
- Witness Chang ignores the fact that voltage support (and other grid services) can now be provided by wind and solar even when they are not generating power.
- Witness Chang repeatedly suggests that, regardless of the CIL, resources from outside Michigan may not be available or cost effective, while in fact the MISO market has been extremely effective at delivering low cost energy.
- Both witness Chang and DTE's IRP dismiss battery storage as an "emerging" technology, limiting its potential role in mitigating real or perceived system balancing challenges, when in fact utilities are including battery storage in significant amounts in IRPs across the country. There are over 5,000 MW of storage in over twenty different utility IRPs as of August 2019. In fact, the Commission has already approved a 450 MW installation of storage as a reasonable and prudent part of the IRP of Consumers Energy.[5] Given the recent reduction in battery costs, combined with the 2040 time horizon of DTE's IRP, DTE should provide a more robust suite of modeling scenarios and analyses of the potential of storage to help integrate renewables. For example,

[5] Case No. U-20165, Order Approving Settlement Agreement (June 7, 2019) and Exhibit A-2, p 166.

alternative sizes and mixes of battery storage, potentially at different locations on the grid, should have been modeled. In addition, it would be insightful to understand what role is played by different battery characteristics, such as the number of hours that the battery is capable of providing full output from a fully-charged state.[6]

- Witness Chang's testimony incorrectly implies that "around the clock" reliability is new, when in fact grid operations and planning methods ensure reliability each hour of the day and year.

- The modeling described by Chang does not apparently accommodate:
  - Flexibility (ramp, economic dispatch, regulation) provided by wind and solar energy
  - Recognition of the rapidly changing cost and availability of battery storage, and the trajectory to 2040
  - Something similar to the dispatchable intermittent resource (DIR) program currently required of all wind resources in MISO, that put wind on economic dispatch
  - Something similar to MISO's flexibility ramp constraint

[6] See for example Denholm et al (2019) The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States, available at: https://www.nrel.gov/docs/fy19osti/74184.pdf.

Because these important factors were not considered in the Brattle Report or the modeling described by the Chang testimony, their conclusions stating that DTE would have difficulty integrating the renewable additions through 2040 cannot be supported.

II. SHORTCOMINGS IN THE BRATTLE REPORT MODELING

Q. Describe the Brattle report's assumption regarding the dispatchability of renewable resources.

A. The modeling performed in the Brattle report assumed that wind and solar would not be "dispatchable" and therefore able to contribute to ramping needs.[7] That was an error. In fact, wind in MISO is already on dispatch, as part of MISO's successful Dispatchable Intermittent Resource (DIR) program.[8] As for solar, a recent report from E3, First Solar and TECO shows that making solar dispatchable reduces costs and curtailment.[9] Ramping is primarily an economic issue, not a reliability issue, and is easily solved by making wind and solar dispatchable.

Q. Did the Brattle report consider the inclusion of ramping constraints in economic dispatch?

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[7] See Brattle report p. 10: "From a resource adequacy perspective, intermittent renewable generation generally provides a limited contribution toward resource adequacy. In contrast, dispatchable generation tends to provide a greater contribution toward resource adequacy per MW of installed capability, compared to intermittent renewable generation."

[8] MISO FERC Electric Tariff, Module A. Available at https://cdn.misoenergy.org/Tariff%20-%20As%20Filed%20Version72596.pdf

[9] Investigating the Economic Value of Flexible Solar Power Plant Operation. Energy and Environmental Economics, Inc. October 2018. Available at https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf

A. No. Another tool that is apparently overlooked in the Brattle modeling is introducing ramp constraints into the modeling. Over the past several years, MISO has developed a ramping constraint and included it in the economic dispatch process.[10] This process ensures that flexible resources with ramping capability are dispatched in a way so as to ensure their ramping capability is available when it is needed.[11] This type of process has reduced ramping difficulties in MISO and the California Independent System Operator (CAISO), but it does not appear that it was part of the Brattle modeling.[12] This ramp capability product modifies the usual merit order dispatch stack so that ramping capability can be made available when needed. Between its implementation May 1, 2016 through November, 2016, MISO found that using this ramp capability product resulted in:

- Reduction in average real-time locational marginal prices (LMP), especially during reserve scarcity conditions (p 5 and 6)
- Reduction in LMP variability (p5)
- Annualized production cost saving of $4.2M. (p5)

Ignoring this ramp-constrained dispatch as the Brattle report did results in the identification of more ramping difficulties that would not exist in practice.

Q. Did the modeling for the Brattle report take into account changing future load shape?

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[10] https://www.misoenergy.org/stakeholder-engagement/issue-tracking/ramp-capability-product-development.

[11] The role of market design and potential new ancillary service products, along with other sources of flexibility are discussed in Exhibit MEC-65, Milligan, Frew, Zhou, and Arent (2015) Advancing System Flexibility for High Penetration Renewable Integration.

[12] MISO Market Subcommittee: Ramp Capability Product Performance Update. Nov 29, 2016. Available at http https://cdn.misoenergy.org/20161129%20MSC%20Item%2005f%20Ramp%20Capability%20Post%20Implementation%20Analysis74816.pdf.

A. No. The modeling done by Brattle does not take into account changes in the future load shape driven by electrification of transport and buildings, and the modeling does not take into account flexible load (such as EV charging).[13] Michigan's goals for building and transportation electrification will translate into significant deployment by 2030.[14] The changes in the load shape and the inclusion of flexible load are important because they increase the value of wind and solar. Early research into the timing and relative magnitude of vehicle charging indicates that much of the charging will generally occur in the evening or night-time hours, although there will be ~10% of the charging during the day. When some type of smart charging technology is implemented, it would be possible for EVs to provide various grid services, which could include a ramping or ramp-like product by altering the charge rate of a suite of vehicles. Although this is not currently available, it is likely that EVs will be able to provide grid services in the near term, and especially by 2040 if the economics are favorable. While the Brattle modeling included Demand Response (DR), it was mostly traditional capacity-based DR rather than the types of flexible load DR that would help smooth ramping requirements.

Q. Did the Brattle report model the correct solar profiles?

A. No. The modeling done by Brattle used fixed-tilt solar instead of tracking solar in its analysis.[15] Brattle's modeling conflicts with DTE's Strategist modeling of solar resources,

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[13] Exhibit MEC-66, Milligan and Kirby (2010) Utilizing Load Response for Wind and Solar Integration and Power System Reliability, shows the impact of various types of demand response on the load shape. Exhibit MEC-67, Denholm, Ela, Kirby, and Milligan (2010) The Role of Energy Storage with Renewable Electricity Generation, provides insights as to the role of storage to change load shape and help integration renewables.

[14] See for example, MPSC Issue Brief, Utility Electric Vehicle Pilot Programs, available at: https://www.michigan.gov/documents/mpsc/EV_Pilot_Issue_Brief_05-02-2019_653974_7.pdf.

[15] Exhibit MEC-68, discovery response ELPCDE-9.76d.

which exclusively assessed single-axis tracking resources.[16] I expect much of the new solar installed in Michigan to use tracking, as its market share nationally has grown to 80 percent. Tracking solar has a production profile that generates more energy later in the day, which would reduce evening ramping requirements, a major concern in witness Chang's testimony.

III. OTHER CONCERNS ABOUT THE BRATTLE REPORT AND WITNESS CHANG'S TESTIMONY

Q. What are your concerns about the Brattle report's treatment of MISO and the wholesale market?

A. Brattle appears to downplay the role of MISO and the wider grid. DTE is part of the larger MISO grid that provides balancing. Witness Chang states there is a lack of "local ramping capability" and then voices a concern regarding DTE's ability to ramp fast enough. The fact is that ramping requirements decline on a per-unit basis when aggregated over a large region, and ramping capability increases linearly. This means that effective ramping can be compiled from the entire MISO market, and these could complement and even replace some local ramping in DTE's service territory when it is economic. Witness Chang more or less acknowledges this point in discovery response MECNRDCSCDE-5.25a.[17] Additionally, when wind/solar are generating power, many existing plants in DTE's service territory will be dispatched down, and therefore have more up-ramp capability during these

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[16] Revised Direct Testimony of Laura Mikulan, p. 66.

[17] Exhibit MEC-69, discovery response MECNRDCSCDE-5.25.

periods. As wind/solar output increases to a high level relative to installed capacity, there is less and less likelihood that DTE would need down-ramp capability.

The Brattle report at page 7 also expresses concern regarding the "growing reliance on imports from MISO." In fact, the market has been widely shown to be effective, and utilities can become more effective in procuring energy via the MISO market, helping to keep rates low. The Day-Ahead Reliability Unit Commitment process at MISO ensures that the entire system will have sufficient resources to maintain balance.[18] And MISO's continual resource adequacy process ensures that shortfalls in adequacy can be identified before becoming binding.

Q. Is DTE's concern about relying on the market justified?

A. I see no reason to think that increasing DTE's reliance on the market should be a cause for concern.

First, DTE argues that while resources may be available from the MISO market, they may not be cost-effective. The MISO market is voluntary, and if a less expensive resource can be chosen by DTE, then it could be used. By definition the market price is the lowest price available. Market pricing is efficient pricing.

During peak periods, which presumably are those that witness Chang is worried about in the context of resource adequacy, prices are generally higher than at other times. But the existence of high market prices does not imply that market resources are not cost-effective. A resource is generally considered to be "cost-effective" if it can provide the needed

[18] See MISO Tariff, Module C, Section 40.1.

service(s) less expensively than any other available resource. If DTE is in a position that it must make a purchase from MISO, and if DTE has no other option, then using the MISO resource is the only, and therefore cost-effective measure available. If DTE were to decide that building a new resource and absorbing both its capital cost and operating cost is less expensive than relying on the market, then it should pursue that option if it can demonstrate a cost/benefit advantage. But paying a relatively "high" price to the market to procure something that has no alternative way of being procured cannot be judged to be not cost-effective.

It is important to acknowledge that renewable energy such as wind/solar have a near-zero marginal cost. This means they are first, or among the first, in the dispatch merit order. As such, the wind/solar will displace some existing generation in the economic dispatch, compared to a no wind/solar case. Purchases from MISO will rarely, if ever, be available to DTE at a near-zero price. This means that it is likely that DTE will *reduce* its purchases from the MISO market as its use of renewables increases. An example of this can be seen in the Minnesota Renewable Integration and Transmission Study (MRITS), for which I was on the technical review committee.[19] The MRITS study examined 40% and 50% renewable energy penetrations in Minnesota, and carried out detailed operational simulations of the Minnesota utilities while also representing MISO, so that a realistic analysis could inform policy-making in the state. The MRITS study is relevant to the DTE case because both DTE and Minnesota[20] are in the MISO market, and therefore they interact with MISO in a similar way. MRITS did not find any ramping difficulties, even at

[19] Exhibit MEC-70.

[20] Minnesota has several utilities, each of which is a MISO member.

50% renewable energy in the state. For example, at page 1-7, MRITS found that: "With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO, production simulation results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission upgrades, expansions and mitigations to accommodate the additional wind and solar resources." MRITS also discussed specific scenarios at pages 7-19 to 7-21. MRITS also found that Minnesota reduced its market purchases from MISO as the renewable energy penetration rate increased.

However, the market interaction is important because ramps can be "settled" across a larger electrical footprint. This was the finding of an NREL Technical Report that I co-authored.[21] Therefore, it is incorrect to assume that DTE will have greater reliance on the MISO market relative to energy purchases.

Q. If DTE were to decide that MISO resources were too costly, would the company have any options?

A. Yes. These options include, but are not limited to, additional storage coupled with renewables. This option is currently very cost-effective, as several recently announced power purchase agreements include storage with renewables (Wind and Solar) at roughly

[21] Exhibit MEC-71. King, J.; Kirby, B.; Milligan, M.; Beuning, S. (2012). Operating Reserve Reductions from a Proposed Energy Imbalance Market with Wind and Solar Generation in the Western Interconnection. 90 pp.; NREL Report No. TP-5500-54660.

1.3 cents per kWh incremental cost.[22] Witness Chang explicitly did not consider the option of adding storage, which further reduces the validity of the report's conclusions.

Q. Are the constraints on adding more renewable generation discussed in the Brattle report reasonable?

A. No. The Brattle report makes a poor case for constraints to adding more variable renewable generation to the Michigan power system, arguments regarding future CIL aside. The lack of accounting for the flexibility contribution from wind/solar resources may be contributing to the Brattle report's concern regarding DTE's ability to effectively integrate 40% annual energy from renewables by 2030. Wind and solar resources can provide many grid services, including disturbance ride-through, reactive and voltage support (even when not generating real power), can slow and arrest frequency decline, can help stabilize and restore frequency, provide frequency regulation, and are dispatchable. I summarized these services in a publication in The Electricity Journal.[23] Yet all of these benefits of wind and solar were either entirely ignored or unreasonably discounted in the Brattle report.

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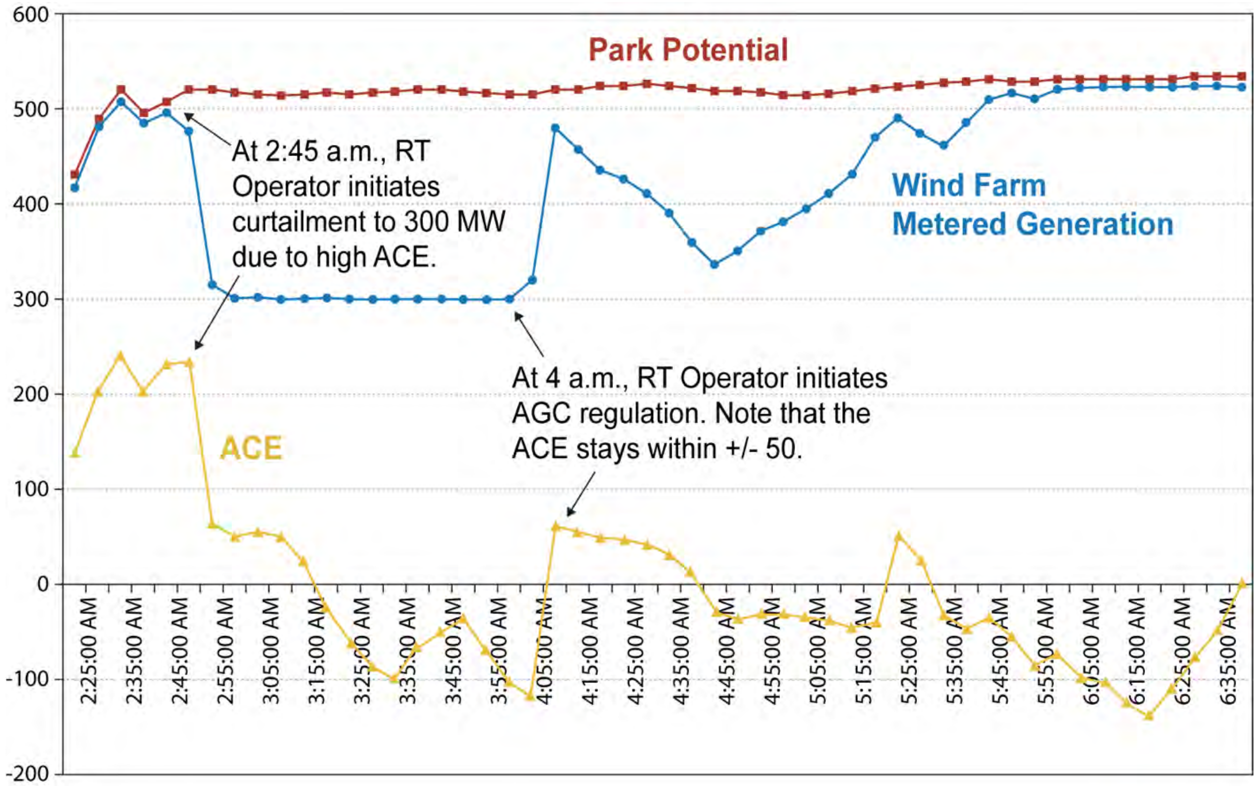
[22] See: WFEC, NextEra Energy Resources, planning largest combined wind, solar & energy storage facility in U.S, available at: https://static1.squarespace.com/static/59d53b2a3e00be7a668b1dd6/t/5d391e3be900dd0001a1a2b9/1564024380771/Skeleton+Creek+wind+solar+storage+announcement+-+WFEC.pdf;

Kent County's Supplemental Environmental Impact Report for the Eland 1 Solar Project, available at: https://psbweb.co.kern.ca.us/UtilityPages/Planning/EIRS/eland1_solar/DEIR/eland1_solar_dseir_vol1.pdf; and

Nevada Power Company's IRP Application from June 24, 2019, available at: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2019-6/39888.pdf.

[23] Exhibit MEC-72, Milligan, M. (2018), Sources of Grid Reliability Services. Electricity Journal, Vol 31, Issue 9. Pp 1-7. November.

The chart below provides an example of wind power providing both automatic generation control (AGC, frequency regulation) and economic dispatch:[24]



The graph is from Xcel Energy in Colorado, and it shows a period of time during which the system operator had difficulty in maintaining area control error (ACE) within limits. During the nighttime in question, coal and other thermal units were at their minimum generation and there was 500 MW from the wind plant. The thermal plants could not be turned off because they would be needed the next day and would have taken too long to turn off and start up again. Instead, the operator utilized advanced controls of the wind plant (multiple wind turbines). At 2:45 the operator dispatched wind energy down from

[24] Excerpted from Exhibit MEC-73, Milligan, M.; Frew, B.; Kirby, B; Schuerger, M.; Clark, K.; Lew, D.; Denholm, P.; Zavadil, B.; O'Malley, M.; Tsuchida, B. Alternatives No More: Wind and Solar Power are Mainstays of a Clean, Reliable, Affordable Grid. IEEE Power and Energy Society, Power and Energy Magazine. Nov/Dec 2015.

about 500 MW to 300 MW. Although that helped reduce ACE, the operator needed to bring ACE up, and generally to keep ACE within approximately 100 MW (up or down) from 0. So, at 4:00 the wind plant is put on automatic generation control (AGC) so that it could respond every 4-6 seconds and keep ACE within nominal bounds. The graph shows that ACE improved once wind was put on AGC. Xcel/Colorado places wind energy on AGC or economic dispatch when needed, and it is easily integrating a significant level of wind energy on their system, approximately 23% of annual electricity demand. This is expected to increase to 42% by 2022.[25]. Although this example shows some of the flexibility available from wind power plants, similar capabilities can be found in solar power and batteries.[26]

Q. Does the Brattle report raise concerns about the operation of wind power plants in extreme cold?

A. Yes, but without analysis and these concerns are also overstated. The Brattle report at page 24 states that during the January 2019 Polar Vortex, a significant amount of wind generation in MISO could not operate due to the adverse effects of the freezing conditions on wind generation equipment. However, as the Commission noted in its Statewide Energy Assessment:

> Many of Michigan's wind turbines are equipped with cold weather packages that include specially formulated oils, software packages and anti-icing treatments for blades. Operators of thermal units have cold weather protocols that include secondary heaters for thawing frozen components, regular turning of coal piles, and pre-firing of idle generation prior to cold weather events. With appropriate forecasting of temperatures and

[25] https://www.xcelenergy.com/energy_portfolio/renewable_energy/wind/co_wind_power.

[26] Exhibit MEC-73.

anticipated load, the impact of events such as PV19 can be greatly reduced.[27]

Q. Please describe your concerns regarding the Brattle report's view of future CIL and its role in renewable integration by DTE.

A. Witness Chang's testimony at pages 6-7 identifies a concern around the CIL and ramping capabilities which is overstated and will be mitigated by several factors over the coming decade.

First, contrary to witness Chang's testimony that the CIL is likely to decrease, work presented by MISO indicates the CIL will instead increase to 4,287 MW by 2023-24.[28]

Second, witness Chang's testimony fails to acknowledge that reactive power for voltage support can be supplied by the power electronics embedded in inverter-based resources like wind, solar, and batteries, even if not generating power.[29]

Third, the CIL should not significantly constrain the ramping capability available from the MISO market. For example, if net demand is ramping up quickly (wind/solar are ramping down and cannot easily be controlled), this increases the need for upward ramping from resources obtained via the MISO market – either via the ramp constraint in MISO's dispatch, or from energy purchases on the 5-minute time step. These imports could be temporary (if economic), and they would allow internal DTE resources to ramp more

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[27] Michigan Statewide Energy Assessment Initial Report (July 1, 2019), p 54, available at: https://www.michigan.gov/documents/mpsc/Sea_Initial_Report_with_Appendices_070119_659452_7.pdf.

[28] Exhibit A-47, Pages 6-7.

[29] Exhibit A-47, Page 7.

slowly until they "catch up", at which point internal resources can replace MISO imports. At this point if the ramp is over then the situation has been successfully managed. If the ramp has not ended, the increasing internal resources may be enough to partially fulfill the ramping need.

For example, suppose the DTE net demand is ramping up at 20 MW/min, or 1200 MW/hour. Internal resources can ramp at 10 MW/min. Thus, MISO could provide 10 MW/min, or 600 MW/hour, matching DTE resources. If the CIL = 4,000 MW, and if 2,000 MW is being imported at the beginning of the ramp, then an additional 2,000 MW is available for ramping. At 600 MW/hour the ramp could be sustained for just over 3 hours. Once DTE resources could catch up and replace the imported ramp, then the import level could be returned to 2,000 MW.

Alternatively, the net demand may be ramping down quickly, caused in part by a fast up-ramp of wind/solar. In that case, regardless of the CIL, wind turbine blades can be feathered, and/or the power electronics in the inverters can limit the up-ramp of the wind/solar to mitigate the ramp.

Q. How does witness Chang approach storage?

A. Both witness Chang and DTE's IRP dismiss battery energy storage as an "emerging" technology and assume no battery storage in their plan, despite the broad realization that battery storage has a significant role to play in the grid, especially with balancing. To the contrary, battery storage is here. Over 1 GW of battery storage is already in operating today in the North American grid.[30] There are nearly 5 GW of proposed battery storage projects in utility IRPs across the country, a number that doubles if you include a recent groundbreaking plan by the Tennessee Valley Authority. These plans are compiled in Exhibit MEC-74. They include 450 MW of storage in Michigan planned by Consumers Energy and approved by this Commission.[31] Witness Chang's testimony raises vague concerns about flexibility and ramping in the future, but leaves out a technology that will likely be deployed in the timeframe of the IRP, and that would alleviate many of the concerns raised.

Q. **Can you summarize your testimony?**

A. Yes. The Chang testimony implies that DTE's renewable energy objectives up thru 2040 will be quite challenging. There are several areas of concern pointed out in the testimony; however, many of these either oversell the fragility of the DTE system, or do not account for emerging best-practices that are already in place in other parts of the U.S. – and even within MISO itself. Examples include:

- Concern that CIL will be reduced in the future when MISO says it will increase
- CL is a significant contributor to obtaining ramping from MISO; it is not
- Voltage support cannot be provided by renewables, and yet wind, solar, and batteries can provide this even when not generating real power
- Battery technology will not be able to significantly contribute to DTE by 2040, when in fact Consumers Energy has significant levels of storage in its IRP

[30] S&P Global Platts. https://blogs.platts.com/2019/03/28/us-expansion-power-battery-storage.

[31] *Id.*

- Does not recognize wind and solar energy's ability to ramp, be dispatched, perform AGC, and does not recognize that DIR is currently in place in MISO for wind energy
- Is concerned about having significant ramping but does not model a flexi-ramp or other ramping product that allows for changing the economic dispatch to maximize ramping capability from the thermal fleet, as currently done in MISO
- Does not recognize the potentially significant changes in load shape and flexibility services from future EV
- Implies more reliance on MISO imports, when a similar study for Minnesota at wind penetrations up to 50% of demand show that MISO imports will be reduced as local renewable generation increases

For each of these reasons, the concerns raised by witness Chang and the Brattle report are overstated and weakly supported, and should not be accorded much weight by the Commission.

Q. Does this conclude your testimony?

A. Yes.

Michael R. Milligan, Ph.D.
Milligan Grid Solutions, Inc.

Michael R. Milligan, Ph.D.

Education and Training

Ph.D., Economics, University of Colorado, Boulder
M.A., Economics, University of Colorado, Denver
B.A., Mathematics, Albion College, Albion, MI

Professional Experience

Dr. Michael Milligan recently retired as Principal Researcher at the National Renewable Energy Laboratory, and he is now an independent power system consultant. He has more than 30 years' experience in analysis and modeling the bulk power system, and more than 25 years focusing on the impacts of wind and solar generation integration into the bulk system. He is the author/coauthor of more than 220 journal articles, conference papers, technical reports, and book chapters on topics that include the physical impacts of variable generation on power system operations, reserves, economics, and resource adequacy. He has also published articles and book chapters on variable generation and energy markets, the impacts of variability pooling and wide-area energy management, conditional firm transmission potential in the West, the application of genetic algorithms and fuzzy logic to wind power plant location optimization, and short-term wind forecasting. He has given papers and presentations in in China, Japan, India, Portugal, Spain, Italy, France, Ireland, England, Scotland, Germany, Netherlands, Malaysia, Canada, Denmark, Sweden, Norway, and Finland, and has developed methods that are used for many aspects of integration analysis.

Dr. Milligan has provided expert testimony in public utility proceedings and workshops around the United States. He advises the Western Interstate Energy Board, was a member of the Western Governors' Association's Clean and Diverse Energy Advisory Committee (CDEAC), and he was the primary author of the wind integration and scenario chapters. He led and contributed to multiple projects analyzing the potential benefits of the proposed Energy Imbalance Market in the West, including reserves and ramping analysis and electricity production simulation. This market is now operating and expanding in the Western Interconnection—parts of California, Nevada, Arizona, Utah, Wyoming, Idaho, Oregon, and Washington are participating. Since its launch in 2014 the EIM has enhanced grid reliability and reduced costs for the market participants, and it improves the ability of the bulk power system to effectively manage the increasing levels of wind and solar power, now and in the future.

Michael has advised the 21st Century Clean Power Partnership (http://www.21stcenturypower.org/projects.cfm), a multilateral effort of the Clean Energy Ministerial, operated by the Joint Institute for Sustainable Energy Analysis. In this role, he has provided guidance to governments and utilities in China, India, South Africa and others on methods to improve the ability of their power systems to efficiently integrate renewable energy. He most recently served as a principal technical advisor to a large-scale renewable energy integration study in India.

Dr. Milligan is an internationally recognized expert in loss-of-load probability analysis and resource adequacy. He led the North American Electric Reliability Corporation (NERC) Task Force for Capacity Value of Variable Generation and co-led the Institute of Electrical and Electronics Engineers (IEEE) Wind Power Coordinating Committee Capacity Value Task Force. He advises regional transmission organizations and utilities on resource adequacy methods and has advised many power system industry task forces and working groups. He was a charter member of the NERC Integrating Variable Generation Task Force and Essential Reliability Services Task Force (now Working Group) and the Western Electricity Coordinating Council's (WECC's) Variable Generation Subcommittee; and has served on multiple WECC committees and has been a key contributor to multiple NERC and WECC reports.

Michael led the Bulk Electric Power System Task Force for NREL's groundbreaking Renewable Electricity Futures study (http://www.nrel.gov/analysis/re_futures/). On behalf of the U.S. Department of Energy, he led the Power System Integration and Transmission task forces for the Wind Vision (https://energy.gov/eere/wind/wind-vision) and the Hydro Power Vision (https://energy.gov/eere/water/new-vision-united-states-hydropower) studies.

Dr. Milligan has advised many power system industry and utility commissions, including the Mid-Continent Independent System Operator; New York Independent System Operator; Independent System Operator of New England, California Independent System Operator; Xcel Energy (Minnesota and Colorado); Portland General Electric; Arizona Public Service; PacifiCorp; Grant County Public Utility District; Nebraska Public Power District; Western Electricity Coordinating Council; Western Interstate Energy Board; North American Electric Reliability Corporation; British Columbia Hydro; Hydro Quebec; Alberta Electric System Operator; commissions in California, Alaska, Minnesota, and Colorado; and the Public Utility Commissioners' (PUC) Energy Imbalance Market (EIM) group in the West. He has also provided technical reviews for several National Renewable Energy Laboratory (NREL) studies, including the Western Wind and Solar Integration Study, the Eastern Wind Integration and Transmission Study, and the Nebraska Statewide Wind Integration Study. Many of these studies are available at www.esig.energy.

Dr. Milligan has presented at hundreds of technical conferences, stakeholder meetings, and webinars. Audiences range from experts in the power system industry to groups with little background in power system operations, design, or markets. He has regularly presented at the Utility Variable-Generation Integration Group (UVIG, now ESIG), including as a keynote speaker on variable-generation integration state of the art, and is on the faculty for the UVIG Short Course on Variable Generation Integration, offered bi-annually. His sustained participation on the International Energy Agency Task 25 for large-scale wind integration (https://www.ieawind.org/task_25.html) helped launch a continuing series of international technical papers on integration issues. International collaborations include papers and projects with VTT Finland, Royal Institute of Technology Sweden, DTU Delft Netherlands, University College Dublin, University of Castilla-La Mancha Spain, LNEG Portugal, Energinet.dk Denmark, ECAR Ireland, Sintef Norway, and Kansai University Japan. He was an invited panelist in 2012 to the Royal Irish Academy in Dublin and an invited keynote speaker at the 2011 Power System Computation Conference in Stockholm. He has hosted visiting researchers from Germany, Ireland, Spain, Australia, and France, and has served on Ph.D. dissertation committees and mentored Ph.D. students at MIT, Stanford, University of Colorado, University College Dublin, Northern Arizona University, University of Delaware, and University of California Berkeley.

In response to the Federal Energy Regulatory Commission (FERC) Notice of Inquiry, he provided comments based on research results to FERC. Based in part on this input, FERC eventually issued Order 764, which directs the conditions under which a transmission provider can assess integration charges for variable generation. His work on cost-causation and integration charges has also influenced the development of integration rates and resulted in an international paper with IEA collaborators.

Awards

- Energy Systems Integration Group (formerly UVIG): Lifetime Achievement Award for sustained contributions to wind and solar power system integration studies. 2018.
- Utility Variable-Generation Integration Group: Technical Achievement Award for sustained advances in renewable energy integration methods. 2012.
- National Renewable Energy Laboratory: H.M. Hubbard Award for two decades of outstanding research contributions and leadership in research and technology, 2010.
- National Renewable Energy Laboratory, President Award (team, 2010)
- National Renewable Energy Laboratory's National Wind Technology Center achievement awards in 2008 (team) and 2009.
- Best paper awards, including papers at the 12th and 13th International Workshops on Large-Scale Integration of Wind Power.

He is a Senior Member of the IEEE Power and Energy Society and a member of the American Economic Association.

Employment History

2017 – present:	Independent Power System Consultant
2015-2016:	Ph.D. advisor, University of California, Berkeley
2014 – Present:	Adjunct Professor and Ph.D. Advisor, Northern Arizona University
2013 – 2014	Ph.D. advisor, MIT, Cambridge, MA
2013 – 2015:	Adjunct Professor, University of Denver
2009 – 2013:	Ph.D. advisor (3), University College, Dublin
2008 – 2009:	Ph.D. advisor, University of Maryland
2008 – 2017:	Principal Researcher, Power Systems Engineering Center, NREL

2006 – 2007: Ph.D. advisor, University of Colorado, Boulder

1992 – 2008 Consultant, Power System Integration, NREL

1982 – 2008: Professor, Economics (1998–2008); Professor, Computer Science and Mathematics (1995–1998); Professor (1982–1995) and Chair (1990–1992), Computer and Information Science Department, Front Range College

1975 – 1982: Power system planner, Tri-State G& T. Developed software for load forecasting and resource analysis. Developed long-range planning models and documents for power and energy requirements, resource utilization, and long-term planning

Technical Articles, Reports, Book Chapters, FERC Filings

1. Milligan, Michael, Sources of Grid Reliability Services. To Appear.

2. Reply Comments of Michael Milligan, Ph.D.: Grid Resilience in Regional Transmission Organizations and Independent System Operators. Docket AD18-7-000. Available at http://www.milligangridsolutions.com/milligan%20ferc%20comments%20AD%2018-7-000%20from%20FERC%20web.pdf. 2018.

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Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol 1 – National Study. National Renewable Energy Laboratory, 2017. https://www.nrel.gov/docs/fy17osti/68530.pdf

7. Aaron Bloom, Bethany Frew, Aaron Townsend, Erik Ela, Todd Levin, Audun Botterud: **Electricity Markets, Renewable Generation and Software Agents: Traditional and Emerging Market Designs.** Springer, 2018. https://www.springer.com/us/book/9783319742618

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Advancing System Flexibility for High Penetration Renewable Integration

Michael Milligan, Bethany Frew, and Ella Zhou
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Joint Institute for Strategic Energy Analysis

This work is a part of the China Grids Program for a Low-Carbon Future, supported by the Children's Investment Fund Foundation.

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Preface

China now installs more renewable electricity each year than any other country in the world. Much of this is *variable* renewable electricity, especially wind and solar generation. A growing body of experience exists from around the world on how to plan and operate electricity grids with high penetrations of variable renewable electricity. China is actively contributing to this body of experience given the rapid growth in renewable electricity deployment there, while at the same time digesting experiences from other countries.

This report is part of a series describing technical collaboration between the National Renewable Energy Laboratory (NREL), the China National Renewable Energy Center (CNREC) along with other key research institutes in China, and the Danish Energy Agency. The collaboration focuses on sharing experiences in the planning, deployment and operation of high-penetration renewable electricity grid systems. The Children's Investment Fund Foundation in the United Kingdom is funding this five-year collaboration.

The core element of the collaboration during this first year was a series of expert engagements in China to share technical knowledge and experience on four key topics:

1. Comprehensive energy scenario design and modeling
2. Renewable energy (RE)-friendly grid development
3. Power system flexibility
4. Boosting distributed generation of RE.

These engagements built on and significantly expanded existing collaboration between the Danish Energy Agency and CNREC experts.

This report summarizes some of the issues discussed during the engagement on the third topic listed above. By design, the focus is on flexibility options used in the United States. Exploration of whether and how U.S. experiences can inform Chinese energy planning will be part of the continuing project, and will benefit from the knowledge base provided by this report. We believe the initial stage of collaboration represented in this report has successfully started a process of mutual understanding, helping Chinese researchers to begin evaluating how lessons learned in other countries might translate to China's unique geographic, economic, social, and political contexts.

We look forward to continuing the collaboration for the remaining four years and building on these initial successes.

Acknowledgments

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This work is a part of the China Grids Program for a Low-Carbon Future, supported by the Children's Investment Fund Foundation.

Acronyms

BA	balancing area
CAISO	California Independent System Operator
CIFF	Children's Investment Fund Foundation
CPP	critical peak pricing
DIR	dispatchable intermittent resource
DR	demand response
EIM	energy imbalance market
ELCC	effective load carrying capability
ERC	effective ramping capability
ERCOT	Electric Reliability Council of Texas
EUE	expected unserved energy
FERC	Federal Energy Regulatory Commission
GW	gigawatt
IRRE	insufficient ramping resource expectation
ISO	independent system operator
LOLE	loss of load expectation
LOLH	loss of load hours
LOLP	loss of load probability
min-gen	minimum generation
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
PFD	period of flexibility deficit
PJM	PJM Interconnection
PTC	production tax credit
RTO	regional transmission organization
RTP	real-time pricing
SPP	Southwest Power Pool
TOU	time of use
VG	variable generation

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1 Introduction

The goal of typical modern electricity systems is to ensure reliable delivery of electricity at an affordable cost to consumers. Flexibility is the ability of a system to respond to variability and uncertainty of demand and supply. Loads change, sometimes in unpredictable ways, and conventional generators may be unavailable due to unexpected events such as natural disaster or mechanical failure. Sources of variable generation (VG), such as wind and solar power, provide power that changes over time based on weather patterns and paths of the sun, which may introduce faster changes in aggregate supply than in systems without VG. As a result, VG increases the response requirements from conventional generators and load, even though it does not increase the overall capacity requirements (Milligan et al. 2011). The relationship between integration of renewable energy and flexibility has received considerable attention in recent years (see for example Holttinen et al. 2013). Grid integration studies in the United States have shown that system flexibility needs increase significantly when more than about 30% of a system's annual electricity demand is provided by VG, assuming certain operational improvements with the increase of VG toward this level (Denholm and Hand 2011). Similar conclusions are drawn in Chinese studies of wind integration, showing a jump in system flexibility issues after 30% penetration of wind (Li 2015). Due to operational and transmission constraints, however, regions such as Jilin and Xinjiang have high levels of wind curtailment even when the penetration level is far less than 30%. This report, along with the Children's Investment Fund Foundation (CIFF) project grid development report *'Renewables-Friendly' Grid Development Strategies* (Hurlbut et al. 2015), will address these issues and lay out the strategies for accommodating a high penetration of renewables.

The need for flexibility applies to all time scales, ranging from the many years that comprise the planning and investment time horizon, to operational planning that may involve days to months, and to operation itself, which encompasses periods as long as a few days to as short as sub-seconds. The shortest time intervals are those in which inertial response provides the first line of defense against imbalance or frequency excursions—we will not address these issues in this report. We do note that wind turbines and solar inverters can now provide simulated primary frequency response and inertial response, along with automatic generation control, and can even respond to dispatch signals. Therefore, wind and solar power are capable of providing some of the flexibility needed by the system; however, these may not be sufficient nor the most economic sources of flexibility. In the discussion that follows, we focus on other sources of flexibility, noting that wind and solar power can provide some of this flexibility given improved power electronics and controls.

This report describes several potential sources of flexibility that can help maintain system balance with high levels of VG. The analysis of flexibility needs falls under the general task of planning for future power system needs, which is itself a broad and complex topic. With high levels of VG, the planning process does not fundamentally change, but rather is augmented so that the characteristics of this generation mix can be properly assessed. That is the focus of this report: to describe sources of flexibility that can be evaluated in the planning process to help the power system operator maintain system balance.

We describe both physical flexibility and institutional flexibility. Physical flexibility, which is the physical capability of power system components to respond to changes in demand and supply, is a necessary but not sufficient condition to achieve flexible operations. The other required condition is institutional flexibility, which is the ability to deploy the physical flexibility when needed and when it is available through operational practices and/or market design structures. Most sources of flexibility include at least some component of physical and institutional flexibility. The importance of institutional flexibility must not be overlooked. In many cases, physical flexibility can be muted by institutional barriers. This is true even without the presence of VG. For example, as we discuss later, physical flexibility can be dampened by something as simple as the market settlement process, in spite of what might otherwise be a good market design. Table 1 summarizes the sources of flexibility that are discussed in this paper and the companion CIFF program paper entitled *'Renewables-Friendly' Grid Development Strategies* (Hurlbut et al. 2015), as well as additional options (see Milligan et al. 2009), and indicates their *dominant* categorization (physical, institutional, or both). We categorize flexibility measures as "physical" if their dominant flexibility provision is based on inherent physical characteristics of that technology or system component. For example, a robust electrical grid relies on transmission lines with sufficient capacity and redundancy; geographically dispersed VG involves building VG resources across large geographic areas to smooth out the aggregated supply.

Institutional measures provide flexibility primarily through market designs or operational practices that are generally technology-agnostic. Flexibility measures that require physical flexibility from the system components as well as proper operational, regulatory, or market structures are categorized as "both." For example, regional transmission planning for economics and reliability requires planning for a robust transmission network that connects flexible generators as well as the proper coordination and market signals to extract that flexibility within the network; VG forecasting effectively integrated into operations requires accurately forecasting the variability of VG and the operational practices to best utilize that information; and primary frequency response, inertial response, and response to dispatch signals with new VG technologies rely on operational and market structures to capture the flexibility from these physical attributes. Additional examples within each category are discussed in depth in Section 5.

Table 1. Flexibility Measures to Assist with the Integration of VG

Flexibility Measure	Physical or Institutional?	Discussed in this Paper	Discussed in *Grid Development* Paper
Larger balancing areas	Both	✓	
Access to neighboring markets	Both	✓	
Faster energy markets	Institutional	✓	
Regional transmission planning for economics and reliability	Both		✓
Robust electrical grid	Physical		
Improved market design	Institutional	✓	
Demand response	Both	✓	
Geographically dispersed VG	Physical		
Strategic VG Curtailment	Both	✓	
VG forecasting effectively integrated into operations	Both		✓
New flexibility ancillary services products	Institutional	✓	✓
Sufficient reserves for VG event response	Physical		✓
Flexible conventional generators	Physical	✓	
Primary frequency response, inertial response, and response to dispatch signals with new VG technologies	Both		
Storage	Physical	✓	

In this report, we first provide an overview of the current system planning process employed in the United States and additional considerations for higher penetration of VG. Then we discuss the process for assessing the overall system's need for flexibility, which includes (1) quantifying the system's flexibility requirements, (2) quantifying the existing system's ability to supply the needed flexibility, and (3) selecting sources of additional flexibility to satisfy any flexibility deficiency. Cost-benefit and additional considerations are also discussed. The report concludes with high-level lessons-learned for consideration by power system planners. There are many details of how the system is operated, coupled with potential market design elements that are complex and are not considered in this initial report. Instead, this report provides a high-level description of flexibility needs in the context of the general resource planning process. Here we do not consider other elements of planning such as power flow, dynamic stability, or transmission planning.

2 Planning for Variable Renewable Energy Sources

In many countries, resource planning has historically been accomplished by projecting future demand patterns, and evaluating one or more potential resource combinations to determine the resource mix that best accomplishes the competing objectives of maintaining reliability and minimizing cost, subject to various risk preferences and regulatory constraints. A central focus of this process is how to achieve and maintain resource adequacy—the level of installed capacity that is necessary to serve demand at all time periods. There are several competing approaches to assessing resource adequacy, including the use of planning reserve margins, which is the percentage by which installed capacity exceeds peak demand, and more rigorous probabilistic approaches based on loss of load probability (LOLP). Common probabilistic approaches include loss of load expectation (LOLE), which is often measured in days/year; expected unserved energy (EUE); and loss of load hours (LOLH). It is worth noting that LOLE and LOLH metrics only capture the number of events and do not reflect the size of the energy or capacity shortfalls. For this reason, the EUE metric is sometimes preferred. Examples of the large, uncorrelated differences that can be observed between the planning reserve margins and three commonly used LOLP-based metrics[1] are shown in Figure 1. The figure also shows that an LOLH of 2.4 hours per year is very different than an LOLE of 0.1 events per year, which indicates that rigorous benchmarking must be performed to determine the level of LOLH that corresponds to an LOLE reliability level of 0.1 events per year (see Ibanez and Milligan 2014). Additional examples, along with relevant discussions, can be found in North American Electric Reliability Corporation (NERC) (2011), Duignan et al. (2012), and Keane et al. (2011). It is important to understand and properly use these differing approaches to resource adequacy, as they can have significant consequences in the resource planning process that is discussed above.

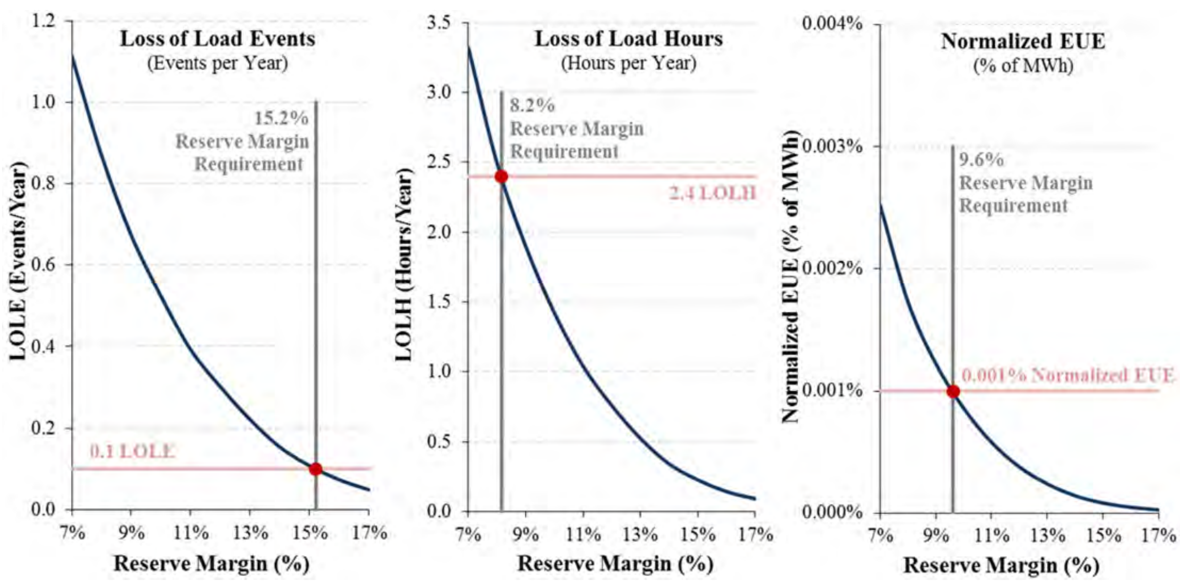


Figure 1. Planning reserve margins required to meet different physical reliability standards

Source: Pfeifenberger et al. 2013

[1] LOLH of 2.4 hours per year and LOLE of 0.1 events per year are different uses in the United States than the common "1 day in 10 years" standard; the 0.0001% normalized EUE standard is used in some international markets (Pfeifenberger et al. 2013).

Once a resource adequacy target has been adopted, the plant mix can be evaluated by calculating LOLP or a related metric. Assessments of the contributions of VG—or any resource type—can be carried out in this type of modeling framework.

The capacity contribution of a given resource or group of resources is called the effective load carrying capability (ELCC), and is graphically represented in Figure 2.

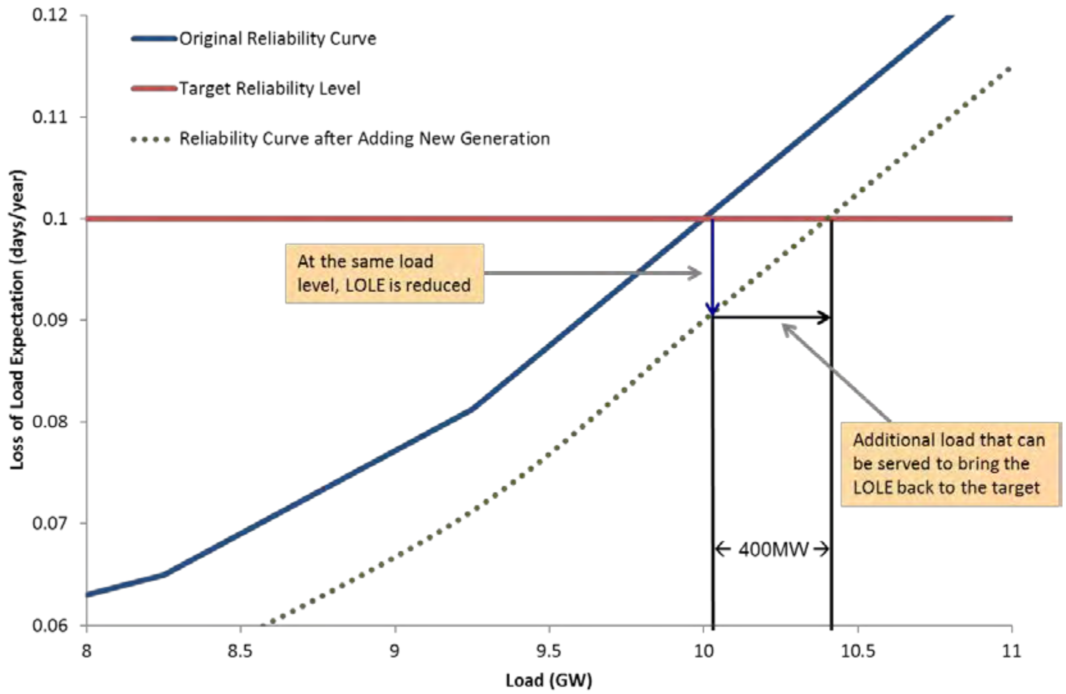


Figure 2. Graphical representation of effective load carrying capability

Source: adapted from Ibanez and Milligan 2014

The y-axis shows the reliability level in terms of days per year of LOLE; note that higher LOLE values denote worse reliability levels. The x-axis shows peak demand, and the original reliability curve (blue line) shows that, with a given resource mix, reliability gets worse at higher levels of peak demand. Assuming a one day in 10 years LOLE, this system can support about 10 gigawatts (GW) of peak demand at the reliability target (horizontal red line). When a new resource is added to the mix (e.g., 2000 MW wind plant), the entire reliability curve shifts right, as shown by the dotted green line. With this new resource, additional demand can be met, and at the new intersection of the reliability curve with the red target line, an additional demand of about 400 megawatts (MW) can be supported. Therefore, the capacity credit, or ELCC, of the new resource is 400 MW.

With high levels of renewable energy, this type of analysis is important so that sufficient resources can be developed in advance of the need. However, this analysis does not capture any of the flexibility needs or the attributes of flexibility solutions that must be addressed so that operational balance in the future can be achieved. New methods are now being developed to span this divide between resource adequacy and flexibility adequacy. For example, California Independent System Operator (CAISO) has implemented flexible capacity requirements and a new ancillary market product to specifically incentivize flexible generator capability (CAISO 2014). These components are discussed in Section 5.7.

The impact of VG on system balancing needs —flexibility— is typically viewed through the "net load," which is load minus VG in each hour (other time increments may be used) and represents the load that must be met by the conventional generation fleet in each time step if all VG is utilized. Figure 3 shows how wind generation can impact system operations in an example week. Net load peaks are shorter in duration, resulting in fewer operating hours for conventional generators; this affects energy-based cost recovery and, consequently, may impede long-term security of supply (for further discussion of this issue see Milligan et al. 2012a and Ela et al. 2014a). Steeper ramps require a faster rate of increase or decrease of dispatchable generation. Lower turn-downs require dispatchable generators to turn down output to low levels (to accommodate high VG output periods) but remain available to rise again quickly (Cochran et al. 2014). Solar generation will result in characteristically similar impacts.

When flexibility needs are not met, the system may experience reliability and economic consequences. These include dropped load, VG curtailment, deviations from the schedule of area power balance, frequency and voltage excursions due to over- or under-generation, negative market prices, and price volatility.

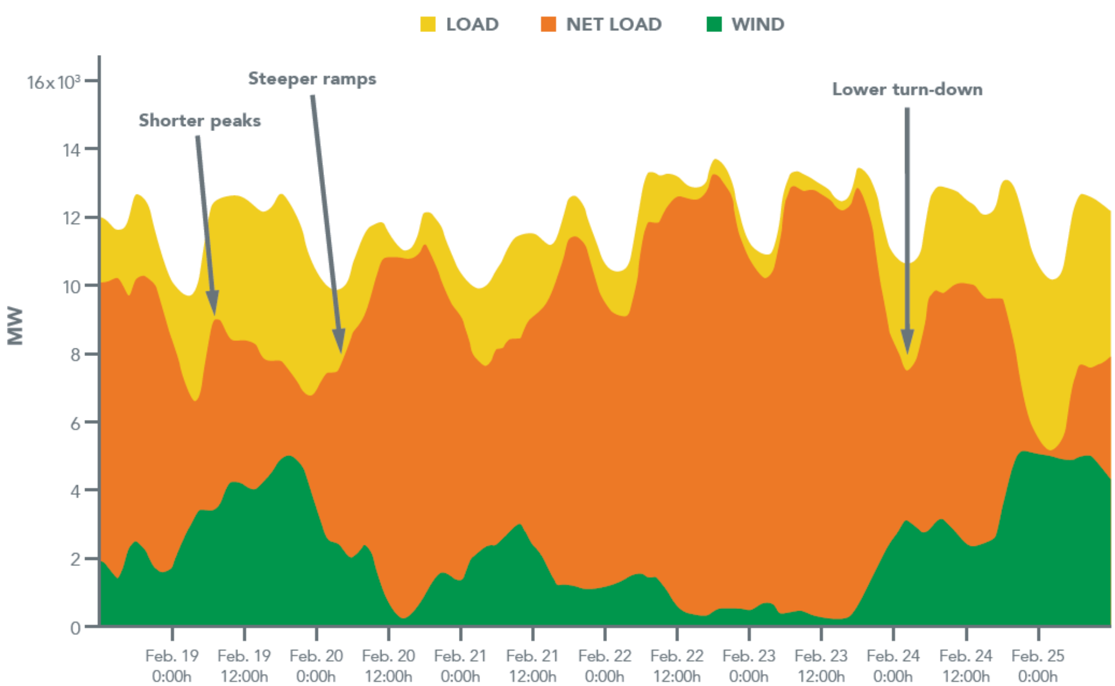
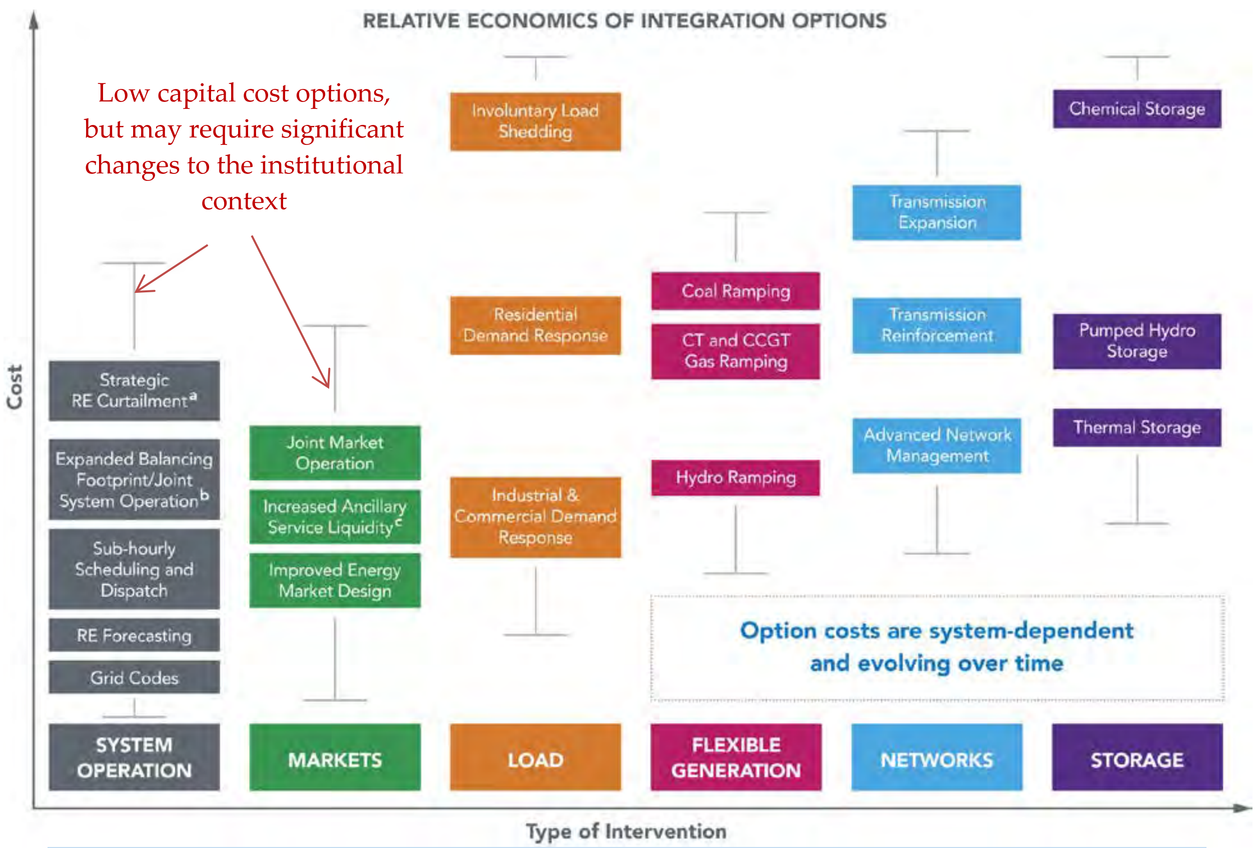


Figure 3. Wind (and solar) generation can lead to greater need for flexibility

Source: Cochran et al. 2014

As described above, flexibility can be provided by a suite of options, including physical and institutional intervention. Predominantly physical options include storage, flexible conventional generation (fast ramping and low output level capabilities), active power controls on VG, demand response through flexible load such as electric vehicles and programmable water and space heating and cooling, and transmission networks with limited bottlenecks and sufficient capacity to access a wide range of balancing resources. Predominantly institutional options provide access to and best extraction of flexibility from the physical system, including large balancing areas (BAs); market designs that utilize centralized scheduling and fast dispatch; improved VG forecasting; and the implementation of demand response (DR) through a smart grid to allow customers to respond to market signals or direct load control (Cochran et al. 2014). It's worth noting that even for predominately physical options, such as storage, appropriate institutional framework needs to be in place to effectively utilize them. Figure 4 provides an alternative summary (compare with Table 1) of a subset of possible flexibility options, divided by category and relative costs. The flexibility options in this figure are ordered by relative cost on the vertical axis, with illustrative error bars indicating that there is a variation among the costs, which are very system-dependent.



a There is a tradeoff between costs of flexibility and benefits of reduced (or no) curtailment, hence a certain level of curtailment may be a sign that the system has an economically optimal amount of flexibility.

b Joint system operation typically involves a level of reserve sharing and dispatch co-optimization but stops short of joint market operation or a formal system merger.

c Wind power can increase the liquidity of ancillary services and provide generation-side flexibility. Curtailed energy is also used to provide frequency response in many systems, for example Xcel Energy, EirGrid, Energinet.dk.

Figure 4. Flexibility options

Source: Cochran et al. 2014

3 Assessing the Need for Flexibility

This section describes data requirements and emerging modeling methods to quantify flexibility needs under future VG resources. The first step in assessing the overall system's need for flexibility is to understand and quantify the system's flexibility requirements. Various data are necessary to determine how much and what type of flexibility a system needs. These include installed capacities, locations of VG resources, and time series data of load and of those same VG resources. It is important that these VG and load time series data be time-synchronized to properly account for the underlying weather patterns (Milligan et al. 2012b).

Determining the need for flexibility begins with the development of a high-quality and fine-temporal-resolution data set, which, fortunately, is the same data set required for the backbone of integration analysis and modeling (NERC 2010). Alternative load profiles—hourly or sub-hourly demand curves for at least one year and covering the planning horizon—provide the first data set that is needed. Because this is a standard planning requirement, we do not describe this process here.

Accompanying this demand data is a complementary data set of wind and solar power, developed in a way that allows for multiple wind/solar penetrations, locations, and timing to be evaluated for alternative scenarios. The state of the art is to ensure that the wind power, demand, and solar power data are all based on the same meteorological year in order to capture accurate correlations between these datasets. Creating plausible scenarios from the data sets described above is the cornerstone of the flexibility needs analysis.

One common first step is to analyze the variability of the net load (load minus VG) constructed at hourly (or shorter) time intervals. Many types of statistical analyses can then be performed on the net-demand data series, which can also address multiple scenarios of renewable buildout, timing, mix of wind and solar, alternative demand scenarios, and many others.

A chronological analysis might analyze ramping needs based on the behavior of net load. An example is shown in Figure 5. This graph shows one week of demand and net load, based on a high wind penetration level. The increasing level of ramping can be discerned in the upper panel, and the lower panel of the graph quantifies the increase in ramping requirements based on the no-wind case.

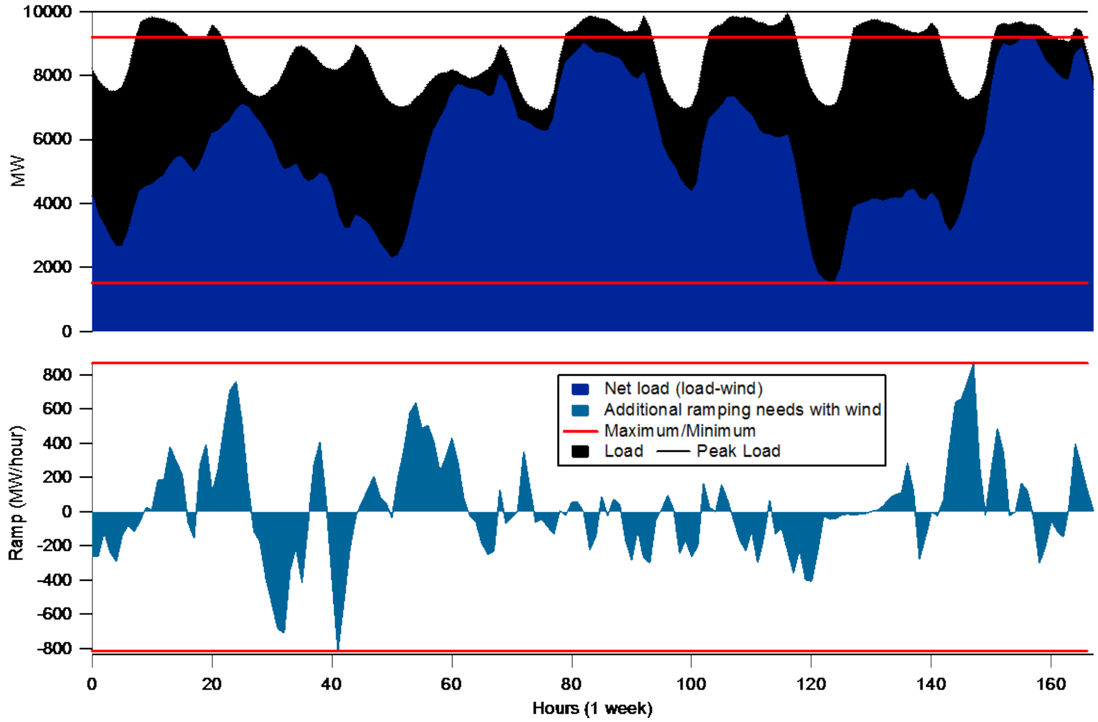


Figure 5. Example time series graph that shows the impact of high levels of wind energy on ramping needs and minimum generation levels (one selected week of data)

Source: Milligan 2014b

In the United States, flexibility needs are assessed using various approaches, which typically start from the net load using the time-synchronized load and VG data mentioned above. In CAISO, a recently approved measure incorporates flexibility needs into resource adequacy plans. Instead of only relying on peak load as an indicator of the required system installed capacity, CAISO will now also incorporate the forecasted net load maximum 3-hour ramp (in megawatts) for each month in its requirements for system capacity specifications (CAISO 2014). This measure assumes that the ramp event is constant over all 3 hours, which is often not the case. Figure 6 shows a distribution of the projected 2018 ratio of the maximum 1-hour net load ramp to the maximum 3-hour net load ramp by month. The different colors represent the percentage of the forecasted ratio each month, shown by quartile. These results show that the largest 1-hour net load ramps often comprises a significant portion of the maximum 3-hour ramp, reflecting shorter duration flexible capacity needs beyond the current 3-hour consideration. These 1-hour net load maximum ramps are projected to grow in size and occupy a larger share of the 3-hour ramp (CAISO 2014). The large single-hour ramp contribution in some months (e.g., March, October, and November) reveals that ramping rates, and not just magnitude, can be an important flexibility requirement.

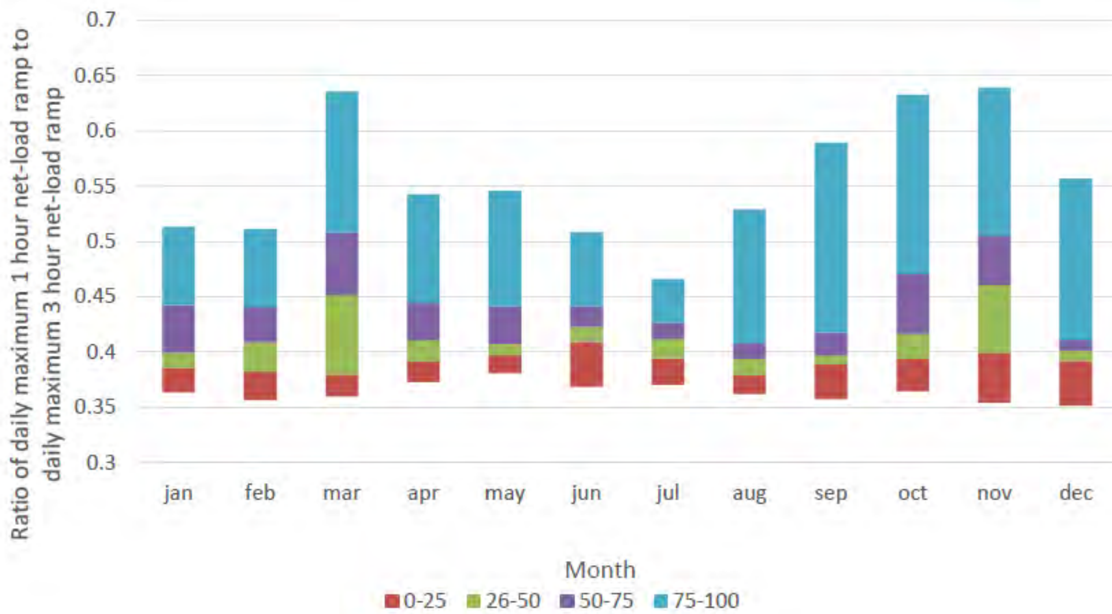


Figure 6. CAISO 2018 distribution of forecasted net load ratio of maximum 1-hr net load ramp to maximum 3-hr net load ramp with relative percentage of contribution (colors)

Source: CAISO 2015a

Annual data can be summarized statistically or can be arranged as duration curves. For example, ramp-duration curves can be constructed that can capture different levels of statistical containment. Figure 7 shows an example that is based on containment levels ranging from 90% to 100% and for time spans up to 12 hours. Comparing alternative ramp envelopes can help inform decisions regarding the type of resource(s) that may be capable of providing the service. For example, the relatively large but infrequent need for 4-hour ramping capability, comparing a 99% and 100% containment level, may suggest some form of DR as compared to a more expensive resource acquisition.

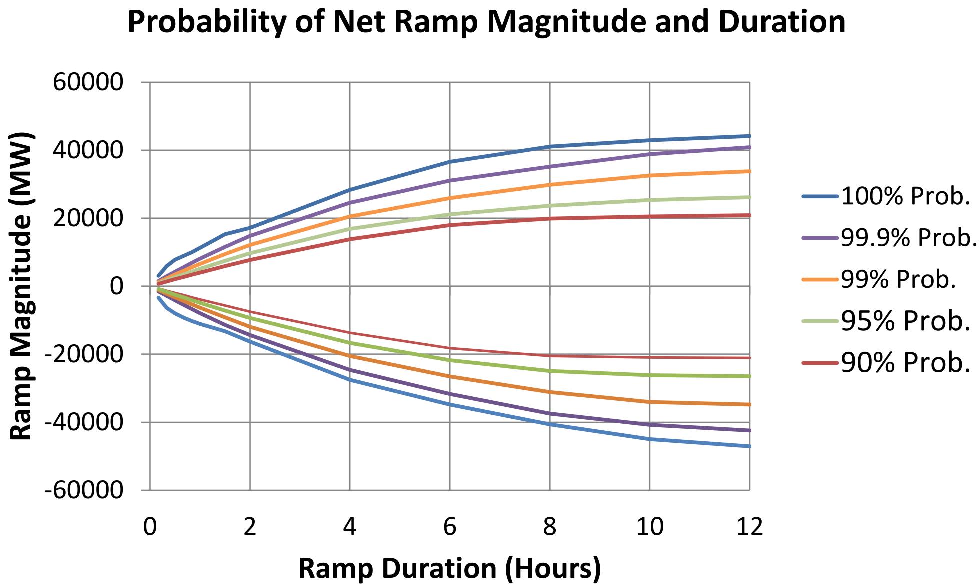


Figure 7. Example ramp duration curve that shows alternative ramping envelopes that correspond to different statistical exceedance levels

Source: King et al. 2011

Other approaches have also been utilized to capture ramp needs based on time of day/time of year. Figure 8 is a so-called "magic carpet" plot, which summarizes one year of hourly data into a visual representation that can be useful for system operators and planners to anticipate the times of day and year that ramping capability will most likely be needed (this particular plot is shown for the Energy Imbalance Market footprint in the western United States, which is discussed in Section 5.1). From the basic single-scenario data, statistical uncertainty bands could also be developed to capture potential impacts of forecasting uncertainty, both from the renewable resource and demand. Composite or multiple diagrams from additional years of data can also help characterize the impacts of both uncertainty and inter-annual variability on flexibility needs. This method, as well as other approaches, could also be extended to different time scales for additional support in identifying and quantifying the system's flexibility needs.

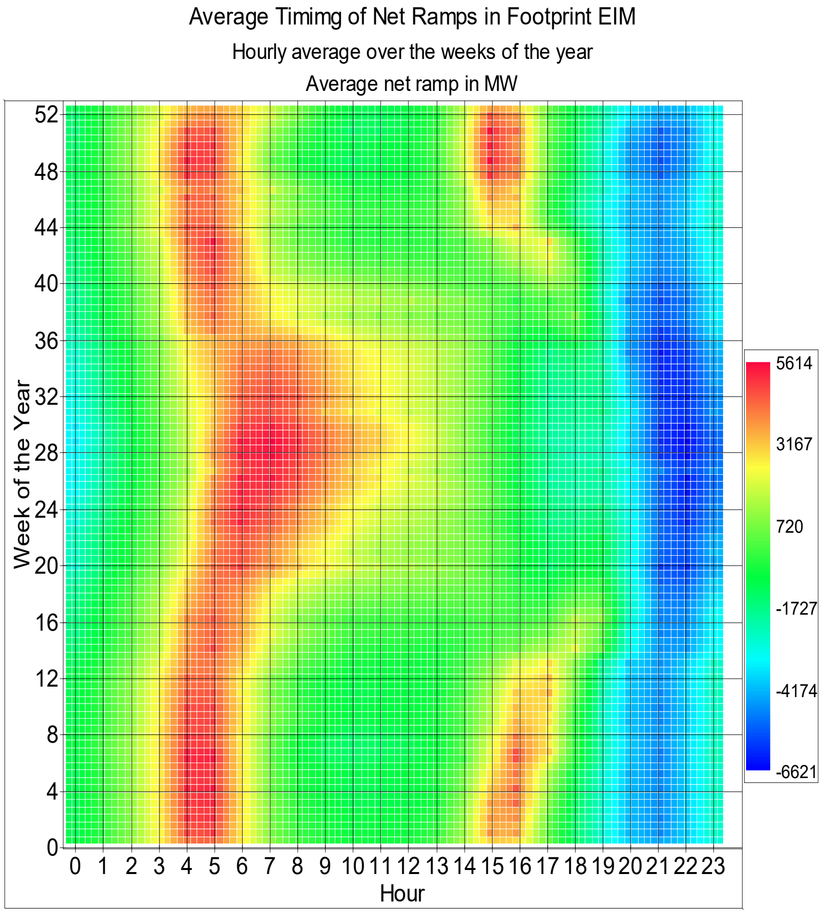


Figure 8. Example net ramp behavior by hour of day and week of year in the Energy Imbalance Area (EIM) footprint

Source: King et al. 2011

When interpreting the results from net-demand analyses such as these, it is important to remember that these analyses assume that wind and solar generation are totally passive and unable to provide ramping or turn-down capability. This assumption is increasingly at odds with industry practice in the United States, where VG resources are being equipped with active power control. These expanded capabilities can be appropriately represented in production simulations by allowing all capable resources to provide some level of required ancillary services, especially balancing services that can be analyzed by production simulation modeling. In such a framework, the economic provision of these services can be robustly calculated, and based on the results of these analyses, mitigating measures can be evaluated (Ela et al. 2012b).

4 Assessing Existing Flexibility Resources

Once the system's flexibility needs have been estimated, the next step is to assess the existing system's ability to supply flexibility by characterizing the flexible resources available to it. Simple approaches compare generation and demand-side resource data against the quantified need from the previous section. Appropriate data include generation characteristics, such as minimum generation (min-gen) levels and ramping rates, and existing alternative sources of flexibility, such as DR resource profiles. Any relevant institutional constraints should also be considered at this point. A simplified spreadsheet tool can be used to estimate the dispatch stack and resulting flexibility (min-gen, ramping magnitude and speed, etc.) for the comparison against the quantified system need; an example of this type of approach can be found in Kirby and Milligan (2005).

A more complex and recommended approach to assess the existing flexibility resources and needed flexibility is to simulate production, using modeling tools such as Plexos, GE-MAPS, Gridview, or Pro-Mod. These grid simulation tools model the operation of the entire bulk power system. These tools are sometimes referred to as "production cost" and "security-constrained unit commitment and economic dispatch" models. "Security-constrained" reflects the inclusion of transmission constraints in the economic dispatch and unit commitment processes. Production simulation requires input data on various costs (of generator fuel; variable operations and maintenance; generator start cost; contract purchase and sale price; transmission wheeling; energy, ancillary services, fuel; market prices, etc.), system load, plant characteristics, transmission capability, and generation uncertainties of VG resources. Assumptions regarding the potential future state of the power system are critically important and will have a significant impact on the model outputs. Some models take a deterministic approach, using a single year of load, wind, solar, and hydro conditions, and incorporating regulation and load following requirements in economic commitment and dispatch decisions. Some models stochastically simulate different conditions with a set of scenarios of different weather years while assuming perfect foresight in unit commitment decisions. Some stochastic models develop an initial commitment considering the uncertainty at that time and adjust commitment or dispatch of resources as needed (Kiviluoma et al. 2010; CPUC 2014; CAISO 2015b).

The flexibility of the simulated system can be assessed by examining several key outputs of the production simulation model. Such outputs include: total up/downward reserve shortfall, max up/downward reserve shortfall, number of hours of up/downward reserve shortfall, total renewable curtailment, maximum renewable curtailment, number of hours of curtailment, total dump energy, maximum dump energy, number of hours of dump energy, along with reliability metrics such as LOLP, LOLE (often expressed as days/year), LOLH-LOLE in units of hours per year, or EUE.

Some relatively new methods for assessing flexibility in the power system include insufficient ramping resource expectation (IRRE), periods of flexibility deficit (PFDs), effective ramping capability (ERC), and CAISO's ramp-based flexible capacity method (discussed above). IRRE uses a probabilistic approach to determine the number of periods when a power system cannot meet each net load ramp. The operational characteristics for each generator, the energy production time series—historical or simulated—of each flexible resource, and each resource's maximum and minimum rated output, start-up time, ramp up and down rate, forced outage probability, and production levels are required for IRRE calculation (Lannoye et al. 2012b). PFD differs from IRRE in that it makes a direct comparison between the available flexibility from a simulated production time series and the net load ramps in the chosen direction. It identifies the time horizons associated with the flexibility deficit so that different solutions might be devised for each flexibility issue (EPRI 2014). ERC describes a unit's contribution to the system's ability to ramp upward or downward over a specified period of time (Lannoye et al. 2012a). ERC is similar to ELCC, except that instead of calculating contributions toward meeting overall capacity needs, ERC uses the unit's maximum ramp in a given direction and time period to indicate contributions toward meeting ramping needs.

5 Options to Increase Flexibility

If the available system flexibility is not sufficient to cover the need as determined by the previous steps, then sources of additional flexibility should be evaluated based on their technical and economic merits. The best solutions are system specific and include both the necessary physical flexibility and the institutional access to that flexibility. In this section, we discuss the most-selected flexibility options from experience in the United States, as summarized in Table 1. The availability of these measures is not uniform throughout the United States.

5.1 Larger Balancing Areas

In the United States, a key physical and institutional flexibility mechanism is increasing the size of BAs.[2] This typically involves the physical interconnection of adjacent regions through an enhanced transmission network. However, there are alternative approaches to achieve some or all of the benefits of such operational consolidation. They include dynamic scheduling, intra-BA scheduling at sub-hourly time steps, or other wide-area economic dispatch concepts that do not require physical consolidation of BAs (Milligan and Kirby 2010a; Denholm and Cochran 2015). Larger BAs provide greater access to load and generation diversity and a larger pool of reserves. This results in numerous operational efficiency benefits. For example, the ramping capability of generation adds linearly, whereas the ramping need of large areas increases less than linearly (Figure 9).

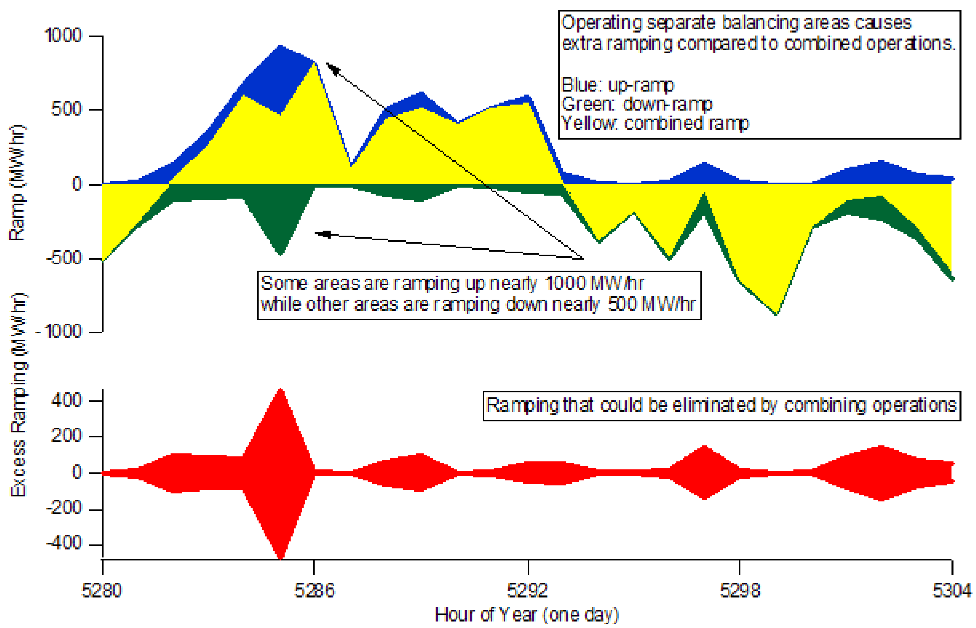


Figure 9. Large BAs result in less total ramping need

Source: Milligan and Kirby 2007

[2] Balancing (Authority) area is the collection of generation, transmission, and loads within the metered boundaries of an entity (Balancing Authority) that integrates resource plans ahead of time and maintains load-interchange-generation balance of that area. The Balancing Authority supports interconnection frequency in real time.

The institutional benefits of larger BA and faster scheduling are shown in Figure 10.[3] The aggregate regulation reserve requirements (and resulting system costs) across this interconnection decrease as the BA footprint grows from small to medium to large (right to left in the figure). These reserve requirements (and costs) also decrease as the dispatch interval and forecast lead times decrease (colored bars). Smaller dispatch intervals correspond to faster energy markets, and smaller forecast lead times correspond to more frequently updated (and therefore accurate) VG and load forecasts.

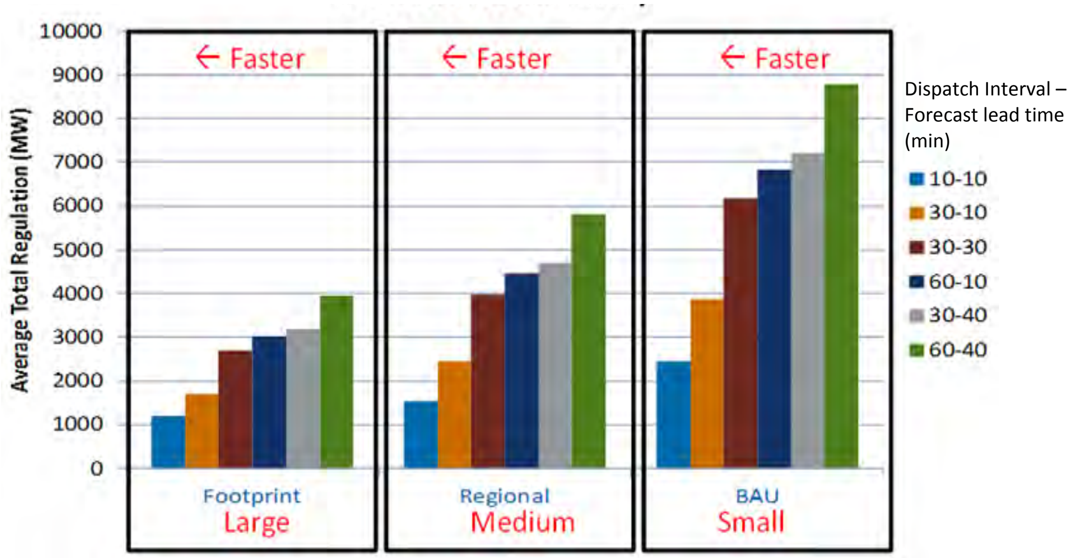


Figure 10. Faster energy scheduling (colors) and larger BAs (panels) greatly reduce aggregate regulation requirements and wind integration impacts

Source: Milligan et al. 2011

Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and PJM Interconnection (PJM) are examples of regional transmission organizations (RTOs) in the United States that have physically expanded to capture these BA size benefits. MISO created and integrated its South Region in 2013, citing benefits of improved reliability and reduced regulation and spinning reserve requirements (see MISO's website[4]). SPP integrated portions of Nebraska in 2009 and was approved in 2014 to add large portions of the upper Great Plains, citing an estimated $334 million in net system benefits from increased access to generation into and out of Nebraska and availability of lower-priced hydro generation (SPP 2009; FERC 2014). Various utilities have joined PJM since 2004, expanding its footprint from North Carolina to Illinois (see PJM's website[5]). In the western United States, a new EIM has been formed (see

[3] This graph includes all of the U.S. Western Interconnection except for California and Alberta.
[4] https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/SouthernRegionIntegration/Pages/SouthernRegionIntegration.aspx.
[5] http://www.pjm.com/about-pjm/who-we-are/territory-served.aspx and http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx.

CAISO's EIM website[6]), and although initial participants include only the CAISO and PacifiCorp, other utilities have announced plans to join the EIM in the next 1 to 2 years, which will increase the effective balancing size of this market. The EIM is a real-time, security-constrained economic dispatch on imbalances, running every five minutes. It therefore does not include the other aspects of the large RTO markets in the United States and is an approach to pooling the economic dispatch of imbalances.

While no BA operator in the United States has ever decided that it is too big, there may be extra cost considerations of a large BA. These include the cost of additional computational requirements for monitoring and operating the system, including security-constrained unit commitment and security-constrained economic dispatch, as well as power system state estimation. Additionally, transmission congestion can prevent the realization of the full set of benefits.

5.2 Access to Neighboring Markets

Access to neighboring markets is both a physical and institutional flexibility measure and is closely related to the larger BA option. It requires physical interconnection via transmission networks and the institutional mechanisms to manage the coordinated operation of those transmission lines and the markets that they connect. This latter coordination across borders can include a wide variety of options, including dynamic scheduling or allowing interchange schedules to change at relatively short time steps.

This flexibility measure captures the interplay between transmission and generator capacity needs. Building new lines allows multiple areas to share generator resources, thereby reducing the total required generating capacity among all constituent regions. The resulting economic and reliability benefits are realized regardless of the VG penetration level. As shown in Figure 11, for modest levels of VG (roughly 7%–20% wind and solar capacity-based penetration in all constituent regions), the total system costs (production and reliability, red dots) decrease as the access to neighboring markets increases (moving from "Island Case" down to "Long Neighbor Case"). At the same time, resource adequacy (0.1 LOLE target, blue dots) benefits are achieved with greater access to neighboring markets. The cases in this figure reflect different levels of neighbor assistance: Base Case, where the neighbors have 15% reserve margins and the Study RTO has 11,000 MW of intertie capacity; "Long Neighbors Case," where the neighbors' reserve margins are increased to 20% compared to 15% in the Base Case (and intertie capability equal to the Base Case); "50% Transmission Case," with interties at 50% relative to the Base Case (and neighbors' reserve margins at 15%); and an "Island Case" with no interties (Pfeifenberger et al. 2013).

[6] "Energy Imbalance Market." 2015. Folsom, CA: California ISO. Accessed September 2015, http://www.caiso.com/informed/pages/stakeholderprocesses/energyimbalancemarket.aspx.

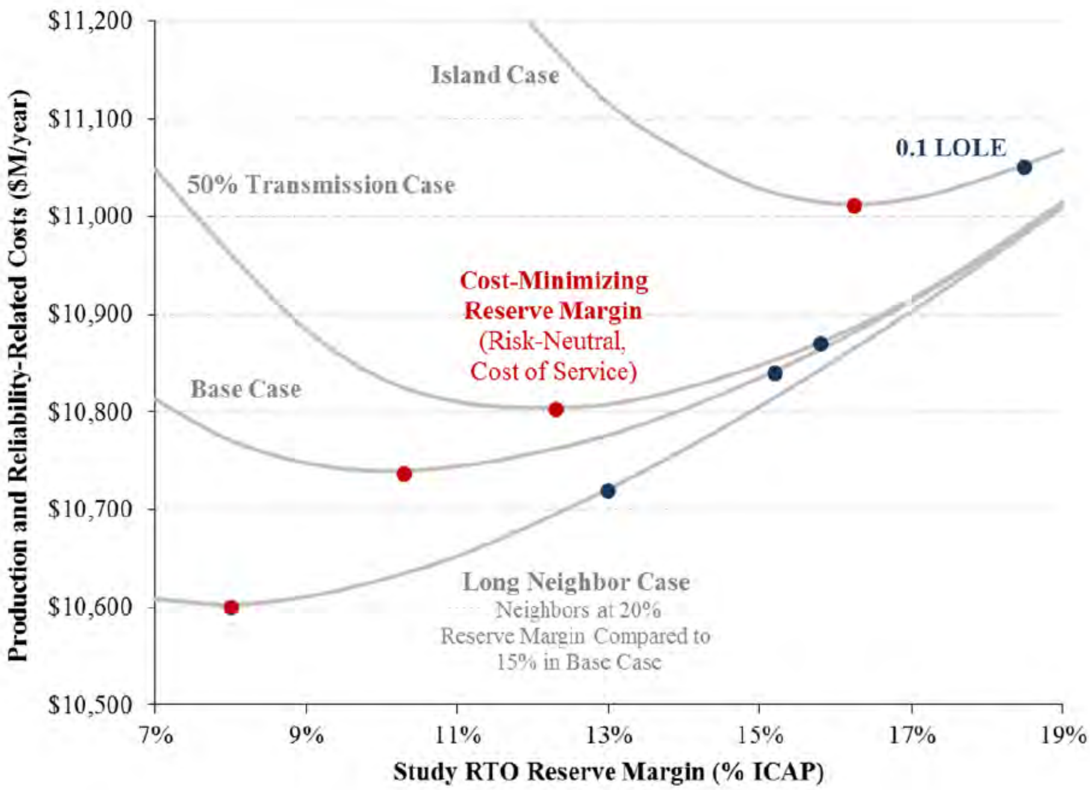


Figure 11. Total system cost versus reserve margin with varying intertie assumptions

Source: Pfeifenberger et al. 2013

These trade-offs are further shown in an analysis of the Western Interconnection in the United States (Ibanez and Milligan 2012), where the authors analyzed alternative wind/solar build-outs from *The Western Wind and Solar Integration Study Phase 2* (Lew et al. 2013). A reference case had 8% annual energy from wind and 3% from solar. Alternative cases had 33% of annual demand supplied by wind and solar split evenly, and high-wind/low-solar and high-solar/low-wind combinations. Ibanez and Milligan evaluated how much effective installed generator capacity could be replaced by transmission based on an assessment of resource adequacy. Key results are presented in Figure 12. The figure shows the reduction in effective capacity—the ELCC of the transmission additions and subsequent reduction in the need for resources—made possible by perfect transmission[7] within each subregion and by perfect transmission across the interconnection. Although copper sheet transmission is unlikely to ever be built, the example shows the trade-off between transmission and generation and the impact that transmission can potentially have on the need for new resource additions.

[7] Assuming perfect transmission—with no congestion or transmission constraints (i.e., perfect energy transfer between any two points in the system)—is often referred to as a “copper sheet” scenario.

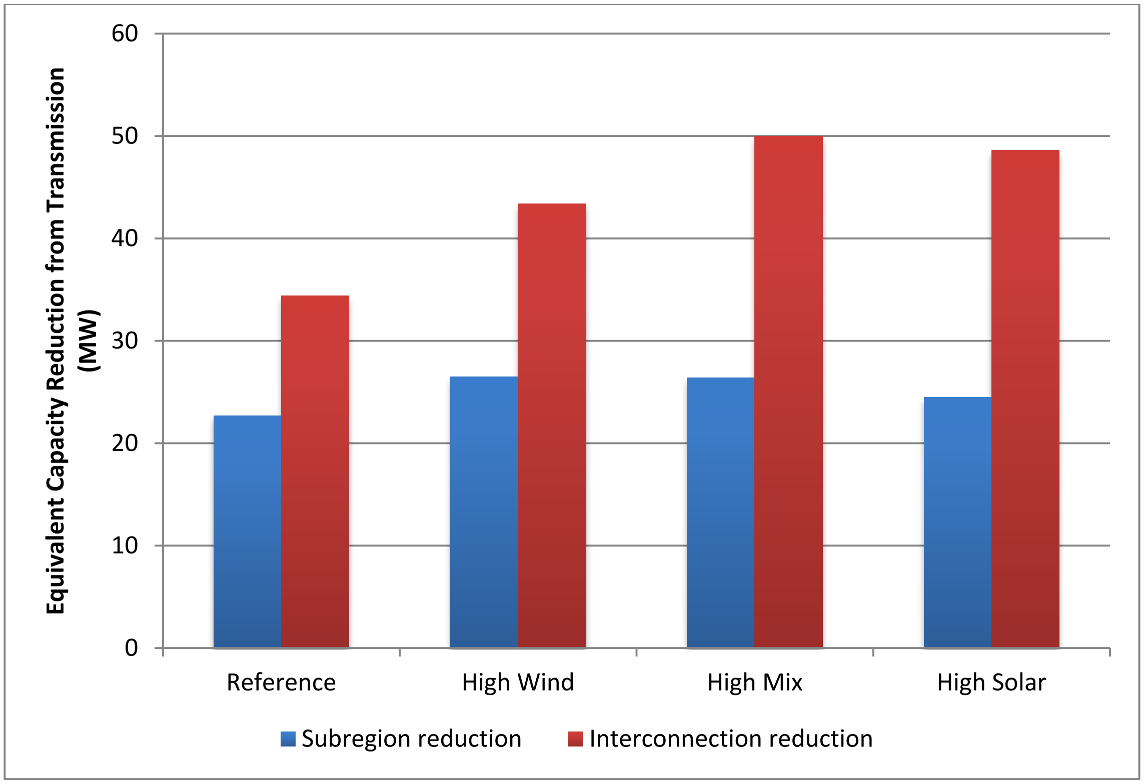


Figure 12. Impact of interconnection on resource adequacy in the western United States

Source: adapted from Ibanez and Milligan 2012

5.3 Fast Energy Market

Fast scheduling and dispatch is a key institutional flexibility mechanism that enables the system to access available physical flexibility that would otherwise remain locked within coarser operational time steps. This concept is summarized in Figure 13 for a case study of the Bonneville Power Authority (BPA) operating area in the Pacific Northwest of the United States. Moving from hour scheduling (top, blue line) to 10-minute scheduling (bottom, red line) results in a significant reduction of spinning and supplemental reserve requirements. This reduction affects both the frequency and magnitude of the reserve needs, because faster scheduling and dispatch can more accurately follow actual system conditions.

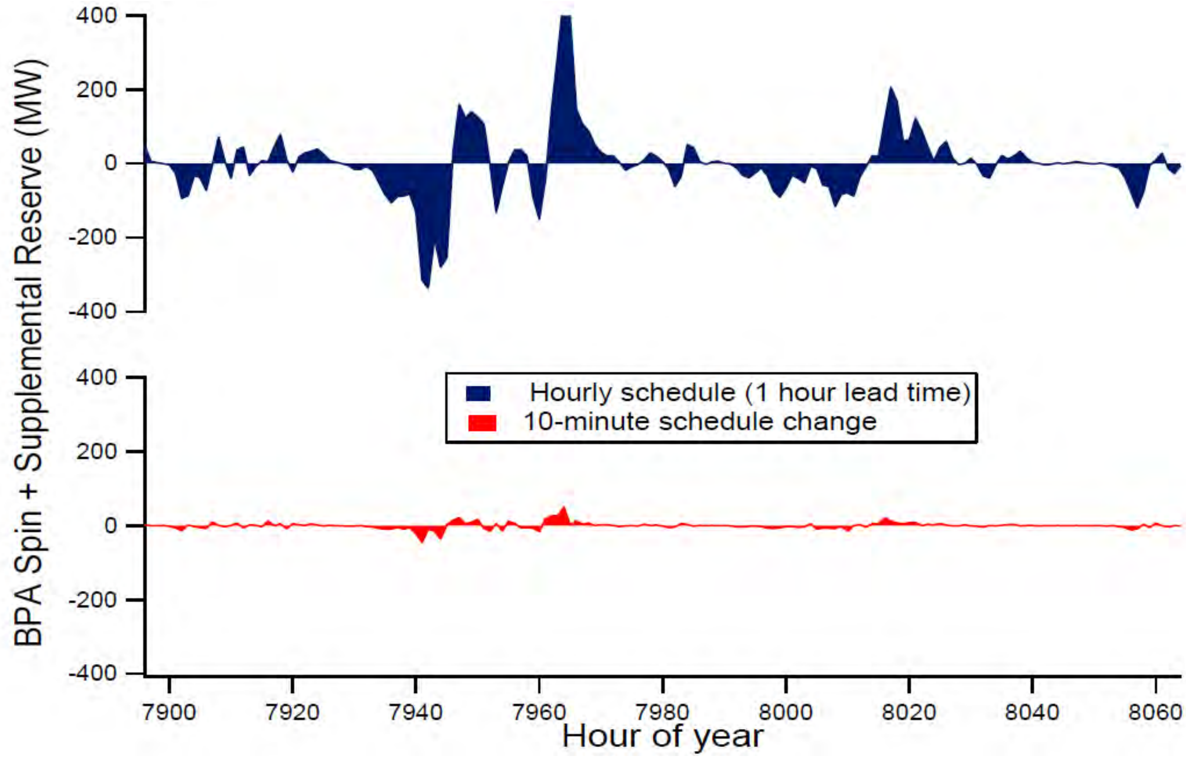


Figure 13. Dynamic/fast scheduling of wind out of BPA

Source: Milligan et al. 2011

Although all RTO markets in the United States operate a 5-minute economic dispatch, market settlements are not necessarily based on 5-minute prices. The temporal resolution of the settlement period determines the price that the generators are actually paid. In some cases, the settlement is carried out every 5 minutes at the 5-minute prices (locational marginal prices are used in all of the U.S. RTO/ISO markets). In other cases, settlement is carried out hourly and is based on an average of all 5-minute prices within the hour.

To explore the impact of settlement on flexibility incentives, Ela et al. (2014a) describe three different operating strategies and how the profit to suppliers differs for each strategy depending on whether an hourly or 5-minute settlement is implemented. These scenarios are shown in Figure 14. The dashed lines are different operating strategies: in the "5-min Sched" scenario, the supplier follows a schedule based on the 5-minute locational marginal prices; in the "Moving Hrly Avg Sched" scenario, the supplier follows an output based on the current hourly moving average locational marginal prices; and the "Perf Knowl Hrly Avg Sched" scenario is a hypothetical example if the supplier had perfect knowledge of only the final average hourly price. The graph shows the difference in flexibility that can be extracted by using the 5-minute settlement (5-minute price), which is significantly greater than hourly settlements (moving hourly average price).

The importance of this conclusion cannot be overemphasized. Frequent scheduling and shorter settlement intervals allow for better pricing of actual conditions and provides incentives for resources that can follow the prices. This example shows that flexibility can be muted by something as simple as the market settlement process in spite of what might otherwise be a good market design.

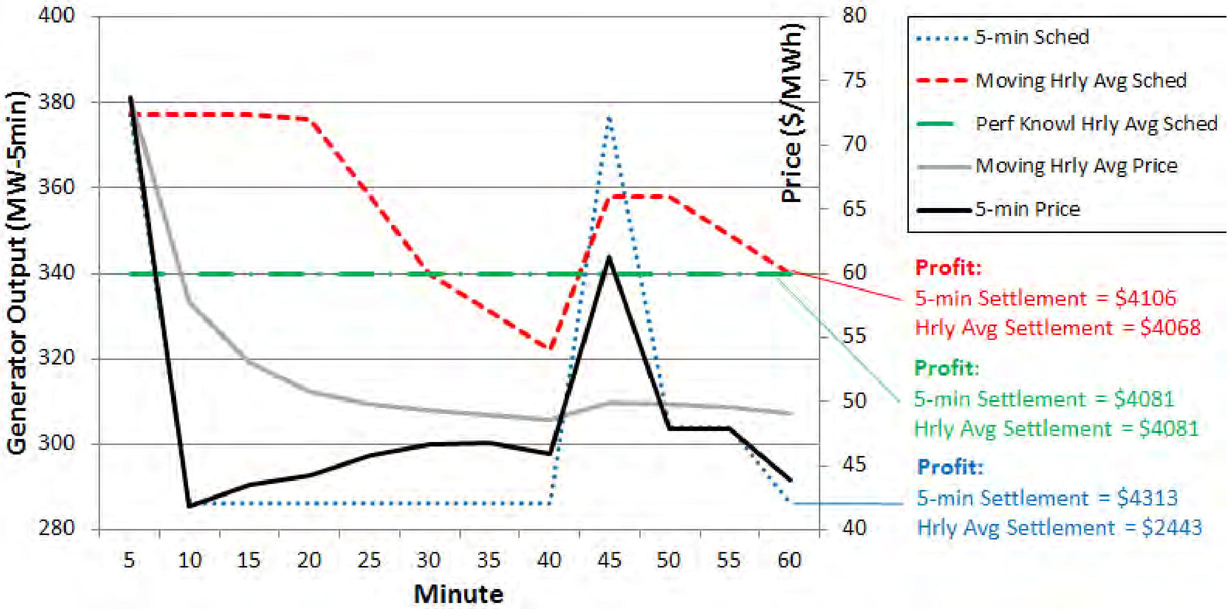


Figure 14. Profits of different operating scenarios with 5-minute settlements versus average hourly settlements

Source: adapted from Ela et al. 2014a

In the United States, different regions have different scheduling and dispatch time step sizes. All restructured markets (i.e., ISOs/RTOs) in the United States have a 5-minute economic dispatch with at least 15-minute interchange scheduling,[8] per Federal Energy Regulatory Commission (FERC) Order 764 as discussed below. Regulated markets have varying time intervals for dispatch and scheduling (e.g., hourly in much of the western United States). Many regions are moving to shorter time intervals to capture the flexibility and market efficiency benefits discussed above. No system has ever decided to go to a longer time interval dispatch. For example, the ERCOT region in the United States moved from a 15-minute to 5-minute dispatch (along with other market improvements) to improve system operation, resulting in a significant reduction of VG curtailment (Bird et al. 2014). Recent federal regulation is also assisting with the push for faster scheduling. FERC Order 764, issued in 2012, requires (among other details) transmission providers to allow customers the option of scheduling at 15-minute intervals instead of hourly to specifically assist with the integration of VG.

5.4 Improved Market Design

Improving market design is an institutional tool to greatly improve power system flexibility. Four major market principles have proved to work in the United States: large, fast, resource-neutral, and performance-based. The first two principles are discussed above. A resource-neutral principle means that all resources, regardless of technology, should compete to supply ancillary services on an equal footing, based on their different reliability contributions. A new potential ancillary service product could be defined by the required notification period, response speed, response depth, or length of performance—such specifications are technology-independent in the

[8] This refers only to scheduling with neighboring regions. In some areas, the conversion to a 15-minute interchange may not yet be complete.

market design. In addition, the payment should be performance-based to ensure consistency: two suppliers who provide different levels of service should be compensated accordingly—greater product provision should lead to higher payment; two suppliers of the same quantity of the same product, regardless of sources, should be compensated in the same way. This principle can also be applied to customers, demand, or demand-response. FERC Order 755 details the rationale for "resource-neutral" and "performance-based" payment and removed the previous "unjust, unreasonable, and unduly discriminatory or preferential" rates that resulted in economically inefficient dispatch of frequency regulation resources (FERC 2011).

Some market designs can have unintended consequences for flexibility. Two examples can be provided from the United States. The first example is the interaction of large energy markets with frequency response as alluded to above. During the past several years, frequency response in the U.S. Eastern Interconnection has been declining. Although there are likely multiple reasons that contribute to this decline, market design is likely contributing to the problem (see Ela et al. 2012a). The eastern energy markets provide for various penalties and/or costs if energy delivery schedules are not met by market participants. Yet if a generating unit responds to a frequency event, causing it to deviate from its energy delivery schedule, there is an economic penalty in many markets, causing the withdrawal of governor response and an overall decline in frequency response. This problem is not insurmountable; markets for frequency response could be designed and co-optimized in the same way that other ancillary service markets are included. For example, see Ela et al. (2014b; 2014c).

The second U.S. example results from the energy-only provisions with the current production tax credit (PTC) for wind energy. This subsidy provides a financial credit for each megawatt-hour generated by a wind plant that has qualified for the credit. However, if a wind plant were to provide the regulation ancillary services (which is still not allowed in many U.S. markets), it would result in a financial loss of the PTC. One possible way to remedy this disincentive would be to broaden the PTC to remunerate for the opportunity cost of providing regulation services. More detailed discussion of active power controls on wind turbines can be found on NREL's website.[9]

Other essential aspects of market design, such as the fundamental value of economic dispatch, the combination of faster markets with effective and widespread renewable energy forecasting, and nodal or zonal markets are discussed in the companion paper '*Renewables-Friendly' Grid Development Strategies* (Hurlbut et al. 2015).

5.5 Demand Response

Structuring markets to properly incentivize and utilize responsive load is a promising flexibility option that requires physical flexibility from responsive loads and the institutional structures to appropriately incentivize the desired response. Such DR serves as a reliability resource by reducing load during critical periods. DR has the potential to provide balancing capability on multiple time scales, ranging from seconds to seasons, by offering energy, capacity, and/or ancillary services (regulation, load-following, contingency). Market designs that emphasize performance requirements, such as notification period, time to start, time to run, etc., can often

[9] http://www.nrel.gov/electricity/transmission/active_power.html.

easily accommodate DR that is technically capable of providing the service. Incorporating DR into the economic dispatch allows for cost-effective utilization of DR.

Figure 15 summarizes how DR (and the related, but different, mechanism of energy efficiency) can adjust the load shape. These responses vary by speed, duration, magnitude, and frequency. Energy efficiency reduces total energy consumption (during the respective time of demand for related services such as lighting) through more efficient end use technologies, such as compact fluorescent or light-emitting diode lighting instead of incandescent light bulbs. Price response programs and peak shaving are energy services that shift load from a more system-constrained time period to a time period with more available supply; pre-cooling with air conditioning or pre-heating water are commons examples of this. Reliability and regulation responses are ancillary services that respond very quickly to deviations in scheduled net load (regulation) or loss of supply (contingency). DR can also serve as a capacity resource by being available to supply “generation” (i.e., negative load) during certain high load hours.

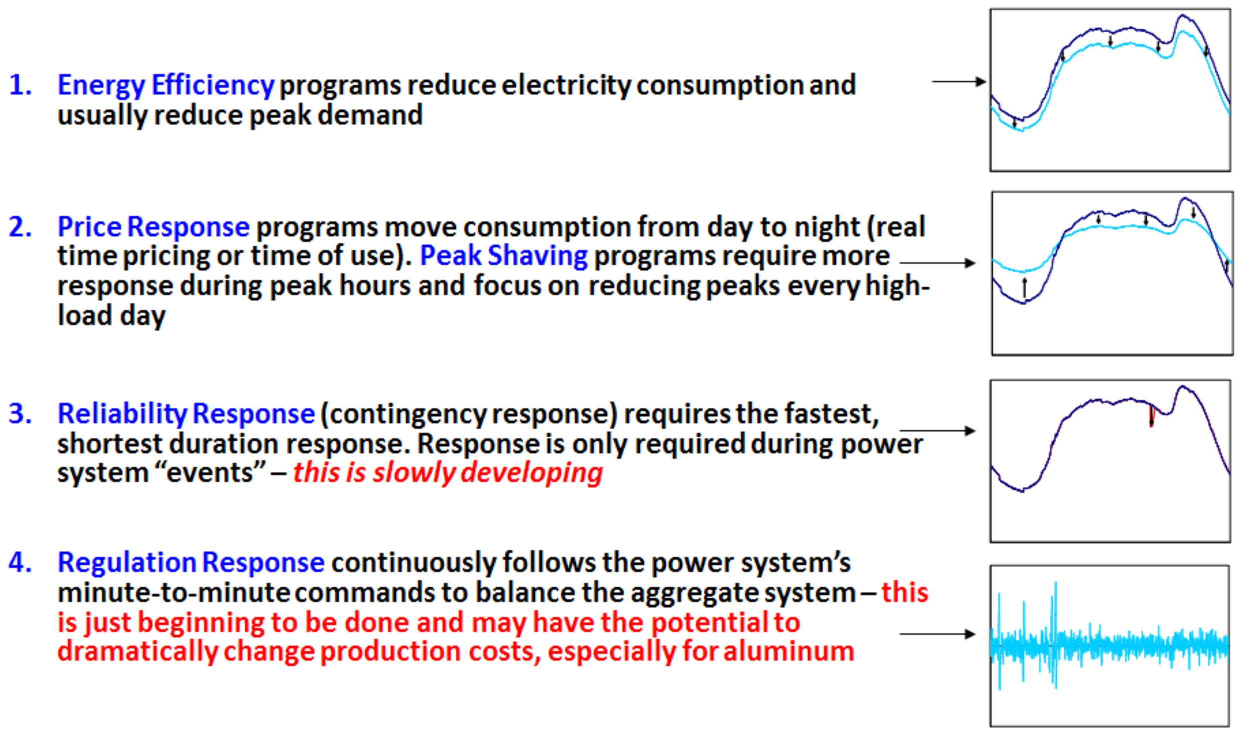


Figure 15. Basic types of demand response with selected notes on their availability

Source: adapted from Milligan and Kirby 2010b

Programs that encourage responsive load modifications in the United States consist of two broad categories: price-based and incentive- or event-based mechanisms (Goldman et al. 2010). Price-based programs (also sometimes referred to as economic DR) motivate end-users to adjust their electricity usage by varying the price of electricity. Incentive- or event-based DR programs (also sometimes referred to as emergency DR) provide financial compensation to end-users for reducing their load upon request or for giving the program administrator direct control over certain consuming equipment (historically, this has primarily focused on air conditioners and water heaters). Event-driven programs usually have upper limits on the duration of individual events and total number of event-hours per year, often no more than 40 to 100 hours per year, which corresponds to times when reserve margins drop below threshold conditions or when wholesale prices spike (Goldman et al. 2010). More utilities in the United States have historically offered price-based rates over incentive-based programs to customers, but it is unclear which category will become the preferred option from both the utility and customer perspectives. A recent study with 10 U.S. utilities revealed nearly double average peak load reduction with price-based DR programs than with incentive-based plans (21% vs. 11%), but this difference was largely eliminated when programmable communicating thermostats were installed (Cappers et al. 2015). Table 2 provides examples of programs within each of these two categories.

Table 2. Common Types of Demand Response Programs

Price Options	Incentive- or Event-Based Options
TOU rates: Rates with fixed price blocks that differ by time of day.[a]	**Direct load control:** Customers receive incentive payments for allowing the utility a degree of control over certain equipment.
CPP: Rates that include a pre-specified, extra-high rate that is triggered by the utility and is in effect for a limited number of hours.	**Demand bidding/buyback programs:** Customers offer bids to curtail load when wholesale market prices are high.
RTP: Rates that vary continually (typically hourly) in response to wholesale market prices.	**Emergency demand response programs:** Customers receive incentive payments for load reductions when needed to ensure reliability.
	Capacity market programs: Customers receive incentive payments for providing load reductions as substitutes for system capacity.
	Interruptible/curtailable: Customers receive a discounted rate for agreeing to reduce load on request.[b]
	Ancillary services market programs: Customers receive payments from a grid operator for committing to curtail load when needed to support operation of the electric grid (i.e., ancillary services).[c]

CPP = critical peak pricing; RTP = real-time pricing; TOU = time of use.

[a] Some analysts do not consider TOU rates to be a dynamic demand response option because the rating periods and prices are fixed, and utilities typically do not regard customers on TOU as a resource that can be dispatched similar to a generator when needed to support grid operations. A well-designed TOU rate, however, may induce customers to make long-term investments that reduce peak demands.

[b] Some utilities also regard interruptible tariffs as a "price-based" option, particularly if their interruptible tariff includes dynamic pricing provisions during emergency events (e.g., some tariffs give customers the option of "riding through" a curtailment event by paying higher real-time prices and still receiving electricity).

[c] Ancillary services demand response arrangements can also be viewed as a pricing program, because real-time pricing signals can be set up under a tariff to trigger event-specific customer behavior.

Source: Goldman et al. 2010

DR programs can be designed in many different ways. The best portfolio for a given system will depend on the system's existing physical and institutional structures and its expected load growth and portfolio deployment. One example for business customers in one California utility, Pacific Gas and Electricity (PG&E), is shown in Table 3.

Table 3. Example Demand Response Programs for Business Customers in California

Program Name	Description (Partial)
Incentive- or Event-Based Demand Response	
Base Interruptible Program	Provides monthly or per-event incentives for curtailing load with either 30-minute or 4-hour advance notification. Curtailments limited to 120 hours per year.
Capacity Bidding Program	Offers monthly payments from May through October for curtailing nominated load on either a day-ahead or day-of basis, up to 24 times per month, when load conditions require the use of generators with heat rates of 15,000 Btu/kWh or greater.
Demand Bidding Program	Provides payments of $0.50–0.60 per kWh to customers who submit day-ahead or day-of offers to curtail load.
Optional Binding Mandatory Curtailment Plan	Allows customers to be exempt from rotating outages in return for agreeing to reduce load by 5 to 15 percent within 15 minutes of notification.
Peak Choice	Allows customers to customize their demand response by selecting from a range of advance notice, timing, load reduction, and number of day options, where incentives are determined by option combinations.
Scheduled Load Reduction Program	Pays $0.10 per kWh for commitments to reduce load one to three times per week, 4 hours at a time, from June through September.
SmartAC (Air Conditioner Load Control)	Offers $25 to customers who allow installation of either an air conditioner compressor switch or a smart thermostat that can be used to control load up to 100 hours per year when CAISO declares emergency or near-emergency conditions. This program is also offered to residential customers.
Price-Based Demand Response	
CPP	Provides lower rates during on-peak and partial-peak hours in exchange for higher (three to five times normal) rates on up to 12 days between May and October when system demand is high.
Demand Response Technical Assistance	
Technical Assistance and Technology Incentive Programs	Provide engineering assistance and cash incentives to support installation of equipment or software supporting demand response.
Integrated Energy Audit	Offer audits that comprehensively address opportunities in energy efficiency, time-of-use management, demand response, self-generation, and renewables.

Sources: <http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/>; <http://www.pge.com/mybusiness/energysavingsrebates/analyzer/integrated/>.

Btu = British thermal unit; CAISO = California ISO; CPP = critical peak pricing; kWh = kilowatt-hour; TOU = time of use.

Source: Goldman et al. 2010

In the PJM region, DR resources perform and are paid like traditional “supply-side” resources (generation). PJM currently allows responsive load to participate, just as a generating unit, in its forward capacity market (peak shaving), “price responsive demand” (as negative load) in the day-ahead and real-time energy markets, and frequency regulation and synchronized reserve in the ancillary services markets (PJM 2014). The energy DR programs are further divided into emergency (voluntary load shedding) and economic (dispatched load shedding) categories. Capacity payments make up the vast majority of all DR revenue in PJM (Figure 16).

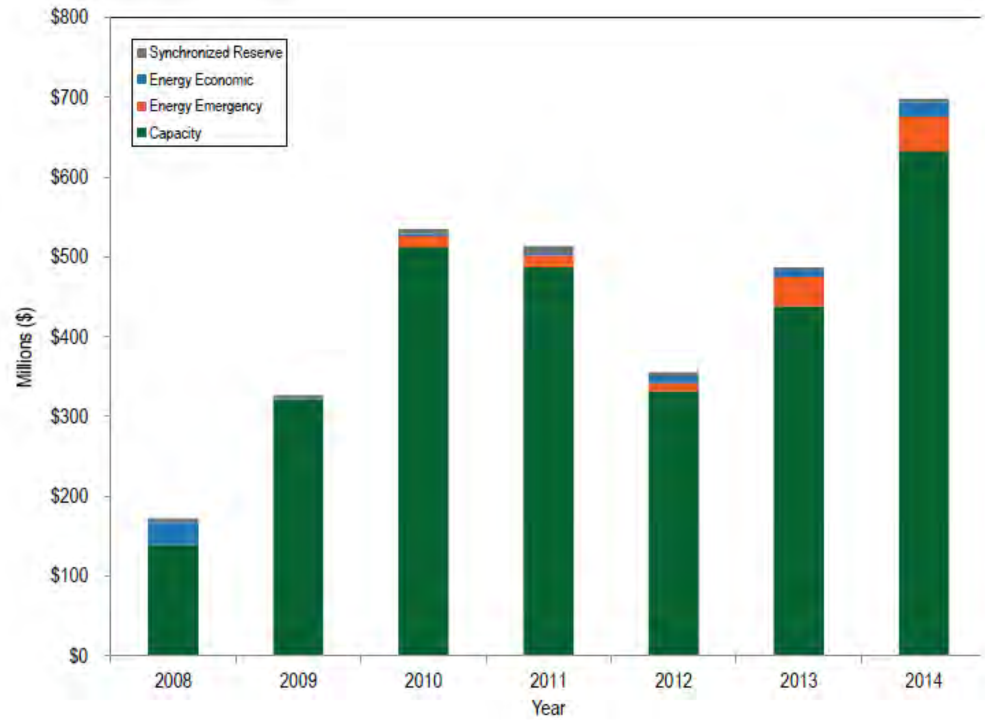


Figure 16. PJM demand response revenue by market, 2008–2014

Source: Monitoring Analytics 2015

However, the exact way in which DR market structures will evolve in the United States is highly uncertain because of current legal issues (EPSA v. FERC 2014) with how DR may or may not compete with generating units. This is largely an issue of revenue sufficiency for existing generators: DR suppresses capacity prices and the frequency of energy and ancillary services scarcity events, which reduces the revenue received by generators to cover both their fixed and variable costs. The PJM region, for example, is establishing alternative approaches for how DR could be implemented to both retain system reliability and meet all legal obligations. These approaches would treat DR as a demand-side resource, where the compensation would shift from payment for energy or capacity (supply-side) to one of avoided costs from avoided energy or capacity (demand-side) (PJM 2014).

A key reliability and economic benefit of these DR programs is a reduction in peak load, which corresponds to a reduction in required system capacity and associated costs. It is cheaper to turn down load than to build new generating capacity. The load duration curve for CAISO shown in Figure 17 illustrates the relationship between system peak capacity requirements and the frequency and size of DR events needed to achieve a given level of peak capacity reduction. For this case, a 5% reduction in peak load would require 20 hours per year of well-targeted DR. Similar observations were noted for the Public Service Company BA in Colorado, with about 3.5% of peak load reduction potential in only 12 hours of the year (Denholm et al. 2015). The 40 to 100 hours per year of individual DR events previously listed is therefore not a strict rule-of-thumb, but depends on the individual system's desired reliability and peak reduction levels.

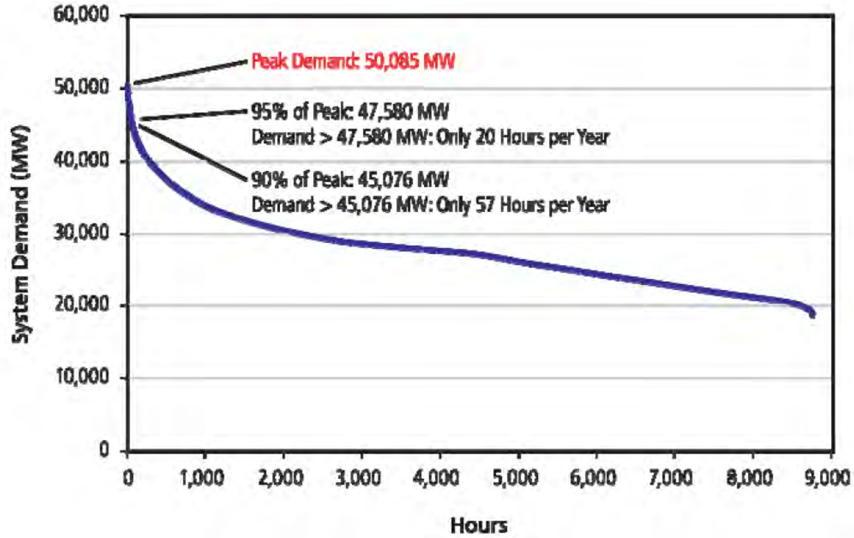


Figure 17. CAISO opportunity for reliability-based demand response

Source: Goldman et al. 2010

Another way for DR programs to benefit the system is through ancillary services, such as contributing to the regulation reserve requirement. Figure 18 shows how the aggregate of numerous responsive load resources can meet the regulation reserve requirement (an ancillary service) in response to the power system operator's automatic generation control signals. This results in an energy-neutral balancing of the minute-to-minute net load deviations. The red line shown on the graph represents the regulation signal sent by the ISO to the DR system server; in this case, the DR system server is Enbala Power Network's real-time control optimization engine "R3OE." Enbala is a DR aggregator for industrial, commercial, and institutional end-users. The green line represents the response of all resources and thus the amount of regulation being provided. Any individual responsive load (each line at the top of the figure) has a very small contribution to the overall regulation requirement, but in aggregate, they can provide a significant and effective resource.

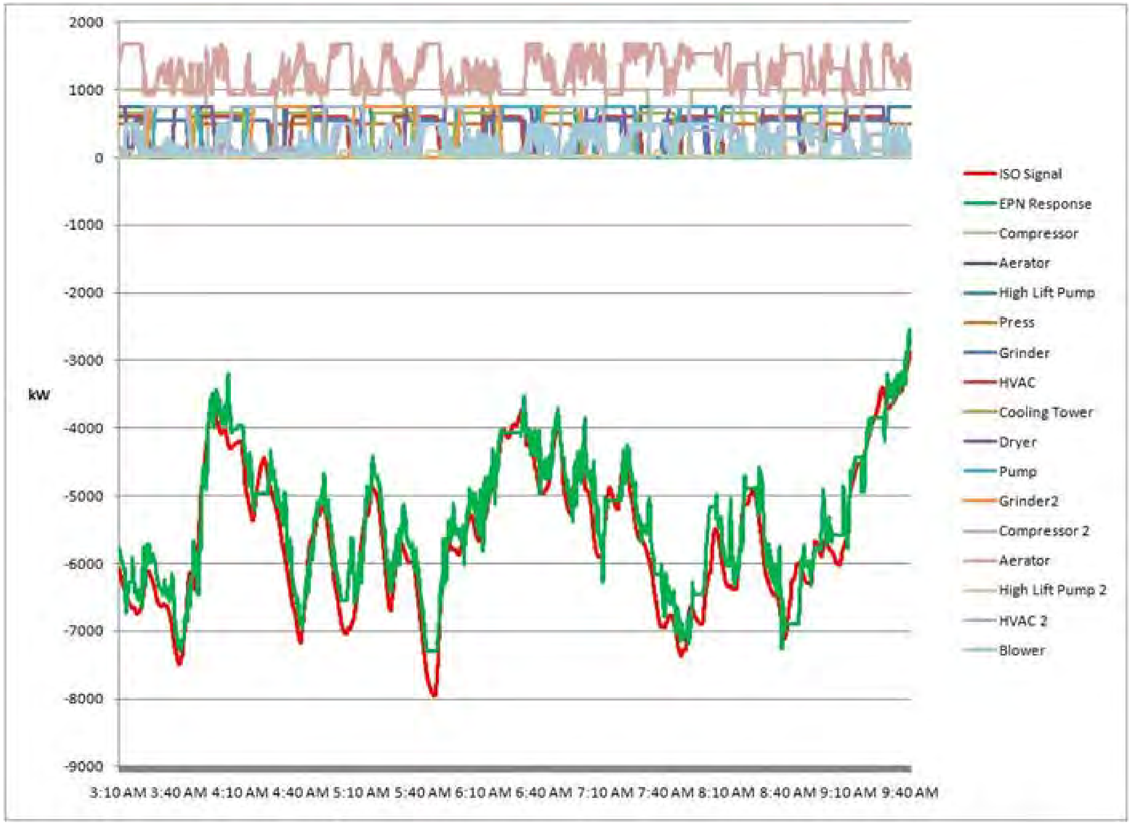


Figure 18. Aggregate demand-side response can meet regulation signal

Source: Milligan 2014b

Hummon et al. (2013) laid out the methods for quantifying these benefits of DR, especially during times when the system is most constrained, in an analysis of DR in the Colorado test system. The study quantified the value of DR to provide energy, capacity, and operating reserves, based on production cost model simulations with aggregate DR resource profiles from Olsen et al. (2013). Results of the study are summarized in the Appendix. The value of DR can be expressed as an annual availability factor[10] (similar to a generator capacity factor) or as the cumulative availability across the year[11] (dollars per megawatt-hour) (Hummon et al. 2013). This value is based on the amount of available resource and its coincidence with times of high production costs, which are generally reflective of times when the system is in greatest need of flexibility.

5.6 Strategic Renewable Energy Curtailment

Curtailment of VG provides flexibility through the physical reduction in supply when more generation is available than the system can utilize. Institutional mechanisms to incentivize and manage that curtailment are critical to accessing this flexibility. The presence of curtailment is an

[10] The annual availability factor is the sum of the maximum capacity available during each time period divided by the peak available capacity times the number of time intervals (i.e., total hours per year).

[11] The cumulative annual availability is the fraction of electricity from an aggregation of end uses that is flexible through DR, which reflects the correlation of each resource's availability to times of high market prices for operating reserves as well as its ability to take advantage of large energy price differences across hours of the day.

indicator of inflexibility in the system, typically resulting because of transmission congestion or lack of transmission access, or less often due to excess generation during low load periods. Usually the most expensive VG plant is curtailed first to alleviate system congestion or to maintain system balance. The economic compensation provided to the VG plant varies and depends on the specifics of the power contract (Bird et al. 2014). In the United States, this economic trade-off is further complicated for projects that utilize production-based subsidies. Some of this curtailed VG can be used for other important grid services, such as regulation up reserves[12], frequency, and ramping services. The economic choice to curtail VG at any given moment reflects the trade-off between the instantaneous value of the energy produced and the value of these other services.

Curtailment of VG is achieved either through manual directives by the system operator or through automated market-based mechanisms, such as special economic dispatch protocols. The first curtailment method is command and control. During over-generation conditions, the system operator can make a decision to curtail VG regardless of whether it is the optimal or economic choice. The level of curtailment ordered by the operator may be too high or too low and may respond too quickly. The second curtailment method is economic curtailment. This incorporates VG generation (and any subsequent over-generation) directly into the economic dispatch process, which (under normal conditions) requires no direct operator intervention and can be done very quickly and cost effectively. In the United States, this method is working today in NYISO and MISO and has attracted significant interest by other regions. Because the use of wind energy is more widespread than solar energy in the United States at the time of this writing, some of the market changes have specified wind energy and not solar energy. In the near future, these approaches may also apply to solar energy. VG resources are bid into the market like conventional generation. The difference is that usually wind will only bid into the dispatch-down market[13]. If this is economical, then that wind will be dispatched downward to help avoid over-generation. As carried out by the real-time market, this can be an optimal solution because (a) only the needed level of dispatch is activated, and (b) the dispatch of wind will only occur if it is the least-cost option.

In 2011, MISO implemented an economic curtailment program called the Dispatchable Intermittent Resource (DIR) protocol, which effectively places the 5-minute dispatch optimization of wind power plants on automatic generation control under command of the MISO real-time market systems. The result is an overall reduction of curtailed VG with a much higher level of operational efficiency and transparency. MISO manages more than 14 GW of wind in its market footprint and has been experiencing local transmission congestion issues during certain periods that were traditionally managed by manual curtailments of specific wind plants. Figure 19 shows monthly total DIR-dispatched wind and the percent that was dispatched downward

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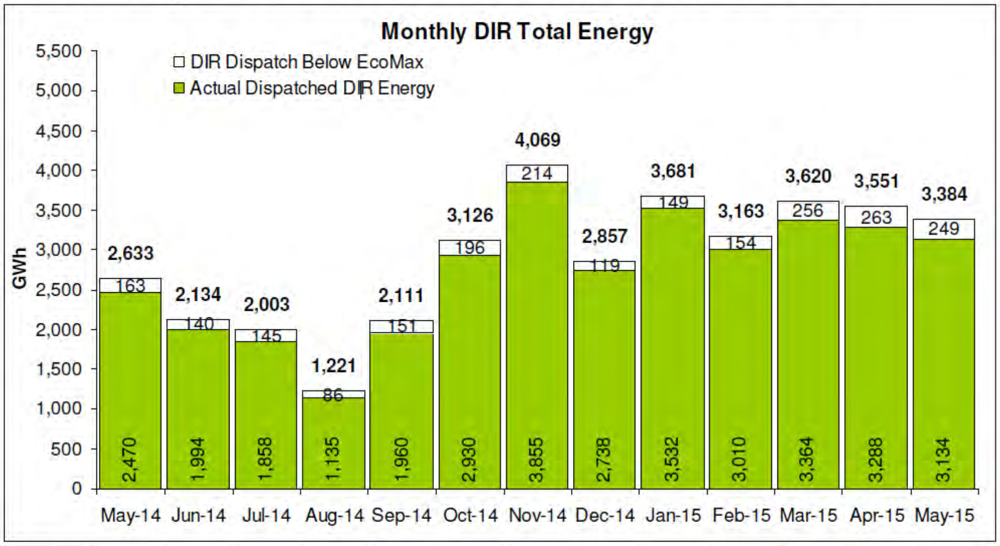
[12] Regulation up service is an ancillary service that provides capacity that can start responding to signals within a set time period (5 seconds in ERCOT). Such capacity is the amount available above any base point but below the high sustainable limit of a generation resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. This typically involves setting aside a portion of output for frequency that would otherwise be used for energy (or that is otherwise curtailed). See more details in ERCOT (2014).

[13] A dispatch down market is a market in which, at times of excessive electricity generation, eligible generators would be offered payments to reduce their output, compensating the unit for its opportunity cost in the energy market.

(below economic maximum) under this DIR protocol. According to MISO, approximately 95% of wind energy's potential can be captured through economic dispatch. All new wind generation facilities in MISO must register as DIRs, and more than 80% of wind generation in MISO is dispatchable.



DIR Dispatch Below EcoMax as a Percent of Available DIR Energy*	6.2%	6.6%	7.2%	7.0%	7.2%	6.3%	5.3%	4.2%	4.0%	4.9%	7.1%	7.4%	7.4%

Figure 19. Wind power plant dispatch in MISO with DIR protocol

Source: MISO 2015

5.7 New Ancillary Services Products

Some market areas in the United States are now investigating the effectiveness of incentivizing energy flexibility as a new ancillary service product, commonly referred to as "FlexiRamp." Such ancillary service products are institutional flexibility measures. Since 2011, CAISO has included a flexibility constraint in its market-clearing engine that ensures that sufficient ramping capacity is committed and available in the real-time commitment and real-time dispatch process (CAISO 2011, Abdul-Rahman et al. 2012). The amount of ramp capability that is required in this constraint is determined by the CAISO operators based on (1) the expected level of variability for the interval, (2) the potential uncertainty as a result of load and VG forecast error, and (3) the differences between the hourly, 15-minute average net load levels and the actual 5-minute net load levels. Units that incur a lost opportunity cost by withholding their capacity from other ancillary services in order to meet this ramping constraint are compensated at an amount equal to the system's incremental cost of increasing the ramping need by one unit. Currently, the constraint is only for upward ramp capability needs. However, CAISO is now proposing to extend this market product to include downward ramping, use the 5-minute real-time dispatch interval rather than the 15-minute real-time pre-dispatch model, include the product in the day-ahead market, and implement a flexibility demand curve to account for both variability (known ramps) and uncertainty (unforeseen ramps).

NREL analysis compares this proposed FlexiRamp product to a look-ahead dispatch with and without freezing the advisory prices. Figure 20 summarizes the financial results for a test system with two generators: G1 is very flexible (100 MW/min ramp rate capability), while G2 is less flexible (10 MW/min ramp rate capability). The positive cash flows (blue bars) are the revenue, negative cash flows (red striped bars) are the costs, and the resulting net profit or loss (diamonds) are shown within each bar, with the value noted above each set of bars. Results with the proposed FlexiRamp product for a single-period dispatch are shown on the left. Results for a multi-period (look-ahead) economic dispatch without the FlexiRamp product are shown in the middle and right sets of bars: the middle set updates the settlement price at each time interval from the look-ahead advisory price, but the right set uses the prices of those future (advisory) time intervals as the final (binding) prices paid to the generators. Results from this analysis reveal that flexible ramping constraints, such as FlexiRamp, perform similar functions as security-constrained economic dispatch from an *operational* standpoint but not from a *pricing/incentive* standpoint. Units that provide reserves for a future (advisory) time interval may not get paid for that service if the binding price is not set to the advisory value, thus removing the incentive of the unit to participate in this market. Thus, other institutional mechanisms, such as utilizing advisory intervals as pricing for the binding interval, can achieve similar outcomes as a flexible ramping product.

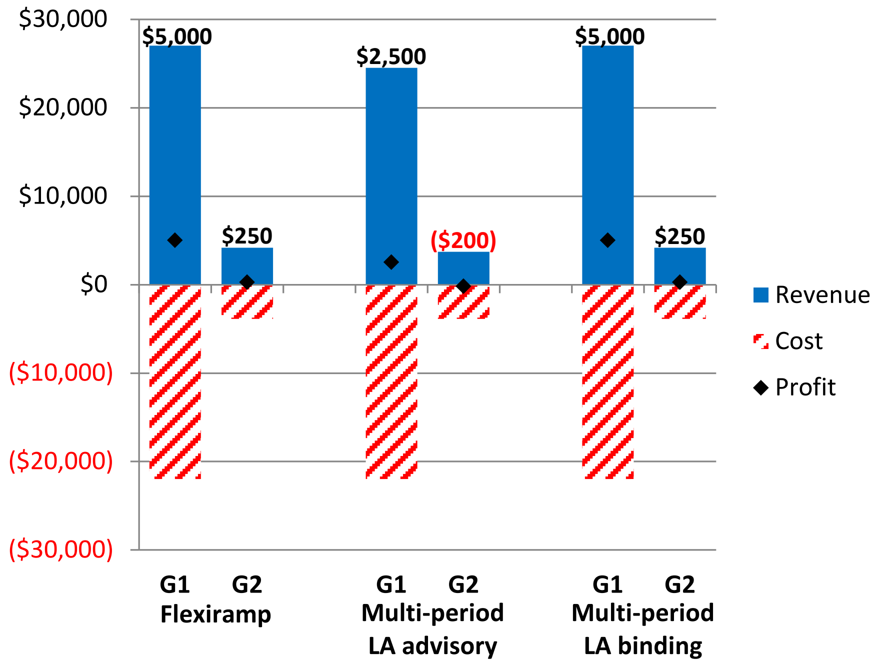


Figure 20. Comparison of CAISO FlexiRamp ancillary service product for a flexible generator (G1) and less flexible generator (G2) for a single period with FlexiRamp, multiple period for current time step (binding), and multiple period for next time step (advisory).

LA = look ahead. Source: Milligan 2014a

5.8 Flexible Conventional Generation Units

Flexible conventional generators, such as coal and natural gas combustion turbines with the ability to cycle on and off and run at lower output in order to follow changes in output from VG, are another important source of physical flexibility. However, the economic viability of these traditionally inflexible plants, particularly coal, which was intended to run at annual capacity factors of around 80%, is uncertain under such operating conditions (Cochran et al. 2013). This is because hardware and extensive operational modifications are required to make these plants flexible (minimum run conditions below 40% of capacity). In China, where coal-fired power plants contribute to over 70% of total electricity generation, a cost-benefit analysis would be of particular importance to determine if the most economical option for these plants is to (a) retrofit, (b) retire, or (c) change operational processes to enhance flexibility. Another option would be to replace or supplement these less flexible generators with fast-start reciprocating engines and combustion turbines with lower minimum loads and higher efficiencies, which can be started within minutes without incurring startup costs and can help provide ramping and non-spinning reserves.

Practical experience in North America has revealed that it is possible to modify a traditionally designed coal plant that was intended to run only at baseload into one that can meet peak demands, cycling on and off up to four times a day to meet morning and afternoon electricity demand (Cochran et al. 2013). Key to this specific success was changing operational practices, as well as inherent design features that facilitate cycling. The main operational changes included monitoring and managing temperature ramp rates, creating a suite of inspection programs for all affected equipment (large and small), and continual training to reinforce the skills needed in monitoring and inspections.

The more frequent start and turndown, or cycling, of traditionally inflexible plants to achieve a higher level of flexibility causes equipment damage, reduces the life expectancy, and impacts emissions. These were modeled and assessed in a comprehensive study of the western United States, which found that up to 33% wind and solar energy led to relatively small cycling impacts on overall emissions and production costs (Lew et al. 2013). Figure 21 summarizes how the additional costs from cycling are significantly outweighed by avoided fuel costs from renewables. However, from the perspective of individual thermal generators, increased cycling costs and lower utilization due to energy displaced by VG may erode profitability. The generator may need higher prices in the ancillary service or capacity markets or other institutional structures to stay financially viable. Market designs and other approaches to incentivize flexibility can help with the transition to a high-renewables future by incentivizing the generation and DR characteristics that are beneficial. Whether this future includes large amounts of retro-fit coal units or alternatives will therefore be a function of the most cost-effective technologies that can provide the needed services under the market structure.

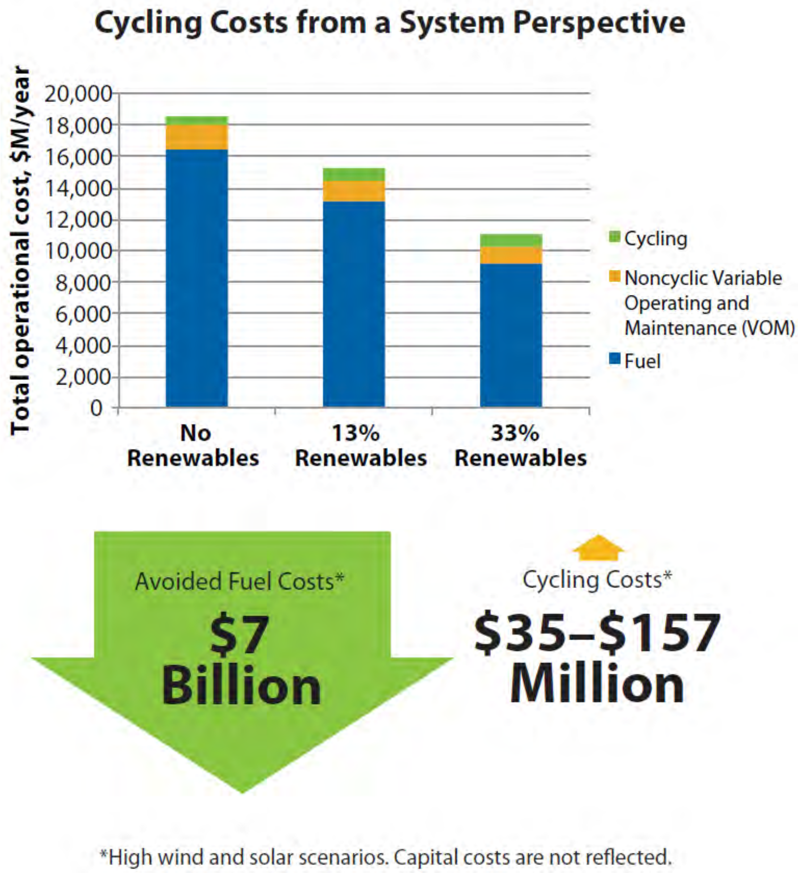


Figure 21. Cycling costs, though can be significant for the plant owner, have a small impact on the overall system operating cost savings due to the integration of renewables

Source: Lew et al. 2013

5.9 Storage

Storage is a physical flexibility option that allows energy produced in one time step to be used, minus efficiency losses, at a later time. Similar to DR, storage can provide firm capacity, energy shifting, and ancillary service benefits. These benefits are determined primarily by the discharge time, as shown in Figure 22. Storage technologies that can respond to changes in demand on short time scales, from minutes to fractions of seconds, are better adapted for power management (bottom left section in this figure). These rapidly responding technologies provide transient stability, frequency regulation, and other ancillary services to maintain voltage and frequency levels within prescribed bounds. Technologies in this regime include flywheels, super-capacitors, and a variety of batteries, which often have smaller capacities. Storage technologies that are better adapted for energy management (upper right section in this figure) provide continuous discharge for extended periods of time to balance changes in load over longer time scales, from days to weeks to seasons. These larger capacity technologies offer firm capacity and energy shifting (arbitrage) services and include pumped hydroelectric storage and compressed air energy storage. Figure 22 does not show thermal energy storage, which would cover a power range from 1 kW (building) to more than 100 MW (concentrating solar power plants), with a discharge time of minutes to several hours (Denholm et al. 2010). An additional cost comparison of select storage technologies is shown in Figure 4.

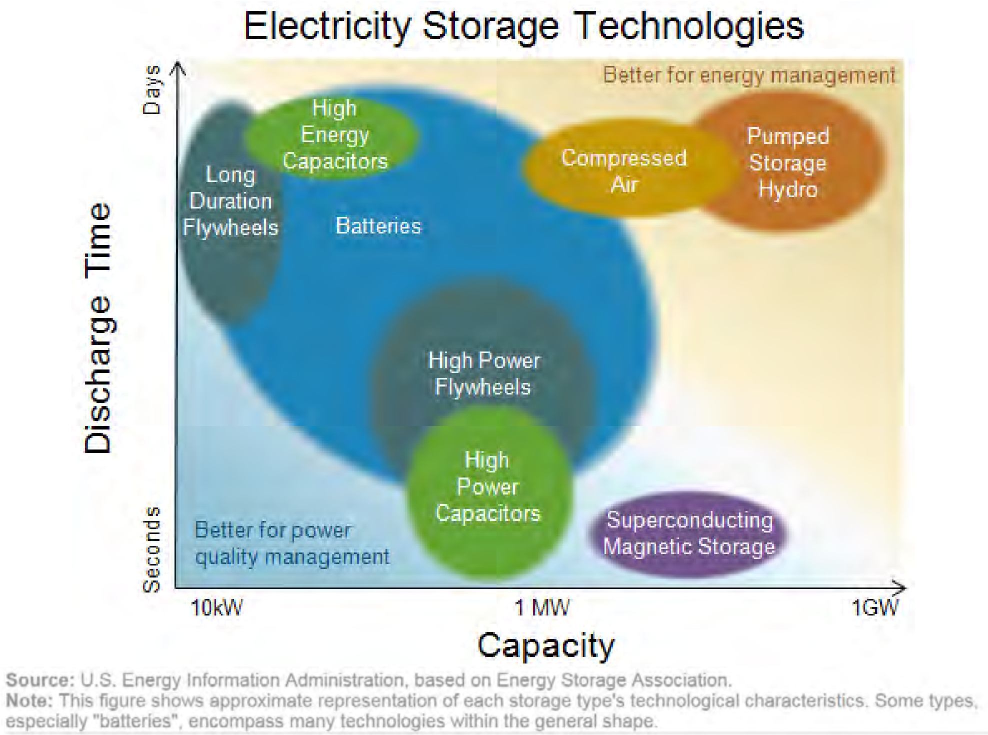


Figure 22. Energy storage technologies and ratings

Source: EIA 2011

The value of storage to the system depends on multiple factors, and—like DR—quantifying this value has been a key challenge for developers in the United States, especially because some benefits are not fully realizable in many markets. Simple metrics, such as levelized cost of energy, are not sufficient; detailed time-series analysis using software tools to co-optimize multiple services provided by different storage technologies are required to properly value storage (Denholm et al. 2013).

The effectiveness of storage depends on many factors, including physical characteristics of the storage technology used (discharge time, efficiency, cost, and storage size on both an energy and capacity basis) and characteristics of the power system (VG penetration, portfolio of VG technologies, amount of existing flexibility). Figure 23 shows one example[14] of how the value of storage (blue, left axis) increases as the penetration of solar generation increases, but this value is diminished when the existing system is more flexible (right versus left plot). Additionally, curtailment of solar generation increases as the penetration of solar increases (right axis), but this curtailment is dampened when storage is present (red versus black lines).

[14] This example is based on the CAISO system with a high diversity of solar generators across the southwest United States. The storage resource assumes 10% of peak capacity with 1 week of storage. The current resource mix case represents a medium-term system that contains about 80% incumbent generators and assumes some load growth and generator retirements. The flexible resource mix case represents a long-term system that has reached a generation equilibrium.

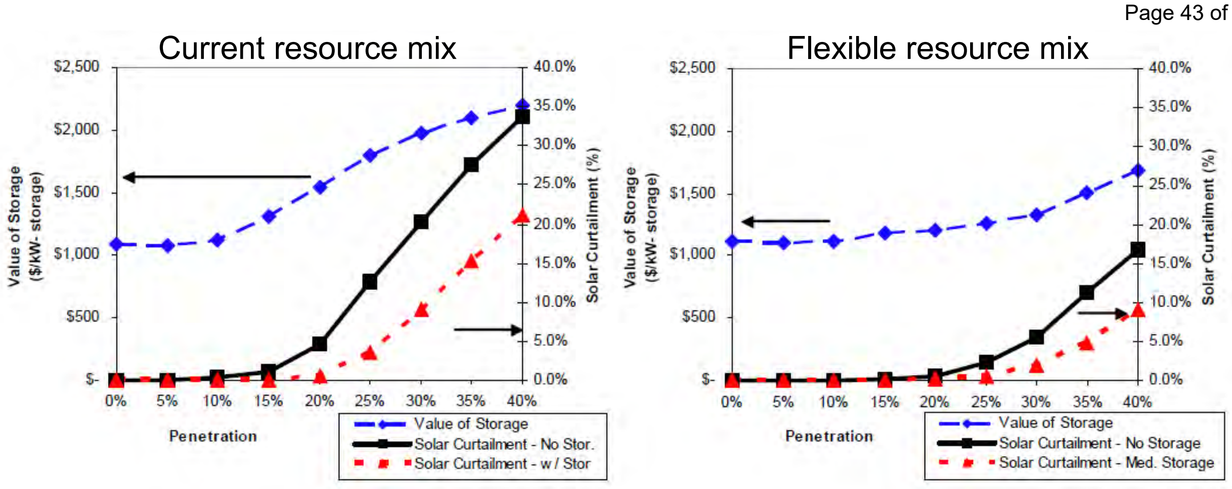


Figure 23. Value of flexibility (shown here for solar) depends on system flexibility and VG penetration

Source: Mills 2008

In the United States, the value of energy storage in restructured markets has historically included energy shifting (arbitrage) and ancillary services (regulation and contingency reserves). Table 4 summarizes these values. In these markets, energy and ancillary services are co-optimized so that the least-cost mix of generators is chosen to provide the necessary energy and ancillary services. Thus, the use of energy storage technologies previously mentioned and shown in Figure 23 (e.g., pumped hydro, batteries, etc.) must compete with other sources of flexibility.

Table 4. Historical Values of Energy Storage in U.S. Restructured Electricity Markets

Market Evaluated	Location	Years Evaluated	Annual Value ($/kW)	Assumptions
Energy Arbitrage	PJM[a]	2002–2007	$60–$115	12 hour, 80% efficient device. Range of efficiencies and sizes evaluated. Also considers price difference suppression effect in a market setting using price/load relationships.
	NYISO[b]	2001–2005	$87–$240 (NYC) $29-$84 (rest)	10 hour, 83% efficient device. Range of efficiencies and sizes evaluated.
	USA[c]	1997–2001	$37–$45	80% efficient device. Evaluates ISO-NE, CAISO, PJM
	CA[d]	2003	$49	10 hour, 90% efficient device.
	CA[f]	2010–2011	$25–$41	4 hour, 90% efficient device.
	CA[h]	2011	$46	16 hour, 75% efficient pumped storage device.
Regulation Reserves	NYISO[b]	2001–2005	$163–$248	
	USA[e]	2003–2006	$236–$$429	PJM, NYISO, ERCOT, ISO-NE.
	CA[f]	2010–2011	$117–$161	Co-optimized arbitrage and regulation, most value is derived from regulation.
Contingency Reserves	USA[e]	2004–2005	$66–$149	PJM, NYISO, ERCOT, ISO-NE.
Combined Services	CA[f]	2010–2011	$117–$161	Arbitrage and regulation, most value is derived from regulation.
	CA[h]	2011	$62–$75	Arbitrage, regulation, and contingency. Included operational constraints of pumped storage.
	USA[g]	2002–2010	$38–$180	Arbitrage and contingency. CAISO, PJM, NYISO, MISO.

[a] Sioshansi et al. 2009
[b] Walawalkar et al. 2007
[c] Figueiredo et al. 2006
[d] Eyer et al. 2004
[e] Denholm and Letendre 2007
[f] Byrne and Silva-Monroy 2012
[g] Drury et al. 2011
[h] Kirby 2012

Source: Denholm et al. 2013

6 Cost-Effectiveness Evaluation of the Options

Multiple approaches to obtain flexibility may be available, in which case it is usually desirable to perform an analysis to compare the costs and benefits of these approaches. In some cases, institutional improvements are most cost-effective because they provide access to flexibility that currently exists, but is otherwise not accessible to the power system operator. Improvements such as large BAs and fast economic dispatch have value even in systems with no VG, and this value can be significantly enhanced with large VG levels. Once implemented, these features will have a long useful life, and therefore deliver benefits over the very long term. Similarly, new transmission interconnections, when coupled with efficient means to pool the operating requirements of two or more regions, have a long life and can therefore provide lasting benefits.

Other flexibility improvements may be more short-lived or may perhaps depend on external factors such as fuel prices. As a general rule, alternative flexibility options can be analyzed in the context of production simulation modeling. The value of each alternative can be calculated by adding it to the mix, adjusting other modeling parameters accordingly, and calculating the production cost savings. This can be done over the long-term, or suitable estimates of the long-term value based on short-term evaluations can be made (but are not as robust). Sensitivities to external factors such as fuel prices, alternative resource mixes, different rates of demand growth or composition, and many others may change the value of any mitigation option.

The value of a given flexibility option will also depend upon what other options have already been adopted. This is illustrated in Figure 10. Using the example data in the diagram, suppose the flexibility option that is under evaluation is the size of the BA. First, let us suppose that all of the regions are operating with a 60-minute dispatch with a 40-minute notification period. The reduction in regulating needs can be estimated as the difference between the green bars in the “small” grouping and in the “large” grouping: approximately 5,000 MW. Alternatively, suppose that all of the regions are already operating at a 10-minute dispatch with a 10-minute notification period (blue bars in the figure). In this case, the reduction in regulating needs is approximately 1,400 MW. Thus, the benefit of a large BA depends on (among other things) the dispatch time step. Because of the non-linear nature of the power system, it is likely that the value of any given source of flexibility depends on other sources that have already been, or have been assumed to have been, adopted.[15]

[15] A similar argument can be made based upon Figure 23, which compares the value of storage in an inflexible system as compared to an already-flexible system.

7 Other Planning Considerations/Issues

Even in regions with large electricity markets, including the United States and Europe, the markets are regulated to ensure that the well-known shortcomings of electricity markets can be mitigated. Ela et al. (2014a) provide a very detailed examination of wholesale electricity market characteristics and impacts, showing some key areas that have not been well thought out. Established text books on power system economics (e.g., Stoft 2002) provide broader frameworks that do not include the consideration of renewables. Therefore, the interplay between the regulatory environment and any market mechanisms must be thoroughly analyzed. For example, in parts of the United States and Europe, there is increasing concern regarding the ability of the energy and ancillary service markets to sufficiently incentivize the development of new capacity that has the needed flexibility characteristics. The extent to which this is a problem is not yet well-known, and possible solutions include several versions of forward capacity markets (with or without flexibility requirements, or tranches). The market structures provide the enabling environment for ensuring both resource adequacy and sufficient flexibility, alongside the appropriate reimbursement mechanisms to incentivize needed attributes of both current and future resources.

8 Conclusions

Worldwide experience with integrating renewables, along with results from high-quality wind/solar integration studies (see Milligan et al. 2015 for a U.S.-based summary) show that integration can be done effectively if the system operator has sufficient tools to manage the increase in variability and uncertainty that will occur with VG. Flexibility is important, and multiple approaches exist for measuring the need for flexibility and the extent to which it is available. Similarly, multiple approaches may be considered to ensure sufficient flexible capacity will be available in the future when it would be needed. Long-term resource adequacy and flexibility are critical considerations for system planning. Multiple approaches and combinations of physical and institutional components, including forward capacity markets, ancillary services markets and other market constructs have proven effective. Assessments of future flexibility needs and evaluation of various market (and technical) constructs utilizing state of the art approaches to security-constrained economic dispatch analysis, combined with sophisticated reliability analyses offer important insights into the discussions for both physical and institutional market developments. Unintended consequences of market design, such as the misalignment of the incentives for generators to provide frequency response in energy markets (Ela et al. 2012a), should be carefully considered and mitigated when they are identified.

Market solutions for economic dispatch and for the acquisition of ancillary services have been shown to be effective in many parts of the world. The key factors that energy markets provide include (1) large BAs, (2) fast energy markets, and (3) incentives for generators to operate efficiently. Markets are not perfect, however, and in the United States and elsewhere there is a significant body of literature that supports the public regulation of electricity markets. The path forward for China may include the development of energy and ancillary service markets, but it may instead comprise other means of providing system flexibility to deliver reliable, affordable power that accommodates the renewable energy goals of the country. Options to consider include a market-like economic dispatch run by State Grid of China Corporation and China Southern Power Grid, some form of EIM,[16] or a full RTO-like structure.

[16] We note that the EIM as implemented in the United States does not include coordination of unit commitment, which likely results in economic inefficiencies. However, the EIM may be a good first step that results in jointly optimizing dispatch, setting the stage for future coordination of unit commitment that could result in additional cost savings and efficiencies (e.g., E3 2015).

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Appendix

Table A-1 shows the DR resource ability during the top 20 hours of load (as a proxy for capacity provision). Figure A-1 shows the value of DR services across a full year.

Table A-1. Availability of Demand Response to Provide Energy in the Colorado Test System on an Annual Basis as Well as in the Top 20 Hours of Greatest Demand

Demand Response Resources Providing Energy[a]	Annual			Top 20 Load Hours	
	Capacity (mean/min/max) [MW][b]	Annual Available Energy with Constraints [GWh][c]	Annual Hours Available[d]	Capacity (mean/min/max) [MW]	% of Load (mean/min/max)
Residential Cooling	10.9 / 0 / 108.7	38.8	5,390	55.1 / 41.3 / 72.2	0.4 / 0.3 / 0.5
Residential Water Heating	1.8 / 0.5 / 3.9	15.7	8,784	1.3 / 1.1 / 1.6	0 / 0 / 0
Commercial Cooling	2.1 / 0 / 46.4	10.7	4,338	8.2 / 4.2 / 12.9	0.1 / 0 / 0.1
Commercial Heating	2.2 / 0 / 25.5	3.8	8,390	0 / 0 / 0	0 / 0 / 0
Municipal Pumping	1.7 / 0.4 / 3.8	2.1	8,784	2.1 / 1.7 / 2.7	0 / 0 / 0
Wastewater Pumping	1.5 / 1.5 / 1.5	1.6	8,784	1.5 / 1.5 / 1.5	0 / 0 / 0
Refrigerated Warehouses	0.2 / 0 / 0.4	0.3	8,685	0.3 / 0.3 / 0.4	0 / 0 / 0
Agricultural Pumping	17 / 1.7 / 41.2	49.9	8,784	36.6 / 32 / 40	0.3 / 0.2 / 0.3
Data Centers	8 / 8 / 8	11.7	8,784	8 / 8 / 8	0.1 / 0.1 / 0.1
Total[e]	**45.4 / 14.5 / 227.8**	**134.6**	**8,784**	**113.1 / 91.8 / 137.3**	**0.8 / 0.7 / 1**

Source: Hummon et al. 2013

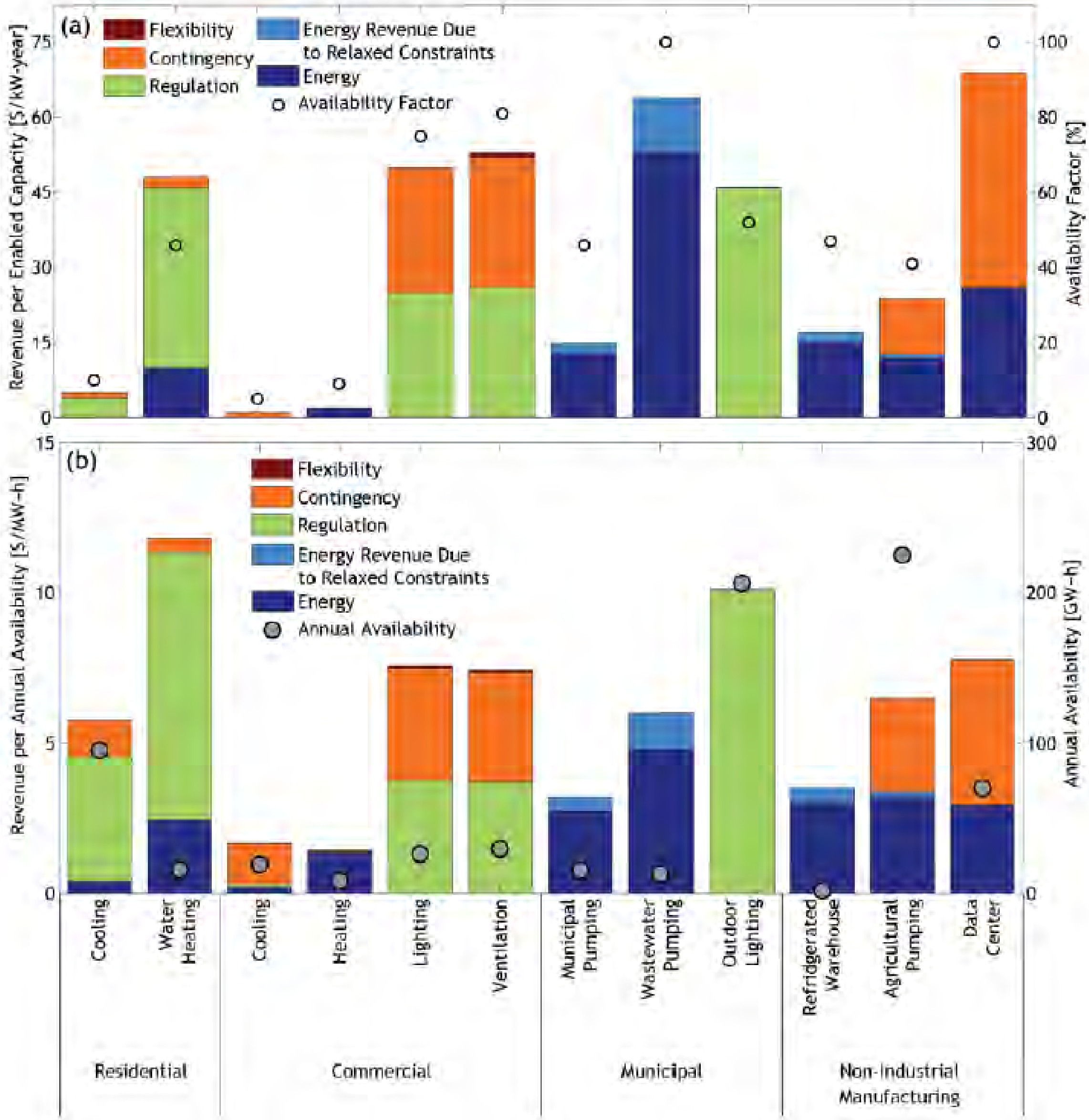

Figure A-1. Average annual revenue (left axis) from the day-ahead market per (a) total enabled capacity and (b) annual availability for each type of DR resource in the Colorado test system

Annual DR resource availability (right axis) is expressed as the (a) annual availability factor or as (b) total annual availability.
Source: Hummon et al. 2013

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Michael Milligan and Brendan Kirby

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Topics: Demand Response
Power System Operations and Wind Energy

Abstract

Responsive load is still the most underutilized reliability resource in North America. It has the potential to provide balancing capability over all time frames: from seconds to seasons. Responsive load could significantly aid in the integration of variable generation sources like wind and solar if institutional frameworks can be developed that will induce loads to respond to price or other signals. This paper examines the balancing requirements imposed by large penetrations of wind generation and characterizes them in terms that are relevant for load response. The relative magnitude, frequency, and duration of events are all important, as are ramp rates and notification times. Responsive loads and generation may interact synergistically to provide better overall response. The statistical behavior of large aggregations of small loads may work well with wind and solar integration. Very large penetrations of wind generation create light load reliability concerns for the power system. These reliability concerns may be economic opportunities for a number of loads that are dependent on low cost energy but which are also flexible in their use. We discuss response potential in the short-run, given a fixed level of resources, and in the long-run where the resource mix can change. Before building or otherwise acquiring new resources, entities (either load or generation) must be assured of a reasonable level of price stability and energy availability. This paper examines the characteristics of concern to the power system, the renewables, and to the loads. The roles of local and regional transmission in facilitating load response are examined.

Introduction

Wind and solar generation add variability and uncertainty to the power system. These are not new characteristics; load itself is variable and uncertain. Sudden unplanned failures make conventional generation variable and uncertain. Wind and solar simply increase the variability and uncertainty of the aggregate power system. The power system deals with uncertainty and variability by having a series of reserves available to respond. The reserves are characterized by their response speed, response magnitude, response frequency, and response duration. Some are dedicated ancillary services, explicitly designed and procured to address a narrow aspect of variability and uncertainty. Others are a characteristic of how energy is scheduled in real-time. All of these efforts deal with controlling the balance of generation and consumption of real power. Historically, this control has concentrated on the generation side, but that is not necessary. Control of energy consumption can be equally effective and often more economic than control of energy supply.

Historic demand response programs have focused on reducing overall electricity consumption by increasing economic efficiency via price-response mechanisms, and by shaving peaks. More recently, responsive loads have started to provide contingency reserves and even minute-to-minute regulation. Rather than reducing overall power system stress by reducing peak loading over multiple hours, these programs are targeted to immediately respond to specific reliability events. This is made possible by advances in communications and controls, and has benefits for the power system and the load. Many of these programs have been successful but demand response remains a limited resource.

As wind and solar increase power system variability and uncertainty, they increase the need for response. Since wind and solar also displace conventional generation, they can reduce the amount of generation that is available to provide response. Demand response may be able to fill this gap, benefiting renewables by facilitating integration, the responsive load through paid services, and all customers through lower costs. Existing ancillary services and reserves specifically designed to respond to large, infrequent ramps which are slower than conventional contingencies are important. The renewables community should support efforts by FERC and others to increase opportunities for demand to provide response to the power system.

Response Requirements

Wind and solar generation are variable and uncertain in all time frames, but wind ramps tend to be slower than load ramps.[1] Figure 1 shows the annual hourly aggregate load and wind for the Northwest balancing areas for 2006 with enough wind generation added to meet 16% of the annual energy requirement (12,026 MW of wind in a 38,952-MW peak load region), while Figure 2 shows one week in January. The seasonal and daily load pattern is apparent as is the slower but less predictable wind variability. Figure 3 presents the hourly energy duration. The net load (load less wind) is naturally lower than the load alone, but the duration curve also has a more pronounced "S" shape with a shorter peak and a sharper minimum. Meeting the net load will require more flexibility than serving the load alone.

The changed load duration shape itself presents an increased opportunity for demand response. There is greater value in reducing load during the super peak because the capital cost of generation designed to serve those last few hours has fewer hours over which to be spread the cost. For example, the highest 4000 MW of demand (roughly 10%) lasts 124 hours for the load alone, and only 66 hours for the load-net-wind. The hourly capital cost of a combustion turbine dedicated to

[1] Both wind and solar generation (excepting of solar thermal with storage) are variable and uncertain. Significantly more wind data and experience is available, however, so this section will concentrate on wind response requirements. However, some of this discussion will also apply to solar, and can be re-visited once more solar data is available for analysis.

supplying those last hours would rise from $605/MWh to $1136/MWh, likely making additional demand response more attractive.

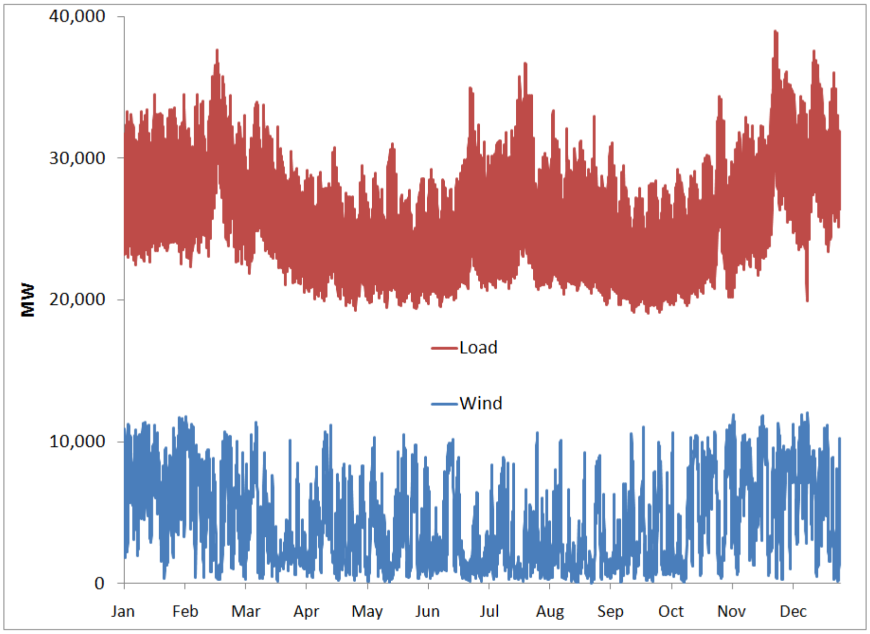

Figure 1 − Load and wind are both variable on time scales ranging from minutes to seasons.

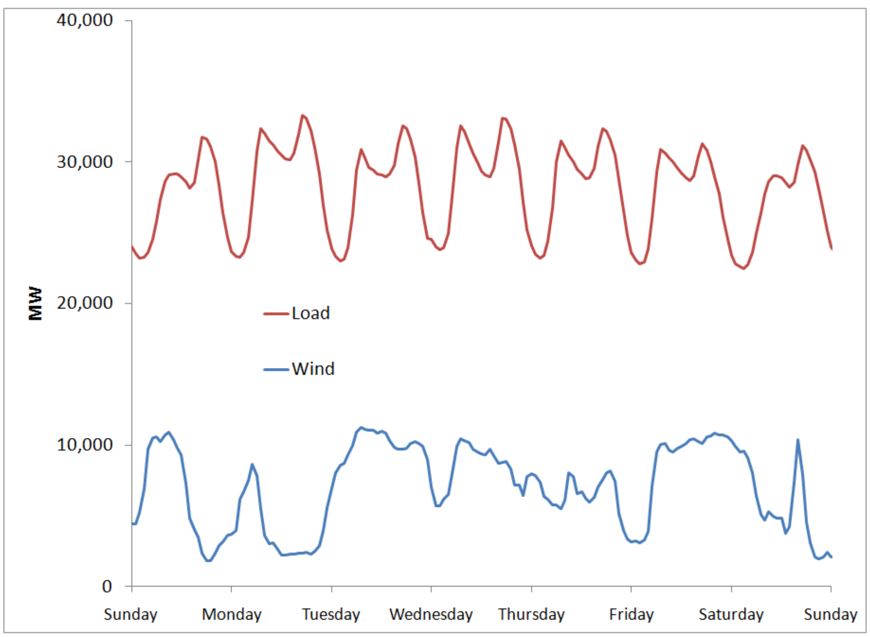

Figure 2 − The slower, less predictable nature of wind is evident when compared with the typically daily load pattern.

Figure 3 also shows that wind typically reduces the system minimum net load. This can create a problem for baseload generation that is unable to back down. Either wind must be spilled or baseload generation must be decommitted when net load is below the minimum load capability of the conventional generation fleet. Decommitting baseload generation may have adverse impacts on the optimal generation mix for the following day. The ability to spill wind addresses the reliability concern but it leaves the economic problem of wasting free energy and loosing environmental credits. As will be discussed later, the minimum load "problem" may be a real opportunity for the appropriate type of responsive load.

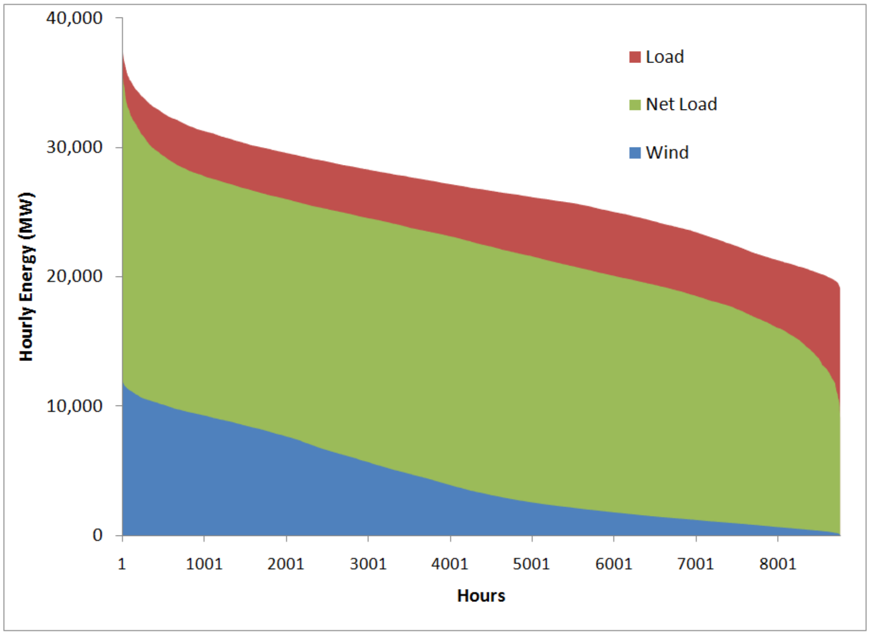

Figure 3 – Adding wind accentuates the "peaky" nature of the load duration curve.

Wind also impacts the system ramping requirements. Figure 4 shows the annual 1-hour ramp duration curve for load, wind, and load-net-wind. For most of the hours, the load ramping requirement exceeds the wind ramping requirement and the net ramping requirement is not greatly increased. Wind ramping differs from load ramping in three important ways, however. First, wind is less predictable than load. The daily load ramping pattern is clear in Figure 2, while a wind pattern is not. Second, the wind ramp duration curve in Figure 4 has a clearer "S" pattern than load; there are a few hours with significantly higher wind ramping requirements in both the up and down directions. Third, wind and load ramping patterns are not symmetric. This last point is made clearer in Figure 5 where the highest 50 hours are shown. Both Figures 4 and 5 are referenced to load and net load so negative numbers actually represent wind increases.

The "peaky" nature of the wind ramp duration curve says that there are few large ramps. This makes wind ramps similar to conventional generation and transmission contingencies: large, infrequent events that can threaten reliability. The relatively infrequent nature of the large wind ramps also suggests that, like conventional contingencies, reserves should focus on standby costs rather than on response costs.

The lack of symmetry in the wind ramp duration curve is important as well. Load increases (and wind decreases) are a reliability concern. If there is insufficient conventional generation or voluntary demand response, the power system is in serious trouble. Load drops (and wind increases) are less of a reliability concern. If other more expensive generation physically can not back down, then properly equipped wind plants can be curtailed to maintain the load/generation balance. The wind up ramps (and load down ramps) can be a serious economic concern, as well as an opportunity for responsive load, but typically not a reliability concern. The lack of symmetry is shown in Figure 5 where there are five hours when the one-hour wind down-ramp rate exceeds the maximum load up-ramp rate. There are 78 hours, however, when the one-hour wind up-ramp rate exceeds the maximum load down-ramp rate. The maximum one-hour load up-ramp rate is 1200 MW/hr greater than the maximum load down-ramp rate, while the maximum wind up-ramp (equivalent of load down-ramp) exceeds the maximum wind down-ramp by 612 MW/hr. Unfortunately, load ramps harder in the up direction. Fortunately, wind ramps harder in the down direction.

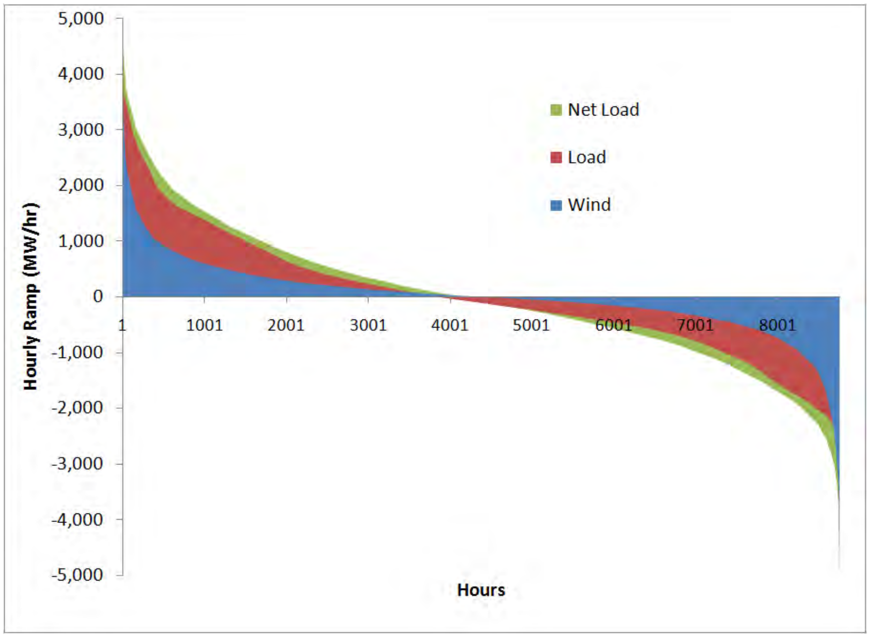

Figure 4 – Large wind ramps are relatively infrequent while load ramps are more evenly distributed.

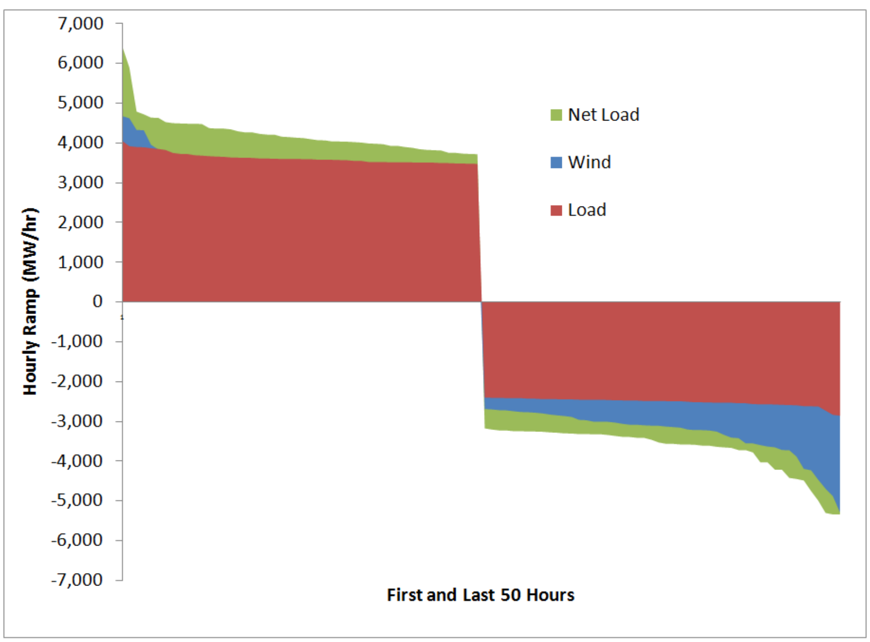

Figure 5 – The non-symmetric nature of large wind ramps is evident from the first and last 50 hours of the ramp duration curve.

Figure 6 extends the analysis to look at ramping requirements over a range of ramp durations from 10 minutes to 12 hours. The curves show the maximum daily MW ramping capability required for ramps of different durations. For example, the maximum daily 12-hour load up-ramp is 6757 MW 50% of the time. These capacity numbers are not completely definitive, of course, since a one-hour ramp may be followed by another one-hour ramp; shorter ramps are often parts of longer ramps. Still, the curves provide insight into the amount of ramping that is required over different time frames. As above, the wind ramps in Figure 6 are referenced to the load ramps for ease of comparison (+ for both the load ramps and the wind ramps is movement in the direction of increasing net load). This analysis confirms that large wind ramps of any duration, but especially for ramps lasting 4 hours or less, are less frequent than load ramps. Large wind ramps are again more like contingencies.

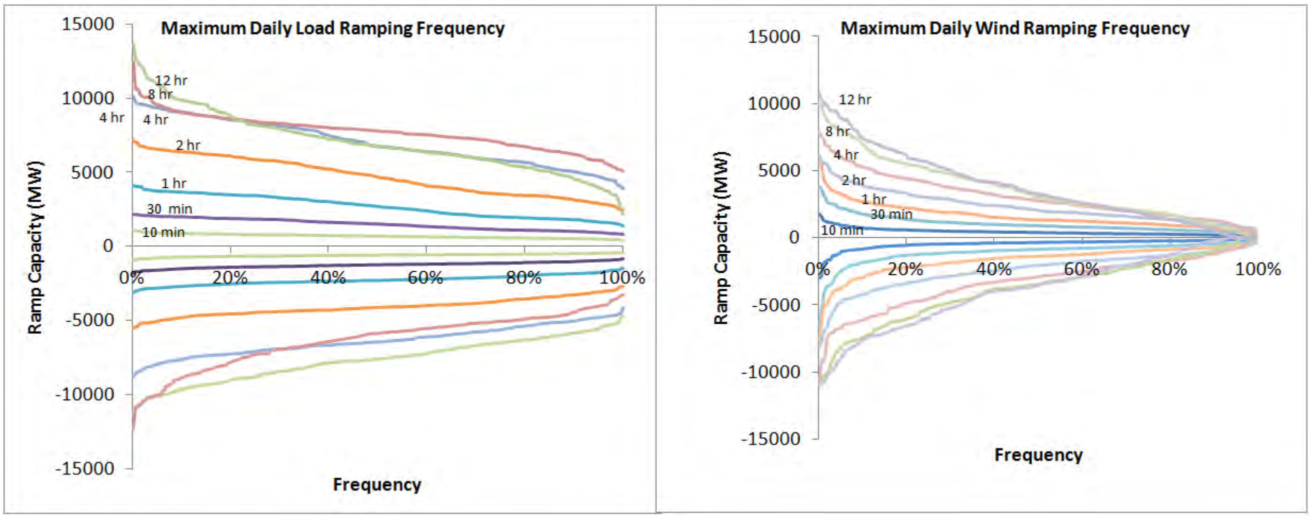

Figure 6 − Maximum daily load and wind ramp frequency for ramps with durations from 10 mintes to 12 hours.

Response Characteristics

Four basic characteristics determine what type of response loads can provide: response frequency, response duration, response speed, and response magnitude. Response notification could also be listed, and is an important consideration for demand response that addresses peak load conditions. We do not list it because, unlike peak load days which are reasonably well predicted the day ahead, wind and solar variability is not well predicted far in advance. Demand response used for wind and solar integration needs to respond with little notification, although it may be possible in some cases to provide information on the *likelihood* of potential response.

Response Frequency

Broadly speaking, response is required continuously (regulation and load following) or infrequently (contingency reserves). Regulation and load following deal with the constant variability and uncertainty, while contingency reserves deal with large, sudden, infrequent excursions. The distinction in event frequency is important because it drives the desired reserve characteristics. The standby cost for contingency reserves is more important than the cost to actually respond because response is required relatively infrequently. Regulation and load following response is constantly required, so the cost of response itself is more important. This distinction can be seen in the selection of generation that supplies response. Non-spinning reserve is often supplied by fast-start combustion turbines whose low capital cost makes standing by inexpensive. The high fuel cost when operating is not a major concern since they do not operate often. Similarly, some loads are better able to provide infrequent contingency response more easily than continuous regulation or load following. The frequency of response (and duration) is more important to some responsive loads than response speed or predictability. Large wind and solar ramps are similar to conventional generation contingency events in terms of infrequency and large magnitude. They tend to differ in that they are slower than the instantaneous failure of a conventional generator. They may require a response that is similar to non-spinning or supplemental operating reserve.

Response Duration

Response duration is not critical to most generators. Once operating, they can continue to do so indefinitely.[2] Costs typically decline with response length as startup costs, for example, are spread over more MWhs. Responsive loads often differ in that response is interrupting their normal flow of business. Longer interruptions are often more disruptive and costs rise with response duration. This is true for loads as diverse as residential air conditioners and aluminum smelters: short interruptions are low cost, but long interruptions are expensive or intolerable. Demand response for wind and solar tail events can be especially effective in dealing with the initial disruption with energy markets providing the slower response that releases demand to return to its normal business.

Response Speed

Response speed is a major concern for generators supplying ancillary services with faster services commanding significantly higher prices. Regulation is the most expensive ancillary service while load following is typically extracted from sub-hourly energy markets at little or no cost. Spinning reserve is two to ten times the price of non-spin in hourly ancillary service markets. Some responsive loads require so much advanced warning that they are not able to provide contingency reserves. For loads that can supply contingency reserves, response speed is typically a communications and control concern rather than a limitation of the demand response itself.

Response Magnitude

Response magnitude distinguishes regulation from contingency reserves. The minute-to-minute random variability of aggregate load is typically one to two percent of the system peak. Wind and solar are typically more variable than load in the regulation time frame per-unit, but not dramatically. The daily load pattern swing is much larger, but it is predictable and it is compensated for through the energy markets or through economic dispatch rather than with a dedicated reserve. Conventional generation and transmission contingencies can be 2000 MW or greater. Wind and solar variability follows a similar pattern with frequent small variations and infrequent large ramps. A difference is that wind and solar ramps are slower than the instantaneous conventional contingency events, with large wind ramps that may take two hours to move two-thousand MW.

[2] Emissions-limited or energy-limited (hydro) generators are an exception.

Existing Demand Response Programs

Utilities have effectively implemented demand response programs for decades, primarily for multi-hour peak load reduction. While many of these programs have been successful, demand response remains a limited resource. The Federal Energy Regulatory Commission (FERC) has recently issued two reports that assess the current state of demand response and begin to draft a national plan for increasing demand response: “A National Assessment of Demand Response Potential” (FERC, 2009) and “National Action Plan on Demand Response (Draft)” (FERC, 2010). FERC found that there is a significant amount of demand response being used today, and the potential for a great deal more with current demand response programs tapping less than a quarter of the resource. FERC’s assessment is significant because it is influencing policy that is likely to result in reliability and market rule changes that increase the amount of demand response. Further, FERC specifically recognizes demand response as useful in supporting variable generation integration.

Figure 7 shows five basic types of demand response (Kirby, 2006). All types except simple energy efficiency are potentially useful in providing response that facilitates variable renewable generation integration. Traditional programs focused on peak shaving and price response. These are two quite different methods for achieving essentially the same physical effect; reducing aggregate demand for a few hours during times of actual or expected system stress. Loads as diverse as residential water heaters and large industrial processes can be used. Response can be either manual or automatic. Time-of-use pricing programs are structured around fixed daily schedules. Interruptible load programs give control to the power system operator, often with restrictions on when and how often response can be called for.

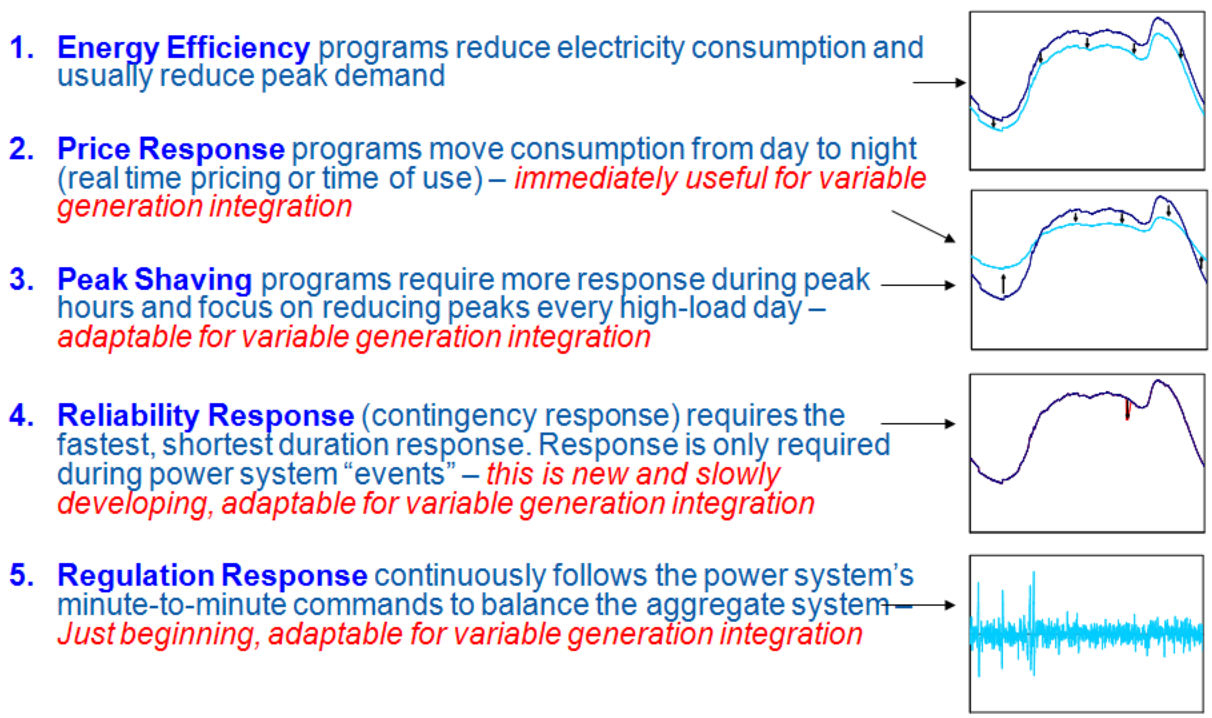

Figure 7 − Four of the five basic types of demand response are potentially useful for facilitating integration of variable renewable generation.

More recently, demand response has begun to be used to directly supply ancillary services to the power system. Rather than reducing overall power system stress by reducing peak loading over multiple hours, these programs are targeted to immediately respond to specific reliability events. This is made possible by advances in communications and controls. A few responsive loads have just begun supplying minute-to-minute regulation, responding to the power system operator's automatic generation control signals. Institutionally, the North American Electric Reliability Corporation (NERC) and the North American Energy Standards Board (NAESB) have recognized that demand response can provide essentially all of the types of response as generation. Figure 8 shows the structuring of demand response hierarchy. Both direct control and customer price response options are covered, as are real-time and day-ahead notification programs.

Nationally, FERC finds that current demand response programs can reduce peak consumption by 4%. Response is greater in some states and lower in others, partly because of regulatory disposition. California, Florida, and New England lead the country while Alaska, Montana, and Wyoming have little or no demand response. Demand response is increasing in the organized markets. ISO/RTOs currently obtain nearly 32,000 MW of response, 6.6% of peak load. If demand response were to spread to areas with little demand response, the total U.S. demand response would be a 9% reduction capability in peak demand. NERC shows current demand response by region and projected response in 2018 in Figures 9 and 10. (NERC, 2009)

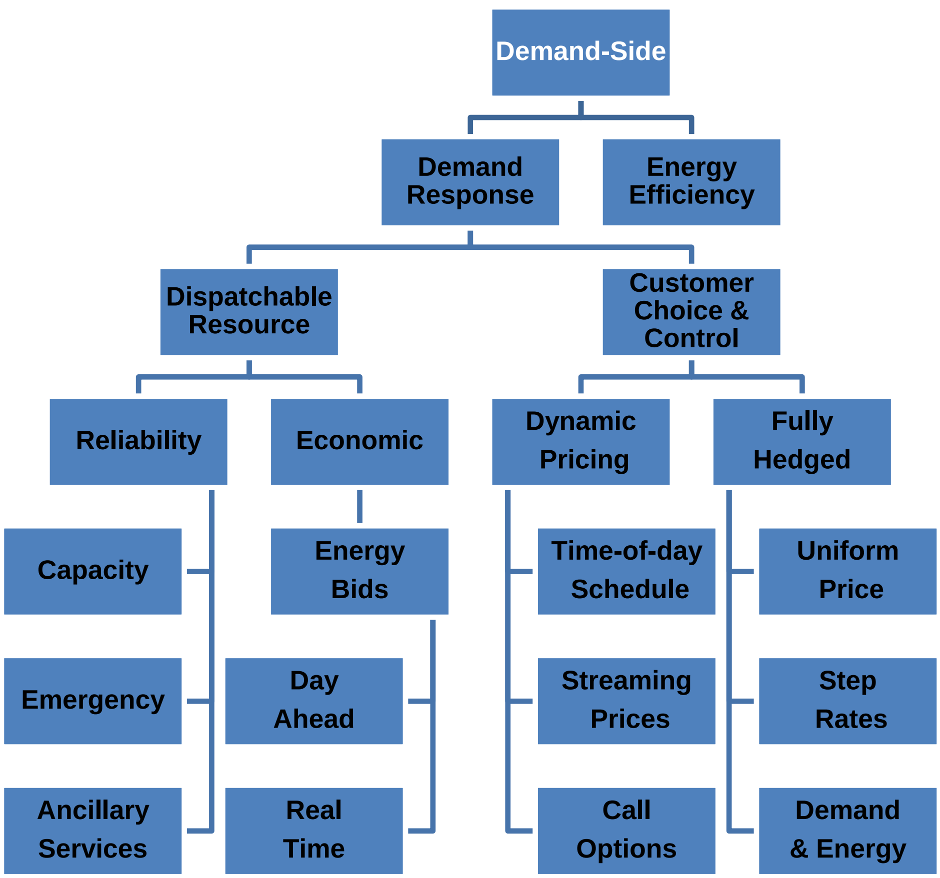

Figure 8 − NERC and NAESB have outlined a full array of potential demand response program options.

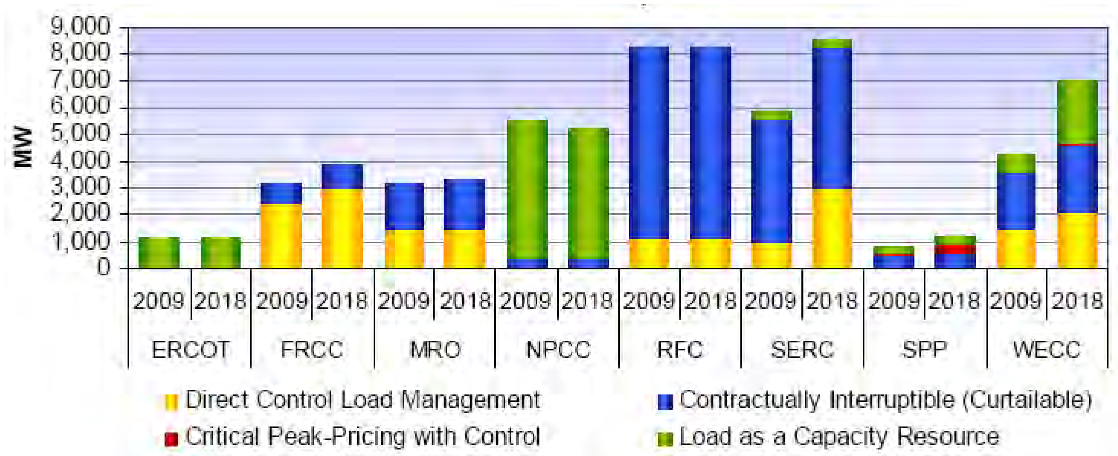

Figure 9 − Regional differences in the current and projected use of demand response are significant (NERC, 2009).

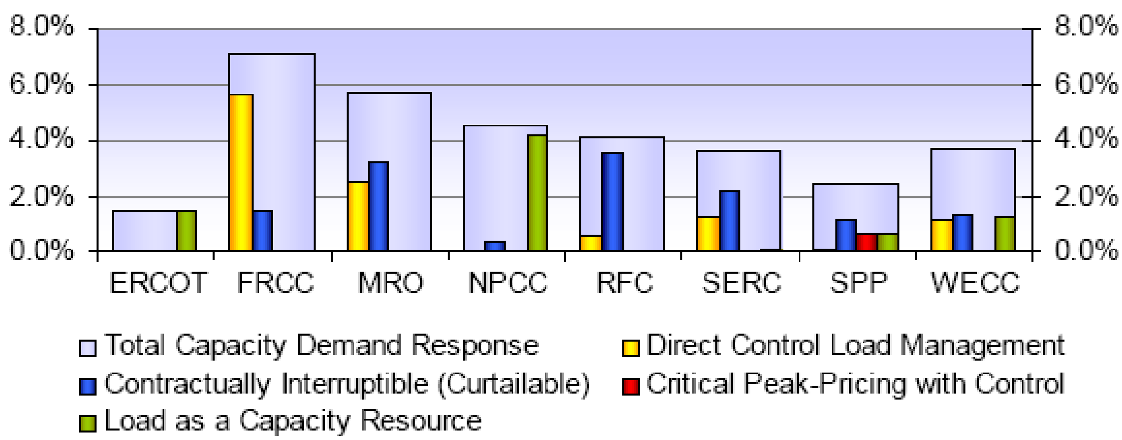

Figure 10 − FRCC obtains the highest percentage of demand response (NERC, 2009).

While NERC shows relatively modest projected increases in demand response over the next eight years, FERC concludes that up to 188 GW of demand response could potentially be available by 2019 (see Figure 11). FERC also differentiated demand response by customer class and finds that, while participation from all customer classes can be increased, residential customers offer a significant potential that will not be realized if business continues as usual (2019, Figure 12).

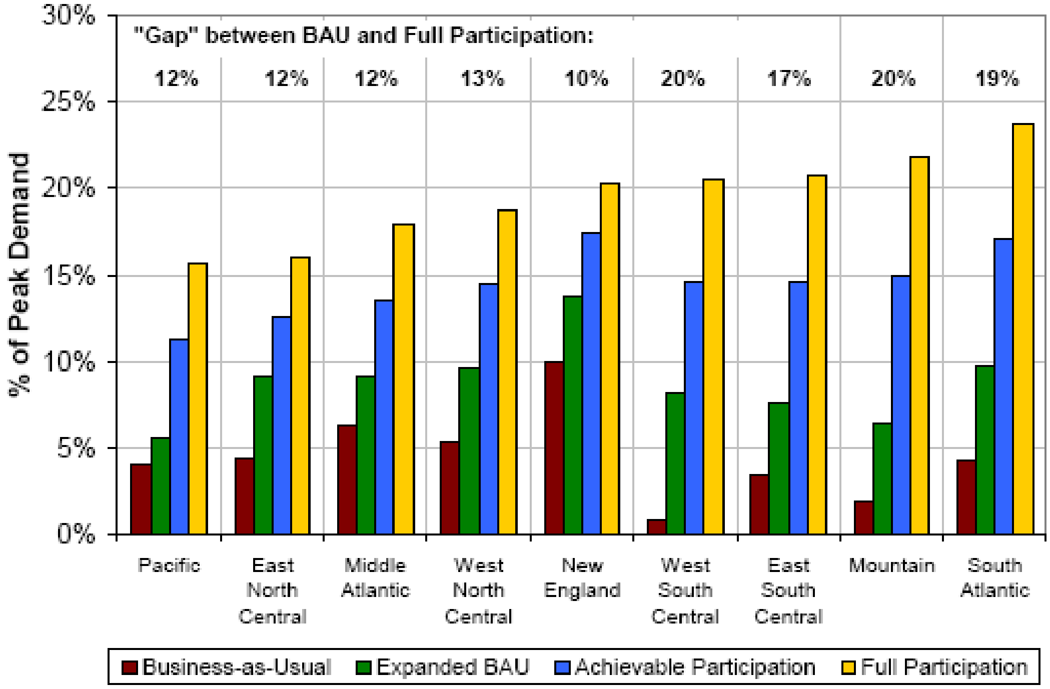

Figure 11 – FERC estimate of regional demand response potential (FERC, 2010).

Dynamic pricing may be an effective method for dealing with variable generation, especially over generation but also response to generation shortfalls. Unfortunately, there is little dynamic pricing in the U.S. today. Thirty-five states have no dynamic pricing programs. One state has a 3% impact while the rest have a 1% to 2% impact. FERC estimates that dynamic pricing could help reduce peak consumption by 14% to 20% (see Figure 13). This is an example of regulatory obstacles as many state regulators feel the need to protect retail customers from price volatility. While the intent is laudable, this denies retail loads the ability to profit from response and blocks the power system (and renewable generation) from obtaining need response.

Responsive loads are beginning to provide the fast ancillary services: regulation, spinning reserve, non-spin, supplemental operating reserve, and emergency response, as shown in Figure 14 (NERC, 2009). Loads provide ancillary services by voluntarily bidding into day-ahead markets. Once selected, the load is obligated to provide the contracted response for the selected hours, often under direct system operator control. Capable responsive loads want to supply ancillary services because ancillary service prices are high, with higher prices for faster response. Regulation is the most difficult ancillary service to provide, requiring the load to adjust consumption every few seconds in response to the system operator's automatic generation control (AGC) commands. Providing contingency reserves (spinning, non-spinning, and supplemental operating reserves) is also attractive to some loads because the response duration is short (11 minutes for spin and non-spin on average in ISO markets) and response is called for relatively infrequently (every few days on average). Advances in technology make the fast communications and control practical. Equipment like air conditioners, water pumping, and appropriate industrial process that can tolerate sudden interruptions are selected. Table 1 shows the annual average ancillary service prices for several regions. Prices declined in 2009 due to the economic downturn but are expected to rebound.

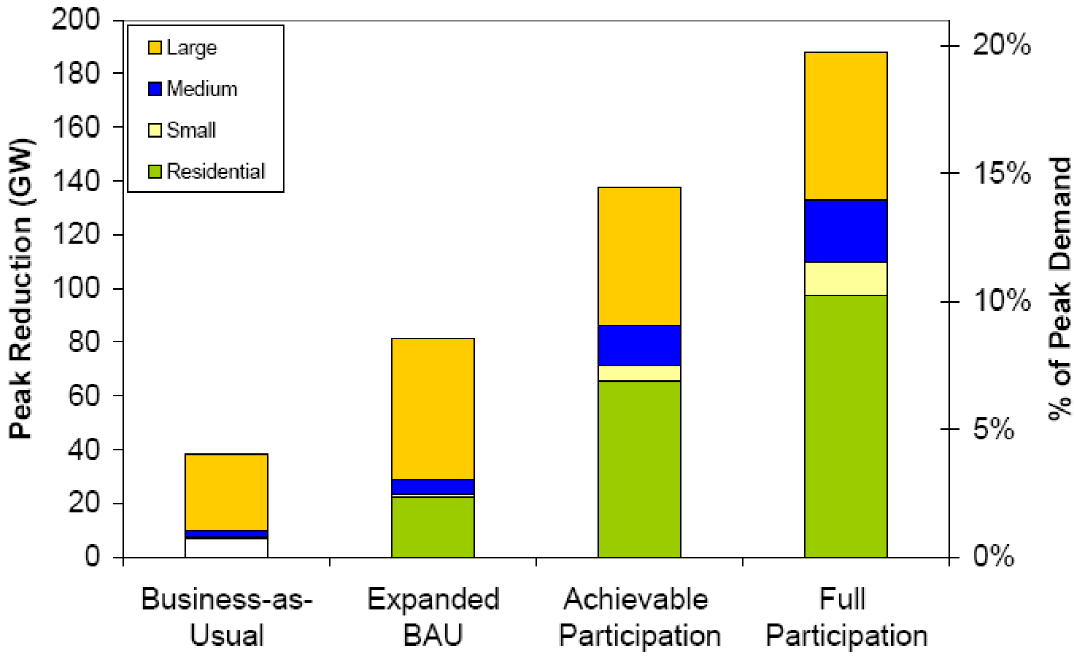

Figure 12 − Demand response can be increased by 2019 if current obstacles are addressed (FERC, 2009).

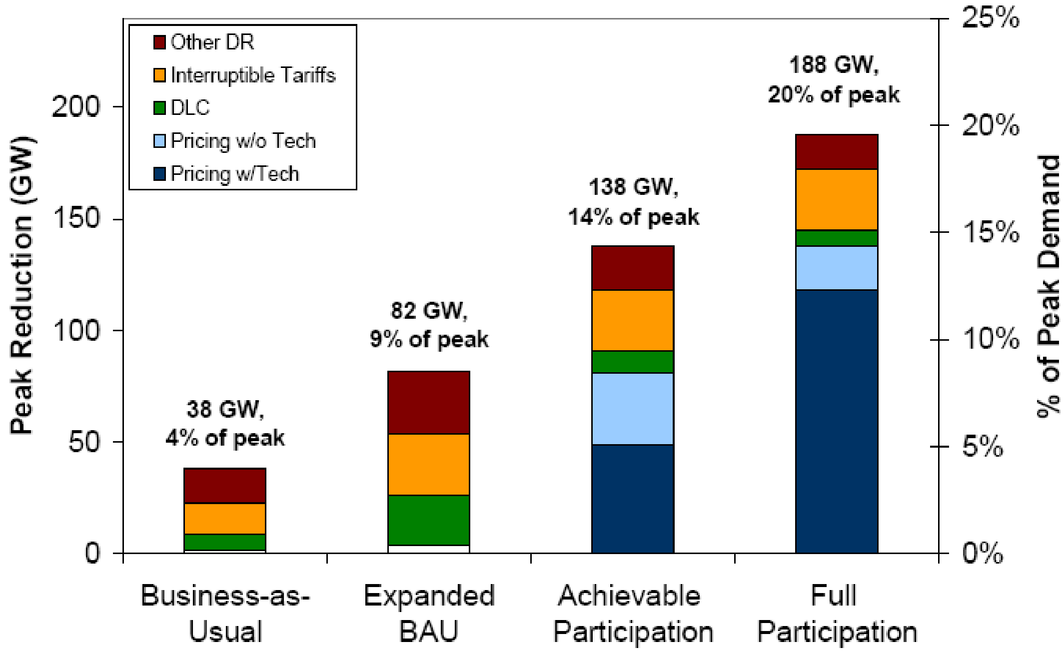

Figure 13 − FERC projects increased potential for price responsive load by 2019 (FERC, 2009).

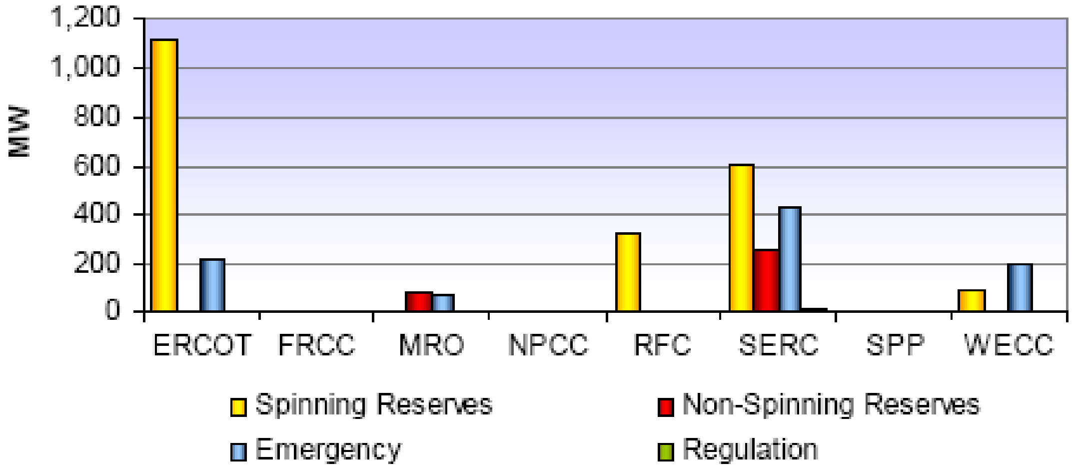

Figure 14 – Responsive loads are beginning to provide the fast ancillary services that are critical for reliability (NERC, 2009).

Table 1 – Non-spin and supplemental operating reserves are 10 to 20 times cheaper than regulation and a better match to wind ramping characteristics.

	2002	2003	2004	2005	2006	2007	2008	2009
				Annual Average $/MWh				
				California (Reg = up + dn)				
Regulation	**26.9**	**35.5**	**28.7**	**35.2**	**38.5**	**26.1**	**33.4**	**12.6**
Spin	**4.3**	**6.4**	**7.9**	**9.9**	**8.4**	**4.5**	**6.0**	**3.9**
Non-Spin	**1.8**	**3.6**	**4.7**	**3.2**	**2.5**	**2.8**	**1.3**	**1.4**
Replacement	**0.90**	**2.9**	**2.5**	**1.9**	**1.5**	**2.0**	**1.4**	
				ERCOT (Reg = up + dn)				
Regulation		**16.9**	**22.6**	**38.6**	**25.2**	**21.4**	**43.1**	**17.0**
Responsive		**7.3**	**8.3**	**16.6**	**14.6**	**12.6**	**27.2**	**10.0**
Non-Spin		**3.2**	**1.9**	**6.1**	**4.2**	**3.0**	**4.4**	**2.3**
				New York (east)				
Regulation	**18.6**	**28.3**	**22.6**	**39.6**	**55.7**	**56.3**	**59.5**	**37.2**
Spin	**3.0**	**4.3**	**2.4**	**7.6**	**8.4**	**6.8**	**10.1**	**5.1**
Non Spin	**1.5**	**1.0**	**0.3**	**1.5**	**2.3**	**2.7**	**3.1**	**2.5**
30 Minute	**1.2**	**1.0**	**0.3**	**0.4**	**0.6**	**0.9**	**1.1**	**0.5**
				MISO (day ahead)				
Regulation								**12.3**
Spin								**4.0**
Non Spin								**0.3**
				New England (Reg +"mileage")				
Regulation			**54.64**	**30.22**	**22.26**	**12.65**	**13.75**	**9.26**
Spin					**0.27**	**0.41**	**1.67**	**0.71**
10 Minute					**0.13**	**0.34**	**1.21**	**0.47**
30 Minute					**0.01**	**0.09**	**0.06**	**0.08**

Demand Response for Renewables Integration

We have shown the increased variability and uncertainty characteristics of high penetrations of variable renewable generation. While the data shown is based on wind, conceptually similar results are expected for solar. We have also shown that demand response is technically proven but under developed. There is a significant potential for increased demand response that could facilitate wind and solar integration.

The response required by wind and solar matches some of the characteristics of existing demand response programs. Large wind ramps are infrequent, like conventional contingencies, but slower than conventional contingencies taking hours to unfold. Solar ramps are faster than wind ramps, but ramps from large collections of solar plants (thousands of MW) will likely still be slower than conventional contingencies. This makes response easier, but may require the creation of an additional response service that is similar to supplemental operating reserve. Fortunately, supplemental operating reserve is the lowest cost ancillary service and an additional slow reserve might be similarly low cost.

Wind and solar also benefit from sub-hourly energy markets to help balance the variable output. Increasing the depth of the sub-hourly market by expanding price responsive load, as envisioned by FERC and shown in Figure 13, will help reduce integration costs.

Minimum Load Conditions

While wind and solar are variable and uncertain in the minutes to months time frame, the annual production is more stable than for hydro. It should be possible to predict minimum load problems on power systems with high wind penetration with reasonable accuracy years in advance. The exact times that surplus energy will be available will not be known, but the magnitude of the surplus (MWh/yr) should be. Publicizing the surplus energy forecast would allow loads to design processes with sufficient flexibility to use the excess energy, benefiting themselves, the power system, and the wind plants.

Loads that might profitably use large amounts of surplus wind energy will need flexibility in their consumption and will need the cost of energy to be a significant factor in their overall operations. Flexibility comes from having some form of storage within the process (thermal energy or intermediate or final product, are examples). Flexibility also comes from having excess production capacity and from a process where product quality is not adversely impacted by stopping and starting the process. The process need not depend exclusively on surplus wind power. Including surplus wind power in the mix could reduce costs for the load, but other supplies could be used when production schedules demand.

Responsive loads could be controlled by the power system operator when minimum load conditions were imminent, but response to real-time price signals will likely be easier and more efficient. From the load’s point of view, surplus nuclear power is nearly as useful as surplus wind. Loads that might be modified to be flexible enough to profit from responding to surplus wind power include:

- Water pumping –
  - Irrigation
  - Municipal: supply and treatment
- Thermal storage –

    - Hot and cold
    - Commercial and residential
    - Space conditioning and cold storage
- Electrolysis −
    - Chlor-alkali
    - Aluminum
- Electric vehicle charging
- Shale oil extraction

Note that significant development will be required for some loads to be able to provide the suggested response, hence the need for an accurate forecast. For example, aluminum smelters are currently optimized to operate at a constant power level. As will be discussed later, some are beginning to supply ancillary services in order to reduce their effective electricity costs. No current aluminum smelter can withstand a multi-hour power interruption without ruining the pot line however. Purchased power accounts for roughly 1/3 of the production cost for aluminum and it is increasingly difficult for domestic producers to compete in the world market. *If* it was known that a high penetration of wind generation was going to be built and that significant surplus energy was expected for many years, then it might be worth developing and investing in a dramatically different aluminum smelting process. Other loads will incur similar capital costs as they are modified to increase their flexibility. A good forecast of the annual surplus energy is required, but the potential for a technical solution is significant.

Three Especially Responsive Loads

Electric vehicles, aluminum smelting, and shale oil extraction provide three examples of responsive loads that potentially can be especially helpful for wind integration. These loads will not provide response simply to help renewables. Rather, they will provide response because it will lower their electricity cost and/or provide ancillary service income. That response also reduces wind integration costs and reduces costs for all customers while improving power system reliability. These three loads are of interest because they are especially flexible. They can provide fast response for regulation and contingency reserves. They can also respond to real-time energy prices, accommodating minimum load conditions and mitigating large wind and solar ramps. None of the loads exist with the full degree of flexibility yet. One or all may be significant by the time wind and solar reach 20% to 30% energy penetration.

Electric Vehicles

Electric vehicles (EVs) are expected to use smart chargers that will incorporate significant communications and control capabilities. Owners will be free to charge whenever necessary to accommodate their driving needs, and some will occasionally charge during the day or as soon as they get home after work, but 80% to 90% are expected to charge overnight. The communications and controls, coupled with the solid-state chargers, will let the utility schedule obtain regulation and/or contingency reserves from the EV fleet. The utility will also be able to schedule EV charging to follow variable generation or to alleviate minimum load problems as long as they complete charging by the time the owner is ready to drive to work. The utility will offer a reduced electric rate for EV charging as compensation for obtaining all of this response.

The ISO/RTO Council expects one-million EVs (plug-in hybrids, extended-range electric vehicles, and battery-electric vehicles) within five years (Kema, 2010). Each EV is expected to consume about 300 watt-hours per mile and average 33 miles per day. That represents a new 10 kwh/day load per EV. The usual “Level 2” 220-volt home charger will be capable of fully charging the car within 1.5 hours. If all the EVs charged simultaneously at their full Level 2 rate, the system would see an additional 5500-MW load. Instead, the utility will have 8 to 12 hours to accomplish the charging. Fast communications and controls will give the utility a significant resource for mitigating variability while still providing the utility with an additional paying load.

Aluminum Smelting

Regulation is the most expensive and most difficult ancillary service to supply. It requires the load to continuously respond to power system operator AGC signals to move up and down. Response must be fast and accurate. Recognizing a new opportunity to reduce net power costs by responding to power system reliability needs, Alcoa modified its Warrick, Indiana, aluminum smelter to provide regulation when the MISO ancillary service market opened in January 2009 (Todd, 2009). Warrick provides regulation by continuously adjusting pot-line voltage in response to MISO-AGC signals. Pot-line chemistry and temperature must be continuously monitored and controlled in response to the power changes. This is an impressive accomplishment for a process that was designed and optimized to operate at a constant power level. Regulation is hard enough, but longer term response is even more difficult for aluminum smelting since the cryolite in the pots must be kept molten by the power being consumed. A plant that was designed with flexibility in mind from the start could likely provide significantly more response.

Evaluating the potential for a load to provide regulation involves: 1) a technical assessment of the underlying process’ physics to determine if control is possible, 2) an assessment of the capabilities of the specific factory where the implementation is proposed, 3) an evaluation of the required communications and control equipment including the equipment costs, 4) an evaluation of any increased process losses and maintenance costs, 5) an evaluation of the lost opportunities when the factory production capacity is switched from making product (aluminum in this case) and is instead used to supply regulation, and 6) a comparison of the expected benefits from selling regulation with the expected costs (including program startup costs) involved in supplying regulation. The physical and economic analyses are heavily intertwined.

Alcoa operates ten aluminum smelters and associated facilities in the United States with a combined average load of 2,600 MW, representing a significant demand response potential. Many other industries can provide similar or greater response. At least one other industrial load is preparing to supply regulation to NYISO.

Oil Extraction from Tar Sands and Shale Deposits

In site heating of oil deposits represents a potentially large and extremely responsive load. There are large deposits of shale oil that may be able to be economically extracted by heating the oil in place before pumping. Two electric power technologies are being tested and show promise of being commercially viable; resistance heating and radio frequency (RF) energy. In both cases, electric heaters are placed in the rock formation and warm the oil deposit in about a month. What makes these loads so interesting from a power system perspective is the decoupling of the load's time constant from that of the power system. While the load needs a month of electric heating, only the average energy is important. Heater power level can be controlled as rapidly as desired (sub-cycle in the RF heater case) to provide any response that is helpful to the power system. The load will likely be price responsive and avoid consumption during times of generation shortage, but it can also supply regulation and contingency reserves when heating. It can also help with minimum load problems and be responsive to wind ramps in either direction. Plant size could be quite large. A 100,000 bbl/day oil shale plant will require 870 MW of average power. Oil shale deposits are estimated to be large enough to support a 10 million bbl/day industry.

Conclusions

Demand response is a proven set of technologies that have been used by utilities to improve reliability for decades. Improvements in communications and controls now make it practical to obtain regulation and contingency reserves as well as peak reduction from responsive loads. Real-time price response is also technically feasible though regulatory barriers exist. FERC has assessed the current state of demand response in the United States and concluded that significantly greater capability exists.

Increasing the pool of responsive resources is beneficial for wind and solar since they add variability and uncertainty to the power system at the same time that they displace generation that itself can provide response. Both voluntary price response and command and control are useful. Variable generation up-ramps are typically not a reliability concern since wind or solar can be spilled. Up-ramps are an economic concern that load response can help with. Down-ramps can be a reliability concern and are certainly an economic concern. Here too load response can help. Wind and solar ramps are slower than conventional contingencies. Responding to large ramps will require price responsive load and may require a new reserve that is similar to supplemental operating reserve. Renewable generation advocates should work to remove barriers to demand response.

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Responsive load is still the most underutilized reliability resource in North America. This paper examines the characteristics of concern to the power system, the renewables, and to the loads.

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The Role of Energy Storage with Renewable Electricity Generation

Paul Denholm, Erik Ela, Brendan Kirby, and Michael Milligan

Technical Report
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List of Acronyms

AC	alternate current
AGC	automatic generation control
AS	ancillary services
CAES	compressed-air energy storage
CCGT	combined-cycle gas turbine
CCR	capital charge rate
CSP	concentrating solar power
DC	direct current
ERCOT	Electric Reliability Council of Texas
EVs	electric vehicles
GW	gigawatt
ISO	independent system operators
LaaR	Load Acting as a Resource (program)
MW	megawatt
NERC	North American Electric Reliability Corporation
PHS	pumped hydro storage
PV	photovoltaics
RTO	regional transmission organization
RE	renewable energy
SMES	superconducting magnetic energy storage
T&D	transmission and distribution
V2G	vehicle to grid
VG	variable generation

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1 Introduction

Renewable energy sources, such as wind and solar, have vast potential to reduce dependence on fossil fuels and greenhouse gas emissions in the electric sector. Climate change concerns, state initiatives including renewable portfolio standards, and consumer efforts are resulting in increased deployments of both technologies. Both solar photovoltaics (PV) and wind energy have variable and uncertain (sometimes referred to as "intermittent")[1] output, which are unlike the dispatchable sources used for the majority of electricity generation in the United States. The variability of these sources has led to concerns regarding the reliability of an electric grid that derives a large fraction of its energy from these sources as well as the cost of reliably integrating large amounts of variable generation into the electric grid. Because the wind doesn't always blow and the sun doesn't always shine at any given location, there has been an increased call for the deployment of energy storage as an essential component of future energy systems that use large amounts of variable renewable resources. However, this often-characterized "need" for energy storage to enable renewable integration is actually an economic question. The answer requires comparing the options to maintain the required system reliability, which include a number of technologies and changes in operational practices. The amount of storage or any other "enabling" technology used will depend on the costs and benefits of each technology relative to the other available options.

To determine the potential role of storage in the grid of the future, it is important to examine the technical and economic impacts of variable renewable energy sources. It is also important to examine the economics of a variety of potentially competing technologies including demand response, transmission, flexible generation, and improved operational practices. In addition, while there are clear benefits of using energy storage to enable greater penetration of wind and solar, it is important to consider the potential role of energy storage in relation to the needs of the electric power system as a whole.

In this report, we explore the role of energy storage in the electricity grid, focusing on the effects of large-scale deployment of variable renewable sources (primarily wind and solar energy). We begin by discussing the existing grid and the current role that energy storage has in meeting the constantly varying demand for electricity, as well as the need for operating reserves to achieve reliable service. The impact of variable renewables on the grid is then discussed, including how these energy sources will require a variety of enabling techniques and technologies to reach their full potential. Finally, we evaluate the potential role of several forms of enabling technologies, including energy storage.

[1] The use of the term "intermittent" has been questioned by the wind energy community as being technically inaccurate. Intermittent implies a short-term "on-off" cycle while the output of wind experiences maximum variations more typically on the order of 10% per hour. Solar PV is perhaps somewhat more "intermittent" because it follows a daily on-off cycle. The description "variable" or "variable and uncertain" has been proposed as a more technically accurate description of the output of a wind power plant (Smith and Parsons 2007).

2 Operation of the Electric Grid

The operation of electric power systems involves a complex process of forecasting the demand for electricity, and scheduling and operating a large number of power plants to meet that varying demand. The instantaneous supply of electricity must always meet the constantly changing demand, as indicated in Figure 2.1. It shows the electricity demand patterns for three weeks for the Electric Reliability Council of Texas (ERCOT) grid during 2005.[2] The seasonal and daily patterns are driven by factors such as the need for heating, cooling, lighting, etc. While the demand patterns in Figure 2.1 are for a specific region of the United States, many of the general trends shown in the demand patterns are common throughout the country. To meet this demand, utilities build and operate a variety of power plant types. Baseload plants are used to meet the large constant demand for electricity. In the United States, these are often nuclear and coal-fired plants, and utilities try to run these plants at full output as much as possible. While these plants (especially coal) can vary output, their high capital costs, and low variable costs (largely fuel), encourage continuous operation. Furthermore, technical constraints (especially in nuclear plants) restrict rapid change in output needed to follow load. Variation in load is typically met with load-following or "cycling" plants. These units are typically hydroelectric generators or plants fueled with natural gas or oil. These "load-following" units are further categorized as intermediate load plants, which are used to meet most of the day-to-day variable demand; and peaking units, which meet the peak demand and often run less than a few hundred hours per year.

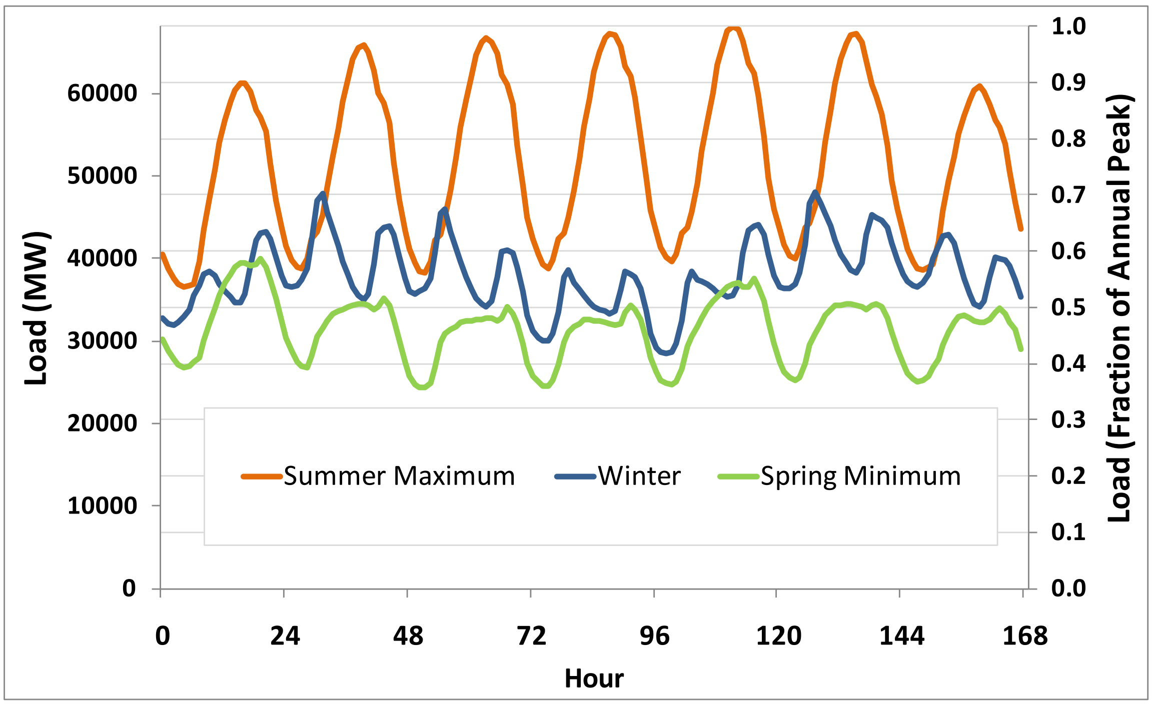

Figure 2.1. Hourly loads from ERCOT 2005

[2] Most of Texas (about 85% of the population) is within the ERCOT grid, which is largely independent of the two larger U.S. grids.

In addition to meeting the predictable daily, weekly, and seasonal variation in demand, utilities must keep additional plants available to meet unforeseen increases in demand, losses of conventional plants and transmission lines, and other contingencies. This class of responsive reserves is often referred to as operating reserves and includes meeting frequency regulation (the ability to respond to small, random fluctuations around normal load), load-forecasting errors (the ability to respond to a greater or less than predicted change in demand), and contingencies (the ability to respond to a major contingency such as an unscheduled power plant or transmission line outage) (NERC 2008).[3] Both frequency regulation and contingency reserves are among a larger class of services often referred to as ancillary services, which require units that can rapidly change output. Figure 2.2 illustrates the need for rapidly responding frequency regulation (red) in addition to the longer term ramping requirements (blue). In this utility system, the morning load increases smoothly by about 400 megawatts (MW) in two hours. During this period, however, there are rapid short-term ramps of +/- 50 (MW) within a few minutes.

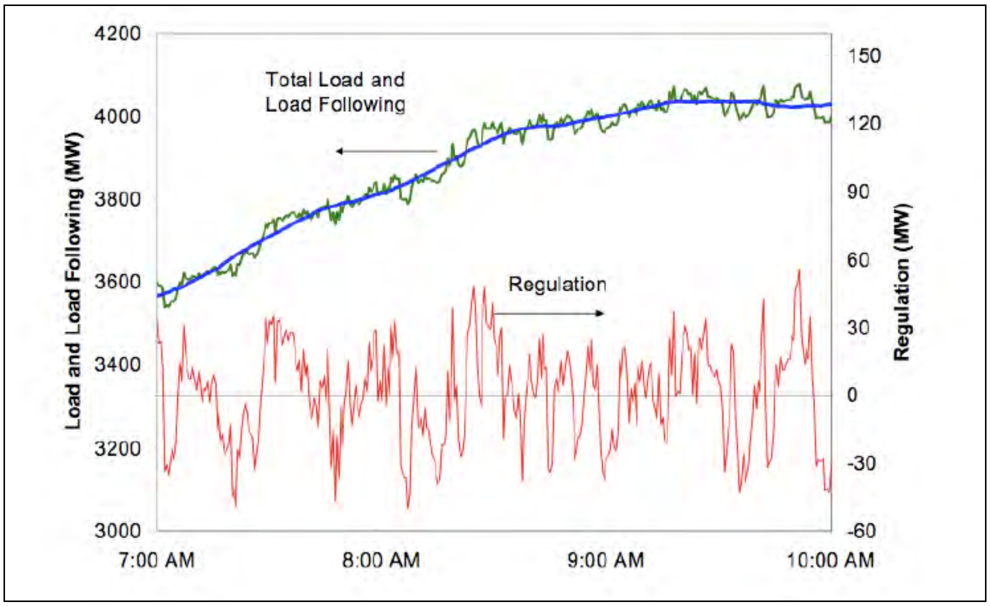

Figure 2.2. System load following and regulation. Regulation (red) is the fast fluctuating component of total load (green) while load following (blue) is the slower trend (Kirby 2004)

Because of the rapid response needed by both regulation and contingency reserves, a large fraction of these reserves are provided by plants that are online and "spinning" (as a result, operating reserves met by spinning units are sometimes referred to as spinning reserves.)[4] Spinning reserves are provided by a mix of partially loaded power plants or responsive loads. The need for reserves increases the costs and decreases the efficiency of

[3] Operating reserves are primarily capacity services (the ability to provide energy on demand) as opposed to actual energy services.
[4] The nomenclature around various ancillary services (especially spinning reserves) varies significantly. While the NERC glossary indicates that spinning reserve applies to both contingency and frequency regulation, the term spinning reserve often is used to refer to only contingency reserves. For additional discussion of nomenclature around contingency and spinning reserves, see Rebours and Kirschen 2005.

an electric power system compared to a system that is perfectly predictable and does not experience unforeseen contingencies. These costs result from several factors. First, the need for fast-responding units results in uneconomic dispatch – because plants providing spinning reserve must be operated at part load, they potentially displace more economic units.[5] (Flexible load-following units are often either less efficient or burn more expensive fuel than "baseload" coal or nuclear units.) Second, partial loading can reduce the efficiency of individual power plants. Finally, the reserve requirements increase the number of plants that are online at any time, which increases the capital and O&M costs.

Figure 2.3 provides a simplified illustration of the change in dispatch (and possible cost impacts) needed to provide operating reserves. The figure on the left shows an "ideal" dispatch of a small electric power system. Two baseload units provide most of the energy, while an intermediate load and two peaking units provide load following. In the "ideal" dispatch, it is possible that the intermediate load unit cannot rapidly increase output to provide operating reserves. Furthermore, during the transition periods when the load-following units are nearing their full output – but before additional units are turned on – there may be insufficient capacity left in the load-following units to provide necessary operating capacity for regulation or contingencies. A dispatch that provides the necessary reserves is provided on the right. In this case, lower-cost units reduce output to accommodate the more flexible units providing reserves. This increases the overall cost of operating the entire system.

[5] This "opportunity cost" associated with uneconomic dispatch is the dominant source of reserve costs (Kirby 2004).

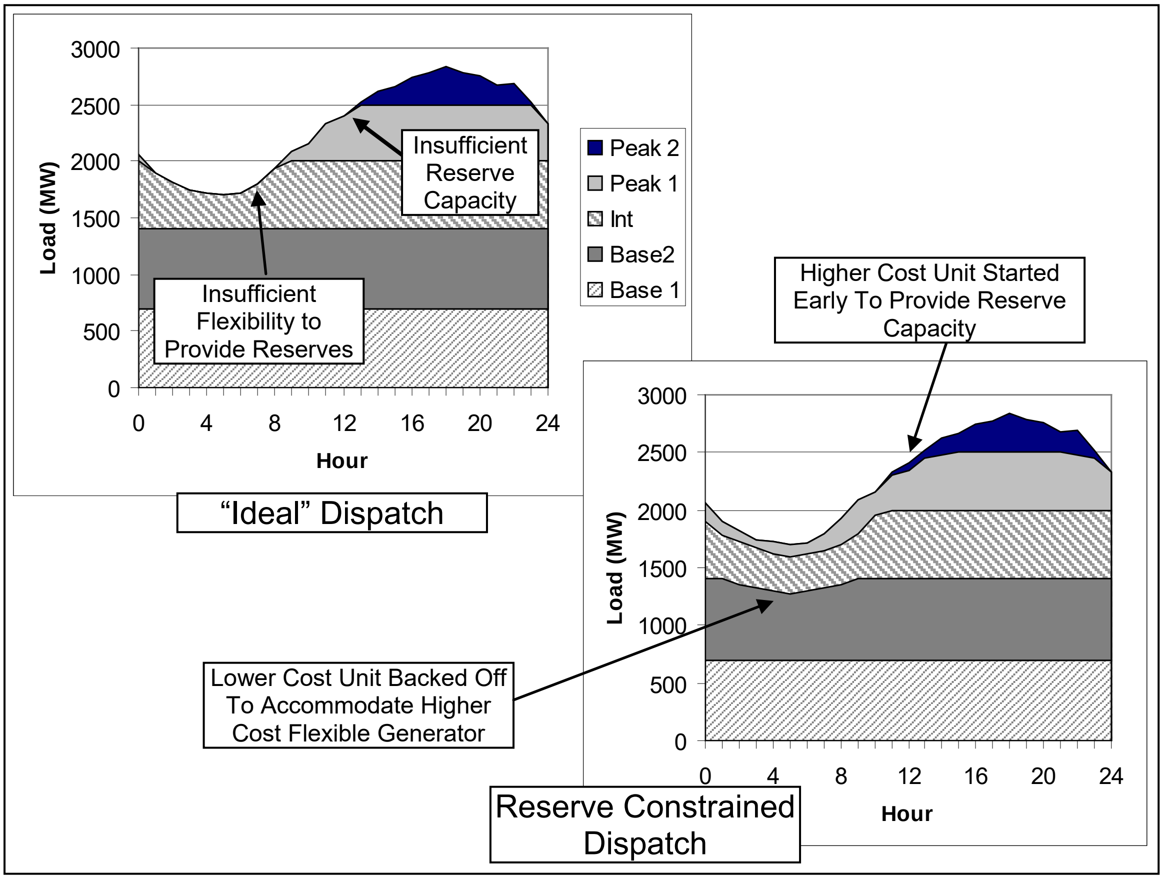

Figure 2.3. Optimal and reserve constrained dispatch

The need for operating reserves and the large variation in demand restricts the contribution from low-cost baseload units and increases the need for units that can vary output to provide both load-following and ancillary services. As a consequence, utility operators have long pursued energy storage as one potential method of better utilizing baseload plants and providing an alternative to lower efficiency thermal generators for meeting variations in demand.

3 Electricity Storage in the Existing Grid

The challenges associated with meeting the variation in demand while providing reliable services has motivated historical development of energy storage. While a number of pumped hydro storage (PHS) plants[6] were built in the United States before 1970, significant interest, research, and funding for new storage technologies began in the early 1970s, associated with dramatic increases in oil prices. This period also saw the largest deployment of PHS based on its competitive economics compared to alternative sources of intermediate load and peaking energy.

3.1 Development of Energy Storage in Regulated Markets

Deployment of energy storage is dependent on the economic merits of storage technologies compared to the more conventional alternatives used to follow load. Before the advent of low-cost, efficient gas turbines now typically used to follow load and provide reserves, utilities often relied on oil- and gas-fired steam turbines (and hydroelectric dams where available). In the 1970s, dramatic price increases in oil and natural gas occurred, along with concerns about security of supply. This led to the Powerplant and Industrial Fuel Use Act, restricting use of oil and gas in new power plants (EIA 2009b). Utilities expected to bring online many new coal and nuclear plants to meet baseload demand, but were left with limited options to provide load-following and peaking services.[7] This led utilities to actively evaluate pumped hydro (along with other storage technologies) as alternatives to fossil-fueled intermediate load and peaking units. The economic analysis and justification of new energy storage facilities during this period was based on a direct comparison of the energy and capacity provided by energy storage to an equivalently sized fossil plant, (choosing the lower net-cost option) which largely ignored any additional operational benefits energy storage can provide. [8]
Figure 3.1 provides a simple framework of comparing these technologies over time. In the figure, the variable (fuel-related) costs are shown for a storage device and fossil-fueled alternatives. In this figure, the storage technology is assumed to be fueled with off-peak coal and has an effective round-trip efficiency of 75%.[9]

[6] PHS stores energy by pumping water from a lower reservoir to an upper reservoir and releasing that stored water through a conventional hydroelectric generator. Additional information about PHS is provided in Section 5.
[7] Concerns about the availability of oil and other peaking fuels in this period was so great that an international conference (including the U.S. National Academy of Sciences) on the subject in 1979 described energy storage as “a vital element in mankind’s quest for survival and progress” (Silverman 1980).
[8] See, for example, EPRI 1976. Here, the proposed method for comparing energy storage to conventional alternatives is based solely on the value of energy and firm capacity value without any actual quantification of operational benefits.
[9] This would be a typical assumption for a pumped hydro plant built during the 1970s and 1980s (EPRI 1976).

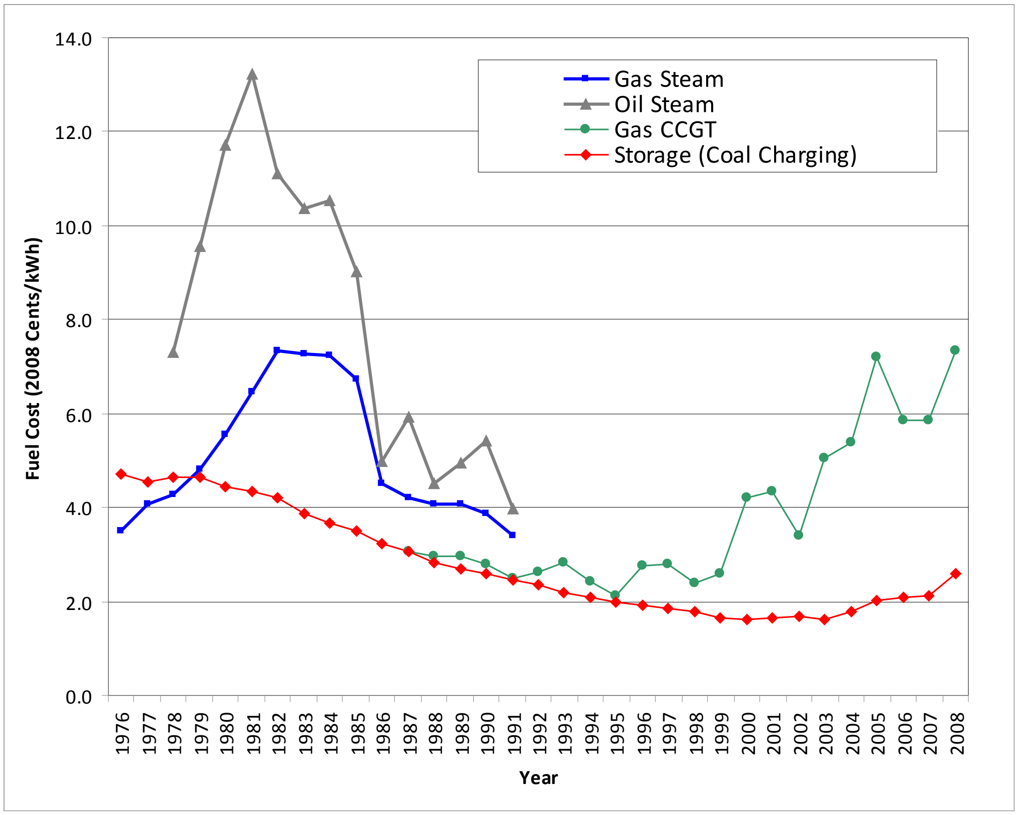

Figure 3.1. Historical fuel costs for intermediate load power plants[10]

Figure 3.1 shows that the variable cost of providing energy from a storage device was much lower than alternatives available in the mid-1970s and early 1980s. While Figure 3.1 provides the fuel costs, the total economics of storage must also consider the fixed costs. During the mid- to late 1970s, gas-fired combined cycle plants were not significantly less expensive than pumped hydro, with cost estimates of $110-$280/kW for a 10-hour PHS device and $175-275/kW for a combined-cycle generator (EPRI 1976). As a result, pumped hydro appeared more economic than alternative generation sources during this time period, even without considering additional operation benefits. It was expected that oil and gas prices would remain high, and that off-peak energy would be widely available (and even less expensive) due to anticipated large-scale deployment of nuclear power plants.

During the mid- to late 1970s, much of the nation's 20 GW of pumped hydro storage was initiated (ASCE 1993), along with significant research and development in a variety of other storage technologies including several battery types, capacitors, flywheels, and superconducting magnetic storage (DOE 1977). Growth projections for energy storage during this period included significant increases of several types (Boyd et al. 1983). However, most PHS development, along with interest in and deployment of other

[10] This figure is intended to represent general trends as opposed to absolute costs. In this figure, fuel prices and generation characteristics are derived from various data sets from the Energy Information Administration.

emerging storage technologies, ended in the 1980s after dramatic reduction in the price of natural gas, increased efficiency and reduced costs of flexible combined-cycle and simple-cycle natural gas turbines, and repeal of the Fuel Use Act in 1987. While estimates from the 1970s place combined-cycle gas turbine (CCGT) units and PHS at similar costs, by the early 2000s, PHS was estimated to be about twice the cost of a CCGT. As a result, even with the increased cost of gas, this dramatic increase in PHS cost (along with the many other factors discussed previously) limited the economic competitiveness of PHS vs. gas-fired generators.[11] Furthermore, while coal prices continued to drop, the limited nuclear build-out eliminated a source of low-cost off-peak electricity. Finally, the simplistic treatment of the economic benefits of energy storage technologies was also a limiting factor. One of the main benefits of energy storage is its ability to provide multiple services, including load leveling (and associated benefits such as a reduction in cycling-induced maintenance) along with regulation and contingency reserves and firm capacity.[12] However, it has always been somewhat difficult to quantify these various value streams without fairly sophisticated modeling and simulation methods, (especially before the advent of energy and ancillary service markets, which will be discussed in the next section). Because the economic analysis is difficult, and benefits of storage are often uncertain, utilities tend to rely on more traditional generation assets, especially in regulated utilities where risk is minimized and new technologies are adopted relatively slowly.[13]

Combined, these factors have restricted deployment of utility-scale energy storage in the United States. Besides PHS, deployment has been limited to a single 110 MW compressed-air energy storage (CAES) facility, and a variety of small projects.[14] A more comprehensive discussion of energy storage technologies and their status is provided in Section 5.

3.2 The Economics of Energy Storage in Restructured Markets

Despite the lack of significant new construction, interest in energy storage never completely disappeared during the period of low-cost peaking fuels. Research and development has continued, along with an increasing number of proposed projects.

[11] PHS also takes longer to build (increasing the risk for investors), requires additional permits, and is typically located farther from load centers, which requires more transmission than gas-fired generators. PHS may also face greater environmental opposition (Strauss 1991).

[12] This problem has been noted many times. For example, "traditionally, when electric utilities evaluate generating additions to their facilities, the evaluation process considers the contribution of each alternative to both capacity and energy requirements. However, the evaluation process often neglects or inaccurately measure potential costs and benefits not directly related to capacity and energy. Operating considerations that reflect the ability (or inability) of a generation resource to respond to the electric system's dynamic operating needs usually fall into this category." (Jabbour and Wells 1992).

[13] Private investors tend to favor lower capital cost investments with faster construction times (i.e., combustion turbines and combined-cycle plants), even if they have higher operating costs, because this reduces perceived economic risk.

[14] To place these values in perspective, between 1993 and 2008, more than 320 GW of conventional capacity was constructed in the United States. With the exception of the completion of previously started PHS facilities and a few demonstration projects, no significant storage capacity was added. The total U.S. utility storage capacity of about 20 GW in 2008 is less than 2% of the total installed generation capacity (EIA 2009a).

Recent renewed interest in energy storage has been motivated by at least five factors: advances in storage technologies, an increase in fossil fuel prices, the development of deregulated energy markets including markets for high-value ancillary services, challenges to siting new transmission and distribution facilities, and the perceived need and opportunities for storage with variable renewable generators.

Emergence of wholesale electricity markets along with increased volatility in natural gas prices has created new opportunities and interest in energy storage. As shown in Figure 3.1, rising natural gas prices in the early 2000s increased the cost-competitiveness of energy storage. However, perhaps the single greatest motivation for proposals to build new energy storage is the creation of markets for both energy and ancillary services including regulation, contingency reserves, and capacity. As of 2009, wholesale energy markets exist in parts of more than 30 states and cover about two-thirds of the U.S. population (IRC 2009). The markets provide real, transparent data for both utilities and independent power producers to consider the opportunities for energy storage. Market data allows evaluation of both the economic yield and optimum location of energy storage devices for arbitrage – the ability to purchase low-cost off-peak energy and re-sell this energy during on-peak periods. Furthermore, the benefits of providing operating reserves and other ancillary services from energy storage can now be evaluated. Previously, the value of these services was largely “hidden” in utilities’ cost of service, and the cost of providing operating reserves, for example, was rarely calculated. The high value of these services is now recognized, and the advantages of energy storage in providing these services is evident, especially because these services generally require fast response and limited actual energy delivery, two qualities that are well-suited to many energy storage devices.

Historical market data can be used to evaluate the potential profitability of energy storage devices that provide various services. Table 3.1 provides the results of several studies of U.S. electricity markets.

Table 3.1. Historical Values of Energy Storage in Restructured Electricity Markets

Market Evaluated	Location	Years Evaluated	Annual Value ($/kW)	Assumptions
Energy Arbitrage	PJM[a]	2002-2007	$60-$115	12 hour, 80% efficient device. Range of efficiencies and sizes evaluated[15]
	NYISO[b]	2001-2005	$87-$240 (NYC) $29-$84 (rest)	10 hour, 83% efficient device. Range of efficiencies and sizes evaluated.
	USA[c]	1997-2001	$37-$45	80% efficient device, Covers NE, No Cal, PJM
	CA[d]	2003	$49	10 hour, 90% efficient device.
Regulation	NYISO[b]	2001-2005	$163-248	
	USA[e]	2003-2006	$236-$429	PJM, NYISO, ERCOT, ISONE
Contingency Reserves	USA[e]	2004-2005	$66-$149	PJM, NYISO, ERCOT, ISONE

[a] Sioshansi et al. 2009
[b] Walawalkar et al. 2007
[c] Figueiredo et al. 2006
[d] Eyer et al. 2004
[e] Denholm and Letendre 2007

The values in Table 3.1 can be translated into a maximum capital cost for the applicable storage technology (equal to the maximum cost of a storage device that can be supported by the revenues available). Figure 3.2 provides a generic conversion between annual costs and total capital costs. This conversion is performed by dividing the annual revenues by the capital charge rate, which produces a total capital cost.[16] The capital charge rate (also referred to as a fixed-charge rate or capital recovery factor) refers to the fraction of the total capital cost that is paid each year to finance the plant. It should be noted that this cost does not include any operation and maintenance costs.[17]

[15] This study analyzed devices up to 40 hours, and found rapidly diminishing returns for devices with storage capacity greater than about 10 hours. The majority of arbitrage benefits are within a day, as opposed to over larger time periods. In addition, while short-term price variation is highly predictable, long-term variations are less predictable, which reduces the certainty of long-term arbitrage opportunities.
[16] This is the inverse of the process of calculating an annualized cost from a capital cost by multiplying by the capital charge rate.
[17] These values also assume that frequency regulation is an energy- and cost-neutral service.

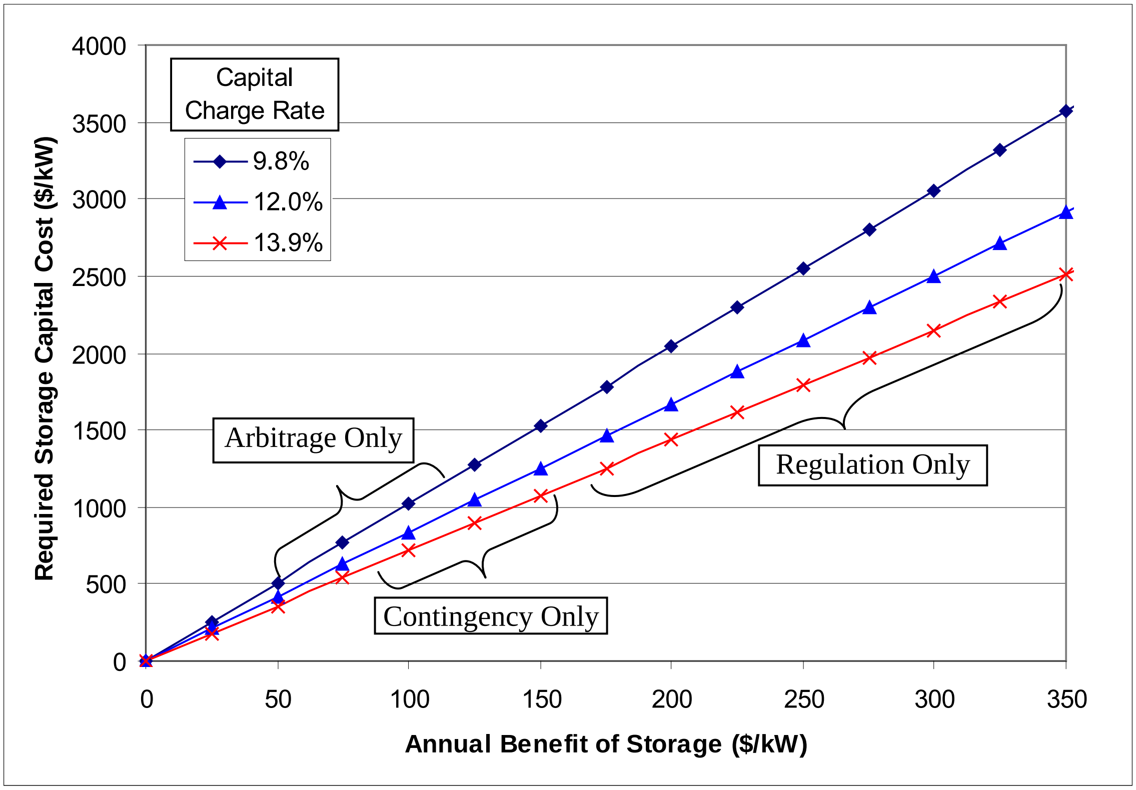

Figure 3.2. Relationship between the annual benefit of storage and capital cost using different capital charge rates[18]

Figure 3.2 shows the range of values and corresponding capital costs for three types of operation: energy arbitrage, contingency reserves, and frequency regulation. In general, energy arbitrage provides the least value. Outside of New York City, the maximum annual value in Table 3.1 for arbitrage was $115/kW (for a 20-hour device), which would translate into a capital cost of $827-1,170/kW – this is below current estimates for most energy storage technologies. While there is significant uncertainty in costs, most energy storage assessments indicate that few commercially available bulk energy storage technologies are deployable for less than $1,000/kW.[19] This reveals the same challenging economics as comparing a storage device to a conventional generator as discussed in Section 3-1. The value of energy arbitrage alone does not appear to justify the deployment of energy storage at current technology costs and electricity prices.

The value of energy storage increases when taking advantage of other individual sources of revenue or even combined services. A device with sufficient energy capacity for energy arbitrage would likely be able to receive capacity payments in locations where

[18]Capital charge rate (CCR) of 9.8% from EPRI 2003, CCR of 12% from Butler et al. 2003, CCR of 13.9% from Eyer et al. 2004.
[19] CAES is one possible exception, but requires analysis of both the electricity price and natural gas prices. See Section 5 and the references in the Bibliography for additional discussion of storage costs.

capacity markets now exist; recent data in the PJM market indicates an additional potential value of $40-90/kW-year.[20]

Alternatively, contingency reserves offer a higher value[21] than energy arbitrage and also require less energy capacity. Obtaining the values for energy arbitrage in Table 3.1 generally requires a device with at least 10 hours of storage capacity; contingency reserves can require as little as 30 minutes, depending on the market and market reliability rules (PJM 2009b). The challenge for a device providing contingency reserves is that the device must be able to respond rapidly, typically in a few minutes or less. Frequency regulation is even more demanding, requiring continuous changes in output, frequent cycling, and fast response. It is also the highest-value opportunity for an energy storage device, and has been the focus of many potential energy storage applications, especially given its fairly small energy requirements.[22]

3.3 Other Applications of Energy Storage

In addition to energy arbitrage and operating reserves, there are several other services that energy storage has provided or could provide in the current grid. Several of these applications are discussed below.

Transmission and Distribution

In addition to generation, storage can act as an alternative or supplement to new transmission and distribution (T&D). Distribution systems must be sized for peak demand; as demand grows, new systems (both lines and substations) must be installed, often only to meet the peak demand for a few hours per year. New distribution lines may be difficult or expensive to build, and can be avoided or deferred by deploying distributed storage located near the load (Nourai 2007). (Energy can be stored during off-peak periods when the distribution system is lightly loaded, and discharged during peak periods when the system may otherwise be overloaded.) Energy storage can also reduce the high line-loss rates that occur during peak demand (Nourai et al. 2008).

[20] PJM's capacity market (Reliability Pricing Model) data derived from http://www.pjm.com/markets-and-operations/rpm.aspx.
[21] More recent data shows a greater range of value for contingency reserves. For example, in 2008, the average value for spinning reserves in NYISO was $10.1 in the east and $6.2 in the west, corresponding to as little as $54/kW-yr. In the same year, the average price in ERCOT was $27.1, corresponding to $237/kW-yr. In 2009, these values fell substantially to $36/kW-yr in NYISO west, and $87/kW-yr in ERCOT.
[22] Frequency regulation theoretically is a net zero energy service over relatively short time scales, meaning the energy capacity of the device can be much smaller than those providing operating reserves and energy arbitrage. Several markets in the United States have changed or have proposed to change their treatment of regulation to accommodate energy-limited storage technologies. Furthermore, it has been suggested that fast-responding storage devices could receive a greater value per unit of capacity actually bid, because they could actually reduce the amount of reserves needed. For example, "faster responsive resources can help to reduce California ISO's regulation procurement by up to 40% (on average)" and "California ISO may consider creating better market opportunities and incentives for fast responsive resources." (Makarov et al. 2008).

Black-Start

Black-start provides capacity and energy after a system failure. A black-start unit provides energy to help other units restart and provide a reference frequency for synchronization. Pumped hydro units have been used for this application.[23]

Power Quality and Stability

Energy storage can be used to assist in a general class of services referred to as power quality and stability. Power quality refers to voltage spikes, sags, momentary outages, and harmonics. Storage devices are often used at customer load sites to buffer sensitive equipment against power quality issues. Electric power systems can also experience oscillations of frequency and voltage. Unless damped, these disturbances can limit the ability of utilities to transmit power and affect the stability and reliability of the entire system. System stability requires response times of less than a second, and can be met by a variety of devices including fast-responding energy storage.

End-Use/Remote Applications

Other applications for energy storage are at the end use. Storage can provide firm power for off-grid homes, but also can provide value when grid-tied through management of time-of-use rates, or demand charges in large commercial and industrial buildings. Energy storage also provides emergency and backup power for increased reliability. In many cases, end-use applications have analogous applications in the grid as a whole (and potentially compete with these applications). For example, using energy storage to time-shift end use is functionally equivalent to energy arbitrage, and a flatter load on the demand side reduces the potential need for load-leveling in central storage applications (and vice-versa). To be economic, end-use applications require time-varying prices and are extremely site-specific.

3.4 Summary of Energy Storage Applications in the Current Grid

Table 3.2 provides a summary of the various applications of energy storage commonly discussed in the literature. Each of these applications provides a potential value to a merchant storage operator in a restructured market or a source of cost reduction to the system.

[23] Large PHS units or other black-start generators must themselves be "black-started" and may use batteries or small generators for this purpose. Many transmission substations also use batteries partly to maintain reliability during power failures.

Table 3.2. Traditional Major Grid Applications of Energy Storage

Application	Description	System Benefits when Provided by Storage	Timescale of Operation
Load Leveling/ Arbitrage	Purchasing low-cost off-peak energy and selling it during periods of high prices.	Increases utilization of baseload power plants and decrease use of peaking plants. Can lower system fuel costs, and potentially reduce emissions if peaking units have low efficiency.	Response in minutes to hours. Discharge time of hours.
Firm Capacity	Provide reliable capacity to meet peak system demand.	Replace (or function as) peaking generators.	Must be able to discharge continuously for several hours or more.
Operating Reserves			
Regulation	Fast responding increase or decrease in generation (or load) to respond to random, unpredictable variations in demand.	Reduces use of partially loaded thermal generators, potentially reducing both fuel use and emissions.	Unit must be able to respond in seconds to minutes. Discharge time is typically minutes. Service is theoretically “net zero” energy over extended time periods.
Contingency Spinning Reserve[24]	Fast response increase in generation (or decrease load) to respond to a contingency such as a generator failure.	Same as regulation.	Unit must begin responding immediately and be fully responsive within 10 minutes. Must be able to hold output for 30 minutes to 2 hours depending on the market. Service is infrequently called.[25]
Replacement/ Supplemental	Units brought on-line to replace spinning units.	Limited. Replacement reserve is typically a low-value service.	Typical response time requirement of 30-60 minutes depending on market minutes. Discharge time may be several hours.

[24] Contingency reserves may be provided by both spinning and non-spinning units, depending on the market. The requirements for non-spinning reserves are the same except the resource does not need to “begin responding immediately.” Full response is still within 10 minutes.

[25] For example, in the PJM regional transmission organization (RTO) in 2008 (covering about 50 million people), synchronized reserves were called a total of 40 times with an average duration of 10 minutes. See http://www.pjm.com/markets-and-operations/ancillary-services.aspx

Ramping/Load Following	Follow longer term (hourly) changes in electricity demand.	Reduces use of partially loaded thermal generators, potentially reducing both fuel use and emissions. Price is "embedded" in existing energy markets, but not explicitly valued, so somewhat difficult to capture.	Response time in minutes to hours. Discharge time may be minutes to hours.
T&D Replacement and Deferral	Reduce loading on T&D system during peak times.	Provides an alternative to expensive and potentially difficult to site transmission and distribution lines and substations. Distribution deferral is not captured in existing markets.	Response in minutes to hours. Discharge time of hours.
Black-Start	Units brought online to start system after a system-wide failure (blackout).	Limited. May replace conventional generators such as combustion turbines or diesel generators.	Response time requirement is several minutes to over an hour. Discharge time requirement may be several to many hours.[26]
End-Use Applications			
TOU Rates	Functionally the same as arbitrage, just at the customer site.	Same as arbitrage.	Same as arbitrage.
Demand Charge Reduction	Functionally the same as firm capacity, just at the customer site.	Same as firm capacity.	Same as firm capacity.
Backup Power/ UPS/Power Quality	Functionally the same as contingency reserve, just at the customer site.	Benefits are primarily to the customer.	Instantaneous response. Discharge time depends on level of reliability needed by customer.

[26] The black-start performance standard in PJM is 90 minutes to start, with an ability to run for 16 hours (PJM 2009a).

It should be noted that Table 3.2 does not include any dedicated renewables applications. Historical motivations for energy storage deployment were based on the challenges of meeting variations in demand using conventional thermal generators. Much of the current attention for energy storage is based on its potential application with renewable energy (primarily solar and wind). Energy storage is seen as a means to "firm" or "shape" the output from variable renewable generators. However, the actual need for storage to perform these roles has yet to be quantified. In addition, it is unclear whether the electric power industry must create entirely new "classes" of energy and capacity services to deal with the increased uncertainty and variability created by large-scale deployment of variable renewables. Determining the role of energy storage with renewables first requires examining the impacts of variable generators on the grid and how these impacts may require the use of various enabling technologies.

4 Impacts of Renewables on the Grid and the Role of Enabling Technologies

The introduction of variable renewables is now one of the primary drivers behind renewed interest in energy storage. A common claim is that renewables such as wind and solar are intermittent and unreliable, and require backup and firming to be useful in a utility system – energy produced by wind and solar should be "smoothed" or shifted to times when the wind is not blowing or the sun is not shining using energy storage. These statements are generally qualitative in nature and provide little insight into the actual role of renewables in the grid, (including their costs and benefits) or the potential use of energy storage or other enabling technologies.

To evaluate the actual role of energy storage in a grid with large amounts of variable renewable generation, we must first return to our previous discussion of the variability of electric demand, and how the conventional generators currently meet this demand. As discussed in Section 2, tremendous variation in daily demand is met by the constant up-and-down cycling of generators. In addition to this daily cycling, frequency regulation and contingency reserves are provided by partly loaded generators and responsive load.[27] Most of these "flexible" generators are hydro units, combustion turbines, some combined-cycle plants, and even large thermal generators, as well as the existing PHS.

Variable generation (VG)[28] will change how the existing power plant mix is operated, because its output is unlike conventional dispatchable generators. It is easiest to understand the impact of VG technologies on the grid by considering them as a source of demand reduction with unique temporal characteristics. Instead of considering wind or PV as a source of generation, they can be considered a reduction in load with conventional generators meeting the "residual load" of normal demand minus the electricity produced by renewable generators.

Figure 4.1 illustrates this framework for understanding the impacts of variable renewables. In this figure, renewable generation is subtracted from the normal load, showing the "residual" or net load that the utility would need to meet with conventional sources.[29] The benefits to the utility include reduced fuel use (and associated emissions)[30] and a somewhat reduced need for overall system capacity (this is relatively small for wind but can be significant for solar given its coincidence with load.)[31] There are also four significant impacts that change how the system must be operated and affect costs.

[27] In some locations such as Texas, demand response typically provides half of the contingency reserve requirements. Other regions also use (or are evaluating) load to provide regulation.
[28] From this point on, variable renewable generators will be referred to as variable generation (VG) following NERC 2009.
[29] This figure uses ERCOT load data from 2005 along with 15 GW of spatially diverse simulated wind data from the same year. See Section 4.2 for more details about the data used.
[30] A reduction in demand from VG or load will reduce the total marginal cost of generation, which includes fuel, emissions costs, and variable O&M. This ignores any additional cost impacts of variability on the remaining generation fleet, which is discussed in the next section.
[31] There are a number of other benefits provided by renewable energy sources such as reduced volatility of fuel prices. This work is not intended to be an analysis of the total benefits of renewables or VG.

First is the increased need for frequency regulation, because wind can increase the short-term variability of the net load (not illustrated on the chart).[32] Second is the increase in the ramping rate, or the speed at which load-following units must increase and decrease output. The third impact is the uncertainty in the wind resource and resulting net load.[33] The final impact is the increase in overall ramping range – the difference between the daily minimum and maximum demand – and the associated reduction in minimum load, which can force baseload generators to reduce output; and in extreme cases, force the units to cycle off during periods of high wind output. Together, the increased variability of the net load requires a greater amount of flexibility and operating reserves in the system, with more ramping capability to meet both the predicted and unpredicted variability. The use of these variable and uncertain resources will require changes in the operation of the remaining system, and this will incur additional costs, typically referred to as integration costs.

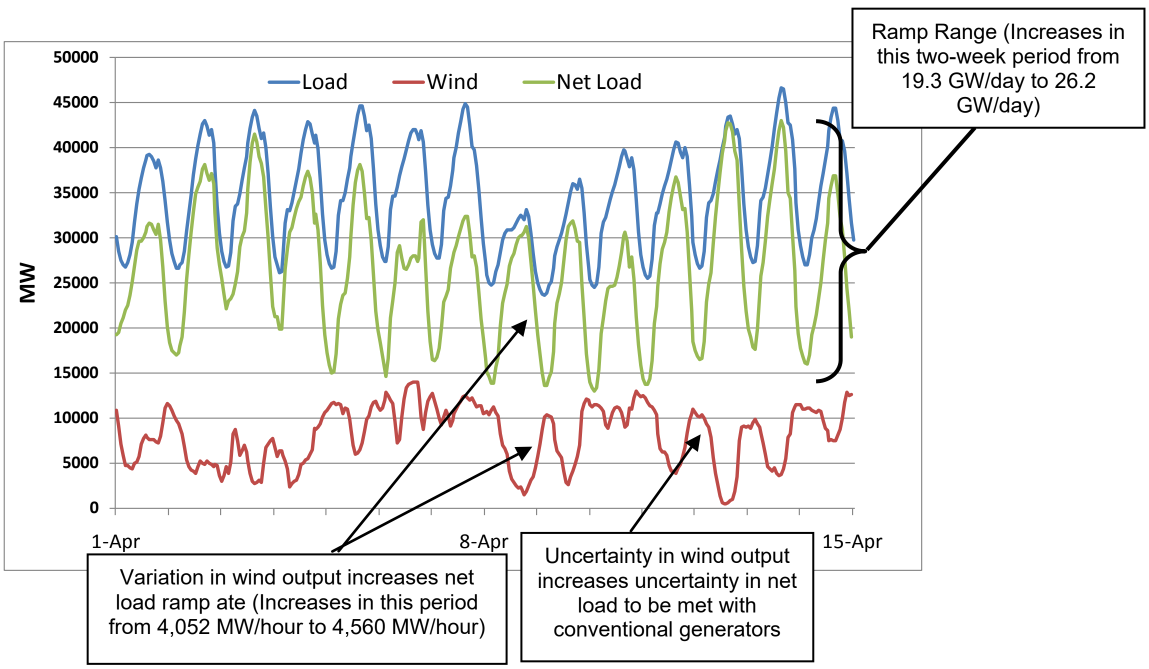

Figure 4.1. Impact of net load from increased use of renewable energy

[32] As discussed later, the impact of short-term wind variability is often overstated, especially considering the benefits of spatial diversity. The impact on minute-to-minute regulation requirements is mitigated by aggregating large amounts of wind because individual wind plant variability is uncorrelated in the regulation time frame. Furthermore, the limited ability to forecast wind and use of persistence forecasts may be a major factor in increased short-term variability of the net load. Finally, newer wind turbines meeting “low-voltage ride-through” standards can add short-duration stability, and have the capability to provide frequency regulation to the grid.

[33] This is actually the combination of the uncertainty in load and the uncertainty in wind. As VG penetration increases, it begins to dominate the net load uncertainty.

4.1 Costs of Wind and Solar Integration from Previous Studies

Concerns about grid reliability and the cost impacts of wind have driven a large number of wind integration studies. These studies use utility simulation tools[34] and statistical analysis to model systems with and without wind and calculate the integration costs of wind.

The basic methodology behind these studies is to compare a base case without wind to a case with wind, evaluating technical impacts and costs. The studies calculate the additional costs of adding operating reserves as well as the other system changes needed to reliably address the increased uncertainty and variability associated with wind generation.

Table 4.1 provides examples of several integration studies from various parts of the United States. In these studies, integration costs are typically divided into three types, based on the timescales important to reliable and economic power system operation. These three types are the first three of the four impacts discussed previously:

Regulation – the increased costs that result from providing short-term ramping (seconds to minutes) resulting from wind deployment.

Load following – the increased costs that result from providing the hourly ramping requirements resulting from wind deployment.

Wind uncertainty – the increased costs that result from having a suboptimal mix of units online because of errors in the wind forecast. This is typically called unit commitment or scheduling cost because it involves costs associated with committing (turning on) too few or too many slow-starting, but lower operational-cost units than would have been committed if the wind forecast been more accurate.

[34] These tools have several names such as “production cost” or “security-constrained unit commitment and economic dispatch” models.

Table 4.1. Summary of Recent Wind Integration Cost Studies (DeCesaro et al. 2009)

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load-Following Cost ($/MWh)	Unit Commitment Cost ($/MWh)	Other ($/MWh)	**Tot Oper. Cost Impact ($/MWh)**
2003	Xcel-UWIG	3.5	0	0.41	1.44	Na	**1.85**
2003	WE Energies	29	1.02	0.15	1.75	Na	**2.92**
2004	Xcel-MNDOC	15	0.23	na	4.37	Na	**4.6**
2005	PacifiCorp-2004	11	0	1.48	3.16	Na	**4.64**
2006	Calif. (multi-year)[a]	4	0.45	trace	trace	Na	**0.45**
2006	Xcel-PSCo[b]	15	0.2	na	3.32	1.45	**4.97**
2006	MN-MISO[c]	36	na	na	na	na	**4.41**
2007	Puget Sound Energy	12	na	na	na	na	**6.94**
2007	Arizona Pub. Service	15	0.37	2.65	1.06	na	**4.08**
2007	Avista Utilities[d]	30	1.43	4.4	3	na	**8.84**
2007	Idaho Power	20	na	na	na	na	**7.92**
2007	PacifiCorp-2007	18	na	1.1	4	na	**5.1**
2008	Xcel-PSCo[e]	20	na	na	na	na	**8.56**

[a] Regulation costs represent 3-year average.
[b] The Xcel/PSCO study also examine the cost of gas supply scheduling. Wind increases the uncertainty of gas requirements and may increase costs of gas supply contracts.
[c] Highest over 3-year evaluation period. 30.7% capacity penetration corresponding to 25% energy penetration
[d] Unit commitment includes cost of wind forecast error.
[e] This integration cost reflects a $10/MMBtu natural gas scenario. This cost is much higher than the integration cost calculated for Xcel-PSCo in 2006, in large measure due to the higher natural gas price: had the gas price from the 2006 study been used in the 2008 study, the integration cost would drop from $8.56/MWh to $5.13/MWh.

The overall cost impact of accommodating wind variability in these studies is typically less than $5/MWh (0.5 cents/kWh), adding less than 10% to the cost of wind energy.[35] The majority of these costs appear to be a result of wind forecasting errors and uncertainty – resulting in "unit commitment" errors where too little or too much capacity is kept online. It is worth noting that wind forecasting is an area of active research, and these errors are expected to decrease in time, which could potentially lead to a corresponding decrease in unit commitment errors and associated costs.

The explanation for this relatively modest impact on costs is largely based on the already significant variation in normal load. The large amount of flexible generation already available to meet the variability in demand has the ability to respond to the greater variability caused by the large-scale deployment of wind. Furthermore, these studies have found significant benefits of spatial diversity – just because the wind isn't blowing in one location, it may be in another. The combination of multiple wind sites tends to smooth out the aggregated wind generation in a system, which reduces the per-unit size of ramps and mitigates the range of flexibility required.[36]

Far less work has been performed on the operational impacts of large-scale solar generation due largely to lower deployment rates compared to wind.[37] In addition, there is insufficient solar data available to estimate impacts on frequency regulation and ramping (Lew et al. 2009.) One study of PV on the Xcel Colorado utility system found integration costs of between $3.51/MWh and $7.14/MWh for a scenario examining 800 MW of solar in a 6,922 MW peaking system, with gas prices ranging from $7.83 to $11.83/MMBTU (EnerNex 2009). Additional studies are ongoing, but it will be some time until knowledge of solar's impact on the grid and associated costs are understood to the degree of wind.[38]

In reality, while these studies divide the costs into three main categories, the source of actual integration costs is largely associated with the fuel costs needed to provide the additional required reserves, along with some variable operations and maintenance costs. To provide regulation and load following, the additional variability requires that utilities run more flexible generators (such as gas-fired units instead of coal units, or simple-cycle turbines instead of combined-cycle turbines) to ensure that additional ramping requirements can be met. This was illustrated previously in Figure 2.3 where a

[35] This actually oversimplifies the situation. Some research indicates that these costs are not entirely integration costs but a modeling artifact of how the "base case" in these studies is actually simulated (Milligan and Kirby 2009).
[36] "Combining geographically diverse wind and solar resources into a single portfolio tends to reduce hourly and sub-hourly variations in real-time output. This would result in a more consistent level of output over a longer time frame, which could reduce the cost of wind integration" (Hurlbut 2009). For additional analysis of spatial diversity, see also Palmintier et al. 2008.
[37] In 2008, more than 8.5 GW of wind was installed in the United States, reaching a total capacity of about 25.3 GW by the end of the year (AWEA 2009). In the same year, 0.3 GW of solar PV was installed, reaching a total capacity of about 1 GW (Sherwood 2009).
[38] The impacts of CSP are largely unquantified as well. However, it is expected that the impact of CSP on short time scales will be significantly less than PV, because CSP has significant "thermal inertia" in the system that will minimize high-frequency ramping events. Furthermore, CSP has the potential advantage of utilizing high-efficiency thermal storage discussed in Section 5.

"nonoptimal" mix of generators was needed to provide the ability to adjust output in response to contingencies and other variations in demand. This combination of higher fuel costs and lower-efficiency units results in increased cost of fuel per unit of electricity generated as opposed to the "no-wind" cases.[39] Additional fuel costs occur from keeping units at part-load, ready to respond to the variability, or from more frequent unit starts. The costs associated with unit commitment or scheduling are also largely captured in increased fuel costs. Most large thermal generators must be scheduled several hours (or even days) in advance to be ready when needed. Ideally, utilities schedule and operate only as many plants as needed to meet energy and reserve requirements at each moment in time. If utilities over-schedule (turn on too many plants), they will have many plants running at part-load, and have incurred higher than needed start-up costs. So, if they under-predict the wind, they will commit and start up too many plants, which incurs greater fuel (and other) costs than needed if the wind and corresponding net load had been forecasted accurately. Conversely, if the wind forecast is too high and the net load is higher than expected, insufficient thermal generation may be committed to cover the unexpected shortfall in capacity. A worst-case scenario would be a partial blackout; but the likely result is the use of high-cost "quick-start" units in real-time, purchasing expensive energy from neighboring utilities (if available), or paying customers a premium to curtail load – all while lower cost units are sitting idle. An example of this is the ERCOT event of Feb. 26, 2008 (Ela and Kirby 2008). On this date, a combination of events – including a greater than predicted demand for energy, a forced outage of a conventional unit, the wind forecast not being given to the system operators, and a lower than expected wind output – resulted in too little capacity online to meet load. As a result, the ERCOT system needed to deploy high-cost quick-start units, as well as pay customers to curtail load through its "load acting as a resource" program.[40] All of this occurred while lower-cost units were idle because the combination of events was unanticipated. [41]

[39] It should be noted that these increased costs are associated with the "residual" part of the system that provides the load not met by VG. This is often a source of confusion and is sometimes interpreted as an increase in fuel use and emissions of the total system – implying that the additional reserve requirements of VG somehow actually increase fuel use and emissions of the system, or that VG has a net negative impact on emissions. This is not the case, and integration studies have universally concluded that any increase in fuel use associated with reserves for VG is much smaller than overall avoided fuel and emissions from displaced conventional generation.

[40] Customers with interruptible loads that can meet certain performance requirements may be qualified to provide operating reserves under the Load Acting as a Resource (LaaR) program. In eligible ancillary services (AS) markets, the value of the LaaR load reduction is equal to that of an increase in generation by a generating plant. See http://www.ercot.com/services/programs/load/laar/

[41] This issue has important implications for the use of storage or any other device used to mitigate uncertainty. Energy storage, like any other generator, needs to be scheduled – a storage device used for load leveling may not be able to simultaneously provide hedging against under-forecasted wind, because it may already be discharging.

While the bulk of the costs associated with wind integration are due to fuel use, the increased cycling also increases wear and tear on generators, which imposes extra maintenance costs.[42]

Results from wind integration studies almost universally come to the conclusion that at the penetrations studied to date (up to about 30% on an energy basis), the analyzed systems do not need additional energy storage to accommodate wind's variability and maintain reliable service.[43] In the studied systems, no new generation technologies are required; but there are some potentially significant operational changes needed to maintain the present level of reliability (along with significant transmission additions needed to exchange resources over larger areas).[44] However, they do not necessarily find the "cost optimal" solution, which may include energy storage or some alternative mix of generation to further reduce the cost of wind integration. Furthermore, these studies have not evaluated much higher penetration levels of RE, where additional system constraints may require additional enabling technologies such as energy storage.

4.2 Limiting Factors for Integration of Wind and Solar Energy

To date, integration studies in the United States have found that variable generation sources can be incorporated into the grid by changing operational practices to address the increased ramping requirements over various timescales. At higher penetrations (beyond those already studied), the required ramp ranges will increase, which adds additional costs and the need for fast-responding generation resources. However, there are additional constraints on the system that will present additional challenges. These constraints are based on the simple coincidence of renewable energy supply and demand for electricity, combined with the operational limits on generators providing baseload power and operating reserves. Of the four operational cost impacts listed in the beginning of Section 4 (regulation, load following, scheduling, and ramping range), only the first three present major quantifiable costs in U.S. studies as of the end of 2009. Yet, it is the fourth constraint that may present an economic upper limit on variable renewable penetration without the use of enabling technologies.[45]

As discussed in Section 1, in current electric power systems, electricity is generated by two general types of generators: baseload generators, which run at nearly constant output; and load-following units (including both intermediate load and peaking plants), which meet the variation in demand as well as provide operating reserves. At current penetrations of wind and solar in the United States, and at the levels studied in most integration studies, wind and solar generation primarily displaces flexible load-following

[42] A number of utilities have expressed the opinion that these costs are not well-captured in previous wind integration studies. This issue is discussed later in this report.
[43] This also explains why no significant new storage has been developed in the United States or Europe despite the 25 GW and 65 GW of wind development, respectively, as of the end of 2008 (EWEA 2009).
[44] The more recent U.S. studies of very high penetration (the Western Wind and Solar Integration Study and the Eastern Wind Integration Study) require power and energy exchanges over larger areas than typically occur in the existing system (Milligan et al. 2009a).
[45] One additional challenge in a high-VG grid is the potential decrease in mechanical inertia that helps maintain system frequency. This concern is not well understood and could be mitigated by a variety of technologies including improved controls on wind generators, or other sources of real or virtual inertia that could include energy storage. See, for example, Doherty et al. (forthcoming).

generators. Figures 4.2 and 4.3 illustrate this issue by providing the impacts of increasing amounts of wind generation in a simulated grid. [46] In Figure 4.2, wind provides 8.5 % of the energy in this four-day period and displaces the output from a mix of gas-fired units, which are already typically used to follow load. Because these generators are designed to vary output, they can do this with modest cost penalties as analyzed in the wind integration studies discussed previously.

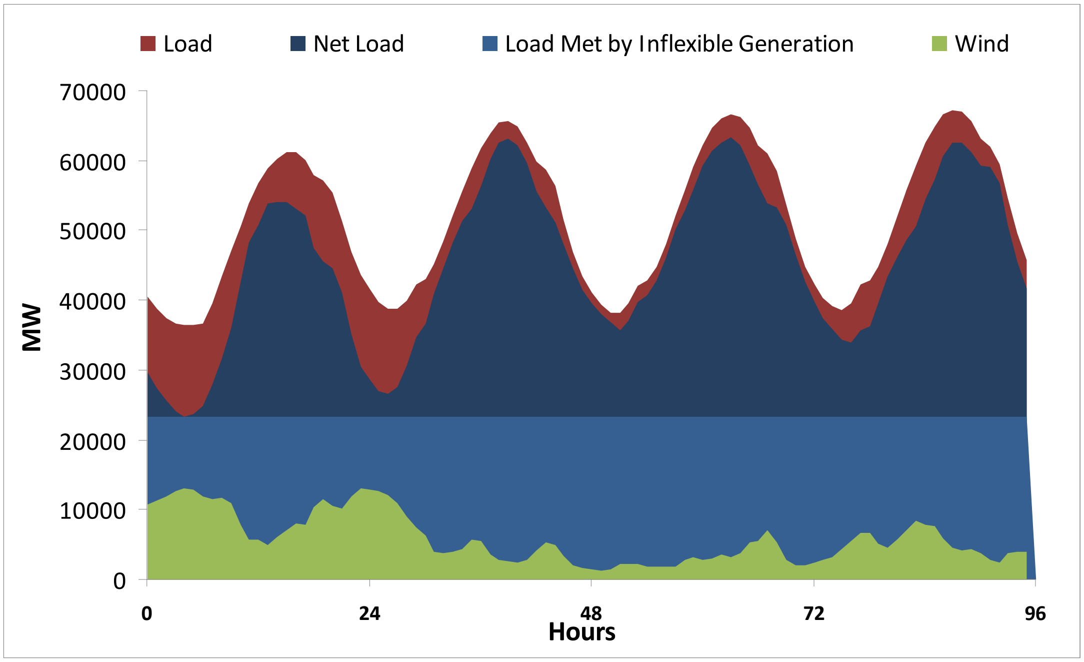

Figure 4.2. Dispatch with low VG penetration (wind providing 8.5% of load)

At higher penetration of RE, the ability of conventional generators to reduce output becomes an increasing concern. In Figure 4.3, wind now provides 16% of the total demand in this four-day period. Variable renewables begin to displace units that are traditionally not cycled, and the ability of these thermal generators to reduce output may become constrained. If the baseload generators cannot reduce output (and some other use cannot be found for this "excess generation"),[47] then wind energy will need to be curtailed – this occurs in the overnight periods in the first two days of this scenario.

[46] This simulation uses historical load data from ERCOT from 2005 and simulated wind data for the same year provided by AWS Truewinds. While the wind and load data is from ERCOT, the mix of generators (flexible and inflexible) is hypothetical and used only to illustrate the impact of VG. For additional discussion of the wind data, see GE Energy 2008.

[47] The alternative to curtailment is finding some alternative use for this energy through enabling techniques and technologies, which may include energy storage. These options are discussed in Section 5.

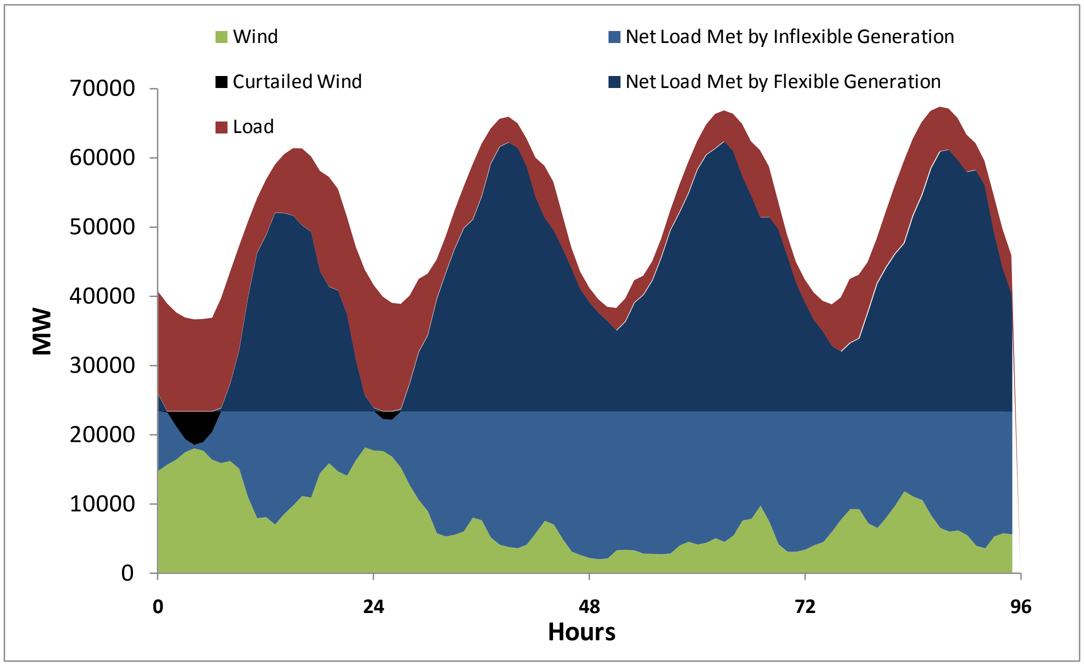

Figure 4.3. Dispatch with higher VG penetration (wind providing 16% of load)

Utilities in the United States have expressed concern about their systems “bottoming out” due to the minimum generation requirements during overnight hours, and being unable to accommodate more variable generation during these periods. Minimum generation constraints (and resulting wind curtailment) are already a real occurrence in the Danish power system, which has a large installed base of wind generation (Ackermann et al. 2009). Due to its reliance on combined heat and power electricity plants for district heating, the Danish system needs to keep many of its power plants running for heat. Large demand for heat sometimes occurs during cold, windy evenings, when electricity demand is low and wind generation is high. This combination sometimes results in an oversupply of generation, which forces curtailment of wind energy production. The need to curtail wind due to minimum load constraints has also been identified as an important component of future power systems in the United States.[48] Modern wind turbines can reliably curtail output, but this is largely undesirable because curtailment throws away cost-free and emissions-free energy.[49]

The actual minimum load is a function of several factors including the mix of conventional generation, as well as the amount of reserves and the types of generators providing those reserves. The ability to cycle conventional units is both a technical and economic issue – there are technical limits to how much power plants of all types can be

[48] “During over-generation periods, when dispatchable generation plants are already operating at their minimum levels, the California ISO needs to have an ability to curtail wind generation on an as-needed basis.” (CAISO 2007)

[49] When curtailing output, wind or other VG can supply operating reserves. In some cases, the value of curtailed energy may actually exceed the value of energy, but the primary value of VG is displacing conventional generation. While Figure 4.3 curtails renewable generation, it not clear which plant “should” be curtailed. Ignoring operational constraints, from a strict economic sense, VG has a lower cost of energy and lower emissions; therefore, it should be curtailed last.

turned down. Large coal plants are often restricted to operating in the range of 50-100% of full capacity, but there is significant uncertainty about this limit. This is partly because utilities often have limited experience with cycling large coal plants, and have expressed concern about potentially excessive maintenance impacts[50] and even safety. It should be noted that because cycling costs are not universally captured in operational models, they may be ignored or underestimated in wind and solar integration studies.[51] The impact of VG on power plant cycling is an active area of research, especially considering the evolving grid and introduction of more responsive generation.[52]

It is unclear what changes in operation practices or generator modification utilities will need to make to cycle below their current minimum load points, which now typically occur during the early morning in spring. In a number of markets, energy prices have dropped below the actual variable (fuel) cost of producing electricity on a number of occasions. This indicates that power plant operators are willing to sell energy at a loss to avoid further reducing output. Figure 4.4 provides one example in the PJM market in 2002, where the price of electricity fell below the variable cost of generation (indicated by the dotted line)[53] from coal-fired units for about 100 hours during periods near the annual minimum. While not definitive, this indicates that under current operational practices, utilities in some systems may be uncomfortable or unable to cycle much below current minimum load levels.[54] In other locations, there may be a greater operating range if plant operators become more comfortable with cycling individual units. As an example, a recent wind integration study of the existing ERCOT system suggested the capability of the system to cycle down to a net load of about 13 GW, compared to the recent annual minimum loads of about 20 GW. However, this would require the coal fleet to cycle to below 50% of rated capacity, and gas plants to perform over an even greater cycling range (GE Energy 2008).

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[50] "Cycling operations, that include on/off startup/shutdown operations, on-load cycling, and high frequency MW changes for automatic generation control (AGC), can be very damaging to power generation equipment." However, these costs can be very difficult to quantify, especially isolating the additional costs associated with cycling above and beyond normal operations (Lefton et al. 2006).

[51] Wind integration studies typically use proprietary software and data sets, and do not always state which costs are and are not included. However, in the Western Wind and Solar Integration Study (the highest penetration U.S. integration study as of 2009) the study states: "'Wear and tear' costs due to increased or harder cycling of units were not taken into account because these have not been adequately quantified." (Lew et al. 2009).

[52] A more detailed analysis of the relationship between wind penetration and plant cycling is provided by Troy et al. (forthcoming).

[53] During this year, the average price paid for coal in this region was about $31/ton. With a typical heat rate of about 10,500 BTU, this translates into a variable cost of $12-14/MWh. This cost can be observed in Figure 4.4 as the "floor" cluster of points at this level. Points below this level represent bids that are less than the cost of generation, but not necessarily uneconomic if the alternative is excessive cycling-induced maintenance or even a forced shutdown and very expensive restart of a coal generator.

[54] Minimum load points would be less of a constraint if power plants could be quickly shut down and started up at low costs. With the exception of certain peaking plants such as aeroderivative turbines and fast-starting reciprocating engines, most plants have minimum up-and-down times, and require several hours to restart (at considerable cost).

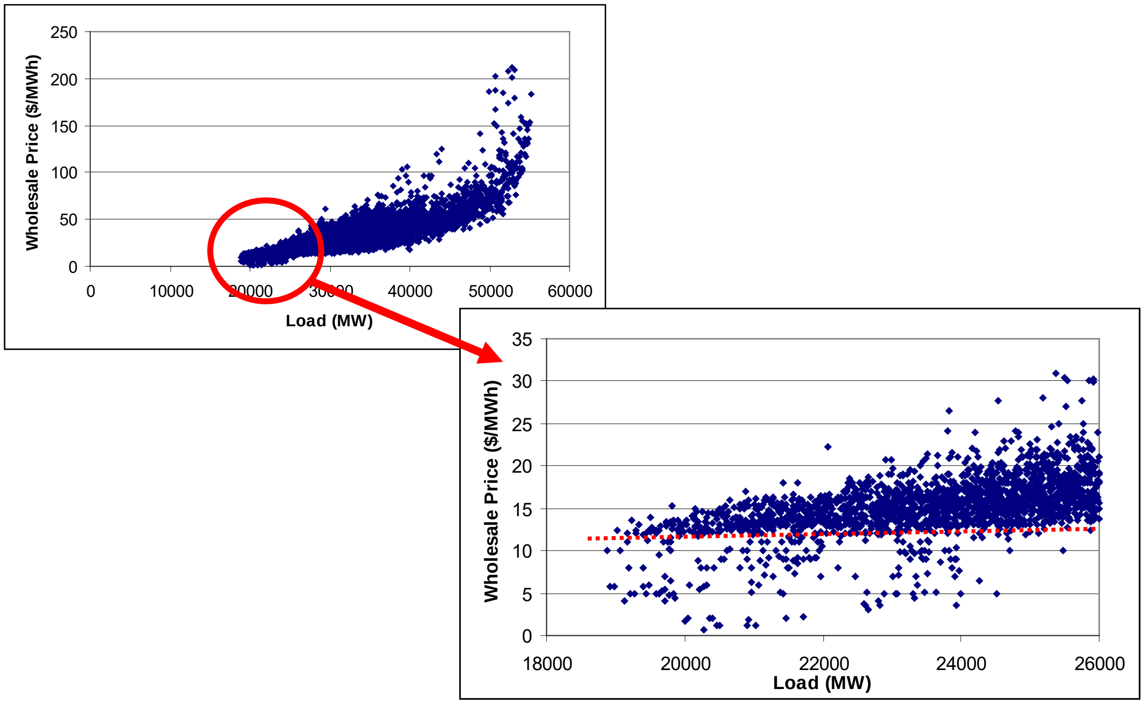

Figure 4.4. Relationship between price and load in PJM in 2002

Overall, the ability to accommodate a variable and uncertain net load has been described as a system's flexibility. System flexibility varies by system and over time as new technologies are developed and power plants are retired. In addition, VG deployment in the United States is still relatively small, and utilities have yet to evaluate the true cycling limits on conventional generators and their associated costs. Also, the additional reserve requirements due to VG at high penetration are still uncertain. As a result, it is not possible to precisely estimate the costs of VG integration or the amount of curtailment at very high penetration; it is also difficult to define with certainty the value of energy storage or other enabling technologies. It is clear, however, that substantial increase in the penetration of wind energy without storage will require changes in grid operation to reduce curtailment.

Figure 4.5 illustrates the fraction of a system's peak load derived from inflexible units as a function of the minimum load point. This is also expressed more generally as the system's "flexibility factor," which is defined as the fraction below the annual peak to which conventional generators can cycle (Denholm and Margolis 2007a and 2007b). In the current grid, the annual minimum load point is typically 30%-40% of annual peak load (or a flexibility factor of 60%-70%). If units cannot be cycled below this point, they will provide 55%-70% of a system's energy; and even with storage, this level of inflexibility leaves only 30%-40% of a system's energy for variable resources. One of the major conclusions of wind integration studies looking at higher penetrations is that minimum load points will need to be lowered substantially below their current annual minimums.[55]

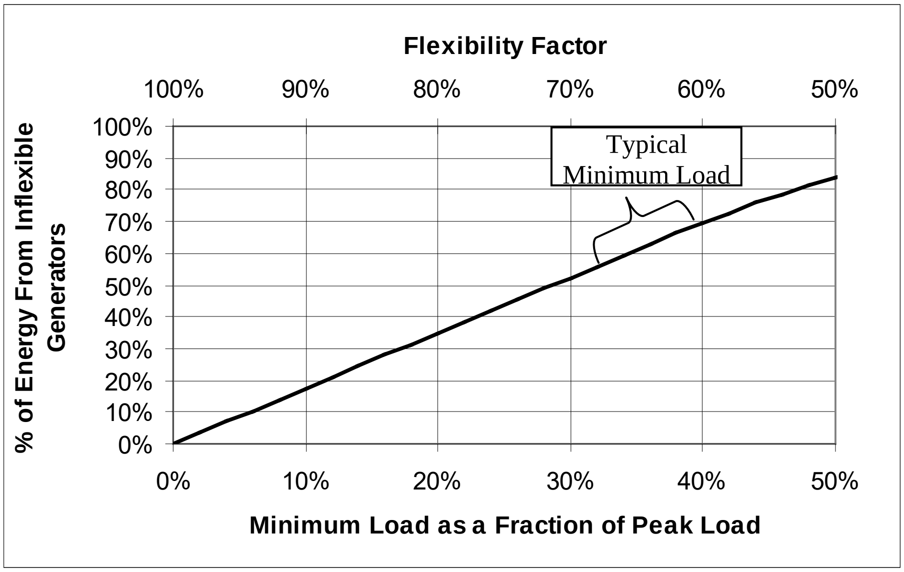

Figure 4.5. Contribution from inflexible generation

Alternatively, it is possible to evaluate the relationship between system flexibility and large-scale penetration of VG, both with and without energy storage or other enabling technologies. Figure 4.6 shows an example of how flexibility affects the potential curtailment of wind and solar energy when deployed without storage. These two charts superimpose load data in ERCOT from 2005 with a spatially diverse set of simulated wind and solar data from the same year.[56,57] The simulation places 19 GW of wind and 11 GW of solar (representing an 80%/20% mix of wind and solar on an energy basis) into the 2005 ERCOT system, which had a peak demand of 60.3 GW. In the left chart, the system is assumed to be unable to cycle below the 2005 minimum point of 21 GW, resulting in substantial VG curtailment. In this simulation, wind and solar provide 20% of the grid's annual energy, and 21% of the total renewable energy production is curtailed. The right graph shows the result of increasing flexibility, allowing for a minimum load point of 13 GW. Curtailment has been reduced to less than 3%, and the same amount of variable renewables now provides about 25% of the system's annual energy.

[55] This is noted in previous wind integration studies such as the ERCOT study (GE 2008), and the more recent Eastern and Western Interconnect studies. "As the penetration of wind and solar increase, the impact on base-load coal increases, becoming very challenging at the 30% penetration." (Milligan et al. 2009b).
[56] Historically, many estimates of the limits of wind penetration have used data from a single or very small set of wind power plants, and often a small balancing area. Without spatial diversity of resource and load, this leads to both excessive ramp rates and excessive curtailment.
[57] The data set is the same as from Figures 4.2 and 4.3, with solar data derived from the National Solar Radiation Database. See Denholm and Margolis 2008 for additional details. The data was processed using the REFlex Model, which compares hourly electricity demand with VG supply and calculates curtailments as a function of system flexibility based on minimum load constraints. The model is described in more detail in Denholm and Margolis 2007a and 2007b.

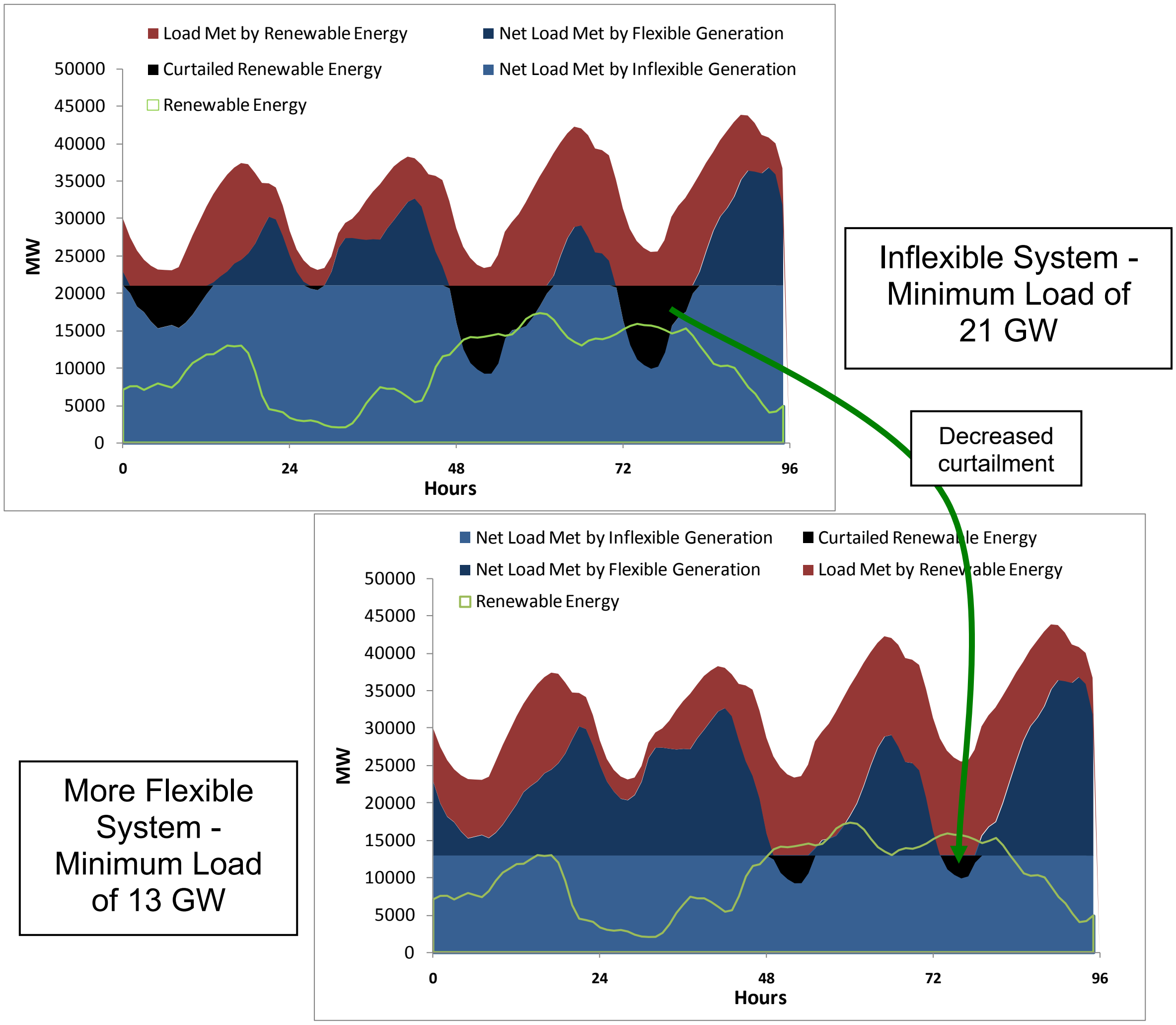

Figure 4.6. Effect of decreasing minimum load point on increased use of RE

These results can be evaluated more generally by examining the amount of curtailment that will result without energy storage as a function of system flexibility. Figure 4.7 shows example results, with three different minimum load/flexibility factors. The first curve illustrates the curtailment that would result if the system could not cycle below its 2005 annual minimum load of 21 GW. The second curve uses a minimum load of 12 GW, which corresponds roughly to the assumptions used in the 2008 ERCOT wind study (GE 2008). The third curve corresponds to a 6 GW minimum load, which largely eliminates baseload units from the generation mix, replacing them with more flexible units.[58]

[58] It should be noted that significant changes in the generation mix and corresponding changes in system flexibility could result from CO_2 emissions constraints. Increased cost of carbon could motivate greater use of natural gas generation, and reduce use of coal, both of which would tend to increase system flexibility, and allow greater economic use of VG. This, in turn, would decrease fuel use and the capacity factor of thermal generators, which would also tend to increase the use of gas-fired generation and decrease the use of coal as the economic optimal mix of generation. For additional discussion, see Lamont 2008.

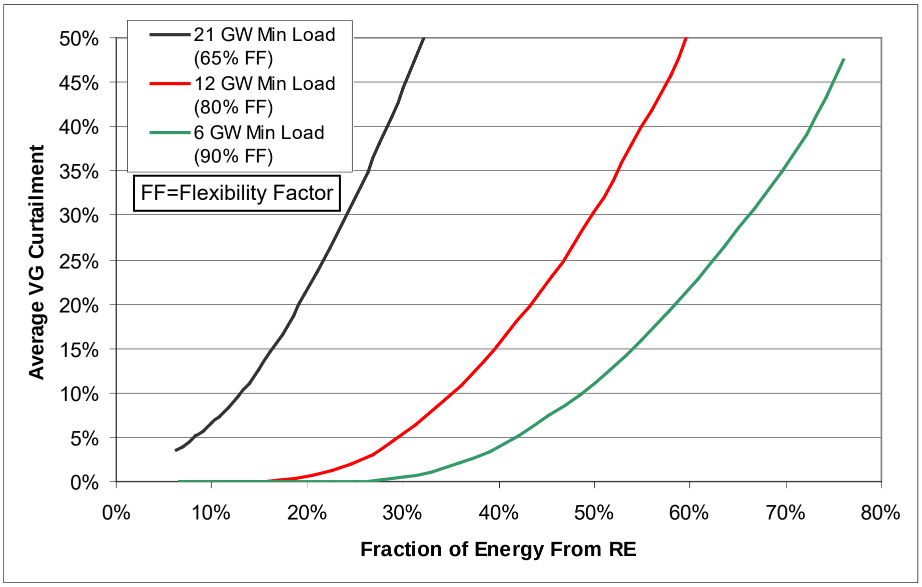

Figure 4.7. Average curtailment rate as a function of VG penetration for different flexibilities in ERCOT

Figure 4.7 somewhat obscures the fact that at the margin, curtailment rates can be very high. Figure 4.8 illustrates the marginal curtailment rate, or the curtailment rate of each incremental unit of VG installed in the system. For example, in the 12 GW minimum load curve, the average curtailment rate (Figure 4.7) when VG is providing 25% of the system's electricity demand is less than 3%, which means that less than 3% of all the VG at this penetration level is curtailed. However, the last unit of energy installed to get to this 25% point has a curtailment rate of more than 10%, as illustrated in Figure 4.8.

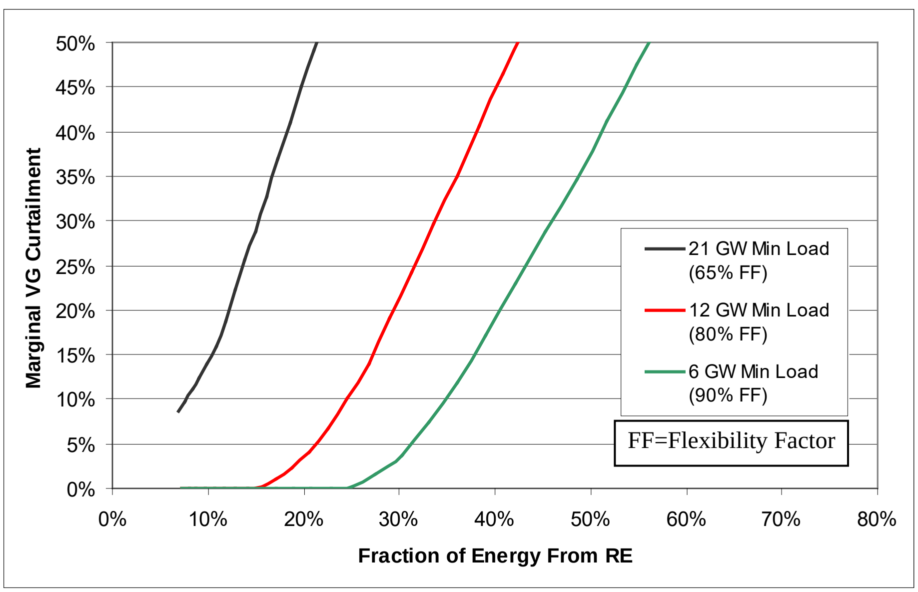

Figure 4.8. Marginal curtailment rate as a function of VG penetration for different system flexibilities in ERCOT (marginal curtailment is defined as the percentage curtailed as a function of the incremental penetration)

Curtailment increases the cost of the VG that is actually used, because curtailment reduces the net capacity factor of the wind and solar generators. Figure 4.9 shows how the effective cost of VG increases due to curtailment. Costs are illustrated in relative terms – a generator with no curtailment has a base cost of 1, which increases with a scale factor equal to (1/1-curtailment rate).

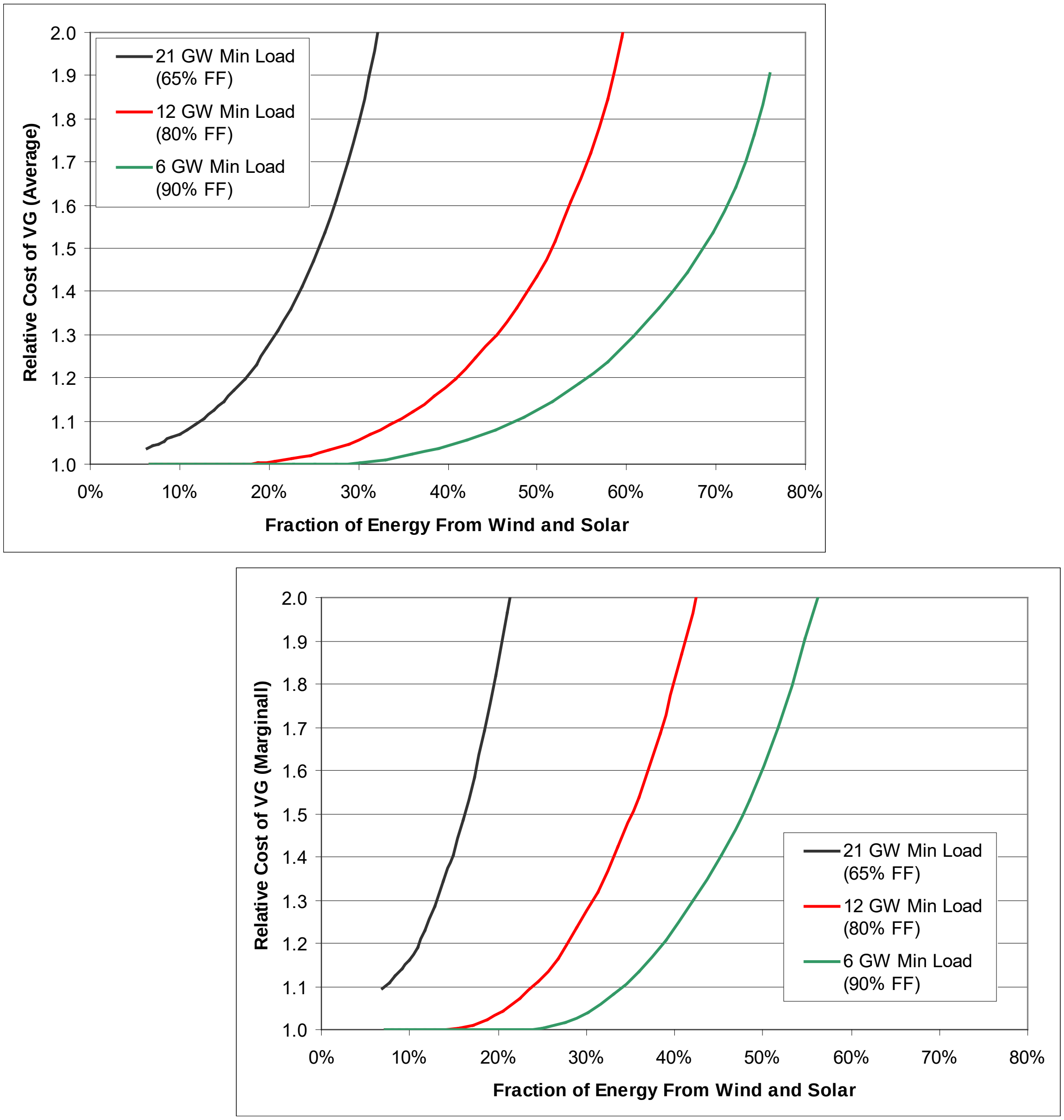

Figure 4.9. Relative cost of VG – average (top chart) and marginal (bottom chart) – as a function of VG penetration for different system flexibilities in ERCOT

This example can be compared to the results of the previous U.S. wind integration studies that find very little curtailment up to about 20% on an energy basis, due to the existing grid flexibility. Beyond this level (up to about 30%), curtailment increases without significant operational changes (Corbus et al. 2009). In the United States, penetrations of VG beyond 30% have yet to be extensively studied; however, the examples in this section suggest curtailment rates will continue to rise substantially without a significant increase in system flexibility or deployment of other enabling technologies such as energy storage.

The results in Figure 4.9 apply to only a specific mix of VG – and a single system – so they cannot be applied generally. However, they do illustrate the trends that may limit the contribution of VG without enabling technologies. Ultimately, the cost of curtailment must be compared to alternatives such as the cost of storage or other enabling technologies, illustrated in Figure 4.10 and discussed in more detail in Section 5.[59]

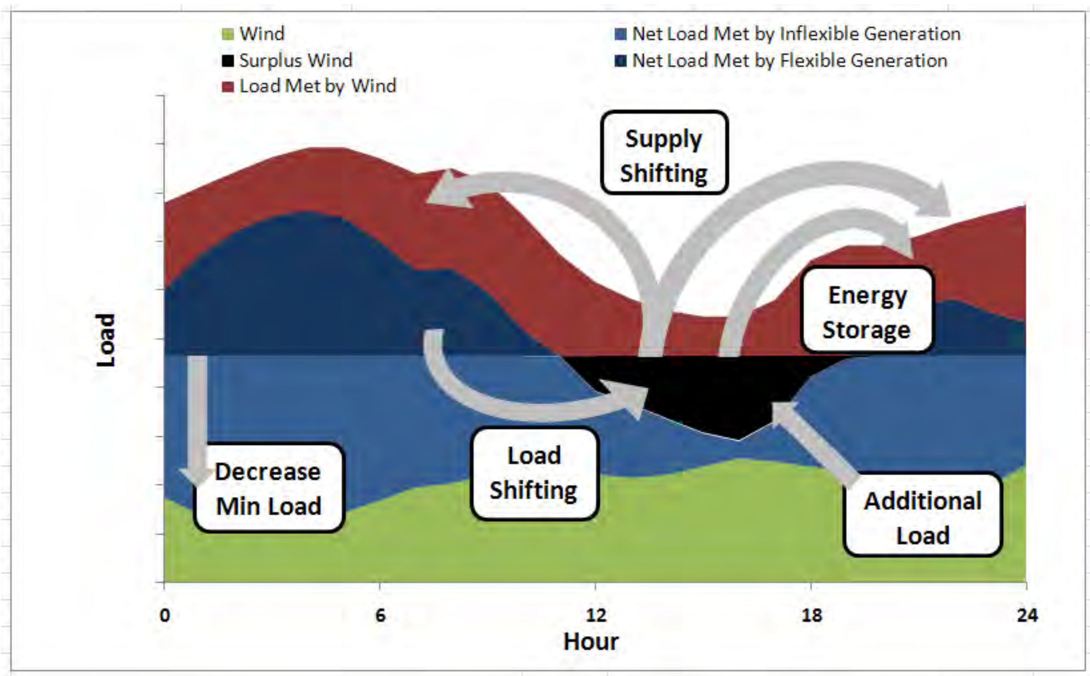

Figure 4.10. Option for increasing the use of VG by decreasing curtailment

Storage provides one solution to avoiding curtailment by absorbing otherwise unusable generation and moving it to times of high net system load (where net load is defined as normal load minus VG). The additional flexibility storage provides is also important. Storage can provide operating reserves, which reduces the need for partially loaded thermal generators that may restrict the contribution of VG. Finally, by providing firm capacity and energy derived from VG sources, storage can effectively replace baseload generation, which reduces the minimum loading limitations.

Figure 4.11 illustrates how the curtailment rate can be reduced by introducing energy storage.[60] The base case (no storage) is identical to Figure 4.7 with a 12 GW minimum

[59] The large number of options available for increasing the penetration of RE is one of the reasons why the question of when storage becomes necessary is very difficult to answer. There is less of a technical limit than an economic one that depends on a large number of factors such as the cost of storage compared to a vast array of alternatives.

[60] The data and methods used for this analysis are the same as before, using the REFlex model to place otherwise curtailed energy into storage and using that stored energy at a later time (Denholm and Margolis 2007b).

load (or an 80% flexibility factor). In addition, a storage device with 5% of the system's power capacity (or 3 GW in a 60 GW peaking system), 20 hours of energy capacity, and a 75% round-trip efficiency is introduced. If this device is used only to absorb otherwise unusable energy, the curtailment rate is reduced substantially. For example, when VG is providing 50% of the system's energy, about 30% of the VG is curtailed without storage, and about 25% with the 3 GW of storage. This includes the additional losses that occur in the storage process. The device's ability to replace firm capacity and potentially reduce the minimum load constraint further reduces curtailment. Adding the ability to reduce the minimum load by 50% of the device's capacity (or about 1.5 GW) reduces curtailment further – in the 50% VG case, the curtailment rate now drops from 30% without storage to 20% of the total VG.[61]

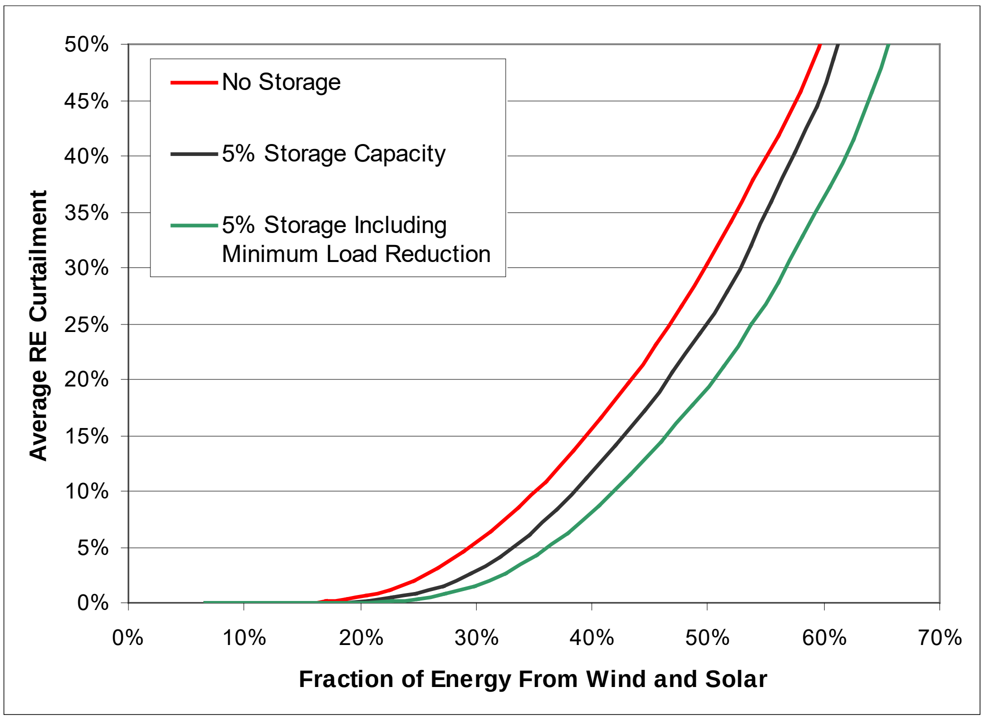

Figure 4.11. Reduction of curtailment resulting from addition of energy storage

While storage provides one solution to the mismatch of VG supply and normal demand, there are a variety of options for increasing the use of VG in the grid. Any evaluation of energy storage should consider the many alternative technologies that can increase grid flexibility and enable VG renewables.

[61] Alternatively, for a given amount of allowed curtailment, the contribution of VG increases with the addition of storage. In the case illustrated in Figure 4.11, a maximum VG curtailment of 10% allows VG to provide about 35% of the total electricity demand. Adding energy storage (with its ability to reduce the minimum load) increases the contribution of VG (for the same amount of allowable curtailment) to about 42% of total demand.

5 Storage and Flexibility Options for Renewables-Driven Grid Applications

The previous section indicates that at high penetration of VG, fundamental changes to the grid may be required to accommodate the increased variability of net load and the limited coincidence of VG supply and normal electricity demand. A number of techniques and technologies – described as flexibility resources – have been proposed to accommodate the impacts of VG and ensure the generation mix matches the net-load requirement.

5.1 The Flexibility Supply Curve

Energy storage is one of many technologies proposed to increase grid flexibility and enable greater use of VG. This set of technologies has been described in terms of a flexibility supply curve that can provide responsive energy over various timescales. The flexibility supply curve is conceptually similar to other resource supply curves where (ideally) the lowest-cost resources are used until they are exhausted, then the next (higher-cost) resource is deployed. The analysis in Section 4, for example, was restricted to ERCOT, and did not consider the opportunity to exchange wind and solar energy with surrounding areas by building interconnections with the other U.S. grids. It also did not consider the ability to shift load by incentivizing customers to use less electricity when VG output is low. Overall, utilities have many "flexibility" options for incorporating greater amounts of VG into the grid, many of which may cost less than using energy storage. Figure 5.1 provides a conceptual supply curve including some of these options.

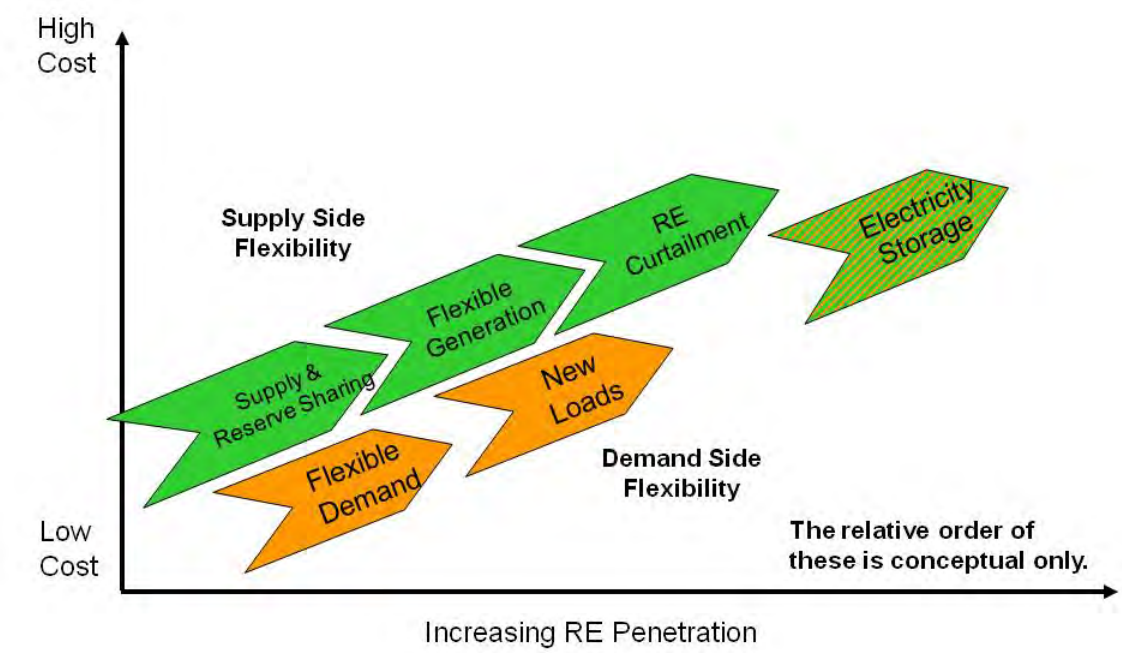

Figure 5.1. Flexibility supply curve[62]

[62] Based on an original by Nickell 2008. While the figure hypothesizes an order of the supply curve, the actual costs and availability of the individual components are conjectural.

Overall, there are two general "types" of flexibility required by variable sources and offered by technologies in this curve. The first can be described as ramping flexibility, or the ability to follow the variation in net load (in the second-to-minute timescale needed for frequency regulation, or the minutes-to-hours timescale needed for load following and forecast error.) This flexibility is the primary requirement at low penetration, as discussed in Section 4.2. The second type of flexibility is energy flexibility, or the ability to increase the coincidence of VG supply with demand for electricity services, which is described in Section 4.3. A description of several of the sources of flexibility is provided below.

a.) **Supply and Reserve Sharing.** This includes the sharing of renewable and conventional supply, operating reserves, and net loads through markets or other mechanisms that effectively increase the area over which supply and demand is balanced. [63] Greater aggregation of loads and reserves has historically been one of the least-cost methods of dealing with demand variability, especially because it often requires operational changes and relatively little new physical infrastructure.[64] It may also require transmission development to increase the spatial diversity of VR resources.

b.) **Flexible Generation.** This includes deploying new, more flexible conventional generators as well as increasing flexibility of existing generators. This can be accomplished by modifying equipment and operational practices[65] to increase the load-following, ramping rate, and ramping range of the grid. This also includes introducing new generators that can be brought online quickly to respond to forecast errors.[66] This may also require increased use of natural gas storage to increase use of flexible gas turbines and decrease contractual penalties for forecast errors in natural gas use (Zavadil 2006). Another source of flexible generation is improved use of existing storage and hydro assets.

c.) **Demand Flexibility.** This includes introducing market or other mechanisms to allow a greater fraction of the load to respond to price variations and provide ancillary services. Responsive demand can provide flexibility over multiple timescales by curtailing demand for short periods or shifting load over several hours. Many of these technologies and processes have been described in terms

[63] "Larger markets and balancing areas that are a central feature of ISOs and RTOs can improve the physical conditions needed to integrate large amounts of wind energy. ISOs and RTOs, with their day-ahead and real-time markets, large geographies to aggregate diverse wind resources, large loads to aggregate with wind, large generation pools that tap conventional generator flexibility… offer the best environments for wind generation to develop." (Milligan et al. 2009b).

[64] This includes introducing sub-hourly markets that allow systems faster response to variability. Large ISOs with 5-minute markets typically have substantially lower wind integration costs.

[65] This could include scheduling generators over shorter time periods, and using sub-hourly wind forecasts instead of "persistence" forecasts that may actually contribute to short-term scheduling errors and increase regulation requirements.

[66] "Extensive changes will be required in the type of new generation built in the state: new units must have greater operating flexibility to start up and shut down without long delays; they must be able to operate at lower minimum loading levels; and they must have faster ramping capability and regulation capability" (CAISO 2007). Examples of more responsive generators include certain aeroderivative gas turbines and reciprocating engines. For additional discussion of flexible generators, see Northwest Power and Conservation Council 2009.

of a "smart grid" and will require regulatory and policy changes in addition to new technologies. In many locations in the United States, demand is increasingly used as a source of grid services.[67]

d.) **VG Curtailment.** Overbuilding VG may result in curtailment of low-value springtime generation, but would allow for a greater overall VG contribution. (This is functionally equivalent to cycling baseload generators in the spring.) Furthermore, curtailed VG provides additional benefits, because it provides a source of operating reserves and potentially allows for de-commitment of thermal units that typically provide these services.

e.) **New Loads.** New controllable loads can be added to absorb otherwise unusable VG. Examples include space and process heating, which currently use fossil fuels. Another possibility is fuel production such as hydrogen via electrolysis or shale oil heating. Electrification of transportation using electric vehicles or plug-in hybrid vehicles is also a potential large-scale application. This may also include electric vehicles providing regulation and contingency reserves with or without the use of vehicle to grid (V2G).

f.) **Electricity Storage.** Electricity storage encompasses a large number of technologies discussed in Section 5.2

The general classes of flexibility resources listed above represent dozens or even hundreds of individual technologies, each with a potential contribution to increasing grid flexibility. The cost and availability of many flexibility resources has yet to be quantified, and there are a variety of regulatory barriers to completely deploying many flexibility options such as demand response.

The cost of storage needs to be compared to the alternatives – this includes the efficiency losses in the storage process that may be avoided by using other enabling technologies. There are, of course, limits to each option on the curve; and the benefits of spatial diversity and demand response are limited because the VG supply cannot be expected to exactly match the demand for electricity services on the multiple timescales. Because of this, electricity storage is considered a potentially important step on the flexibility supply curve when lower-cost options are saturated or otherwise unavailable.

5.2 Deployment and Operational Balancing of Renewable Energy – Individual Plant Storage vs. Power System Storage

The previous section suggests that incorporating increased levels of VG most efficiently will require a variety of flexibility options. Likewise, the most efficient operation and location of flexibility options – including storage – must be considered. While flexibility resources can be considered renewable enabling technologies, their historical application has been to benefit the grid as a whole. It is often suggested that energy storage be co-located with, and operationally tied to, the output of individual VG facilities. However, this is not how the current system balances the large variability in net demand.

[67] As an example, ERCOT currently obtains half of its spinning reserve requirements from responsive load, and the ERCOT event of February 2008 discussed previously is an example of an application of load as a source of "up" ramping, used to meet demand until conventional generators could be started and dispatched.

Furthermore, the services needed to address variability and uncertainty are generally the same services that storage currently provides to the grid. Table 5.1 lists several renewable-specific applications that have been proposed (EPRI 2004). As an example, one potential renewable-specific application of storage is “time-shifting” of wind from periods of low demand to periods of high demand. However, this application is fundamentally the same as energy arbitrage, and the benefits of this application are greatest when the energy storage operator can choose from all of the generators in a system, and store energy when the cost is lowest, instead of storing only wind generation.

Table 5.1. Dedicated Renewable Applications of Energy Storage and Their Whole-Grid Counterpart

RE Specific Application	“Whole Grid” Application
Transmission Curtailment	Transmission Deferral
Time Shifting	Load Leveling/Arbitrage
Forecast Hedging	Forecast Error
Frequency Support	Frequency Regulation
Fluctuation Suppression	Transient Stability

Despite the attractiveness of a smoothed and shifted output from each generator, this approach results in a significant decrease in the efficiency of the entire system, and eliminates the benefits of resource aggregation. For example, demand of any individual electricity consumer can be very irregular, with rapid unpredictable ramps. Distributed energy storage could be used to smooth these individual demands. However, this would result in storage devices being charged in one location, while simultaneously discharged in another, wasting both the cost of storage devices and the losses in the storage process. The aggregated net demand of many individual consumers is considerably smoother, and would require much less storage to “flatten” if desirable. Likewise, operational integration between energy storage and any individual or groups of VG would be nonoptimal and likely result in simultaneous charging and discharging. By aggregating the entire net load of a system, including all loads and VG supply, storage or other flexibility options can be deployed at the lowest cost and greatest efficiency. [68] This is especially the case when spatial diversity substantially reduces variability over multiple timescales.

There are some exceptions when there are benefits of operationally combining VG and energy storage, typically through co-location and sharing of certain high-cost components. The best example is integrating thermal storage into a concentrating solar power (CSP) plant; another example is sharing power electronics in a distributed PV/battery system.

There are several other applications where co-location of VG and storage may make sense. Wind plants placed in areas of weak transmission can potentially introduce power quality and stability issues, and storage can be a mitigating technology; however,

[68] In effect, combining individual VG and storage is essentially the creation of very small balancing areas. This is actually the opposite of how the grid is evolving, with the creation of larger balancing areas and the use of reserve sharing agreements across utilities. Balancing individual VG would dramatically increase reserve requirements and would incur much greater costs than at the system level.

improved power electronics in modern wind turbines may be a lower-cost alternative. Finally, combining wind and energy storage has been proposed as an alternative (or supplement) to developing new transmission capacity. Increased deployment of wind energy will require substantial new transmission, and storage co-located with remote wind resources can help decrease the need for new transmission.[69] This has been proposed to relieve congestion in the ERCOT grid, for example, where the state's best wind resources are located largely in the sparsely populated western part of the state, and transmission capacity is limited (Desai et al. 2003). Despite these potential applications, the majority of storage deployed in the grid will likely be a shared resource, which will benefit the entire system and not just a single generator or load (Smith et al. 2007). Just as loads are balanced in aggregate, the net load in the future grid – after all VG sources are included – will be balanced by a mix of conventional generation, plus flexibility options that include energy storage.

5.3 Energy Storage Technologies and Applications

This section provides a brief overview of commercially available energy storage technologies. It is not intended to be a comprehensive discussion, because there are a large number of sources available that discuss the technical performance, current applications, vendors, and costs in detail. A number of more comprehensive reviews of energy storage technologies are provided in the Bibliography.

The choice of an energy storage device depends on its application in either the current grid or in the renewables/VG-driven grid; these applications are largely determined by the length of discharge. Energy storage applications are often divided into three categories, based on the length of discharge. Table 5.2 indicates the three regimes of energy storage applications commonly discussed.

Table 5.2. Three Classes of Energy Storage

Common Name	Example Applications	Discharge Time Required
Power Quality	Transient Stability, Frequency Regulation	Seconds to Minutes
Bridging Power	Contingency Reserves, Ramping	Minutes to ~1 hour
Energy Management	Load Leveling, Firm Capacity, T&D Deferral	Hours

The first two categories of energy storage applications in Table 5.2 correspond to a range of ramping and ancillary services, but do not typically require continuous discharge for extended periods of time. In the case of renewables-driven applications, this could require discharge times of up to about an hour to allow fast-start thermal generators to come online in response to forecast errors. (Bridging power typically refers to the ability of a

[69] Use of dedicated long-distance transmission for wind or solar will be limited by the relatively low capacity factor of the resource. Storage could increase line-loading and help reduce curtailment due to transmission constraints. For additional discussion, see Denholm and Sioshansi 2009.

storage device to "bridge" the gap from one energy source to another.)[70] The third category (energy management) corresponds to energy flexibility, or the ability to shift bulk energy over periods of several hours or more.

The references in the Bibliography provide a number of assessments and charts with estimates of technical performance and costs. Figure 5.2 provides one example of the range of technologies available for these three classes of services, and shows that many technologies can provide services across various timescales.

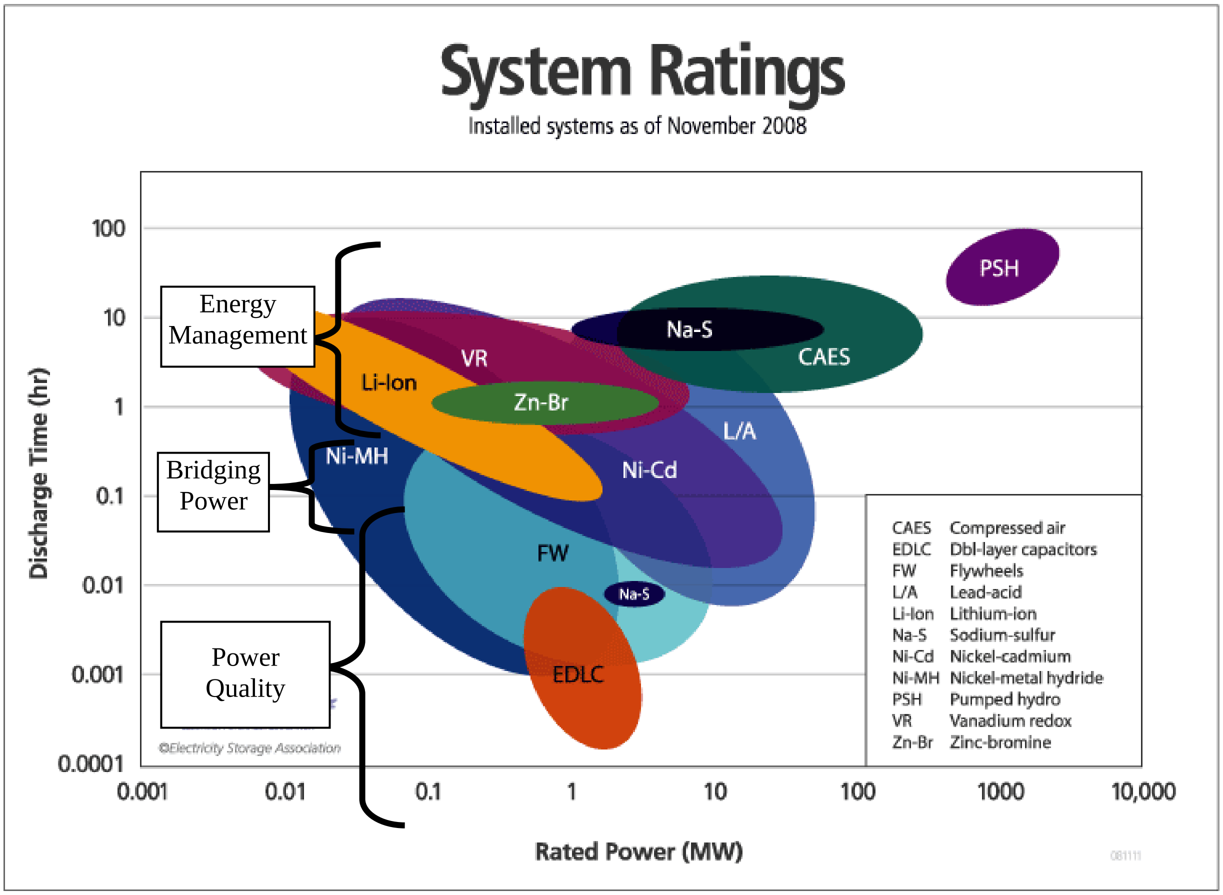

Figure 5.2. Energy storage applications and technologies[71]

[70] This often refers to the time it takes after a power failure for an isolated system to switch from the grid to a backup generator. However, this term may also be useful to describe the ability to address forecast errors and bring up standby generators during times of unforeseen decreases in wind or conventional generation.
[71] This chart represents technologies actually deployed or proposed as of November 2008. It does not include a number of pre-commercial products or represent the total range of applications. For example, most of the batteries listed could be scaled up in either energy or power capacity, while at least 1 CAES plant of greater than 1,000 MW has been proposed. Alternatively, PSH plants of less than 50 MW have been constructed (ESA 2009).

It should be noted that this chart does not include thermal energy storage, which would cover a power range of a few kilowatts (kW) for thermal energy storage in buildings to more than 100 MW in CSP plants, with a discharge time of minutes to several hours.

When considering the technical performance or costs of energy storage, there are a number of caveats to consider. The first is the technical and commercial maturity of the storage technology. As of 2009, only four energy storage technologies (sodium-sulfur batteries, pumped hydro, CAES, and thermal storage)[72] have a total worldwide installed capacity that exceeds 100 MW.[73] This doesn't mean that there isn't market potential for any individual technology or storage, in general; but it makes it difficult to assess the state of any individual technology given its limited deployment to date. This also leads to some uncertainty in two of the primary performance indicators for energy storage devices: efficiency and cost. Both of these values are often imprecisely reported, which makes it difficult to perform an accurate assessment of the potential for individual technologies or compare different technologies. Some major caveats when considering electricity storage include:

Efficiency

1) The standard measure of an electricity storage device's efficiency in the grid is the AC to AC round-trip efficiency, or AC kWh_{out}/kWh_{in}.[74] However, this is not always the value reported, especially for devices that store DC energy such as batteries and capacitors. In some cases, the DC-DC round-trip efficiency may be reported, and additional losses in power conversion efficiencies must be considered if the device is to provide applications in the grid.
2) Reported round-trip efficiencies may not include "parasitic" loads. These include heating and cooling of batteries and power-conditioning equipment. These parasitic loads can vary considerably depending on use, climate, and the length of each storage cycle.
3) The round-trip efficiency of several technologies cannot be directly compared. Thermal storage provides some, but not all of the services of a "pure" electricity storage device; while compressed-air energy storage is a hybrid device that requires both electricity and natural gas. These factors limit the value of a direct comparison, as discussed in more detail later in this section.

Cost

1) As stated before, only a few storage technologies have been deployed at large scale (greater than 100 MW). Estimated prices for emerging technologies may be for a semi-custom product (and consequently very high) or projected costs based on mass production (and perhaps overly optimistic). Even with more mature

[72] This excludes small distributed applications including uninterruptible power supplies, off-grid homes, and the substation batteries. These applications are dominated by lead-acid batteries.
[73] 100 MW is equivalent to a small power plant and negligible in terms of overall grid-scale capacity. As of January 2008, the United States had 1,087,791 MW of installed capacity (EIA 2009a).
[74] The U.S. electric grid uses alternative current (AC) while batteries, capacitors, and several other electric storage technologies charge and discharge direct current (DC).

technologies such as PHS and CAES, it has been some time since either has been built in the United States, so the cost of the next plant is somewhat uncertain.[75]

2) As with any generation technology, large variations in prices occur from year to year due to commodity prices and the global economy. Therefore, cost estimates of storage technologies from different years may reflect market conditions as opposed to real differences.
3) Storage technologies offer different classes of services and are comprised of an energy component and power component. The total cost of a storage device includes both components, with the limits of the target application. As a result, a direct comparison of a PHS device with a flywheel, for example, has limited value.

5.3.1 Storage Technologies for Power Quality Applications

Power quality applications require rapid response – often within less than a second – and include transient stability and frequency regulation. As with the other applications, the timescales of discharge may vary; but this class of services typically requires discharge times of up to about 10 minutes and nearly continuous cycling. Technologies for these applications include flywheels, capacitors, and superconducting magnetic energy storage (SMES).

Flywheels

Flywheels store energy in a rotating mass. Flywheels feature rapid response and high efficiency, making them well-suited for frequency regulation. Several flywheel installations have been planned or deployed to take advantage of high prices in frequency regulation markets (Lazarewicz 2009).

Capacitors

Capacitors[76] store electricity in an electric charge. Capacitors have among the fastest response time of any energy storage device, and are typically used in power quality applications such as providing transient voltage stability. However, their low energy capacity has restricted their use in longer time-duration applications. A major research goal is to increase their energy density and increase their usefulness in the grid (and potentially in vehicle applications.)

Superconducting Magnetic Energy Storage (SMES)

SMES stores energy in a magnetic field in a coil of superconducting material. SMES is similar to capacitors in its ability to respond extremely fast, but it is limited by the total energy capacity. This has also restricted SMES to "power" applications with extremely short discharge times. Several demonstration projects have been deployed.

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[75] Furthermore, PHS and CAES depend on site-specific geologic conditions, which makes costs difficult to generalize.

[76] These devices have several names such as ultracapacitors and supercapacitors. "There is some uncertainty within the industry on the exact name for capacitors with massive storage capability. This is in part due to the many names of products by different manufacturers, but also due to the relative newness of the industry and recent advances." (EPRI 2003).

5.3.2 Storage Technologies for Bridging Power

Bridging power applications include providing contingency reserves, load following, and additional reserves for issues such as forecast uncertainty and unit commitment errors. This set of applications generally requires rapid response (in seconds to minutes) and discharge times in the range of up to about an hour. Far less cycling is required than for power quality applications.

This application is generally associated with several battery technologies, which include lead-acid, nickel-cadmium, nickel-metal hydride, and (more recently) lithium-ion. Due to their rapid response, they can provide power quality services such as frequency regulation; but the continuous cycling requirement can limit battery life. Several demonstration projects have been built using these technologies to provide operating reserves.

5.3.3 Storage Technologies for Energy Management

Energy management applications include moving power over longer timescales, and generally require continuous discharge ratings of several hours or more. Technologies for these applications include several battery types, pumped hydro, compressed air, and thermal energy storage.

High-Energy Batteries

For many batteries, there is considerable overlap between energy management and the shorter-term applications discussed previously. Furthermore, batteries can generally provide rapid response, which means that batteries “designed” for energy management can potentially provide services over all the applications and timescales discussed.

Several battery technologies have been demonstrated or deployed for energy management applications. In addition to the chemistries discussed previously, the commercially available batteries targeted to energy management include two general types: high-temperature batteries and liquid electrolyte flow batteries

The most mature high-temperature battery as of 2009 is the sodium-sulfur battery, which has worldwide installations that exceed 270 MW (Rastler 2008). Alternative high-temperature chemistries have been proposed and are in various stages of development and commercialization. One example is the sodium-nickel chloride (ZEBRA) battery.

The second class of high-energy batteries is the liquid electrolyte “flow” battery. This battery uses a liquid electrolyte that flows across a membrane. The advantage of this technology is that the power component and energy component can be sized independently. As of 2009, there has been limited deployment of two types of flow batteries – vanadium redox and zinc-bromine. Other combinations such as polysulfide-bromine have been pursed, and new chemistries are under development.

In the United States, a primary application of energy management batteries has been T&D deferral; however, demonstration projects have been deployed for multiple applications (Nourai 2007, EPRI 2003).

Pumped Hydro Storage (PHS)

Pumped hydro is the only energy storage technology deployed on a gigawatt scale in the United States and worldwide. In the United States, about 20 GW is deployed at 39 sites, and installations range in capacity from less than 50 MW to 2,100 MW.[77] Many of the sites store 10 hours or more, making the technology useful for load leveling. PHS is also used for ancillary services. PHS uses conventional pumps and turbines and requires a significant amount of land and water for the upper and lower reservoirs. PHS plants can achieve round-trip efficiencies that exceed 75% and may have capacities that exceed 20 hours of discharge capacity. Environmental regulations may limit large-scale above-ground PHS development. However, given the high round-trip efficiencies, proven technology, and low cost compared to most alternatives, conventional PHS is still being pursued in a number of locations.[78] Alternative lower-impact configurations have been studied, including using a natural or mined underground formation for the lower reservoir, but this configuration has yet to be commercialized.

Compressed Air Energy Storage (CAES)

CAES technology is based on conventional gas turbine technology and uses the elastic potential energy of compressed air. Energy is stored by compressing air in an airtight underground storage cavern. To extract the stored energy, compressed air is drawn from the storage vessel, heated, and then expanded through a high-pressure turbine that captures some of the energy in the compressed air. The air is then mixed with fuel and combusted, with the exhaust expanded through a low-pressure gas turbine. The turbines are connected to an electrical generator.

CAES is considered a hybrid generation/storage system because it requires combustion in the gas turbine. The performance of a CAES plant is based on its energy ratio (energy in/energy out) and its fuel use (typically expressed as heat rate in BTU/kWh). CAES performance is estimated at an energy ratio of 0.6-0.8 and a heat rate of 4,000-4,300 BTU/kWh (Succar and Williams 2008). Because CAES uses both electricity and natural gas, a single-point definition of the round-trip efficiency of a CAES device does not represent an economic figure of merit.

The primary disadvantages of CAES are the need for an underground cavern and its reliance on fossil fuels. Alternative configurations for CAES have been proposed using manufactured above-ground vessels, new turbine designs to reduce fossil fuel use, or designs that re-use the heat of compression and avoid fuel use altogether.

Thermal Energy Storage

Thermal energy storage is sometimes ignored as an electricity storage technology because it typically is not used to store and then discharge electricity directly. However, in some applications, thermal storage can be functionally equivalent to electricity storage. One example is storing thermal energy from the sun that is later converted into electricity

[77] A complete list – including capacity, location, date of initial operation, and ownership – is available from EIA Form EIA-860, “Annual Electric Generator Report.”

[78] About 30 GW of new pumped hydro capacity has been proposed between 2006 and 2009. This represents more than double the existing capacity, and certainly implies there are considerable opportunities for new pumped hydro capacity (Adamson 2009).

in a conventional thermal generator. Another example is converting electricity into a form of thermal energy that later substitutes for electricity use such as electric cooling or heating.

The first example (storing thermal energy that is later converted into electricity) can be used with many types of thermal generators but is most often associated with concentrating solar power. In this application, thermal energy from the solar field is stored in molten salt or another medium. This energy can be recovered later and used to generate electricity, which turns this technology into a dispatchable source of energy.

Care must be used when discussing the efficiency of thermal energy storage. One of the major issues with electricity storage is efficiency losses. Electricity is a high “quality” source of energy, and transforming electricity into a stored medium and back incurs considerable losses. Thermal energy is a much lower quality of energy, but can be stored with much higher efficiency. In a CSP plant, thermal energy is stored before conversion to electricity. As a result, the round-trip efficiency of CSP thermal storage may be close to 100%, much higher than any electricity storage technology. However, CSP thermal storage can only store thermal energy produced from the solar field, as opposed to other storage technologies that can store electricity produced from any source.

Likewise, end-use energy storage can have extremely high round-trip efficiencies. Demand for electric-power cooling can be shifted by storing cold energy in the form of chilled water or ice during off-peak times and releasing that cold energy during times of peak demand. This effectively stores electricity with high round-trip efficiency.[79]

End-use hot storage can also be used in both space heating and water heating applications. (Controllable water heating somewhat blurs the line between energy storage and demand response.) As with other forms of thermal storage, the effective round-trip efficiency of end-use hot storage is much higher than “pure” electricity storage devices but is limited by daily and seasonal heating demands.

5.4 Electric Vehicles and the Role of Vehicle to Grid

Electric vehicles (EVs – used here to represent both “pure” electric vehicles or plug-in hybrid electric vehicles) are a potential source of flexibility for VG applications. The charging of EVs can potentially be controlled, and provide a source of dispatchable demand and demand response. Controlled charging can be timed to periods of greatest VG output, while charging rates can be controlled to provide contingency reserves or frequency regulation reserves. Vehicle to grid (V2G) (where EVs can partially discharge stored energy to the grid) may provide additional value by acting as a distributed source of storage. EVs could potentially provide all three grid services discussed previously. Most proposals for both controlled charging and V2G focus on short-term response services such as frequency regulation and contingency. Their ability to provide energy

[79] Losses in the storage system are relatively small and occur through heat exchange from the stored cold energy and the surrounding environment. These losses can be partially offset by the potential increase in compressor efficiency when making ice or chilled water in the cooler evening compared to the daytime, which achieves net efficiencies close to 100%.

services is more limited by both the storage capacity of the battery, as well as the high cost of battery cycling. This could restrict their ability to provide time-shifting (energy arbitrage) beyond their ability to perform controlled charging.[80] The role of V2G is an active area of research, and because electrified vehicles in any form have yet to achieve significant market penetration, it is difficult to assess their potential as a source of grid flexibility. However, analysis has demonstrated potential system benefits of both controlled charging and V2G (Denholm and Short 2006). The role of EVs as an enabling technology requires additional analysis of their unique temporal characteristics of availability, unknown battery costs and lifetimes, and the availability of smart charging stations to maximize their usefulness while parked.

[80] This conclusion depends on the anticipated cycle life and cost of EV batteries. See Sioshansi and Denholm 2009 and Peterson et al. 2010 for a discussion of the impact of battery life and cycling on the value of V2G. However, controlled charging (without V2G) is still a potentially significant source of flexibility, with the ability to raise the minimum load and avoid curtailment.

6 Conclusions

The increasing role of variable renewable sources (such as wind and solar) in the grid has prompted concerns about grid reliability and raised the question of how much these resources can contribute before enabling technologies such as energy storage are *needed*. Fundamentally, this question is overly simplistic. In reality, the question is an economic issue: It involves the integration costs of variable generation and the amount of various storage or other enabling technologies that are economically viable in a future with high penetrations of VG. To date, integration studies of wind to about 20% on an energy basis have found that the grid can accommodate a substantial increase in VG without the need for energy storage, but it will require changes in operational practices, such as sharing of generation resources and loads over larger areas. Beyond this level, the impacts and costs are less clear, but 30% or more appears feasible with the introduction of "low-cost" flexibility options such as greater use of demand response. However, these studies have not necessarily focused on storage and generally do not attempt to determine the optimal system (including the amount of storage) that provides the lowest cost of energy.

There are technical and economic limits to how much of a system's energy can be provided by VG without enabling technologies based on at least two factors: coincidence of VG supply and demand and the ability to reduce output from conventional generators. At extremely high penetration of VG, these factors may cause excessive (and costly) curtailment, which will require methods to increase the useful contribution of VG However, the concern regarding how much VG can be used before storage is the most economic option for further integration currently has no simple answer, primarily because the availability and cost of grid flexibility options are not well understood and vary by region.

It is clear that high penetration of variable generation increases the need for all flexibility options including storage, and it also creates market opportunities for these technologies. Historically, storage has been difficult to sell into the market, not only due to high costs, but also because of the array of services it provides and the challenges it has in quantifying the value of these services – particularly the operational benefits such as ancillary services. The challenge of simulating energy storage in the grid, estimating its total value, and actually recovering those value streams continues to be a major barrier. VG complicates this issue because variability adds additional analysis challenges. The ability to simulate the cost impacts of VG and benefits of storage is still limited by the methods and data sets available. It is understood that VG increases the need for flexible generation and operating reserves, which can be met by energy storage. However, the value of energy storage is best captured when selling to the entire grid, instead of any single source. Evaluating the role of storage with VG sources requires continued analysis, improved data, and new techniques to evaluate the operation of a more dynamic and intelligent grid of the future.

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13. SUPPLEMENTARY NOTES

14. ABSTRACT *(Maximum 200 Words)*
Renewable energy sources, such as wind and solar, have vast potential to reduce dependence on fossil fuels and greenhouse gas emissions in the electric sector. Climate change concerns, state initiatives including renewable portfolio standards, and consumer efforts are resulting in increased deployments of both technologies. Both solar photovoltaics (PV) and wind energy have variable and uncertain (sometimes referred to as “intermittent”) output, which are unlike the dispatchable sources used for the majority of electricity generation in the United States. The variability of these sources has led to concerns regarding the reliability of an electric grid that derives a large fraction of its energy from these sources as well as the cost of reliably integrating large amounts of variable generation into the electric grid. In this report, we explore the role of energy storage in the electricity grid, focusing on the effects of large-scale deployment of variable renewable sources (primarily wind and solar energy).

15. SUBJECT TERMS
NREL; energy analysis; energy storage; electric grid; renewable energy; wind energy; solar energy; variability; solar photovoltaics; PV; variable generation; energy cost; renewable electricity generation; Paul Denhom; Erik Ela; Michael Milligan; Brendan Kirby

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Standard Form 298 (Rev. 8/98)
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MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-9.76d
Respondent:	Supplemental
	J. W. Chang
Page:	1 of 1

Question: Please refer to Exhibit A-47, "Integrating Renewable into Lower Michigan's Electricity Grid" by The Brattle Group.

d) Provide all configuration data (e.g. location, system nameplate size, system configuration (fixed tilt, single-axis tracking, etc.), DC/AC rating, etc.) that is required to exactly reproduce each solar generation profile data found in "Workpaper JWC-02 - Figure 3.xlsx" tab "Solar Profiles" with the tool indicated in question 76(a) above.

Supplemental Answer:

As noted in response to ELCPDE-9.76b, the solar generation profiles were accessed through NREL SAM Tool Version 2017.9.5. In this version, we selected the "Photovoltaic (detailed) No financial model" option. We then selected the six locational weather files listed with their NREL IDs in our response to ELCPDE-9.76b. As explained in that response, these weather files are based on NREL's National Solar Radiation Database (NSRDB) as of August 22, 2018.

For each location-specific weather file, we set the "Desired array size" under "System Sizing" field within the "System Design" tab, to 5GWdc (i.e., 5,000,000 kWdc). No other changes to the default parameters in the System Design tab or other tabs were made.
Enclosed is our SAM_System_Settings.sam file, which can be read into the SAM tool Version 2017.9.5, and be used with the each of the location-specific weather files we listed in our response to ELCPDE-9.76b. This System Settings file contains the settings we used.

Original Answer: See response to ELPCDE-9.76.b. The remaining configuration data used to develop our solar shapes were the NREL default settings upon download for the NREL SAM Tool (Version 2017.9.5). For the Array size, we specified the desired size at 5GWdc. Note that new release of NREL's SAM tool may reflect different default input values. New SAM tool releases also incorporate updated weather irradiance data files from NREL's (NSRDB). The SAM tool version we used to develop the six locational solar TMY shapes can be downloaded from NREL's website.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-5.25a
Respondent:	J. W. Chang
Page:	1 of 1

Question: Refer to the direct testimony or Ms. Chang, page 7, raising concerns regarding the ability of DTE to meet its ramping requirements by 2040, with anticipated renewable share of energy demand at 30%, and the related discussion in Exhibit A-47. For purposes of this question, assume that Xcel/Colorado (Public Service Co. of Colorado) currently operates with 23% from wind and is planning on operating with 42% of wind energy by 2022 (https://www.xcelenergy.com/energy_portfolio/renewable_energy/wind/co_wind_power. Further, for purposes of this question assume that 700 MW of new solar energy is also anticipated in the Xcel/CO footprint.

a. Do you agree that larger balancing areas can integrate renewables more efficiently than small balancing areas? If not, explain why not.

Answer: DTE Electric objects to this request because it assumes facts not in evidence by providing only unsupported assumptions, and it is not reasonably calculated to lead to the discovery of admissible evidence because any comparison of DTE Electric and Xcel are irrelevant as they are not similar utilities and operate under different statutory and regulatory regimes. Subject to and notwithstanding this objection, generally, larger balancing areas that have flexible resources can integrate renewables more efficiently than smaller balancing areas with less flexible resources, all else being equal.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-5.25b
Respondent:	J. W. Chang
Page:	1 of 1

Question: Refer to the direct testimony or Ms. Chang, page 7, raising concerns regarding the ability of DTE to meet its ramping requirements by 2040, with anticipated renewable share of energy demand at 30%, and the related discussion in Exhibit A-47. For purposes of this question, assume that Xcel/Colorado (Public Service Co. of Colorado) currently operates with 23% from wind and is planning on operating with 42% of wind energy by 2022 (https://www.xcelenergy.com/energy_portfolio/renewable_energy/wind/co_wind_power. Further, for purposes of this question assume that 700 MW of new solar energy is also anticipated in the Xcel/CO footprint.

b. Do you agree that Xcel/Colorado is a smaller utility than DTE, and Xcel does not currently operate in part of an RTO/ISO market? If not, explain why not.

Answer: DTE Electric objects to this request because it assumes facts not in evidence by providing only unsupported assumptions, and it is not reasonably calculated to lead to the discovery of admissible evidence because any comparison of DTE Electric and Xcel are irrelevant as they are not similar utilities and operate under different statutory and regulatory regimes. Subject to and notwithstanding this objection, it is true that Xcel/CO currently does not operate inside an RTO/ISO market. Xcel/Colorado's balancing authority area had a peak load of 8,634 MW in 2018[1] and DTE's peak load was 10,520 MW in 2018.

Attachments: *N/A*

1 EIA 930 data compiled by ABB Velocity Suite.

GE Energy Consulting

Minnesota Renewable Energy Integration and Transmission Study

Final Report

Prepared for:

- The Minnesota Utilities and Transmission Companies
- The Minnesota Department of Commerce

Prepared by:

- GE Energy Consulting, *with contributions by:*
  - The Minnesota Utilities and Transmission Companies
  - Excel Engineering, Inc.
  - MISO

In Collaboration with MISO

October 31, 2014

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Updates

Revision #	Date	Update	By
r1	January 5, 2015	Table 2-1 : corrected typos	mjs/jea
		Tables 3-1 and 3-2: clarified column headings	jea/mjs

MINNESOTA DEPARTMENT OF COMMERCE

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AN EQUAL OPPORTUNITY EMPLOYER

October 31, 2014

In 2013 the Minnesota Legislature adopted a requirement for a Renewable Energy Integration and Transmission Study[1] (MRITS). MRITS is an engineering study of increasing the Minnesota Renewable Energy Standard to 40% by 2030, and to higher proportions thereafter, while maintaining system reliability.

Background. MRITS builds upon prior renewable integration studies and related technical work and is coordinated with recent and current regional power system study work. Over summer 2013, Commerce reviewed prior and current related studies and worked with stakeholders and study participants to identify key issues. In fall 2013, Commerce held a stakeholder meeting to discuss the objectives, scope, schedule, and process. The study began in November 2013 and was completed in October 2014.

Study details. *MRITS is focused on the reliability impacts of increased levels of variable renewables (wind and solar generation) and the associated costs of those impacts.* The study scope was developed from statutory guidance, stakeholder input, and technical study team refinement. MRITS incorporates three core and interrelated analyses: 1) *Power flow analysis* for development of a conceptual transmission plan, which includes transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and system flexibility; 2) *Production simulation analysis* which evaluates hour-by-hour operational performance for an entire year, including reserve violations, unserved load, wind / solar curtailments, thermal cycling, and ramp rate and ramp range, and, to screen for challenging time periods; and 3) *Dynamics analysis*, which includes transient stability analysis and weak system strength analysis. The broad study scope and the aggressive schedule have been very significant challenges.

Technical team. *The MN utilities and transmission companies, in coordination with MISO, conducted the engineering study.* The Department of Commerce directed the study. The Minnesota utilities and transmission companies engaged early in the study development and, through the active participation of the companies' most experienced planning and operations engineers, worked hard and constructively throughout the year to accomplish, in collaboration with MISO, a successful and timely completion of the study. A preeminent technical study team of highly skilled local, regional, and national engineering organizations was assembled to work collaboratively on the analysis. This included major contributions from the Minnesota utilities and transmission companies (siting, conceptual transmission plan), Excel Engineering Inc (power flow analysis, conceptual transmission plan), MISO (production simulation analysis), and GE

[1] MN Laws 2013, Chapter 85 HF 729, Article 12, Section 4; MPUC Docket No. CI-13-486.

Energy Consulting (operational performance analysis, dynamics analysis, mitigations and solutions, study report). Great River Energy (GRE) provided key early and ongoing study leadership. GRE's Gordon Pietsch organized and coordinated full participation by the Minnesota utilities and transmission companies and GRE's Jared Alholinna led the technical study team – both worked tirelessly and effectively to ensure the best, most knowledgeable, most experienced engineers were organized, funded, focused, and coordinated throughout the study.

Study review. The study has greatly benefited from extensive ongoing review and guidance by an expert Technical Review Committee (TRC). The Department of Commerce appointed and led the TRC, which included engineers with experience and expertise in electric transmission system engineering, electric power system operations, and renewable energy generation technology. Seven TRC meetings, four full day and three half day, were held throughout the course of the study to review and discuss the study methods and assumptions, scenarios, model development, results, and key findings. *With excellent input from the utilities and transmission companies, MISO, renewables specialists, and national experts, consensus was reached on overall study methods and assumptions, on the scenarios to be studied, on the modeling approach, and on the results and key findings.*

Key findings. *The analytical results from this study show that the addition of wind and solar (variable renewable) generation to supply 40% of Minnesota's annual electric retail sales can be reliably accommodated by the electric power system.* The MRITS operational and dynamics analyses results show that, with upgrades to existing transmission, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy) with wind and solar resources increased to achieve 40% renewable energy in Minnesota and with current renewable energy standards fully implemented in neighboring MISO North/Central states. *Further analysis would be needed to ensure system reliability at 50% of Minnesota's annual electric retail sales from variable renewables.* With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO North / Central (10% above current renewable energy standards in neighboring states), MRITS production simulation results show that, with significant transmission upgrades and expansions in the five state area, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy). Due to study schedule limitations, no dynamic analysis was performed for 50% renewable energy in Minnesota (Scenarios 2 and 2a) and this analysis is necessary to ensure system reliability.

Thank you to all of the study participants for an extraordinary and collaborative effort and for successful completion of a ground breaking study.

Sincerely,

William Grant
Deputy Commissioner, Division of Energy Resources

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Nomenclature

BAU	Business as Usual
CC or CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring Systems
CF	Capacity Factor
CO2	Carbon Dioxide
CSCR	Composite Short-Circuit Ratio
CV	Capacity Value
DA	Day-Ahead
DIR	Dispatchable Intermittent Resource
DPV	Distributed Photovoltaic Generation Resource
DR	Demand Response
DSM	Demand Side Management
EI	Eastern Interconnection
EMTP	Electro-Magnetic Transients Program
ERGIS	Eastern Renewable Generation Integration Study (by NREL)
EWITS	Eastern Wind Integration and Transmission Study (by NREL)
FERC	Federal Energy Regulatory Commission
GE	General Electric International, Inc. / GE Energy Consulting
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour Ahead
HVDC	High-Voltage Direct-Current
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LBA	Local Balancing Authority
LMP	Locational Marginal Prices
MRITS	Minnesota Renewable Energy Integration and Transmission Study
MTEP	MISO Transmission Expansion Plan
MVA	Megavolt Ampere
MVP	Multi-Value Project
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation

Nomenclature

NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NS	Non-Synchronous
O&M	Operation & Maintenance
PJM	PJM Interconnection, LLC.
POI	Point of Interconnection
PPA	Power Purchase Agreement
PSCAD	Manitoba HVDC Research Centre's Electro-Magnetic Transients Simulation program (Power System Computer Aided Design)
PSH	Pumped Storage Hydro
PV	Photovoltaic
RE	Renewable Energy
REC	Renewable Energy Credit
RES	Renewable Energy Standard
RGOS	Regional Generation Outlet Study
RPS	Renewable Portfolio Standard
SCED	Security Constrained Economic Dispatch
SCR	Short-Circuit Ratio
SCUC	Security Constrained Unit Commitment
SES	Solar Energy Standard
SOx	Sulfur Oxides
ST	Steam Turbine
STATCOM	Static Compensator
SVC	Static Var Compensator
TPL	NERC's Transmission Planning Standard
TRC	Technical Review Committee
TWh	Terawatt Hour (1000 Megawatt hours)
VOC	Variable Operating Cost
WTG	Wind Turbine-Generator
ZVRT	Zero-Voltage Ride-Through

1 EXECUTIVE SUMMARY

1.1 Background

In 2013 the Minnesota Legislature adopted a requirement for a Renewable Energy Integration and Transmission Study[1] (MRITS). The MN utilities and transmission companies, in coordination with MISO, conducted the engineering study. The Department of Commerce directed the study and appointed and led the Technical Review Committee (TRC). It is an engineering study of increasing the Minnesota Renewable Energy Standard to 40% by 2030, and to higher proportions thereafter, while maintaining system reliability. The final study includes: 1) A conceptual plan for transmission for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility, and 2) Identification and development of potential solutions to any critical issues encountered.

All utilities with Minnesota retail electric sales and all Minnesota transmission companies participated and/or were represented in the study. Eight Minnesota Local Balancing Authorities are represented and over 85% of the Minnesota retail sales are in the four largest Local Balancing Authorities (LBA): Xcel Energy (NSP), Great River Energy, Minnesota Power, and Otter Tail Power. The study area is within the NERC reliability region Midwest Reliability Organization (MRO). Nearly all of the Minnesota retail sales are within the Midcontinent Independent System Operator (MISO). The Local Balancing Authorities within MISO, including the Minnesota LBAs, are functionally consolidated.

Prior studies of relevance include the 2006 Minnesota Wind Integration Study[2], the 2007 Minnesota Transmission for Renewable Energy Standard Study[3], the 2009 Minnesota RES Update, Corridor, and Capacity Validation Studies, the 2008 and 2009 Statewide Studies of Dispersed Renewable Generation[4], the 2010 Regional Generation Outlet Study, the 2011 Multi Value Project Portfolio Study, the 2013 Minnesota Biennial Transmission Project Report[5], the 2013 MISO Transmission Expansion Plan, and recent and ongoing MISO transmission expansion planning work[6] .

[1] MN Laws 2013, Chapter 85 HF 729, Article 12, Section 4; MPUC Docket No. CI-13-486.
[2] 2006 MN Wind Integration Study. Prepared for the MPUC, Nov 2006.
Final Report Volumes I & II, Final Report Presentation. http://www.puc.state.mn.us/PUC/electricity/013752
[3] "Minnesota RES Update Study Technical Report." March 2009. "RES Transmission Report." November 2007.
"Southwest Twin Cities – Granite Falls Transmission Upgrade Study Technical Report." March 2009.
"Capacity Validation Study Report." March 2009. http://www.minnelectrans.com/reports.html
[4] Dispersed Renewable Generation Studies. June 2008 and September 2009.
http://mn.gov/commerce/energy/topics/resources/Reports-Data/Energy-Reports.jsp
[5] http://www.minnelectrans.com/, November 1, 2013.
[6] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx

1.2 Study Objectives and Overall Approach

The study objectives are listed below.

1. Evaluate the impacts on reliability and costs associated with increasing Renewable Energy to 40% of Minnesota retail electric energy sales by 2030, and to higher proportions thereafter;
2. Develop a conceptual plan for transmission necessary for access to regional geographic diversity and regional system flexibility;
3. Identify and develop options to manage the impacts of the renewable energy resources;
4. Build upon prior wind integration studies and related technical work; Coordinate with recent and current regional power system study work;
5. Produce meaningful, broadly supported results through a technically rigorous, inclusive study process.

This study is focused on the reliability impacts of increased levels of variable renewables (wind and solar generation) and the associated costs of those impacts.

MRITS builds upon prior wind integration studies and related technical work and is coordinated with recent and current regional power system study work. The study scope was developed from statutory guidance, stakeholder input, and technical study team refinement.

MRITS incorporates three core and interrelated analyses: 1) *Power flow analysis* for development of a conceptual transmission plan, which includes transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility; 2) *Production simulation analysis* for evaluation of operational performance, including reserve violations, unserved load, wind / solar curtailments, thermal cycling, and ramp rate and ramp range, and, to screen for challenging time periods; and 3) *Dynamics analysis*, which includes transient stability analysis and weak system strength analysis.

The MRITS study area is Minnesota-centric, which focuses on the combined operating areas of the Minnesota utilities and transmission companies, in the context of the MISO North/Central areas and the neighboring regions to the west and north.

The base study models (baseline and scenarios) are coordinated with and consistent with MISO models and databases including dispatch to the MISO market. Additional options were considered in Task 7 (Identify & Develop Mitigations / Solutions) as needed.

The key study tasks are:

- Develop Study Scenarios; Site Wind and Solar Generation (Lead contributors: Minnesota Utilities; Minnesota Department of Commerce)
- Perform Production Simulation Analysis (Lead Contributor: MISO)
- Perform Power Flow Analysis; Develop Transmission Conceptual Plan (Lead Contributors: Minnesota Utilities & Transmission Owners; Excel Engineering)
- Evaluate Operational Performance (Lead Contributor: GE Energy Consulting)

- Screen for Challenging Periods (Lead Contributor: GE Energy Consulting)
- Evaluate stability related issues, including transient stability performance, voltage regulation performance, adequacy of dynamic reactive support, and weak system strength issues (Lead Contributor: GE Energy Consulting)
- Identify and Develop Mitigations and Solutions (Lead Contributor: GE Energy Consulting)

1.3 Development of Study Scenarios

The Baseline scenario has sufficient renewable energy generation to satisfy the current renewable energy standards and solar energy standards for all states in the study region. For Minnesota, the Baseline scenario was based on current Minnesota utility plans to meet the Minnesota Renewable Energy Standard (RES) and the Solar Energy Standard (SES) with renewable energy (wind, solar, small hydro, biomass, etc) from the Minnesota-centric area and incorporates refinements from the technical study team. For non-Minnesota MISO states in the study footprint, the Baseline scenario was based on the prior approved 2013 MISO Transmission Expansion Plan (MTEP13).

Scenario 1 builds on the Baseline scenario by adding incremental wind and solar (variable renewables) generation to the Baseline model to supply a total of 40% of Minnesota annual electric retail sales from renewables in the study year and with all states at full implementation of their current RESs.

Scenario 2 builds on Scenario 1 by adding incremental wind and solar generation to the Scenario 1 model to supply 50% of Minnesota electric retail sales from total renewables and by further adding incremental wind and solar generation to supply an additional 10% of the non-Minnesota MISO North / Central retail electric sales from total renewables (i.e. to increase the MISO footprint renewables 10% above full implementation of the current RESs).

Table 1-1 Study Scenarios

Scenario	Minnesota RE Penetration	MISO Wind & Solar Penetration (including Minnesota)
Baseline	28.5%	14.0%
Scenario 1	40.0%	15.0%
Scenario 2	50.0%	25.0%

Note: MISO has an additional 3% renewable energy penetration in all scenarios from existing small biomass and small hydro.

The horizon year for this study was 2028 (to represent 2030 conditions). System load levels for Minnesota and MISO regions were scaled up from present levels by an assumed annual growth rate of 0.5% for Minnesota and 0.75% for the rest of MISO North / Central.

All scenarios, including the Baseline, required more wind and solar generation than what is already installed on the grid. Therefore, the study team used a combination of wind/solar resource maps and wind/solar profile data (from NREL) to guide selection of sites for prospective future wind and solar plants with cumulative capacities consistent with the renewable energy targets for each study scenario. Wind Plant sites were distributed among several of MISO's renewable energy zones (originally developed in the MISO Regional Generation Outlet Study and used in the Multi-Value Project Portfolio study).

1.4 Development of Transmission Conceptual Plans

A conceptual transmission plan was developed for each of the study scenarios. System reliability was determined through traditional transmission planning methods, criteria, and assumptions. Steady state performance characteristics were evaluated with the system intact as well as under powerflow contingency conditions (N-1 outages and selected multiple contingency outages per NERC TPL Category C2 & C5).

The Baseline scenario started with a transmission model that was consistent with the 2013 MTEP 2023 model. This Baseline transmission model incorporates planned transmission lines, including the CapX2020 Group I lines and the MISO Multi-Value Project (MVP) portfolio. A very limited number of facilities were overloaded in the Baseline Scenario.

For Scenario 1, a total of 54 transmission mitigations were added to accommodate the increased wind and solar generation. These mitigations included transmission line upgrades, transformer additions/replacements, and changes to substation terminal equipment, with a total estimated cost of $373M. No new transmission lines were required.

In Scenario 2, a total of 17,245 MW of new wind/solar generation was added to increase Minnesota renewable energy penetration to 50% and MISO renewable energy penetration to 25%. A total of 9 new transmission lines and 30 transmission upgrades were added to the Scenario 1 transmission system, with a total estimate cost of an additional $2.6B. Note that an undetermined portion of the Scenario 2 transmission expansions and upgrades are associated with increasing MISO's renewable penetration from 15% to 25%.

Note that for the development of transmission conceptual plans, the new wind and solar resources were connected to high voltage transmission buses. The actual connection processes will likely require additional plant-specific interconnection facilities for the new wind and solar plants.

1.5 Evaluation of Operational Performance

Operational performance of the electric power grid with increased levels of renewable generation was analyzed using production simulation analysis, which simulates hourly operation of the system for an entire year. The PLEXOS simulation tool uses a Day-Ahead Security Constrained Unit Commitment (SCUC) and Real-Time Security Constrained Economic Dispatch (SCED) interleaved market dispatch solution. This type of modeling accurately captures the forecast uncertainties realized between a Day-Ahead and Real-Time markets. Modeling of forecast uncertainty becomes increasingly important when dealing with high levels of wind and solar generation because the output tends to be more stochastic in nature.

MISO used the 2013 MTEP Business as Usual (BAU) dataset as a starting point for the Baseline Scenario, with modifications to the system load level to reflect the 2028 horizon year for this study. The BAU future is considered the status quo future and continues current economic trends. The MTEP futures are created by MISO and vetted by the MISO Planning Advisory Committee (PAC) stakeholder committee. Information for the production modeling dataset is sourced from Ventyx and updated through an extensive MISO process to bring it into line with the most current data and expected future conditions. Coal unit retirements totaling 12.6 GW were included in the model per MISO's anticipated effects of prior EPA regulations.

Future EPA regulations, such as the recently proposed Clean Power Plan (111d) which is still in development, are not modeled nor considered in this study. The model footprint includes all areas in the Eastern Interconnect, with the exception of Florida, ISO New England and Eastern Canada.

For the Scenarios 1 and 2, new wind and solar generation was added at the locations determined in the siting task and transmission system upgrades/expansions were added per the conceptual transmission plans.

One aspect of the BAU set of assumptions is that many coal plants within MISO will continue to operate as they do now. That is, the plants remain on-line when economic market signals would have initiated a brief period of decommitment and effectively act as "must-run" units. In order to examine the sensitivity to changing this assumption, and to the assumption of coal unit retirements, Scenarios 1a and 2a were added to the production simulation analysis as sensitivity cases relative to Scenarios 1 and 2. Scenarios 1a and 2a included the following changes in assumptions:

- All coal units were economically committed
- Nine additional coal units in the Minnesota-centric region were assumed to be available (These units were assumed unavailable in Scenarios 1 and 2)
- Forced outage modeling of conventional generation was included

The production simulation results were analyzed to assess system operational performance with respect to the following parameters; annual energy production by type of generating resource, renewable energy resource utilization and curtailment, cycling duty of thermal plants, adequacy of ramping capability of the MISO generation fleet, and risk of reserve violations and unserved load. For Scenario 1, the results were also screened to select challenging operating conditions for dynamic performance, and these operating points were subsequently analyzed with fault simulations in the dynamics task.

1.6 Dynamic Performance Analysis

A dynamic simulation model was developed to perform transient stability analysis of the study scenarios. A series of dynamic data files were provided by the Minnesota utilities, based on the MTEP 2013 dataset. As with the power flow and production system models, new wind and solar generation was added at the locations determined in the siting task and transmission system upgrades/expansions were added per the conceptual transmission plans. In order to capture possible fault-induced delayed recovery issues caused by reduced levels of synchronous generation, the load models in the Minnesota-Centric region were refined to include a more detailed representation of load composition, including dynamic characteristics.

New utility-scale wind and solar photovoltaic (PV) plant models were consistent with current NERC and FERC minimum requirements (e.g. voltage regulation, power factor, voltage ride-through). Full commercial technical capability (e.g. synthetic inertia, frequency response) was not modeled. Distributed PV was modeled as lumped generation at locations (per the siting task) with no reactive power or voltage regulation capability.

New wind plants were split roughly 50/50 between Type 3 (double fed asynchronous generator (DFAG) and Type 4 (full converter).

A representative number of regional power system fault conditions were simulated to stress the system in different ways.

- Faults known to be severe challenges to system transient stability from numerous past stability studies,
- Faults in regions with high concentrations of wind and solar plants, where voltage recovery is highly dependent on the reactive power support from wind and solar plants.
- Faults affecting major transmission interfaces during periods of high power transfer

The results of all dynamic simulation cases were screened with respect to a set of performance criteria, including angular stability, oscillatory stability, voltage dips, and voltage recovery.

Weak system issues were also investigated using the dynamic system models. When the ac system impedance is high relative to the aggregate rating of wind and solar generation in a given region, the internal controllers and regulators within wind and solar inverters become less stable. If the system is excessively weak, control instabilities may occur. Composite short-circuit ratio analysis was conducted to determine system strength in the study scenarios with respect to emerging industry understanding of this issue.

1.7 Key Findings

This study examined two levels of increased wind and solar generation for Minnesota; 40% (represented by Scenarios 1 and 1a) and 50% (represented by Scenarios 2 and 2a). In the 40% Minnesota Scenario, MISO North/Central is at 15% (current state RESs). The 50% Minnesota Scenario also included an increase of 10% (to 25%) in the MISO North/Central region. Production simulation was used to examine annual hourly operation of the MISO North/Central system for all four of these scenarios. Transient and dynamic stability analysis was conducted for Scenarios 1 and 1a but not on Scenarios 2 and 2a.

1.7.1 General Conclusions for 40% RE Penetration in Minnesota

With wind and solar resources increased to achieve 40% renewable energy for Minnesota and 15% renewable energy for MISO North/Central, production simulation and transient/dynamic stability analysis results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission mitigations, as described in Section 1.4, to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

Dynamic simulation results indicate that there are no fundamental system-wide dynamic stability or voltage regulation issues introduced by the renewable generation assumed in Scenario 1 and 1a. This assumes:

- New wind turbine generators are a mixture of Type 3 and Type 4 turbines with standard controls
- The new wind and utility-scale solar generation is compliant with present minimum performance requirements (i.e. they provide voltage regulation/reactive support and have zero-voltage ride through capability)
- Local-area issues are addressed through normal generator interconnection requirements

1.7.2 General Conclusions for 50% RE Penetration in Minnesota

With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO, production simulation results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission upgrades, expansions and mitigations to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

No dynamic analysis was performed for the study scenarios with 50% renewable energy for Minnesota (Scenarios 2 and 2a) due to study schedule limitations and this analysis is necessary to ensure system reliability.

1.7.3 Annual Energy in the Minnesota-Centric Region

Figure 1-1 shows the annual load and generation energy by type for the Minnesota-Centric region. Comparing Scenarios 1 and 1a (40% MN renewables) with the Baseline,

- Wind and solar energy increases by 8.5 TWh, all of which contributes to bringing the State of Minnesota from 28.5% RE penetration to 40% RE penetration
- There is very little change in energy from conventional generation resources
- Most of the increase in wind and solar energy is balanced by a decrease in imports. The Minnesota-Centric region goes from a net importer to a net exporter.

Comparing Scenarios 2 and 2a (50% MN renewables) with Scenarios 1 and 1a (40% MN renewables),

- Wind and solar energy increases by 20 TWh. Of this total, 4.8 TWh brings the State of Minnesota from 40% to 50% RE penetration and the remainder contributes to bringing MISO from 15% to 25% RE penetration
- Most of the increase in wind and solar energy in the Minnesota-Centric region is balanced by a decrease in coal generation and an increase in net exports to neighboring regions
- Gas-fired, combined-cycle generation declines from 5.0 TWh in Scenario 1 to 3.0 TWh in Scenario 2.

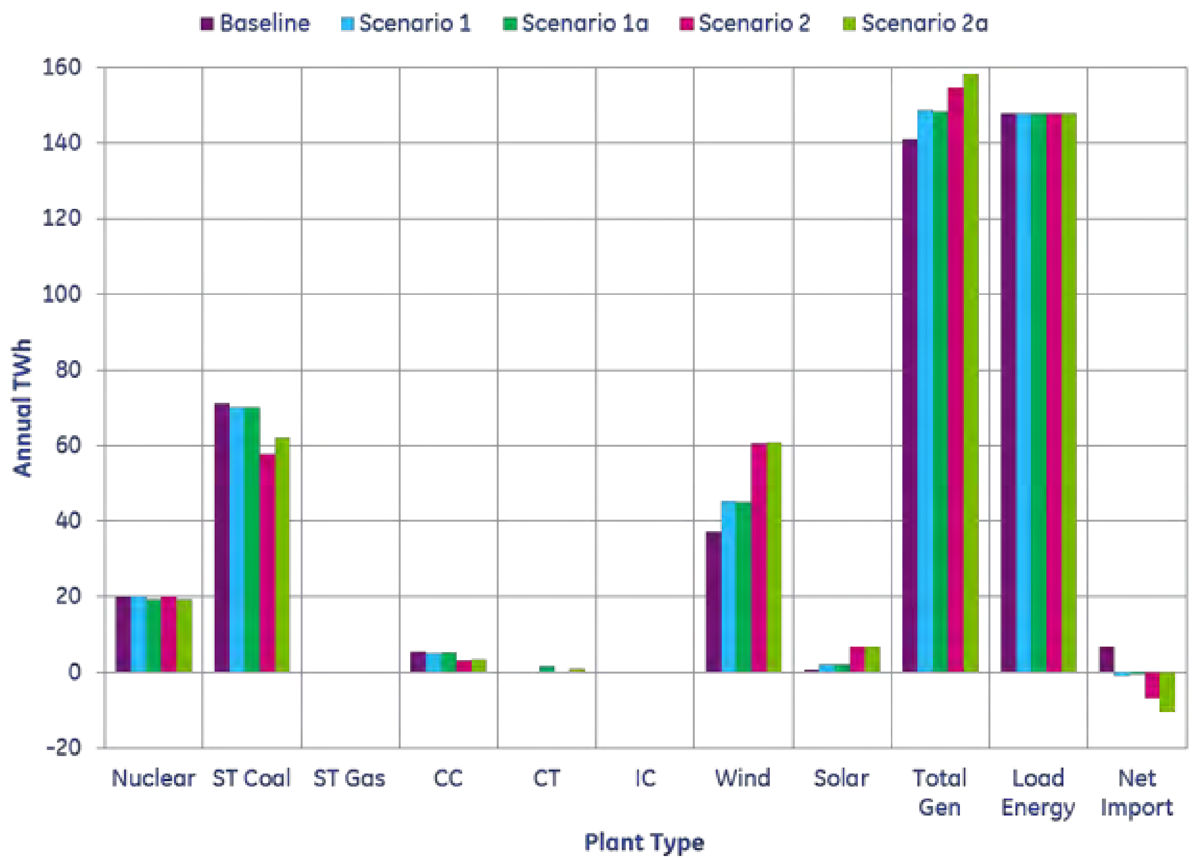

Figure 1-1 Annual Energy by Type in Minnesota-Centric Region for Study Scenarios

1.7.4 Cycling of Thermal Plants

Most coal plants were originally designed for baseload operation; that is, they were intended to operate continuously with only a few start/stop cycles in a year (mostly due to scheduled or forced outages). Increased cycling duty could increase wear and tear on these units, with corresponding increases in maintenance requirements. Many coal plants in MISO presently are designated by the plant's owner to operate as "must-run" in order to avoid start/stop cycles that would occur if they were economically committed by the market.

Scenarios S1a and S2a assumed that all coal plants in MISO are subject to economic commitment/dispatch (i.e., not must-run) based on day-ahead forecasts of load, wind and solar energy within MISO. Production simulation results show significant coal plant cycling due to economic market signals:

- Small coal units (below 300 MW rating) could have an additional 100 to 200 starts per year, beyond those due to forced or planned outages.
- Large coal units (above 300 MW) could have an additional 20 to 100 starts per year

Scenarios S1 and S2 assumed almost all coal plants would continue to operate as they do today. Coal units were on-line all year (except for scheduled maintenance periods) and were not decommitted during periods of low market prices. The results of these scenarios confirmed that the coal units could remain must-run with minor impacts on overall operation of the Minnesota-Centric region. Coal plant owners could choose to continue the must-run practice to avoid the detrimental impacts of increased cycling as wind and solar penetration increases. Doing so would likely incur some additional operational costs when energy prices fall below a plant's breakeven point. Wind curtailment would also be about 0.5% higher than if the coal plants were economically committed.

An attractive solution to the coal plant cycling issue may exist between the two bookend cases analyzed in this study. Scenarios 1a and 2a assumed that unit commitment was determined on a day-ahead basis, using day-ahead forecasts of wind and solar energy. The result was a high number of start/stop cycles of coal plants, sometimes with down-times of less than 2 days. If the unit commitment process was modified to use a longer term forward market (say 3 to 5 days ahead), then coal plant owners could adjust their operational strategy to consider decommitting units when prolonged periods of high wind/solar generation and low system loads are forecasted. A forward market would depend on longer term forecasts of wind, solar and load energy, consistent with the look-ahead period of the market. Although such forecasts would be somewhat less accurate than day-ahead forecasts, the quality of the forecasts would likely be adequate to support such unit commitment decisions.

This study did not examine the economic or wear-and-tear impacts of increased cycling on coal units. Further information on this topic can be found in the NREL Western Wind and Solar Integration Study Phase 2 report[7] and the PJM Renewable Integration Study report[8].

Combined-cycle (CC) units are better able to accommodate cycling duties than coal plants. Simulation results show that combined cycle units in the Minnesota-Centric region experience from 50 to 200 start/stop cycles per year. Cycling of CC units declines slightly as wind and solar penetration increases. This decline is primarily due to a decrease in CC plant utilization as wind and solar energy increases.

1.7.5 Curtailment of Wind and Solar Energy

In general, a small amount of curtailment is to be expected in any system with a significant level of wind and solar generation. There are some operating conditions where it is economically efficient to accept a small amount of curtailment (i.e., mitigation of that curtailment would be disproportionately expensive and not justifiable).

Overall curtailment in the Minnesota-Centric region is relatively small in all study scenarios, as shown in Table 1-2. Wind curtailment in Baseline and Scenario 1 is primarily due to local transmission congestion at a few wind plants. This congestion could be mitigated by transmission modifications, if economically justifiable.

Wind curtailment in Scenario 2 is due to system-wide operational limits during nighttime hours, when many baseload generators are dispatched to their minimum output levels. This type of curtailment could be reduced by decommitting some baseload generation via economic market

[7] http://www.nrel.gov/electricity/transmission/western_wind.html
[8] http://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx

signals. The effectiveness of this mitigation option is illustrated by comparing Scenario 2 (coal units must-run) with Scenario 2a (economic coal commitment). Wind curtailment decreases from 2.14% to 1.60% (reduction of 332 GWh of wind curtailment). Solar curtailment decreases from 0.42% to 0.24% (reduction of 12 GWh of solar curtailment).

Table 1-2 Wind and Solar Curtailment for Study Scenarios

Scenario	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Wind Curtailment	0.42%	1.00%	1.59%	2.14%	1.60%
Solar Curtailment	0.09%	0.00%	0.23%	0.42%	0.24%

Note: Curtailment is calculated as a percentage of available annual wind or solar energy.

1.7.6 Other Operational Issues

No significant transmission system congestion was observed in any of the study scenarios with the assumed transmission upgrades and expansions. Transmission contingency conditions were considered in both the powerflow analysis used to develop the conceptual transmission system and the security-constrained economic dispatch in the production simulation analysis.

Ramp-range-up and ramp-rate-up capability of the MISO conventional generation fleet increases with increased penetration of wind and solar generation. Conventional generation is generally dispatched down rather than decommitted when wind and solar energy is available, which gives those generators more headroom for ramping up if needed.

Ramp-range-down and ramp-rate-down capability of the MISO conventional generation fleet decreases with increased penetration of wind and solar generation. In Scenario 2, there are 500 hours when ramp-rate-down capability of the conventional generation fleet falls below 100 MW/min. Periods of low ramp-down capability coincide with periods of high wind and solar generation. Wind and solar generators are capable of providing ramp-down capability during these periods. MISO's existing Dispatchable Intermittent Resource (DIR) process already enables this for wind generators. It is anticipated that MISO would expand the DIR program to include solar plants in the future.

1.7.7 System Stability, Voltage Support, Dynamic Reactive Reserves

No angular stability, oscillatory stability or wide-spread voltage recovery issues were observed over the range of tested study conditions. The 16 dynamic disturbances used in stability simulations included key traditional faults/outages as well as faults/outages in areas with high concentrations of renewables and high inter-area transmission flows. System operating conditions included light load, shoulder load and peak load cases, each with the highest percent renewable generation periods in the Minnesota-Centric region.

Overall dynamic reactive reserves are sufficient and all disturbances examined for Scenarios 1 and 1a show acceptable voltage recovery. The South & Central and Northern Minnesota regions get the majority of their dynamic reactive support from synchronous generation. Maintaining sufficient dynamic reserves in these regions is critical, both for local and system-wide stability.

Southwest Minnesota, South Dakota and at times Iowa get a significant portion of dynamic reactive support from wind and solar resources. Wind and Solar resources contribute significantly to voltage support/dynamic reactive reserves. The fast response of wind/solar inverters helps voltage recovery following transmission system faults. However, these are current-source devices with little or no overload capability. Their reactive output decreases when they reach a limit (low voltage and high current).

Synchronous machines (either generators or synchronous condensers), on the other hand, are voltage-source devices with high overload capability. This characteristic will strengthen the system voltage, allowing better utilization of the dynamic capability of renewable generation. The mitigation methods discussed below, namely stiffening the ac system through new transmission or synchronous machines, will also address this concern.

Local load areas, such as the Silver Bay and Taconite Harbor area, require reactive support from synchronous machines due to the high level of heavy industrial loads. If all existing synchronous generation in this region is off line (i.e. due to retirement or decommitment), reinforcements such as new transmission or synchronous condensers would be required to support the load.

Dynamic simulation results indicate that it is critical to maintain sufficient system strength and dynamic reserves to support high flows on the Northern Minnesota 500 kV lines and Manitoba high-voltage direct-current (HVDC) lines. Insufficient system strength and reactive support will limit Manitoba exports to the U.S. Existing transmission expansion plans, as modeled in this analysis, address these issues and are sufficient for the anticipated levels of Manitoba exports.

The Manitoba HVDC ties and the 500 kV transmission system in Northern Minnesota require reactive support from synchronous generators, the Dorsey and Riel synchronous condensers, and the Forbes static var compensator (SVC) to maintain the expected level of Manitoba exports. Without sufficient reactive reserves, the system could be unstable for nearby transmission disturbances. The current transmission plans, as modeled in this analysis, address this issue.

1.7.8 Weak System Issues

Composite Short-Circuit Ratio (CSCR) is an indicator of the ability of an ac transmission system to support stable operation of inverter-based generation. A system with a higher CSCR is considered strong and a system with a lower CSCR is considered to be weak. CSCR is calculated as the ratio of the composite short-circuit MVA at the points of interconnection (POI) of all wind/solar plants in a given area to the combined MW rating of all those wind and solar generation resources.

Low CSCR operating conditions can lead to control instabilities in inverter-based equipment (Wind, Solar PV, HVDC and SVC). Instabilities of this nature will generally manifest as growing voltage/current oscillations at the most affected wind or solar plants. In the worst conditions (i.e., very low CSCR), oscillations could become more wide-spread and eventually lead to loss of generation and/or damage to renewable generation equipment if not adequately protected against such events.

This is a relatively new area off concern within the industry. The issue has emerged as the penetration of wind generation has grown. Understanding of the fundamental stability issues is rapidly growing as more wind plants are being installed in regions with weak ac systems.

Equipment vendors, transmission planners and consultants are all working to gain a better understanding of the issues. Modeling and simulation tools have already been developed to enable detailed analysis of the phenomena. Wind and solar inverter control systems are being modified to improve weak system performance.

Synchronous machines (either generators or synchronous condensers) contribute short-circuit strength to the transmission system and therefore increase CSCR. Therefore, system operating conditions with more synchronous generators online will have higher CSCR. Also, stronger transmission ties (additional transmission lines or transformers, or lower impedance transformers) between synchronous generation and regions of wind and solar generation will increase CSCR. SVCs and STATCOMs do not contribute short-circuit current, and because they are electronic converter based devices with internal control systems similar to wind/solar inverters, their presence in a weak system region could further reduce the effective CSCR and exacerbate the control system stability issues that occur in weak system conditions.

There are two general situations where weak system issues generally need to be assessed:

- Local pockets of a few wind and solar plants in regions with limited transmission and no nearby synchronous generation (e.g. plants in North Dakota fed from Pillsbury 230 kV near Fargo).
- Larger areas such as Southwest Minnesota (Buffalo Ridge area) with a very high concentration of wind and solar plants and no nearby synchronous generation

This study examined the sensitivity of weak system issues in Southwest Minnesota. Observations are as follows:

The trouble spots identified in this analysis are not very sensitive to existing synchronous generation commitment. While there is very little synchronous generation within the area, the region is supported by a strong networked 345 kV transmission grid. Primary short circuit strength is from a wide range of base-load units in neighboring areas, and interconnected via the 345 kV transmission network. Commitment, decommittment or outages of individual synchronous generators do not have significant impact on CSCR in these identified areas.

Transmission outages will lower system strength and make the issue worse. When performing CSCR and weak system assessments as wind and solar penetration increases, it will be prudent to consider normal and design-criteria outages at a minimum (i.e, outage conditions consistent with MISO reliability assessment practices).

1.7.9 Mitigations

There are two approaches to improving wind/solar inverter control stability in weak system conditions:

- To improve the inverter controls, either by carefully tuning the equipment control functions or modifying the control functions to be more compatible with weak system conditions. With this approach, wind/solar plants can tolerate lower CSCR conditions.
- To strengthen the ac system, resulting in increased short-circuit MVA at the locations of the wind/solar plants. This approach increases CSCR.

The approaches are complementary, so the ultimate solution for a particular region would likely be a combination of both.

Mitigation through Wind/PV Inverter Controls

Standard inverter controls and setting procedures may not be sufficient for weak system applications. Loop gains of internal control functions inherently increase when system impedance increases, thereby reducing the stability margin of the controllers. Developers and equipment vendors must be made aware when new plants are being proposed for weak system regions so they can design/tune controls to address the issue. Wind plant vendors have made significant progress in designing wind and solar plant control systems that are compatible with weak system applications.

This approach becomes somewhat more difficult when there are wind/solar plants from multiple vendors in one region. The level of analysis requires detailed modeling of all affected wind plants at a level of detail that requires the use of proprietary control design information from the vendors. Vendors are very reluctant to share such data, except with independent consultants who can guarantee strict data security. However, this approach is gaining traction and a few projects have made effective implementations. The key to success is that project developers and equipment vendors must be informed beforehand that a given wind or solar plant will be installed at a weak system location. This enables the appropriate control design studies to be initiated before the project is installed.

In the event that such control-based approaches are not sufficient, it would be possible to further improve weak system performance by employing one or more of the system-level mitigations discussed below.

Mitigation by Strengthening the AC System

CSCR analysis of the Southwest Minnesota region shows that synchronous condensers located near the wind and solar plants would be a very effective mitigation for weak system issues. Synchronous condensers are synchronous machines that have the same voltage control and dynamic reactive power capabilities as synchronous generators. Synchronous condensers are not connected to prime movers (e.g. steam turbines or combustion turbines), so they do not generate power.

Other approaches that reduce ac system impedance could also offer some benefit:

- Additional transmission lines between the wind/solar plants and synchronous generation plants
- Lower impedance transformers, including wind/solar plant interconnection transformers

Series capacitors on transmission lines could be used to increase CSCR and to improve the transmission system’s capability to transfer energy out of regions with high concentrations of wind and solar resources. However, series capacitors create subsynchronous frequency resonances in the transmission system which affect the performance of control systems within wind and solar plants. These resonances introduce an additional challenge to wind/solar plant control designs, which must maintain stable operation in the presence of the resonant conditions.Mitigation through "must-run" operating rules for existing generation was found to be not very effective. The plants with synchronous generators are not located close enough to effected wind/solar plants.

2 PROJECT OVERVIEW

2.1 Background

In 2013 the Minnesota Legislature adopted a requirement for a Renewable Energy Integration and Transmission Study[1] (MRITS). The MN utilities and transmission companies, in coordination with MISO, conducted the engineering study. The Department of Commerce directed the study and appointed and led the Technical Review Committee (TRC). It is an engineering study of increasing the Minnesota Renewable Energy Standard to 40% by 2030, and to higher proportions thereafter, while maintaining system reliability.

The final study includes:

1. A conceptual plan for transmission for generation interconnection and delivery and for access to regional geographic diversity and regional supply and system flexibility, and
2. Identification and development of potential solutions to any critical issues encountered.

All utilities with Minnesota retail electric sales and all Minnesota transmission companies participated and/or were represented in the study. Eight Minnesota Local Balancing Authorities are represented and over 85% of the Minnesota retail sales are in the four largest Local Balancing Authorities: Xcel Energy (NSP), Great River Energy, Minnesota Power, and Otter Tail Power. The study area is within the NERC reliability region Midwest Reliability Organization (MRO). Nearly all of the Minnesota retail sales are within the Midcontinent Independent System Operator (MISO). The Local Balancing Authorities within MISO, including the Minnesota LBAs, are functionally consolidated.

Prior studies of relevance include the 2006 Minnesota Wind Integration Study[2], the 2007 Minnesota Transmission for Renewable Energy Standard Study[3], the 2009 Minnesota RES Update, Corridor, and Capacity Validation Studies, the 2008 and 2009 Statewide Studies of Dispersed Renewable Generation[4], the 2010 Regional Generation Outlet Study, the 2011 Multi Value Project Portfolio Study, the 2013 Minnesota Biennial Transmission Project Report[5], the 2013 MISO Transmission Expansion Plan, and recent and ongoing MISO transmission expansion planning work[6] .

2.2 Objectives

1. Evaluate the impacts on reliability and costs associated with increasing Renewable Energy to 40% of Minnesota retail electric energy sales by 2030, and to higher proportions thereafter;

1 MN Laws 2013, Chapter 85 HF 729, Article 12, Section 4; MPUC Docket No. CI-13-486.

2 2006 MN Wind Integration Study. Prepared for the MPUC, Nov 2006. Final Report Volumes I & II, Final Report Presentation. http://www.puc.state.mn.us/PUC/electricity/013752

3 "Minnesota RES Update Study Technical Report." March 2009. "RES Transmission Report." November 2007. "Southwest Twin Cities – Granite Falls Transmission Upgrade Study Technical Report." March 2009. "Capacity Validation Study Report." March 2009. http://www.minnelectrans.com/reports.html

4 Dispersed Renewable Generation Studies. June 2008 and September 2009. http://mn.gov/commerce/energy/topics/resources/Reports-Data/Energy-Reports.jsp

5 http://www.minnelectrans.com/, November 1, 2013.

6 https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx

2. Develop a conceptual plan for transmission necessary for access to regional geographic diversity and regional system flexibility;
3. Identify and develop options to manage the impacts of the renewable energy resources;
4. Build upon prior wind integration studies and related technical work; Coordinate with recent and current regional power system study work;
5. Produce meaningful, broadly supported results through a technically rigorous, inclusive study process.

2.3 Study Timeline

June – August 2013

Commerce: Reviewed prior and current studies and worked with stakeholders and study participants to identify key issues, began development of a draft technical study scope, and accepted recommendations of qualified Technical Review Committee (TRC) members;

September 2013

Commerce: Held a stakeholder meeting to discuss the objectives, scope, schedule, and process; Commerce appointed the Technical Review Committee;

September / October 2013

Commerce, in consultation with the MN utilities, finalized the study scope;

October 2013

The MN utilities, in consultation with Commerce, identified the technical study team;

November 2013 – October 2014

The study was completed. The Technical Review Committee has reviewed all technical work in this study on an ongoing basis, throughout the study.

2.4 Study Scope

This study is focused on the reliability impacts of increased levels of variable renewables (wind and solar generation) and the associated costs of those impacts.

MRITS builds upon prior wind integration studies and related technical work and is coordinated with recent and current regional power system study work. The study scope was developed from statutory guidance, stakeholder input, and technical study team refinement.

MRITS incorporates three core and interrelated analyses: 1) *Power flow analysis* for development of a conceptual transmission plan, which includes transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility; 2) *Production simulation analysis* for evaluation of operational performance, including reserve violations, unserved load, wind / solar curtailments, thermal cycling, and ramp rate and ramp range, and, to screen for challenging time periods; and 3) *Dynamics analysis*, which includes transient stability analysis and weak system strength analysis.

The MRITS study area is Minnesota-centric, which focuses on the combined operating areas of the Minnesota utilities and transmission companies, in the context of the MISO North/Central areas and the neighboring regions to the west and north.

The base study models (baseline and scenarios) are coordinated with and consistent with MISO models and databases including dispatch to the MISO market. Additional options were considered in Task 7 (Identify & Develop Mitigations / Solutions) as needed.

The key study tasks are:

- Develop Study Scenarios; Site Wind and Solar Generation (Task 1)
- Perform Production Simulation Analysis (Tasks 2 and 4)
- Perform Power Flow Analysis; Develop Transmission Conceptual Plan (Task 3)
- Evaluate Operational Performance (Task 6a)
- Screen for Challenging Periods; Perform Dynamics Analysis (Task 5 and 6b)
- Identify and Develop Mitigations and Solutions (Task 7)

The study task flow chart is shown in Figure 2-1.

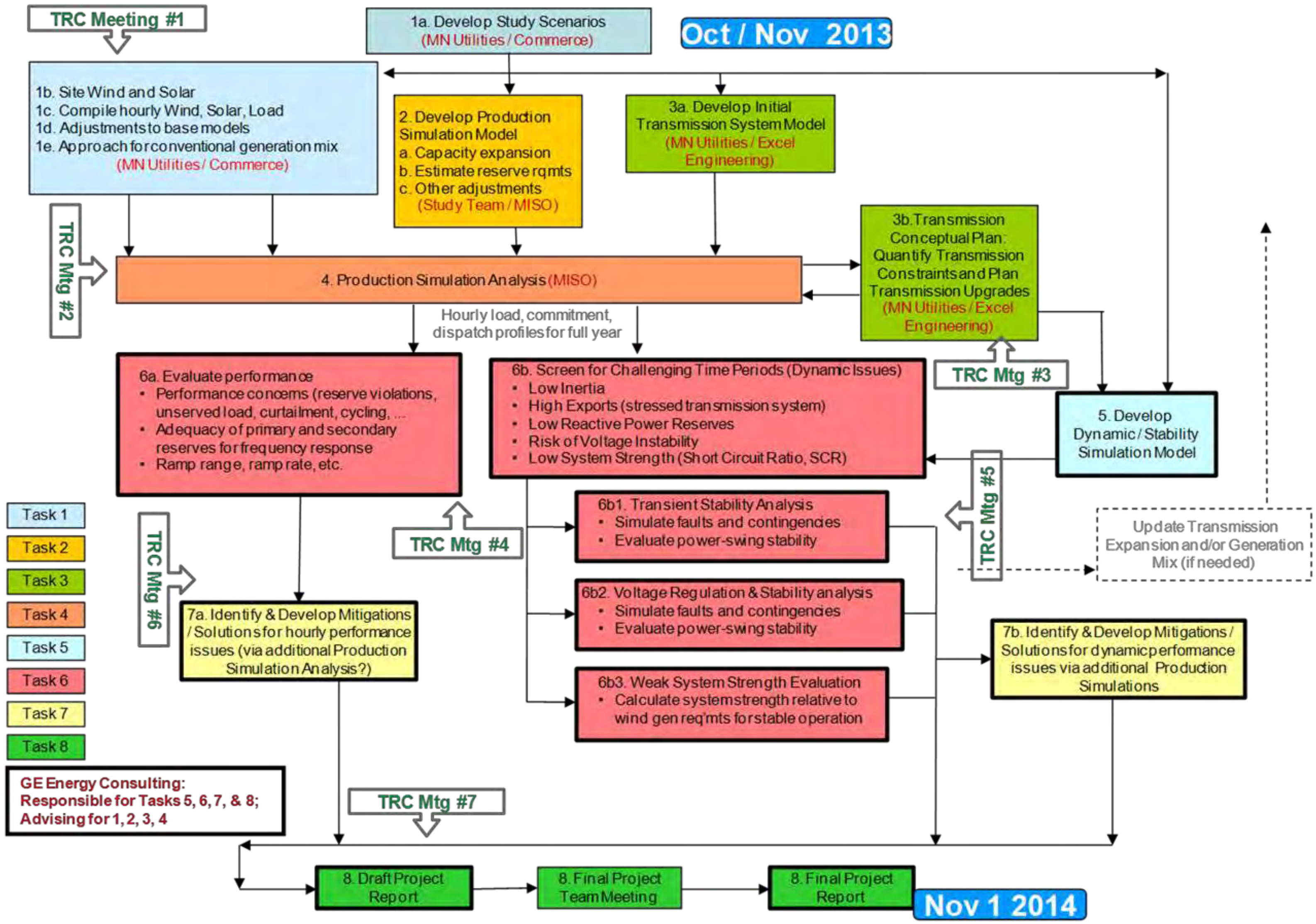

Figure 2-1 Flowchart of Project Tasks

2.5 Study Scenarios

The MRITS study scenarios were developed from statutory guidance, stakeholder input, and technical study team refinement.

The study year of 2028 was selected to help ensure that all models and system data were coordinated with and are consistent with MISO MTEP13 models and databases. It was also thought that 2028 was suitably near to 2030 as written in legislation, especially considering the difficulty in projecting an accurate load forecast fifteen years into the future.

Each of the study scenarios builds on the prior scenario, starting with the Baseline. The Baseline scenario has sufficient renewable energy generation to satisfy the current renewable energy standards and solar energy standards for all states in the study region. For Minnesota, the Baseline scenario was based on current Minnesota utility plans to meet the Minnesota Renewable Energy Standard (RES) and the Solar Energy Standard (SES) with renewable energy (wind, solar, small hydro, biomass, etc.) from the Minnesota-centric area and incorporates refinements from the technical study team. For non-Minnesota MISO states in the study footprint, the Baseline scenario was based on the prior approved 2013 MISO Transmission Expansion Plan (MTEP13).

1. Scenario 1 builds on the Baseline scenario by adding incremental wind and solar (variable renewables) generation to the Baseline model to supply a total of 40% of Minnesota annual electric retail sales from renewables in the study year with all states at full implementation of their current RESs.
2. Scenario 2 builds on Scenario 1 by adding incremental wind and solar generation to the Scenario 1 model to supply 50% of Minnesota electric retail sales from total renewables and by further adding incremental wind and solar generation to supply an additional 10% of the non-Minnesota MISO North / Central retail electric sales from total renewables (i.e. to increase the MISO footprint renewables 10% above full implementation the current RESs).

Model	Minnesota	MISO North/Central (includes MN)
Baseline	28.5%	14.0%
Scenario 1	40.0%	15.0%
Scenario 2	50.0%	25.0%

Within each of the scenarios, the allocation of the RES was further divided between wind and solar resources and within the solar allocation was divided between centralized utility sized solar (UPV) and distributed small PV (DPV).

It was assumed that the growth in energy sales for Minnesota and MISO (includes Minnesota) would increase by 0.5% and 0.75% respectively. Given these assumptions and the allocation of resources for each scenario, Table 2-1 describes the amount of additional wind and solar resources included in the models.

Table 2-1 Wind and Solar Resource Allocations for Study Scenarios

	2013	2028				
MN Retail Sales (GWH)	66,093	71,227				
		Wind MW		**PV MWac**		
Minnesota-centric	**Wind (MW)**	**Total**	**Incremental**	**Total**	**Incremental**	
Existing + signed GIA	8,922				**UPV**	**PV**
Baseline		5,590		457	361	96
Scenario 1		7,521	1,931	1,371	723	191
Scenario 2		8,131	610	4,557	2,756	430

	2013	2028				
MISO Retail Sales (GWH)	498,000	557,000				
		Wind MW		**PV MWac**		
MISO (includes Minnesota)	**Wind (MW)**	**Total**	**Incremental**	**Total**	**Incremental**	
Existing + signed GIA	15,320				**UPV**	**PV**
Baseline		22,229	6,900	1509	1,413	96
Scenario 1		24,160	1,931	2,442	723	210
Scenario 2		37,796	13,636	8,643	5,636	565

Note that Minnesota Baseline renewable percentage includes qualifying small hydro and biomass. MISO retail sales and percentages are MISO North and Central (they do not include MISO South).

Minnesota wind generation was sited Minnesota-centric (Minnesota, North Dakota, South Dakota, and northern Iowa). Minnesota solar generation was sited in Minnesota, eastern South Dakota and northern Iowa. MISO wind and solar generation was sited per the MISO Transmission Expansion Planning assumptions. The generation siting process and assumptions are described in greater detail in subsequent sections of this report.

3 WIND AND SOLAR GENERATION SITING

Per the project plan, this task focused on selecting sites for wind and solar resources to meet the requirements of the study scenarios. Minnesota wind and solar resources were sited in the Minnesota-centric area (MN, ND, SD, northern Iowa) based on existing wind and solar, planned wind and solar (including those with signed Interconnection Agreements, wind sites in MVP portfolio planning), and MN utility announced projects. Wind and solar resources in the interconnection queues also helped inform the siting selection process.

MISO future wind and solar was sited per MTEP guidelines (e.g. at expanded RGOS zones on a pro rata basis).

As described in the previous chapter, there are significant amounts of new wind and solar generation to locate in Minnesota and within MISO for the study scenarios. Table 3-1 and Table 3-2 show the Minnesota and MISO wind and solar build-outs for the Baseline, Scenario 1 and Scenario 2 cases to be studied. Table 3-3 shows the key assumptions that were used during the build-out process.

Table 3-1 Minnesota-Centric Wind and Solar Amounts to be Sited

	Minnesota Centric			
	Wind MW	PV MWac		
	Incremental	Incremental		
		Utility PV	Distributed PV	Total Increm. PV
Baseline		361	96	457
Scenario 1	1,931	723	191	914
Scenario 2	610	2,756	430	3186

Table 3-2 Non-MN-Centric Wind and Solar Amounts to be Sited

	Non-MN MISO			
	Wind MW	PV MWac		
	Incremental	Incremental		
		Utility PV	Distributed PV	Total Increm. PV
Baseline	6900	1052	0	1052
Scenario 1	0	0	19	19
Scenario 2	13026	2,880	135	3015

Table 3-3 Key assumptions for Wind & Solar Build-Outs

Wind Annual Capacity Factor	Utility Scale PV Central CPV fraction	Annual Capacity Factor (AC)	Residential & Commercial PV Distributed DPV fraction	Annual Capacity Factor (AC)	
Minnesota					**MN**
38%					existing
38%	80%	18%	20%	17%	**Baseline**
42%	80%	18%	20%	17%	**S1**
42%	85%	18%	15%	17%	**S2**
MISO					**MISO**
32%					existing
37%	90%	17%	10%	16%	**Baseline**
37%	90%	17%	10%	16%	**S1**
37%	90%	17%	10%	16%	**S2**

PV assumptions:
- S1 20% distributed, 80% centralized
- S2 15% distributed, 85% centralized

3.1 Siting for Wind Resources

The wind profile data used in this study were derived from existing wind data sets from NREL. The data set are for the years, 2004, 2005 and 2006 and was initially developed for Eastern Wind Integration and Transmission Study (EWITS) and updated for Eastern Renewable Generation Integration Study (ERGIS) on hourly and 10 minutes intervals. MISO had been using the data set year 2005 but downloaded and updated their data using the updated ERGIS 2006 data set.

MISO also added recently signed Generation Interconnection Agreements for Xcel Energy and MidAmerican Energy Company (MEC) wind generation projects and these reduced the MN, ND & IA future/proxy wind to compensate for the addition. MISO also minimized wind siting at RGOS Zones

MN-E, MN-H, MN-L, WI-F and allowed non-MN MISO wind, to serve non-Minnesota MISO state RPSs, to include MN sited wind generation. The MISO wind was then prorated on the projected 2018, 2023 and 2028 additions. Bus names and bus numbers were corrected accordingly.

3.1.1 Minnesota Wind

Minnesota Wind is intended to serve the Minnesota RES and is sited in the Minnesota-centric area which includes all of Minnesota, parts of North Dakota and South Dakota as well as northern Iowa.

A For the Baseline Model

MTEP13 siting principles which uses the current MISO state RPSs, and corresponding wind siting including the existing and planned wind sites. (Table 3-4)

B For Scenario 1

Adding 1931 MW into the Minnesota-centric area and sited per Minnesota wind resource and consistent with expanded MISO renewable energy (MVP/RGOS) zones (see Table 3-5). Xcel Energy had recently signed Generation Interconnection Agreements for four wind plants totaling 750 MW and this was included in the 1931 MW and these locations are shown in green in Figure 3-2.

C For Scenario 2

Minnesota wind for Scenario 2 was increased by 610 MW above what was in Scenario 1. See Table 3-6.

3.1.2 MISO (non-MN) Wind

Non-MN Wind is intended to serve the MISO state RPSs for states other than Minnesota. The wind resources are sited per MTEP wind resource in the MISO footprint including in the Minnesota-Centric Area.

A For Baseline

Beyond the wind included in the MTEP 2013 models, which includes the existing and planned wind projects in MISO, 6900 MW was added MISO wide to meet the current MISO state RPSs (including MN). This is shown in Table 3-2.

B For Scenario 1

No non-MN MISO wind was added.

C For Scenario 2

Beyond the Baseline, 13,026 MW of non-Minnesota wind was added baseline in the RGOS zones primarily in Iowa, Illinois, Indiana and Michigan (see Table 3-8). MEC had recently signed generation interconnection agreements for four wind plants totaling 932.6 MW and this was included in the 13,026 MW total. These four locations are shown in green in Figure 3-3.

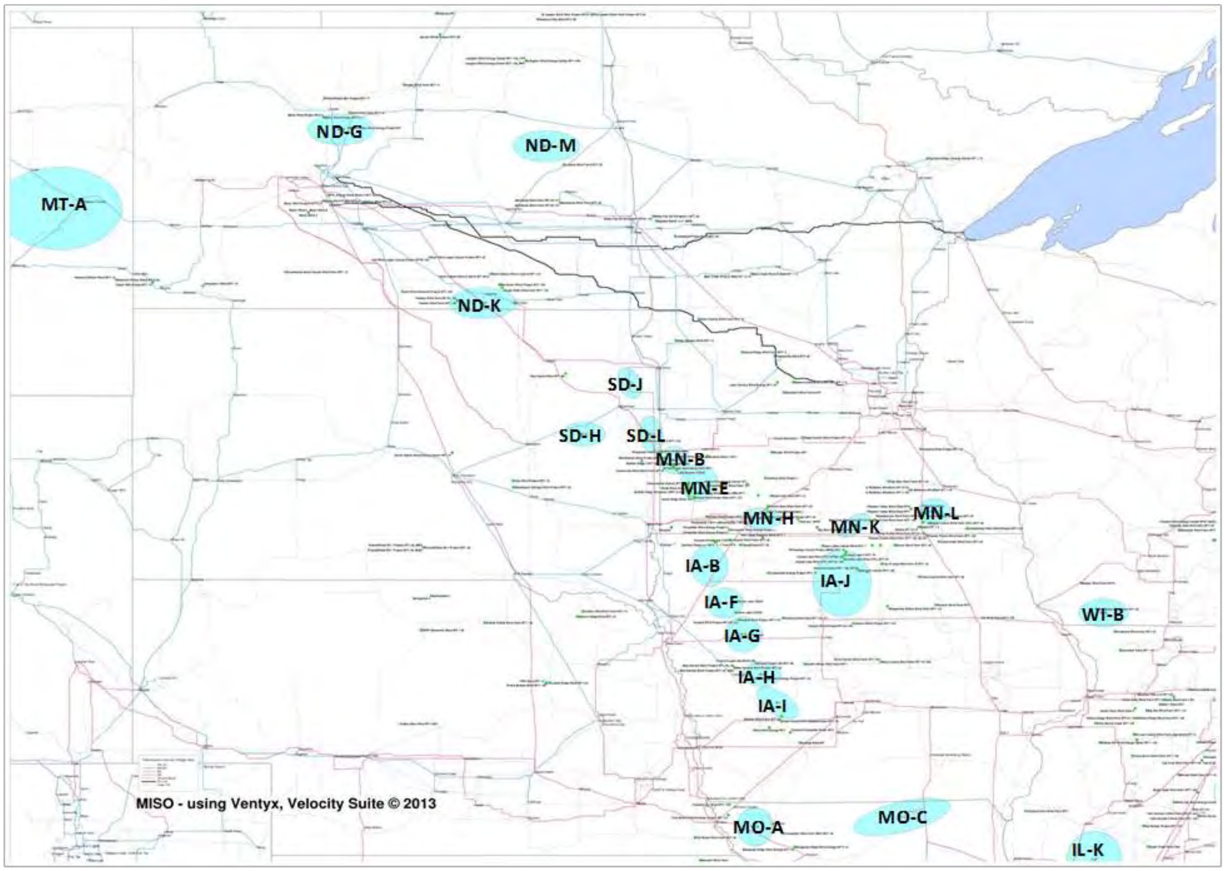

Figure 3-1 RGOS Wind Zones

Table 3-4 MISO Wind Locations-Baseline

RGOS Zone	Bus Name	Existing and Signed GIAs (MW)	MISO - Baseline Wind Additions (MW)			Total wind amounts in Baseline Scenario (MW)
			2018	2023	2028	
IA-B	SHELDON	610	23	63	239	934
IA-F	SHELDON	675	23	61	233	992
IA-G	RAUN	805	21	56	214	1096
IA-H	GRIMES	415	17	45	170	647
IA-I	GRIMES	383	10	26	101	520
IA-J	WEBSTER	1735	1	4	14	1754
IL-F	BROKAW	891	126	48	21	1085
IL-K	PAWNEE	420	94	71	0	585
IN-E	WESTWD	350	11	30	115	507
IN-K	HORTVL	200	15	40	154	409
MI-B	REESE	305	378	0	0	683
MI-C	WYATT	233	345	0	0	579
MI-D	WYATT	112	278	0	0	390
MI-E	REESE	333	378	0	0	711
MI-F	WYATT	32	378	0	0	410
MI-I	PALISADES		191	0	0	191
MN-B	LYON COUNTY	985	6	16	60	1066
MN-E	CHANARAMBIE	891				891
MN-H	LAKEFIELD	553				553
MN-K	HUNTLEY	1251	14	36	140	1441
MN-L	PLEASANT VALLEY	813				813
MO-A	ATCHISON T	146	224	0	0	370
MO-C	ADAIR		314	0	0	314
MT-A	BAKER	200	11	28	107	345
ND-G	GRE-MCHENRY	780	16	41	156	994
ND-K	ELLENDALE	171	13	34	130	348
ND-M	GRE-RAMSEY	887	4	12	48	952
SD-H	BIG STONE SOUTH (West of)		23	63	239	324
SD-J	BIG STONE SOUTH	40	23	61	232	355
SD-L	BROOKINGS	207	23	63	239	531
WI-B	DUBUQUE CTY	121	18	49	186	374
WI-D	NORTH APPLETON	267	20	54	203	543
WI-F		520.6	0	0	0	521
	Totals	**15,329**	**3000**	**900**	**3000**	**22,229**

Table 3-5 Incremental Minnesota-Centric Wind Locations for Scenarios 1&2

RGOS Zone	Bus Name	Incremental MN Wind for Scenario 1	Incremental MN wind for Scenario 2	Total Scenario 1 & 2 Incremental MN wind
IA-B	SHELDON	125	50	175
IA-J	WEBSTER	75	10	85
MN-B	LYON COUNTY	218	191	409
MN-E	CHANARAMBIE	50		50
MN-H	LAKEFIELD	125		125
MN-K	HUNTLEY	150	129	279
MN-L	PLEASANT VALLEY	75		75
MN	ODELL (G826)	200		200
MN	PLEASANT VALLEY (J278)	200		200
ND-G	GRE-MCHENRY	0	80	80
ND-K	ELLENDALE	50		50
ND-M	GRE-RAMSEY	25	30	55
ND	BORDERS (J290)	150		150
ND	COURTNEY (J262/J263)	200		200
SD-H	BIG STONE SOUTH (West of)	50		50
SD-J	BIG STONE SOUTH	108	50	158
SD-L	BROOKINGS	130	70	200
	Totals	**1931**	**610**	**2541**

Table 3-6 Minnesota-Centric Wind Siting

State	Baseline Scenario	Incremental MN Wind gen for Scenario 1	Incremental MN Wind gen for Scenario 2	Total Incremental Wind Scenario 1 & 2
IA %	24.5%	10.4%	9.8%	10.2%
MN %	**43.5%**	**52.7%**	**52.5%**	**52.7%**
ND %	20.9%	22.0%	18.0%	21.1%
SD %	11.1%	14.9%	19.7%	16.1%

Table 3-7 Non Minnesota MISO Wind Locations- Scenario 1 & 2

RGOS Zone	Bus Name	Incremental Non-MN Wind for Scenario 1	Incremental Non-MN Wind for Scenario 2
IA-B	SHELDON		361
IA-F	SHELDON		397
IA-G	RAUN		350
IA-H	GRIMES		240
IA-I	GRIMES		67
IA-J	WEBSTER		25
IA	HIGHLAND (R39)		500
IA	LUNDGREN (R42)		250
IA	VIENNA II (H009)		44
IA	WELLSBURG (H021)		138.6
IL-F	BROKAW		398
IL-K	PAWNEE		345
IN-E	WESTWD		329
IN-K	HORTVL		425
MI-B	REESE		736
MI-C	WYATT		676
MI-D	WYATT		552
MI-E	REESE		736
MI-F	WYATT		736
MI-I	PALISADES		391
MN-K	HUNTLEY		261
MO-A	ATCHISON T		453
MO-C	ADAIR		620
MT-A	BAKER		309
ND-G	GRE-MCHENRY		353
ND-K	ELLENDALE		367
ND-M	GRE-RAMSEY		130
SD-H	BIG STONE SOUTH (West of)		638
SD-J	BIG STONE SOUTH		571
SD-L	BROOKINGS		568
WI-B	DUBUQUE CTY		507
WI-D	NORTH APPLETON		550
WI-F			0
	Totals	**0**	**13,026**

Table 3-8 Non-MN MISO Wind Siting

State	Baseline Scenario	Incremental Non-MN Wind for Scenario 1	Incremental Non-MN Wind for Scenario 2
IA %	26.7%	n/a	18.2%
IL %	7.5%	n/a	5.7%
IN %	4.1%	n/a	5.8%
MI %	13.3%	n/a	29.4%
MN %	**21.4%**	n/a	**2.0%**
MO %	3.1%	n/a	8.2%
MT %	1.6%	n/a	2.4%
ND %	10.3%	n/a	6.5%
SD %	5.4%	n/a	13.6%
WI %	6.5%	n/a	8.1%

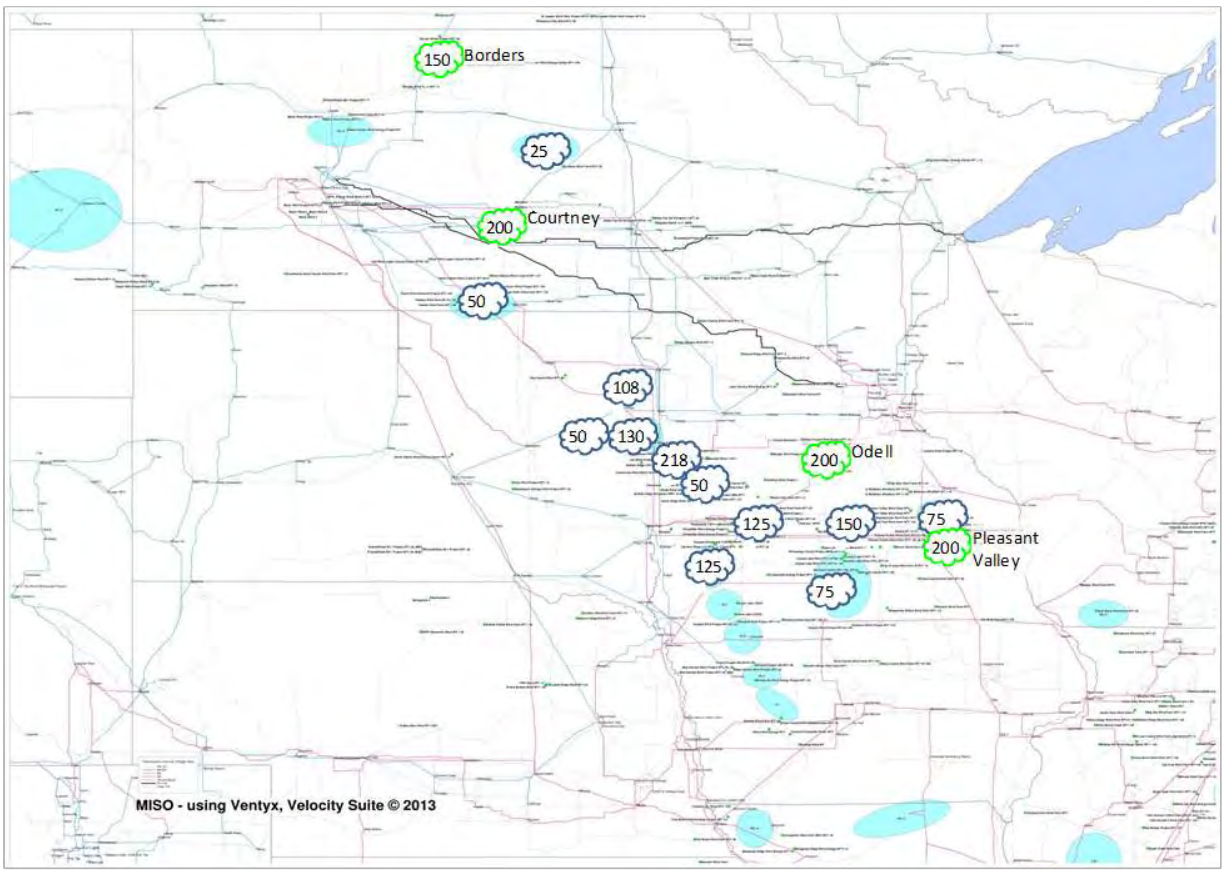

Figure 3-2 MN & Non MN Scenario 1 Wind Siting

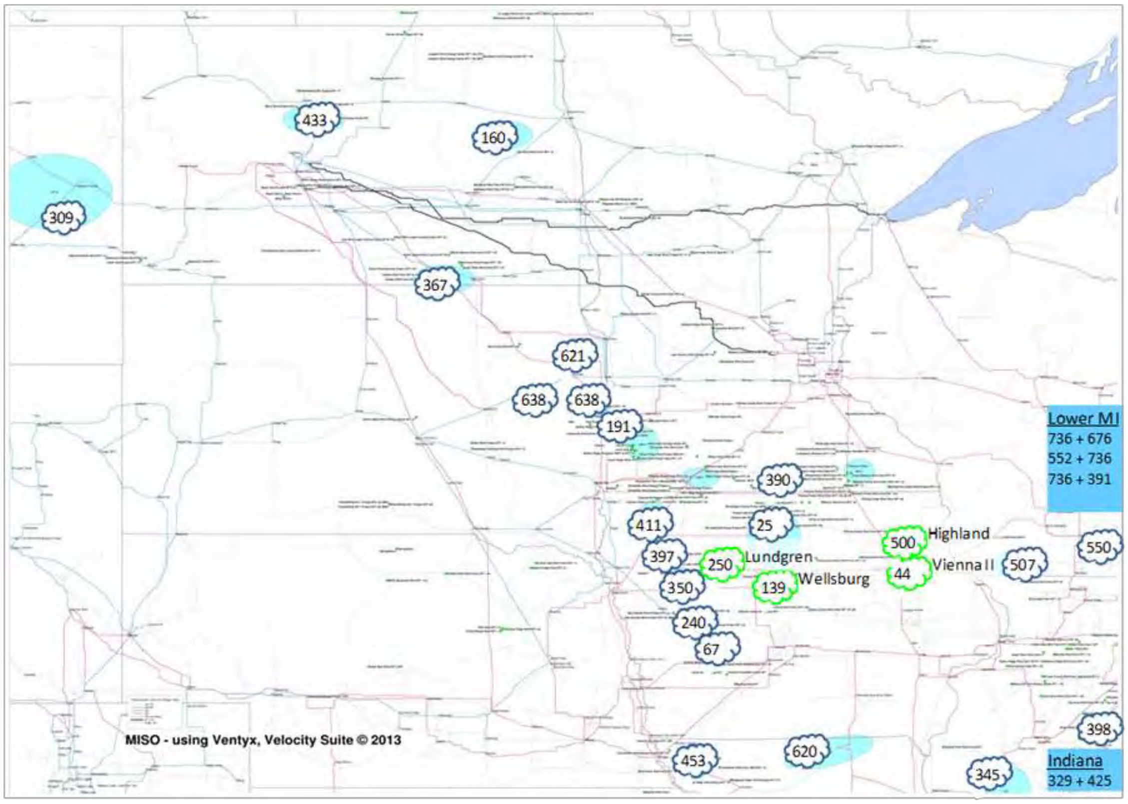

Figure 3-3 RGOS Wind Zones w/MN & Non MN Scenario 2

3.2 MISO Wind Reassignment

The Non-MN MISO wind was sited per as described in the previous section. However after the production simulation analysis showed significant amounts of wind congestion at some plants in western MISO, it was decided to relocate some of this congested wind sites to less congested areas. A portion of the wind generation was moved from the "Top 4" congested sites and reassigned to the "Bottom 10" least congested sites.

This reassigned generation only involved the non-MN MISO wind and this generally relocated the wind generation to the south and east locations with lower capacity factor. As a result of the placing this generation at sites with lower capacity factors, or reduced average wind speeds, the wind nameplate had to be increased in order to maintain the equivalent wind energy prior to and after the shift.

Table 3-9 displays the shifted sites, nameplate capacity and annual energy outputs. Figure 3-4 shows the locations of the wind sites that were shifted; the sites in red represent the 4 most congested sites. The wind resources from these locations were shifted to the sites shown in yellow.

Table 3-9 Wind Shift from the 4 Most-Congested to the 10 Least-Congested Sites

Zone	Company	Basecase (MW)	S1 (MW)	S2 (MW)	Basecase Curtailment (GWh)	S1 Curtailment (GWh)	S2 Curtailment (GWh)	S2 Capacity Adjustment (M	S2 Energy Adjustment (GWh)
SD-H:1	OTP	324	374	1,012	25.7	0.9	1,226.6	(311)	(1,229)
ND-K:1	MDU	177	227	595	5.0	26.3	895.2	(293)	(898)
IA-G:1	MEC	292	292	642	0.6	1.7	495.6	(129)	(499)
MN-K:1	Alliant West	190	340	731	3.7	30.9	444.4	(118)	(447)
								(851)	**(3,293)**
H009:1	MEC	-	-	44	-	-	0.3	83	329
H021:1	Alliant West	-	-	139	-	-	0.1	97	329
IL-F:1	Ameren IL	194	194	591	-	-	-	106	329
IN-E:1	Duke Energy IN	157	157	486	-	-	-	103	329
MI-C:1	Detroit Edison	345	345	1,022	-	-	-	111	329
MI-B:1	Detroit Edison	378	378	1,114	-	-	-	89	329
MI-F:1	Detroit Edison	378	378	1,114	-	-	-	98	329
MI-E:1	Detroit Edison	378	378	1,114	-	-	-	80	329
MI-I:1	Consumers Energy	191	191	582	-	-	-	84	329
MI-D:1	Detroit Edison	278	278	830	-	-	-	96	329
								947	**3293**
							Net	**96**	**0**

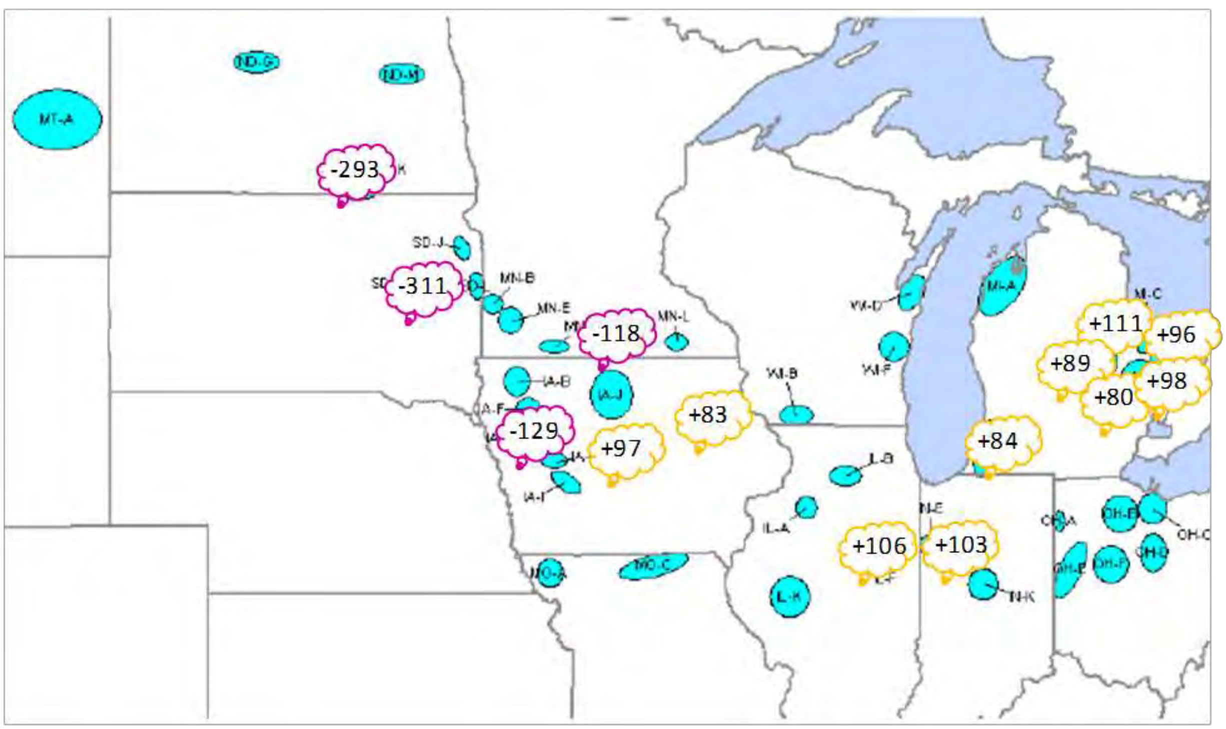

Figure 3-4 Wind Shift from the 4 Most-Congested to the 10 Least-Congested Sites

3.3 Siting of PV Solar Resources

The Non-Minnesota MISO photovoltaic solar data set came from the ERGIS hourly solar data. For Minnesota solar data, NREL developed additional 2006 hourly solar power data with 10 km resolution, which allow the siting of additional utility-scale solar in Minnesota that was not present in the ERGIS data.

For utility-scale solar plants in Minnesota, the data was processed to create individual solar plants simulating a 1.25:1 module-to-inverter ratio. This was done to approximate the additional solar panels that are used to reduce the losses and increase the capacity factor of utility-scale solar plants by having the capacity of the photovoltaic panels exceed the capacity of the inverter. This process involved setting the ac rating at 80% of the dc nameplate rating and clipping the output to the ac rating. (For example, the raw values for a 50 MWdc PV plant were limited to 40 MWac to create a 40 MW plant for the study.) The capacity values were revised accordingly so they reflect the ac bus bar values.

The ERGIS data already contained values for the utility-scale solar plants outside of Minnesota and the distributed solar (both inside and outside of Minnesota). These values reflected typical losses due to inverter efficiency and other factors. The distributed solar dc to ac losses varied from 79% to 85% with an average of 82%. Non-Minnesota utility-scale solar losses varied from 77% to 89% with an average of 83%. However the assumed annual energy numbers remain the same because the ac ratings are based on the maximum output value for each site rather than the dc values.

3.3.1 Minnesota PV Solar

The solar generation added in the Minnesota-Centric area was split between Distributed PV and Centralized utility scale PV on a 20%/80% basis for the Baseline and Scenario 1, and a 15%/85% split for Scenario 2, respectively. The 1.5% solar mandate enacted in 2013 legislation dictated that at least 10% of the solar was to be distributed, but the splits were determined in the stakeholder study scoping process. The distributed PV was assumed to be sited at load centers.

The Centralized utility scale PV was spread by solar resource largely over the southern half of Minnesota, however there was some sited in the northern portion of the state as utilities in the northern part of the state indicated that they would prefer to site closer to their service territory even knowing that the energy output would be slightly less than the southwest portion of the state. Note: there is an approximately 10% decrease in solar resource strength from the south west corner of MN to Duluth, MN in the north east. The solar strength does not follow an intuitive rule where further south equals stronger solar strength, but rather the solar strength gradient generally follows a NW to SE line, such that Alexandria, MN has about the same solar value as the Twin Cities. This is shown in Figure 3-5.

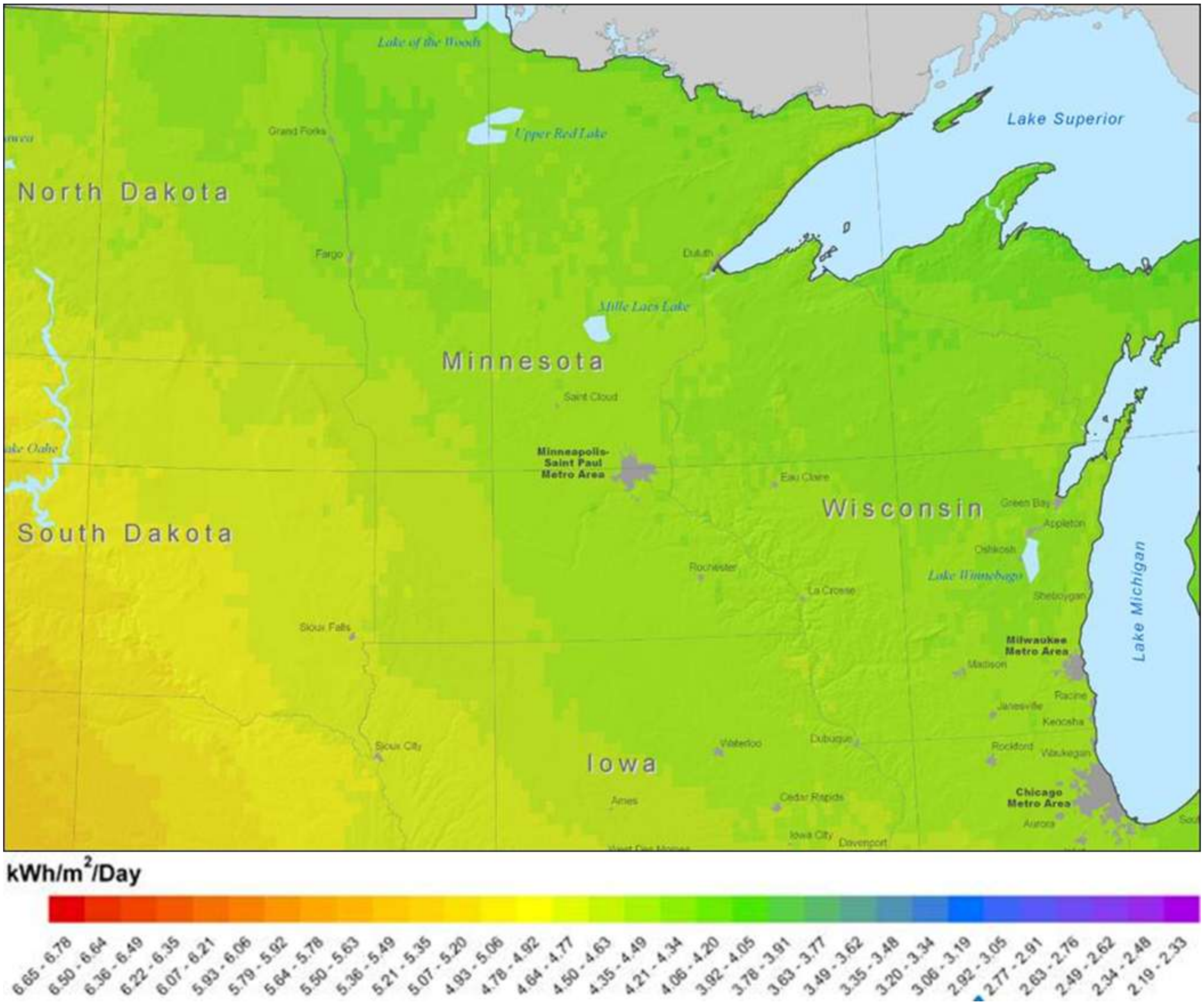

Figure 3-5 United States Photovoltaic Solar Resource (portion of)

- For the Baseline scenario, a total of 457 MWac PV was added with 96 MW being distributed and 361 MW classified and sited as Utility scale solar.
- For Scenario 1, a total of 914 MWac PV was added with 191 MW being distributed and 723 MW classified and sited as Utility scale solar.
- For Scenario 2, a total of 3,186 MWac PV was added with 430 MW being distributed and 2,756 MW classified and sited as Utility scale solar.

These solar generation amounts are shown in Table 3-10 and Table 3-11. The locations are shown in Figure 3-6, Figure 3-7, and Figure 3-8.

Table 3-10 Minnesota Utility PV Sites for Study Scenarios

Location	Baseline	Scenario 1	Scenario 2	Total at each site
Riverton 230	2	5	5	12
Badoura 230	3	8	10	21
Hubbard 230	5	10	15	30
Wing River 230	5	10	15	30
Alexandria 345	20	20	50	90
Quarry 345		30	80	110
Chub Lake 345	20	20	100	140
Prairie Island 345		30	100	130
North Rochester 345		30	100	130
Byron 345	20	20	100	140
Pleasant Valley 345	20	30	100	150
Sheas Lake 345	20	30	100	150
Owatanna 115			50	50
Wilmarth 345		50	100	150
Adams 345	20	30	100	150
Hayward 161			51	51
Cedar Mountain 345	20	30	100	150
Willmar 230			80	80
Big Stone South 345	20	30	100	150
Hazel 345	20	30	100	150
Lyon County 345	20	30	100	150
Fort Ridgley 115			50	50
Chanarambie 115			50	50
Fox Lake 161			50	50
Winnebago(Huntley) 345	30	40	100	170
Brookings 345	26	40	100	166
West New Ulm 115			50	50
Lakefield 345	30	40	100	170
Pipestone 115			50	50
Nobles 345	30	40	100	170
Split Rock 345	30	40	150	220
Ledyard, IA 345		40	200	240
Obrien, IA 345		40	200	240
Totals	**361**	**723**	**2756**	**3840**

Figure 3-6 MN Solar for Utility Locations - Baseline

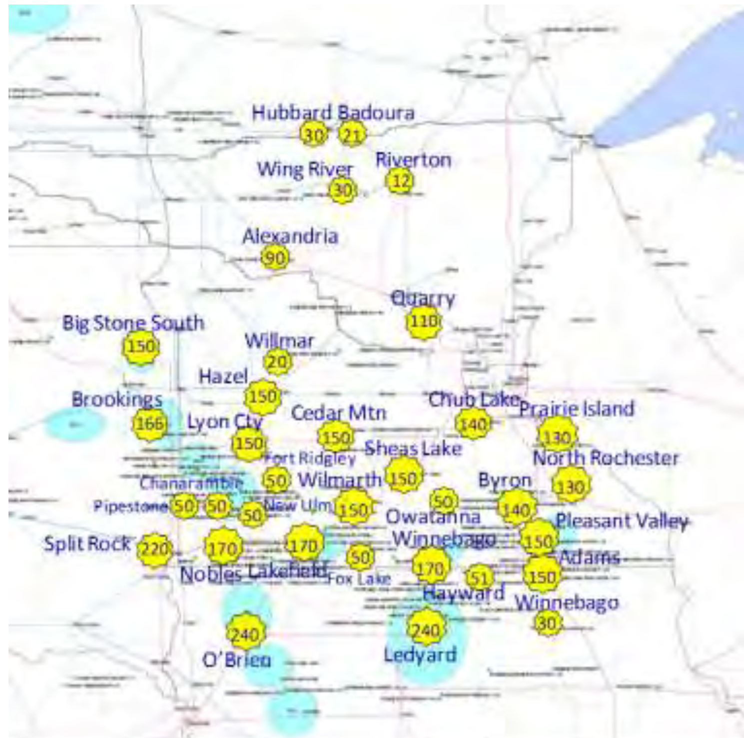

Figure 3-7 MN Solar for Utility Locations - All Scenarios

Table 3-11 MN Distributed PV Sites for Study Scenarios

Location	Baseline	Scenario 1	Scenario 2	Total at each site
	MW (AC)			
NORTHERN HILLS	4	6	15	25
SOUTH FARIBAULT	2	4	9	15
CANNON FALLS	3	9	21	33
INVER HILLS	6	12	28	46
BLUE LAKE	4	9	18	31
GRE-MCLEOD	3	5	13	21
TERMINAL	9	34	30	73
PARKERS LAKE	14	24	92	130
AS KING	8	14	32	54
BLAINE	3	6	14	23
COON CREEK	8	10	24	42
DICKINSON	4	7	16	27
ELM CREEK	2	4	9	15
KOLMAN LAKE	4	7	16	27
BLAINE	4	7	16	27
ELK RIVER	4	7	16	27
ELM CREEK	2	4	9	15
CHISAGO	4	7	16	27
SHERBURNE CTY	3	5	13	21
RUSH CITY	2	3	7	12
PAYNESVILLE	3	7	16	26
Totals	**96**	**191**	**430**	**717**

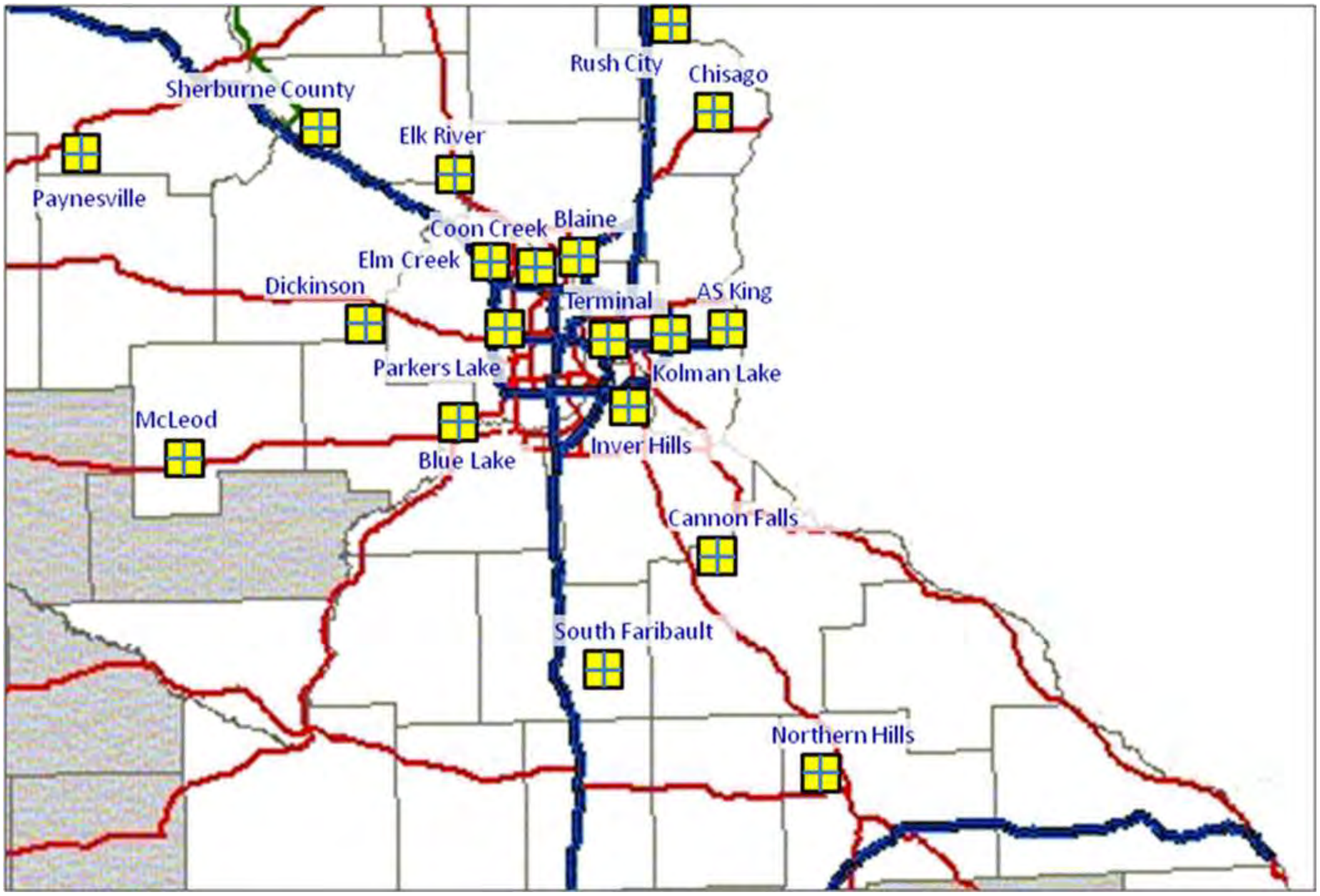

Figure 3-8 MN Distributed PV Sites

3.3.2 Non-Minnesota PV Solar

MISO solar was sited at ERGIS solar data set locations with a fixed 10%/90% split between Distributed PV and Central utility scale PV and this split was also determined in the stakeholder study scoping process.

- For the Baseline no solar was added.
- For Scenario 1, a total of 19 MWac of distributed PV was added.
- For Scenario 2, a total of 3,015 MWac PV was added with 135 MW being distributed and 2,880 MW classified and sited as Utility scale solar.

These solar generation amounts are shown in Table 3-12 and Table 3-13. The locations are shown in Figure 3-9.

Table 3-12 Non-MN Solar for Utility Locations

State	Baseline	Scenario 1	Scenario 2	Total at each site
	MW (AC)			
Michigan	126	0	189	**315**
Indiana	239	0	521	**681**
Illinois	188	0	377	**572**
Iowa	39	0	55	**94**
Missouri	431	0	1583	**2079**
Arkansas	7	0	39	**48**
Kentucky	22	0	116	**143**
Totals	**1052**	**0**	**2880**	**3932**

Table 3-13 Non-MN Distributed Solar for Study Scenarios

Location		Baseline	Scenario 1	Scenario 2	Sub-totals	Totals
	City	MW (AC)				
MI	Detroit	0	1	6	7	31
	Flint	0	0	4	4	
	Grand Rapids	0	1	6	7	
	Ann Arbor	0	1	6	7	
	Lansing	0	1	5	6	
IN	Indianapolis	0	1	6	7	26
	Evansville	0	1	6	7	
	Fort Wayne	0	1	6	7	
	South Bend	0	0	5	5	
IL	Rockford	0	1	7	8	22
	Champaign	0	1	6	7	
	Peoria	0	0	3	3	
	Springfield	0	1	3	4	
Wi	Milwaukee	0	0	6	6	22
	Madison	0	0	4	4	
	Kenosha	0	1	4	5	
	Green Bay	0	1	6	7	
IA	Des Moines	0	1	6	7	26
	Cedar Rapids	0	1	5	6	
	Sioux City	0	1	5	6	
	Davenport	0	1	6	7	
MO	St Louis	0	1	6	7	27
	St Charles	0	1	6	7	
	St Peters	0	1	6	7	
	O'Fallon	0	0	6	8	
	Totals	**0**	**19**	**135**	**154**	**154**

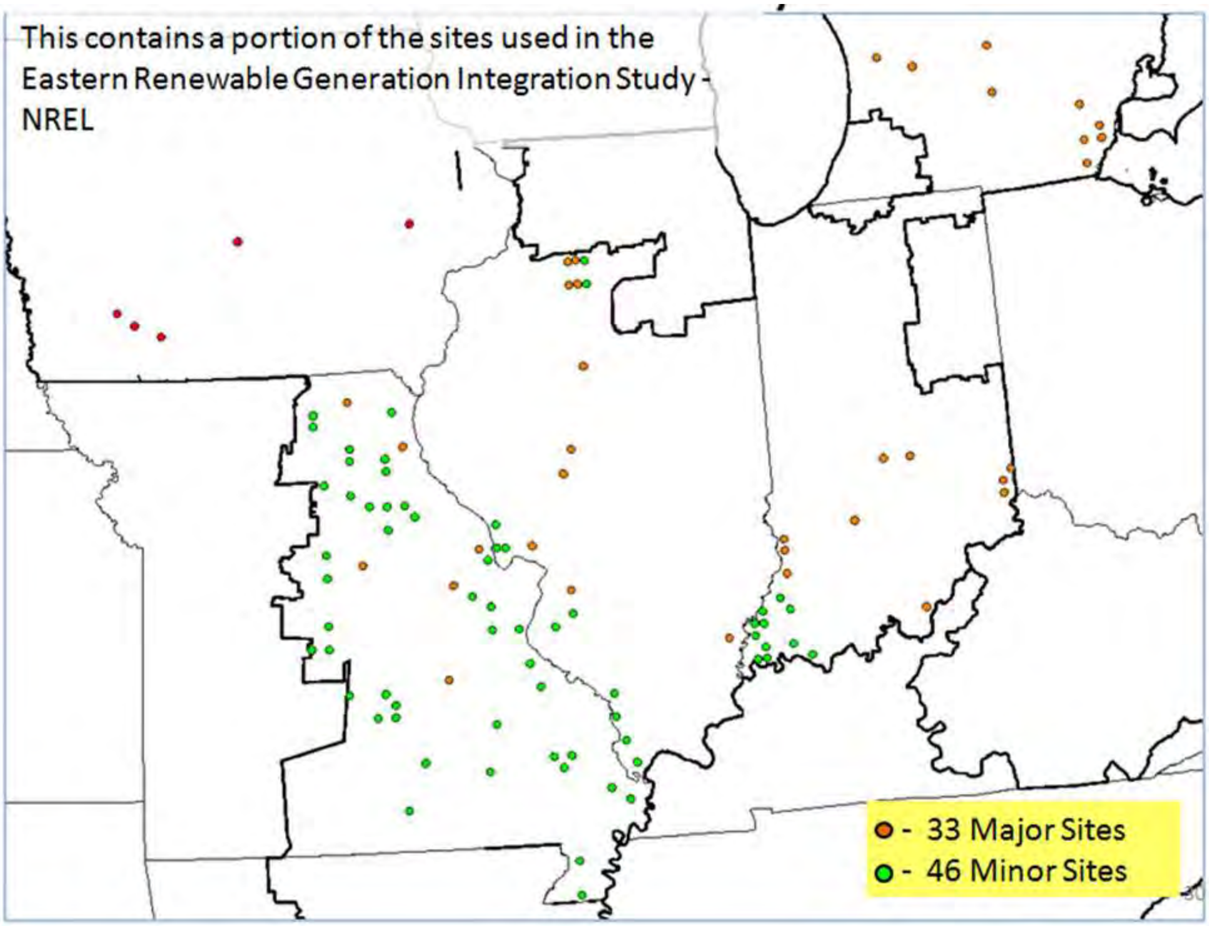

Figure 3-9 Locations of Non-MN Solar - Utility Locations

4 TRANSMISSION SYSTEM CONCEPTUAL PLANS

In 2013, the Minnesota Legislation adopted a requirement that all electrical utilities and transmission companies in the state of Minnesota to conduct an engineering study to evaluate the impacts of raising Renewable Energy Standard (RES) to 40% by the year 2030 and to higher proportions thereafter. This Minnesota Renewable Energy Integration and Transmission Study reviewed the impacts on reliability and costs, including necessary transmission network upgrades, of increasing the RES while maintaining system reliability. As part of this study, Excel Engineering, Inc. was asked to help by performing a Transmission System Conceptual Plan Study. This portion of the study was designed to use powerflow analysis to evaluate certain transmission configurations alongside the production modeling.

4.1 Study Assumptions and Methodology

4.1.1 Study Procedure

The Siemens Power Technologies, Inc. "PSS/E" digital computer powerflow simulation program was used for the steady state thermal analysis to identify the limiting facilities (lines or transformers) which were encountered as the power injection (generation output) was added at the sites of interest per the MRITS Wind-Solar Siting. Beyond the initial load scale-up to configure the models to 2028, the analysis described in this report is based on the "generation to generation" method of modeling new generation resources; consistent with MISO evaluation practice; beyond the initial load scale-up to configure the models to 2028. The "generation to generation" method involves adding new generation and simultaneously backing down or turning off an equal amount of existing generation to keep the system balanced where generation equals load (plus system losses).

A conceptual transmission plan was developed with respect to the Baseline and each scenario. System reliability was determined by technical analyses performed under traditional transmission planning methods, criteria, and assumptions. Performance characteristics to be addressed include the steady-state performance of the following:

Contingency Analysis (powerflow)

- System Intact
- N-1
- Common Structures / Breaker failure (NERC TPL Category C2 & C5)

The local balancing authority areas indicated below were monitored and evaluated for contingency analysis.

Greater than 300 kV

- Wisconsin Electric Power
- ITC Midwest
- MidAmerican Energy Company
- Montana Dakota Utilities
- American Transmission Company

Greater than 200 kV

- Southern Manitoba Area:
  - Facilities South of Winnipeg / Brandon to US border

Greater than 100 kV

- Xcel Energy
- Minnesota Power
- Southern Minnesota Municipal Power Agency
- Great River Energy
- Otter Tail Power
- Western Area Power Administration
- Dairyland Power Cooperative
- ITC Midwest (facilities in Minnesota)
  - Northern Iowa Area: Facilities North of Sioux City / Fort Dodge / Iowa Falls / Waterloo / Dubuque into Minnesota

4.1.2 Models Employed

The study base models used were the 2023 Summer Off-peak (70% load) case and 2023 Summer Peak case from the 2013 MTEP series of models. These models represent the transmission system as it is presently anticipated to be configured in the year 2023. The models were then modified to create a 2028 Baseline model representation with the following additions:

All CapX2020 Group 1 Projects[1]

- Monticello-Quarry-Alexandria-Bison (Fargo) 345 kV line
- Brookings Co-Lyon Co-Cedar Mountain-Helena-Chub Lake (Lake Marion)-Hampton Corner 345 kV, Lyon Co-Hazel Creek 345 kV
- Hampton Corner-North Rochester-North La Crosse 345 kV line
- Wilton-Cass Lake-Boswell 230 kV line

All MISO Multi Value Projects (MVPs) approved in 2011

- Big Stone South-Brookings 345 kV line
- Brookings Co-Lyon Co-Cedar Mountain-Helena-Chubb Lake (Lake Marion)-Hampton Corner 345 kV, Lyon Co-Hazel Creek 345 kV (same as shown in CapX2020 Group 1 Projects)
- Lakefield Jct.-Huntley-Ledyard-Kossuth-O'Brien & Kossuth-Webster 345 kV lines
- Ledyard-Colby-Killdeer-Blackhawk-Hazelton 345 kV line
- Briggs Road-North Madison-Cardinal & Dubuque Co.-Spring Green-Cardinal 345-kV lines
- Ellendale-Big Stone South 345 kV line
- Ottumwa-Adair 345 kV line
- Adair-Maywood-Palmyra 345 kV line
- Palymra-Maywood-Merleman-Meredosia-Ipava & Meredosia-Pawnee 345 kV lines
- Pawnee-Pana-345 kV Line
- Pana-Mt. Zion-Kansas-Sugar Creek 345 kV line
- Reynolds-Burr Oak-Hiple 345 kV

[1] http://www.capx2020.com/, accessed 9/25/2014

- Michigan Thumb Loop Expansion 345 kV line
- Reynolds-Greentown 765 kV line
- Pleasant Prairie-Zion Energy Center 345 kV line
- Fargo-Maple Ridge-Oak Grove 345 kV Line
- Sidney-Rising 345 kV line

Other Transmission Projects

- MTEP Appendix A Projects with In-Service date Prior to 2023
- Manitoba Hydro Bipole III
- Antelope Valley Station-Charlie Creek-Williston-Tioga 345 kV
- Hazleton-Salem 345 kV
- Dorsey-Iron Range 500 kV (Great Northern Transmission Line)
- Increase Square Butte HVDC to 550 MW
- Center - Prairie 345 kV line
- Transmission Owner's transmission changes
    - Winger-Thief River Falls 230 kV line

4.1.2.1 Load Scaling

The load was scaled up in the following areas to get to the 2028 proposed levels.

For Minnesota Utilities

- 0.5% Annually
- 590 MW

For other MISO North and Central Utilities

- 0.75% Annually
- 3460 MW

4.1.2.2 Generation Additions:

The following generation was included: All In-service and/or signed Generator Interconnection Agreements at the start of the analysis.

- Minnesota Power's-Bison Wind 600 MW
- Manitoba Hydro's Keeyask Hydro 695 MW
- Transmission Owner's generation changes

All generation added from the MRITS Wind-Solar Siting were added by the following dispatch criteria of their nameplate value.

Summer Peak Model

- Wind – 20%
- Solar – 60%

Summer Off-Peak Model

- Wind – 90%
- Solar – 60%

The following switched shunt capacitors were added to all models at the following buses for additional voltage support. This was a broad and major addition necessary to build the Baseline model with the load and generation additions to keep the system near 1.0 p.u. voltage, in order to help meet existing MISO North/Central state RPSs.

Switched shunt capacitors were added to all models at the following buses

- 400 MVAR @ Adams 345 kV bus
- 300 MVAR @ Blackhawk 345 kV bus
- 200 MVAR @ Blue Lake 230 kV bus
- 300 MVAR @ Colby 345 kV bus
- 300 MVAR @ Eau Claire 345 kV bus

4.1.3 Baseline Model

The following amounts of generation were added to the MTEP13 2023 models to obtain a Baseline model which meets the current MN RES and other MISO state RPSs.

4.1.3.1 MRITS Wind-Solar Siting

Added beyond MTEP13 2023 models

- Total wind – 6900 MW
- Total Solar – 1509 MW
  - MN Utility PV – 361 MW
  - MN Distributed PV – 96 MW
  - Non-MN Utility PV – 1052 MW
  - Non-MN Distributed PV – 0 MW

Incremental Total – 8409 MW

4.1.4 S1 Model (Added beyond Baseline)

The following amounts of generation were added to the Baseline models to obtain an S1 model which would meet a 40% MN RES standard and existing RPSs in other MISO North/Central states.

4.1.4.1 MRITS Wind-Solar Siting

- Total wind – 1931 MW
  - MN Wind – 1931 MW
  - Non-MN Wind – 0 MW
- Total Solar – 933 MW
  - MN Utility PV – 723 MW
  - MN Distributed PV – 191 MW
  - Non-MN Utility PV – 0 MW
  - Non-MN Distributed PV – 19 MW

Incremental Total – 2864 MW

4.1.5 S2 Model (Added beyond S1)

The following amounts of generation were added to the S1 models to obtain an S2 model which would meet a 50% MN RES standard and a 10% RPS increase in other MISO states.

4.1.5.1 MRITS Wind-Solar Siting

- Total wind – 13636 MW
    - MN Wind – 610 MW
    - Non-MN Wind – 13026 MW
- Total Solar – 6201 MW
    - MN Utility PV – 3840 MW
    - MN Distributed PV – 717 MW
    - Non-MN Utility PV – 3932 MW
    - Non-MN Distributed PV – 154 MW

Incremental Total – 19837 MW

4.2 Results

4.2.1 SCED /MISO Footprint

4.2.1.1 Generation Dispatch Methodology

The models were built while incorporating the wind generation and solar generation within the MISO North and Central footprint. Some wind generation was added using the Security Constrained Economic Dispatch (SCED) which is similar to what is done when MISO creates a base MTEP model and this allows for generation re-dispatch for mitigating overloads. The SCED method determines how the generation resources participating in the market would be dispatched based on economics and reliability where the most cost effective resources are dispatched while maintaining system reliability. This effectively allowed the low-cost wind generation to remain on the system, while other more expensive generation sources are turned down when needed to alleviate congestion. The remainder of the new generation added in the Baseline, S1 and S2 was dispatched in a manner consistent with the MISO Generation Interconnection studies and designated “Footprint Dispatch” and is described as, essentially scaling the whole footprint up and down to keep the swing bus within a certain range after the project under study was added. It is assumed that the swing bus is set based on where it started in the pre-project case.

One of the purposes of the Multi-Value Project (MVP) portfolio was to provide delivery of wind resources needed to meet the MISO state Renewable Portfolio Standards (RPSs). Thus it was decided that for the Baseline case, the 6900 MW (3000+900+3000), deemed the “Multi Value Project wind” and which was required to meet the existing MN RES and other MISO state RPSs, would be dispatched in a SCED methodology and will utilize the MVPs for delivery into the MISO market. Once the Baseline model had been established by using SCED to alleviate constraints, the MISO footprint dispatch methodology was used to offset renewable generation additions in the S1 and S2 scenarios.

4.2.1.2 Baseline

The Baseline models were built incorporating the wind generation of 6900 MW dispatched by Security Constrained Economic Dispatch (SCED) methodology and the solar generation of 1509 MW dispatched across the MISO North and Central footprint. This process first involved adding the 6900 MW of RGOS wind in 20% and 90% (of nameplate) dispatch amounts to the 2028 Summer Peak and Summer Off Peak models respectively and then having MISO run the SCED on these models. Wind plants were modeled at a ±0.95 power factor at the point of interconnection to the transmission system.

MISO performed the SCED on the models and provided the generation changes for the insertion of 6900 MW of Baseline wind generation. These SCED models were then adjusted by adding750 MW of new hydro in Manitoba and then dispatching it to WPS (367 MW) and MP (383 MW) along with the 1509 MW of Solar using the "Footprint Dispatch" method which yields the Baseline model. Note: the 367 & 383 MW of hydro add up to 750 MW and are contractual amounts associated with the Great Northern Dorsey to Iron Range 500 kV project.

The following two Baseline models then were created.

S70 -	Summer Off-Peak (70%) Baseline	MRITS2028-S70-R17-Basea.sav
SUM -	Summer Peak Baseline	MRITS2028-SUM-R17-Basea.sav

Figure 4-1 shows how the bus angles for the Off-Peak condition in the Upper Midwest after generation was added from the original 2013 MTEP 2023 model to the Baseline. In examining the bus angle figure, the larger the phase angle difference between points indicates higher power transfers, lower stability margins and more operational issues such as closing in lines after outages, etc.

A very limited number of facilities were overloaded in the Baseline Scenario, so it was determined to be a good starting point for the study. See the Appendix for the full listing (available upon request from GRE).

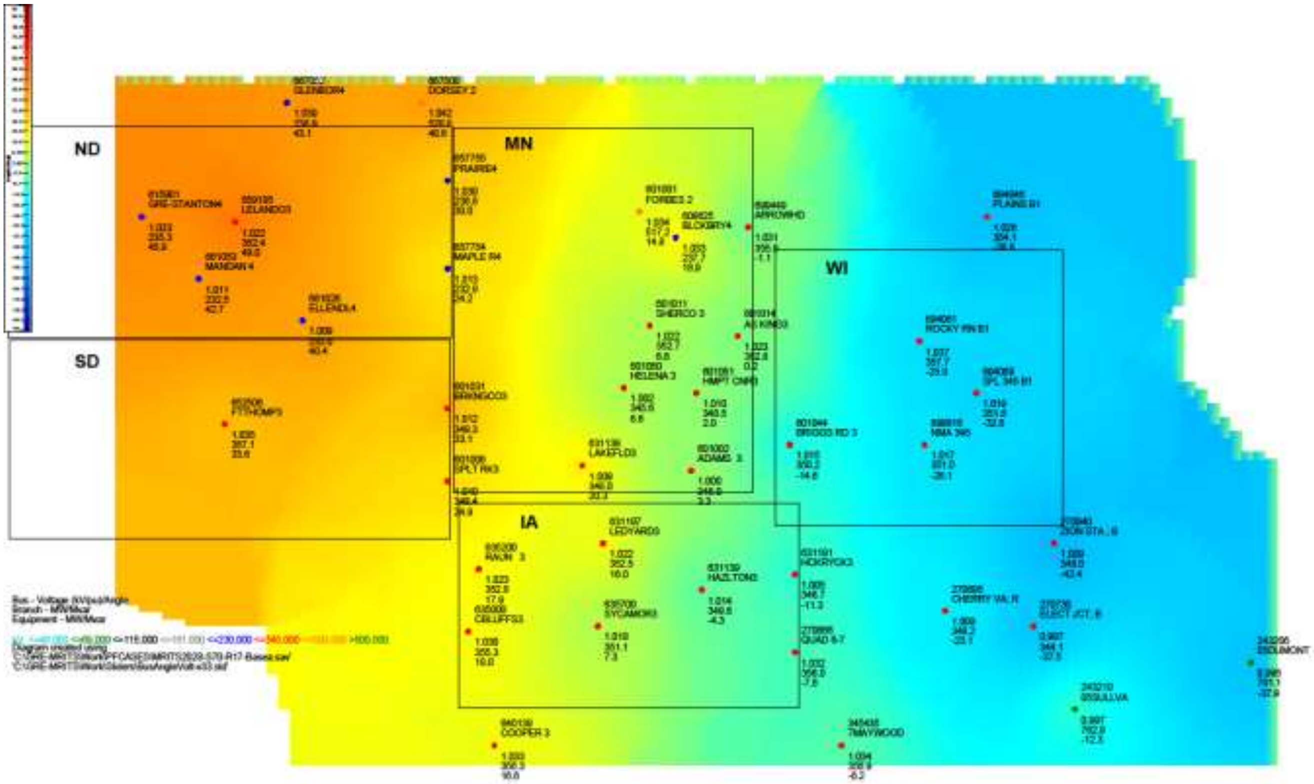

Figure 4-1 Bus Angles from MRITS2028-S70-R17-Basea SCED Model

4.2.1.3 Scenario S1

Similar to some of the generation in Baseline, all of Scenario S1 generation was dispatched to the MISO footprint and the following models were created for S1 Scenario.

S70 -	Summer Off-Peak (70%) S1	MRITS2028-S70-R20-S1.sav
SUM -	Summer Peak S1	MRITS2028-SUM-R20-S1.sav

Figure 4-2 shows how the bus angles change during the Off-Peak condition in the Upper Midwest as the generation was added from Baseline to S1.

As shown in the Bus Angle figure, a bus angle change when moving from Northwest to Southeast is a little more extreme than in the Baseline model.

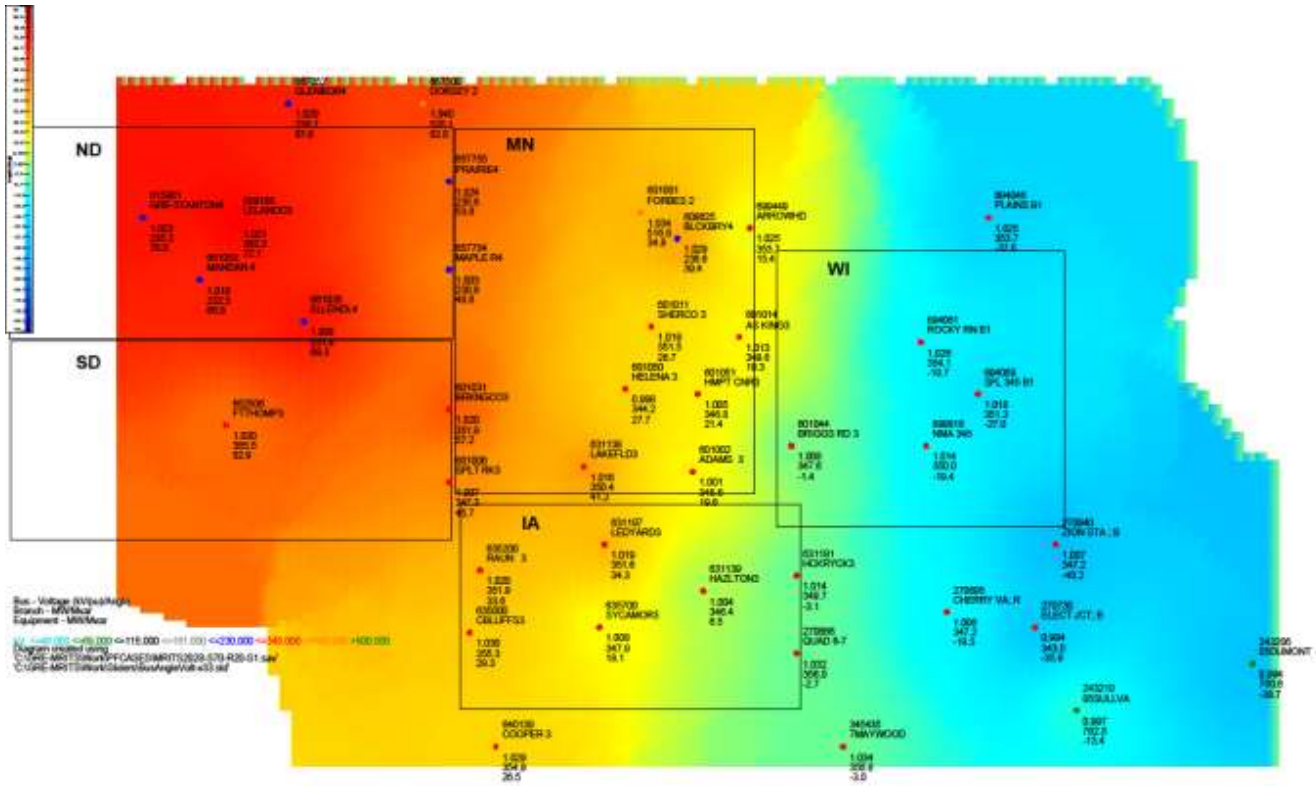

Figure 4-2 Bus Angles from MRITS2028-S70-R20-S1 Model0

Table 4-1 lists mitigation for identified overloads which were required for the S1 Scenario. See Appendices B4 and B6 for the full listing. All costs associated in this report are based on 2014 planning level cost estimates with a ±30 % margin of error.

Table 4-1 S1 Transmission Mitigation

Branch	Possible Mitigation	COST ($M)
Brookings Co-White 345 kV line	WAPA terminal equipment- 1800 MVA	0.50
Cedarsauk-Edgewater 345 kV line	ATC uprate- 750 MVA	1.00
Helena-Scott Co. 345 kV line	XEL rebuild as double circuit	30.00
Ottumwa-Montezuma 345 kV line	ITC uprate- 956 MVA	1.00
Split Rock-White 345 kV line	WAPA terminal equipment- 1195 MVA	1.00
Riverton-Mud Lake 230 kV line	GRE uprate- 383MVA	9.00
98L Tap-Hilltop 230 kV line	MP rebuild - 400 MVA	11.20
Panther-Mcleod 230 kV line	XEL uprate- 391	0.20
Willmar-Granite Falls 230 kV line	GRE rebuild 391MVA	50.00
Hankinson-Wahpeton 230 kV line	OTP uprate- 361 MVA	0.30
Briggs Road-Mayfair 161 kV line	XEL rebuild- 400 MVA	10.00
Drager-Grand Junction 161 kV line	CBPC rebuild- 326 MVA	37.50
Boone Jct-Fort Dodge 161 kV line	MEC / CIPCO rebuild- 326 MVA	62.50
Hazleton-Dundee 161 kV line	ITC terminal equipment- 326 MVA	0.20
Liberty-Dundee 161 kV line	ITC rebuild- 326 MVA	6.50
Wabaco-Rochester 161 kV line	DPC rebuild - 400 MVA	10.90
43L Tap-Laskin 138 kV line	MP rebuild - 200 MVA	3.00
Wilmarth-Swan Lake 115 kV line	XEL terminal equipment- 144 MVA	0.20
Wilmarth-Eastwood 115 kV line	XEL uprate- 310 MVA	3.00
Souris-Velva Tap 115 kV line	XEL terminal equipment- 144 MVA	0.20
Monticello-Oakwood 115 kV line	XEL rebuild- 310 MVA	12.00
Black Dog-Wilson 115 kV line	XEL terminal equipment- 310 MVA	0.20
Chisago-Lindstrom 115 kV line	XEL upgrade- 400 MVA	0.50
Scott Tap-Scott Co. 115 kV line	XEL Rebuild- 310 MVA	2.00
Hassan-Oakwood 115 kV line	XL rebuild- 310 MVA	7.00
Velva Tap-McHenry 115 kV line	XEL terminal equipment- 144 MVA	0.20
Hibbard-Winter St 115 kV line	MP rebuild - 240 MVA	3.00
Etco-Forbes 115 kV line	MP rebuild - 200 MVA	3.00
Forbes-Iron Tap 115 kV line	MP rebuild - 200 MVA	3.00
Hibbing-44L Tap 115 kV line	MP terminal equipment- 80 MVA	0.20

Branch	Possible Mitigation	COST ($M)
Iron Tap-Tbird 115 kV line	MP rebuild - 200 MVA	3.00
Tbird-37L Tap 115 kV line	MP rebuild - 200 MVA	3.00
Blackberry-Panasa Naswak 115kV	MP upgrade- 240 MVA	2.16
Rugby OTP-Rugby CPC 115 kV line	OTP rebuild - 200 MVA	1.00
Halliday-Beulah 115 kV line	WAPA terminal equipment- 144 MVA	0.20
Rugby-Rugby CPC 115 kV line	BEPC rebuild - 200 MVA	1.00
Johnson Jct-Morris 115 kV line	GRE terminal equipment- 99 MVA	0.20
Johnson Jct-Ortonville 115 kV line	OTP/MRES rebuild - 200 MVA	16.00
Fort Randall-Spencer 115 kV line	WAPA terminal equipment 144 MVA	0.20
Blaisdell-Palermo 115 kV line	BEPC rebuild - 200 MVA	8.00
Logan-SW Minot 115 kV line	BEPC rebuild - 200 MVA	7.00
Hazel Creek 345/230 kV Tx #6	XEL add 2nd 336 MVA transformer	6.00
Stone Lake 345/161 kV Tx #9	XEL replace with 448 MVA transformer	7.50
Eau Claire 345/161 kV Tx #9 & 10	XEL replace BOTH with 448 MVA transformers	15.00
Lyon Co 345/115 kV Tx #1	XEL add 2nd 448 MVA transformer	7.50
McHenry 230/115 kV Tx #1	GRE replace with 187 MVA transformer	2.00
LaCrosse 161/69 kV Tx #1 & 2	XEL replace BOTH with 112 MVA transformers	3.20
Marshland 161/69 kV Tx #1 & 2	XEL replace BOTH with 112 MVA transformers	3.20
Gravel Isle 161/69 kV Tx #5 & 6	XEL replace BOTH with 112 MVA transformers	3.20
West Faribault 115/69 kV Tx #1 & 2	XEL replace BOTH with 140 MVA transformers	3.60
Paynesville 115/69 kV Tx #1 & 2	XEL replace with 70 MVA transformer	2.80
Prentice 115/69 kV Tx #5	XEL replace with 70 MVA transformer	1.40
Holcombe 115/69 kV Tx #1	DPC replace with 70 MVA transformer	1.40
Glendale 115/69 kV Tx #1 & 2	GRE replace Both with 112 MVA BOTH transformers	3.20
	Add breakers at Arrowhead 115kV bus*	2.00
	Total Cost	**373.06**

* To mitigate the contingencies that remove the full 115 kV bus sections, install a breaker-and-half scheme

The map in Figure 4-3 shows all the mitigation required to fix the transmission concerns for dispatching S1 generation to the MISO Footprint. The mitigations are spread throughout the study region.

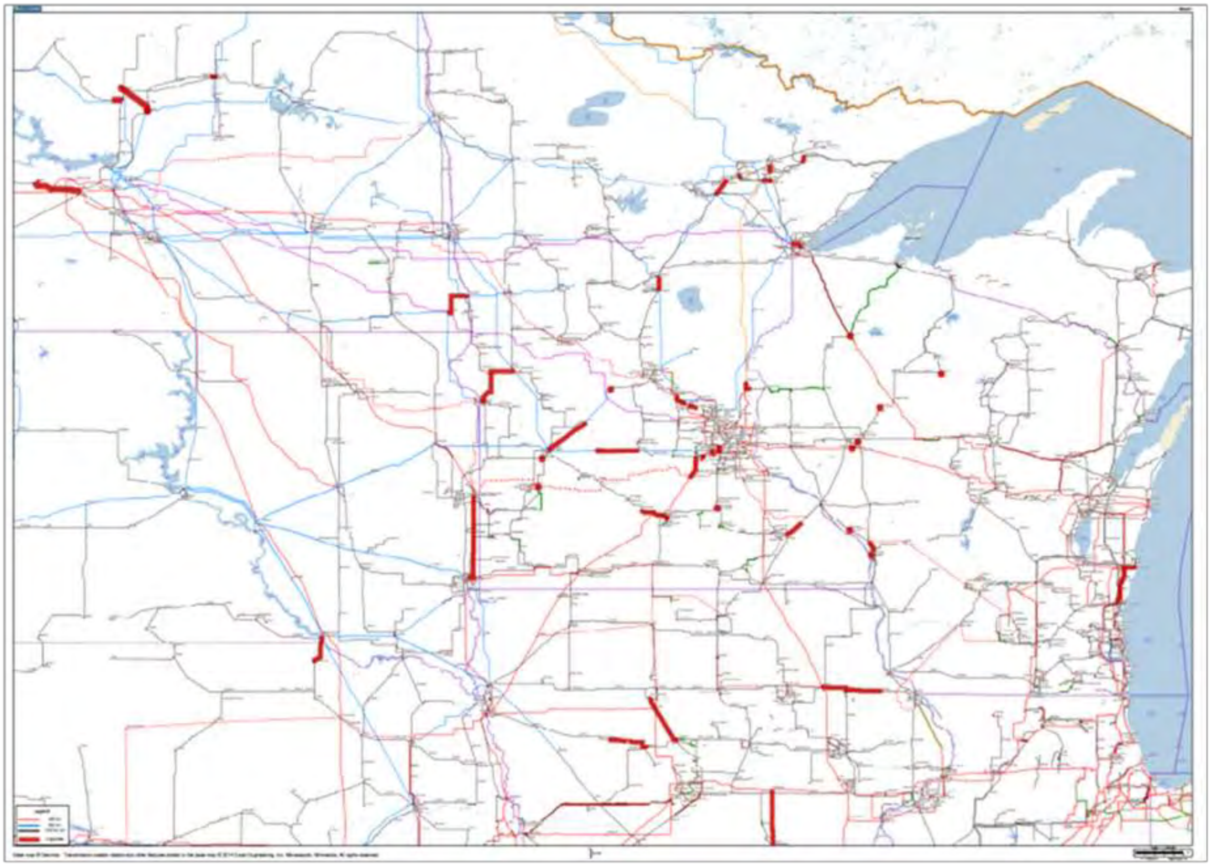

Figure 4-3 S1 Transmission Mitigation Map

The S1 powerflow cases were repeated to verify transmission upgrade results and ensure that the mitigations didn't cause subsequent cascading issue on the system. These mitigations are considered conceptual at this point and thus have not been optimized where, for example, one upgrade or a new facility may alleviate one or more of the identified overloads. Thus, further study would be required for the identification of the most practicable upgrade to alleviate these violations. These 54 mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade the facilities.

4.2.1.4 S2 Scenario

The S2 Scenario generation could not be added or dispatched to the MISO footprint similar to Scenario 1 without making some changes and/or additions to the Scenario 1 models primary due to the large amount of renewable generation (17245 MW) being added to the model. The generation addition created an extensive number of violations during system intact conditions along with some extreme contingencies that were difficult to solve.

Figure 4-4 shows an extreme difference in how the bus angles change during the Off-Peak condition in the Upper Midwest as the generation is added from S1 to S2.

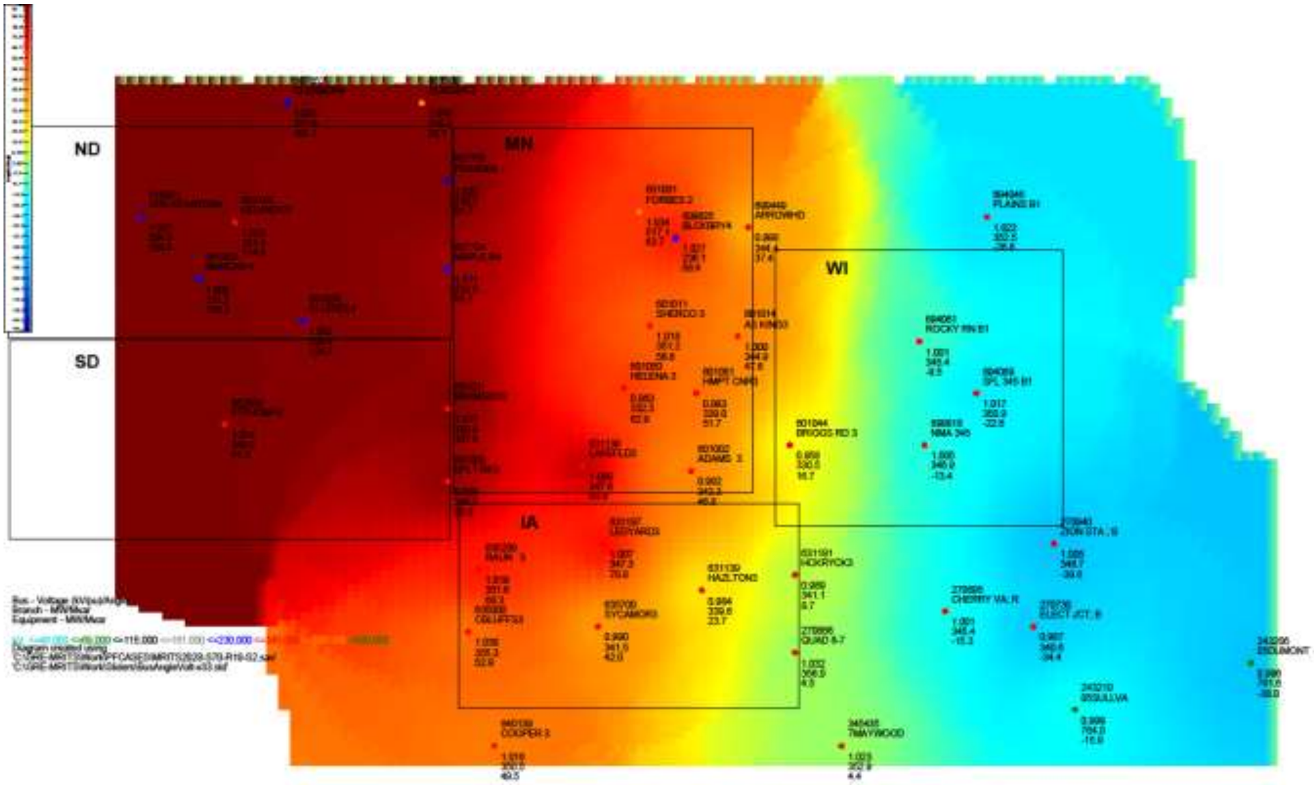

Figure 4-4 Bus Angles from MRITS2028-S70-R19-S2 Model

4.2.2 Scenario 2

4.2.2.1 Transmission Expansion

In order to get the additional S2 17,245 MW of generation necessary to increase the MN RES to 50% and MISO states collectively to 25% into the case, the transmission expansion projects shown in were included. These expansions are also shown on the map in Figure 4-5.

Figure 4-6 shows how the bus angles change during the Off-Peak condition in the Upper Midwest when added the S2 Transmission Expansion. The change occurs mostly in the area east and southeast of Minnesota.

The cases used with these changes were:

S70 -	Summer Off-Peak (70%) S2	MRITS2028-S70-R19-S2-Trans.sav
SUM -	Summer Peak S2	MRITS2028-SUM-R19-S2-Trans.sav

Table 4-2 S2 Transmission Expansion

Branch	COST ($M)
Corridor Project (rebuilding existing 230 kV line to 345 kV) Hazel Creek-Panther-Mcleod-Blue Lake double circuit 345 kV line	466.00
Iron Range-Arrowhead 345 kV line	182.00
Sheldon-Eau Claire-Alma-Adams-Killdeer 345 kV line	700.00
Blackhawk-Montezuma 345 kV line	196.00
Big Stone South-Hazel Creek 345 kV line	200.00
Bison-Alexandria-Quarry-Monticello 345 kV line #2(dbl circuit CapX2020)	204.10
Brookings Co-Lyon Co 345 kV line #2(dbl circuit CapX2020)	58.00
Helena-Chub Lake-Hampton 345 kV line #2(dbl circuit CapX2020)	47.00
Hampton-North Rochester-Alma 345 kV line #2(dbl circuit CapX2020)	75.00
Total Cost	**$2,128.10**

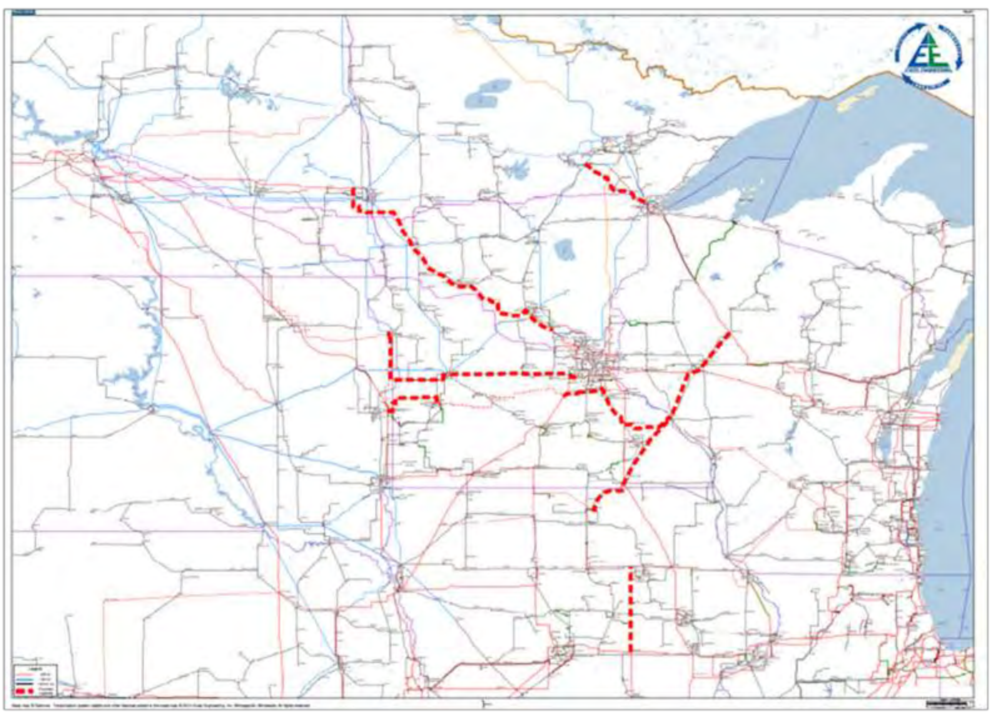

Figure 4-5 S2 Transmission Expansion Map

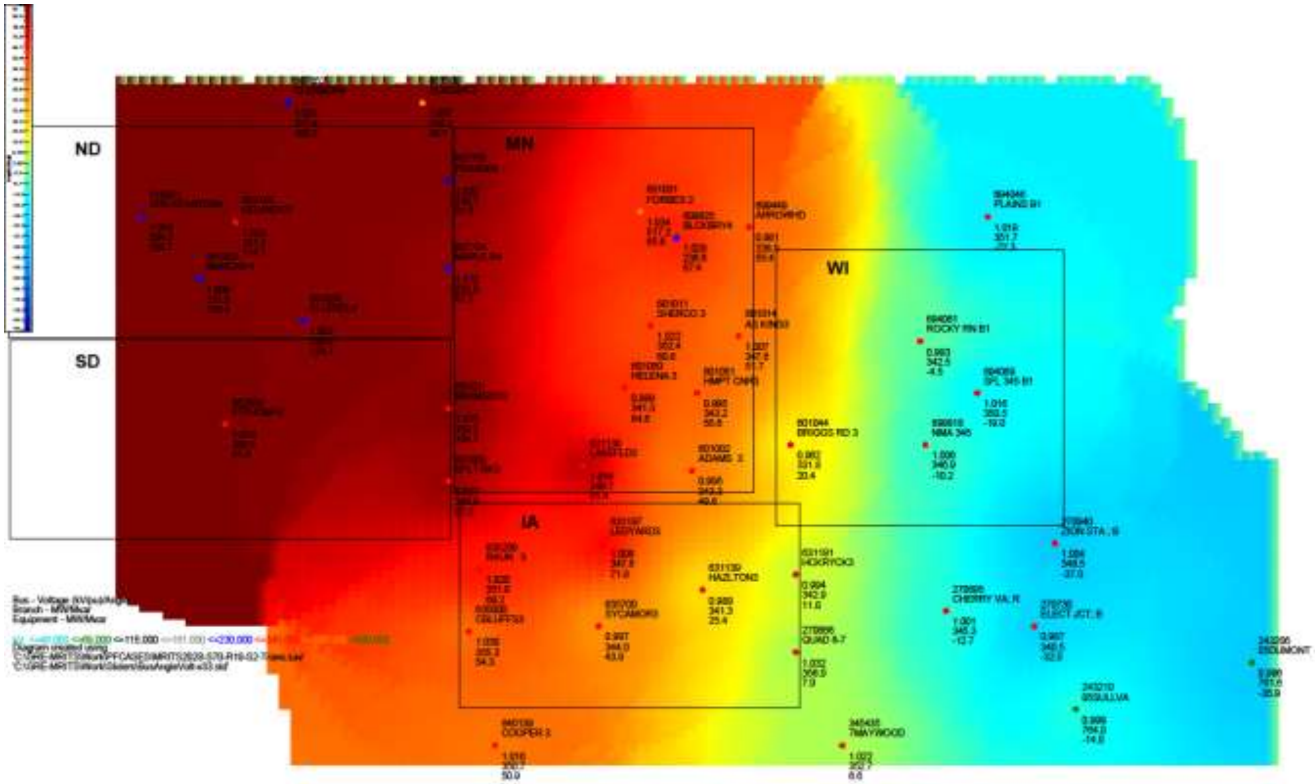

Figure 4-6 Bus Angles from MRITS2028-S70-R19-S2-Trans Model

4.2.2.2 SCED and Top 4 to Bottom 10

Even after the transmission expansion was added to the models, there were still concerns with the amount of equipment overload violations in the model along with some outages not allowing the model to solve. The MRITS task force decided to perform SCED on the S2 cases with the S1 mitigation and the S2 transmission expansion. MISO performed the SCED on models. The cases used for the S2 results were:

S70 -	Summer Off-Peak (70%) S2	MRITS2028-S70-R19-S2-Trans-R2-SCED-A.sav
SUM -	Summer Peak S2	MRITS2028-SUM-R19-S2-Trans-R2-SCED-A.sav

Based on the Production Cost Modeling results, it was noted that several of the wind generation sites from the MRITS Wind-Solar Siting were causing overloads in the thermal case were also congested and thus restricted in the production modeling. The MRITS TRC decided that the top 4 congested non-Minnesota centric generation sites would have generation reduced and moved to the bottom 10 least congested non-Minnesota centric generation sites (T4B10) (as described in the Siting Section). The resulting new S2 cases were:

S70 -	Summer Off-Peak (70%) S2	MRITS2028-S70-R19-S2-Trans-R2-SCED-A-T4B10.sav
SUM -	Summer Peak S2	MRITS2028-SUM-R19-S2-Trans-R2-SCED-A-T4B10.sav

Figure 4-7 shows how the bus angles change during the Off-Peak condition in the Upper Midwest when the S2 Transmission Expansion is added with SCED of S2 generation and the Top4-Bottom10.

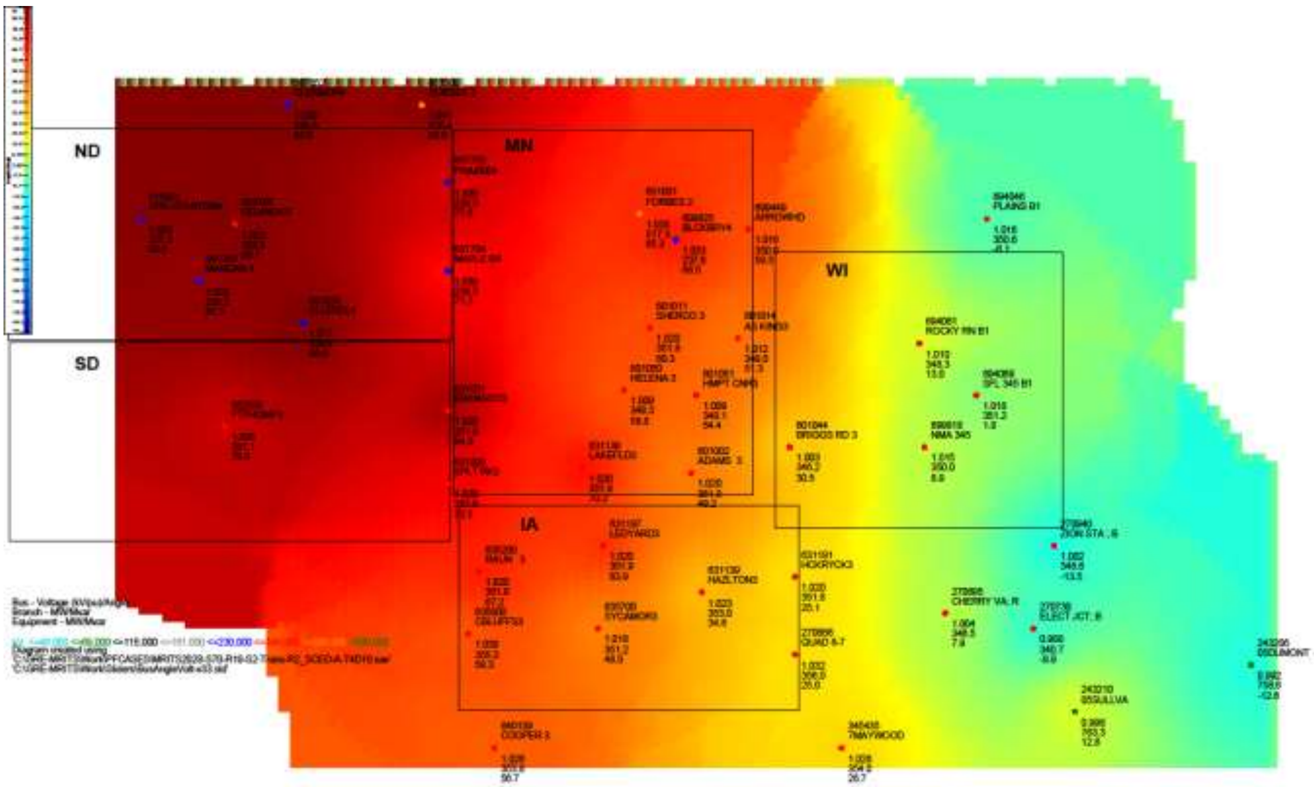

Figure 4-7 Bus Angles from MRITS2028-S70-R19-S2-Trans-R2-SCED-A-T4B10 Model

In addition to the S2 Transmission Expansions ($2.128B from) and moving some wind generation from the top 4 congested sites to the bottom 10 least congested non-Minnesota centric generation sites, steady state thermal analysis results identified transmission mitigation for the S2. The S2 additional mitigations are shown in Table 4-3. The locations are shown in Figure 4-8. See the Appendix for the full listing (available upon request from GRE).

Table 4-3 S2 Transmission Mitigation

Branch	Possible Mitigation	COST ($M)
Gardner Park-Sheldon 345 kV line	ATC uprate to 1219 MVA	10.00
Sioux City-Twin Church 230 kV line	NPPD rebuild 390 MVA	37.76
McHenry-Coal Creek Tap 230 kV line	GRE rebuild 450 MVA	78.08
Lakefield-Dickenson Co. 161 kV line	ITC Rebuild 400 MVA	26.75
Triboji-Dickenson Co. 161 kV line	ITC Rebuild 400 MVA	3.00
Huntley-Freeborn 161 kV line	ITC Rebuild 400 MVA	47.88
Webster-Wright 161 kV line	MEC Rebuild 400 MVA	14.75
Alma-Lufkin 161 kV line	DPC Rebuild - 400 MVA	31.50
La Crosse-Mayfair 161 kV line	XEL Rebuild 400 MVA	4.63
Devils Lake-Ramsey 115 kV line	GRE Uprate 120 MVA	0.50
Velva Tap-GRE McHenry 115 kV line	XEL Rebuild310 MVA	5.20
Souris-Velva Tap 115 kV line	XEL Rebuild310 MVA	19.60
Sheldon Pump-Osprey 115 kV line	XEL Rebuild310 MVA	20.90
Osprey-Hawkin 115 kV line	XEL Rebuild 310 MVA	14.00
Hutch McLeod-Hutchinson 3M 115 kV line	GRE Rebuild 310 MVA	5.20
Hutch Muni-Hutchinson 3M 115 kV line	GRE Rebuild 310 MVA	1.10
Sioux City 345/230 kV Tx 1	WAPA replace with a 2x336 MVA transformer	12.00
Stone Lake 345/161 kV Tx 9	XEL modified S1 mitigation, but adding a 2nd 336 MVA transformer rather than replacing	-
GRE McHenry 230/115 kV Tx #1	GRE replace with 224 MVA transformer	4.00
GRE Spring Creek 161/69 kV Tx #2	GRE replace BOTH with 112 MVA transformers	3.20
Prairie 115/69 kV Tx #2	MPC add 69 kV breakers	2.00
GRE St. Boni 115/69 kV Tx #1	GRE replace with 112 MVA transformer	1.60
Split Rock 345/115 kV Tx # 11	XEL add 3rd 448 MVA transformer	7.50
	Total Cost	**351.14**

As seen in Figure 4-8, the mitigations are spread throughout the study region and there is a recognition that there may have been more system overloads outside the study monitor area.

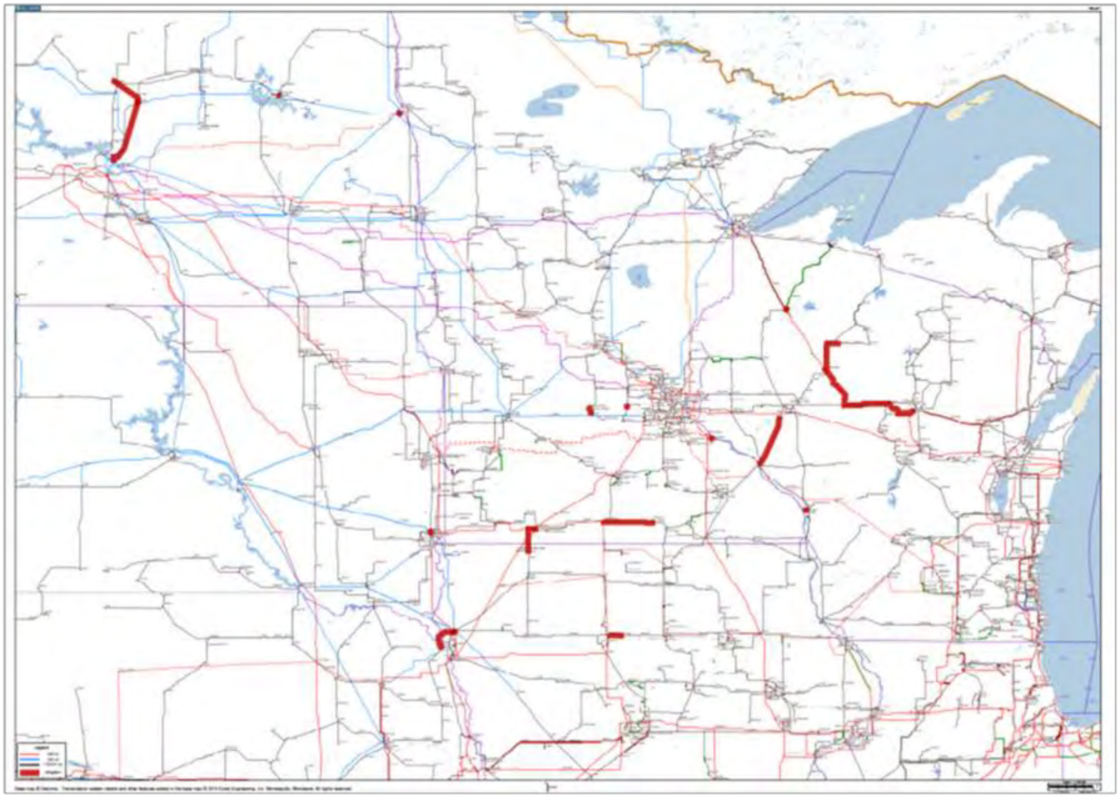

Figure 4-8 Transmission Mitigation Map

The S2 powerflow cases were repeated to verify transmission upgrade results. The transmission expansions and mitigations are considered high-level and conceptual at this point and thus have not been intensively analyzed and compared with other alternative mitigations nor have the projects been optimized where, for example, one upgrade or a new facility may alleviate one or more of the identified overloads.

Thus, further study would be required for the identification of the most practicable expansion or upgrade to alleviate these specific violations or widespread grid issues. These upgrades would require coordination with study and validation by MISO and other utilities. These 9 expansions and 23 mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade and build the facilities.

4.2.2.3 Production Cost Mitigation

Following the steady state power flow modeling which produced the transmission expansions and mitigations, Production Cost Modeling was performed to determine if any additional transmission facilities should be upgrades to help alleviate market congestion. This generation siting shift assisted in producing a more reliable and efficient market system. Table 4-4 lists mitigations from the production cost analysis. See the Appendix for the full listing (available upon request from GRE).

Table 4-4 S2 Transmission Mitigations from Production Cost Analysis

Branch	Possible Mitigation	COST ($M)
Blackhawk SW Yd-Colley Rd 138 kV line	ATC Rebuild- 400 MVA	1.95
Adams 161/69 kV Tx #1 112MVA	ITC replace with 112 MVA transformer	1.60
Huntley (Winnebago) 161/69 kV Tx #1 70 MVA	ITC replace with 70 MVA transformer	1.40
NW Beloit-Paddock 138 kV line	ATC Rebuild- 400 MVA	3.15
Hankinson-Wahpeton 230 kV line	OTP Rebuild- 430 MVA	40.80
Wapello Co.-Jeff 161 kV line	ITC Rebuild- 400 MVA	33.90
Blue Earth Tap-Huntley (Winnebago) 161 kV line	ITC Rebuild- 400 MVA	5.25
	Total Cost	**88.05**

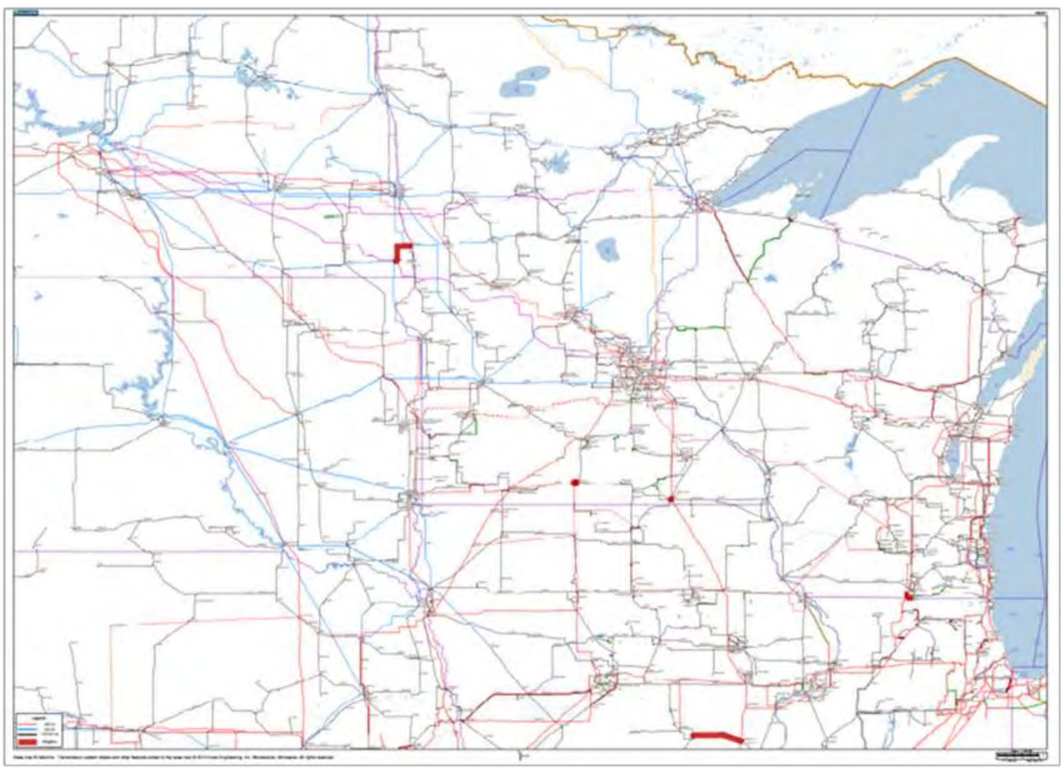

Figure 4-9 Map of S2 Transmission Mitigations from Production Cost Analysis

4.2.2.4 HVDC Transmission

Given the large number and magnitude of 345 kV mitigations identified for Scenario 2, it was decided to conduct a mitigation sensitivity using a HVDC design to deliver the non-MN MISO wind located in western MISO to eastern MISO. This HVDC multi-terminal line design was guided by Bus Angles shown in Figure 4-4 in order to connect the HVDC terminals to the extreme angle differences (Red and Blue). The HVDC line was approximately 800 miles long and operated at 600 kVdc with two converter buses located at Brookings County and O'Brien County and two invertor buses located Breed (Sullivan) and Dumont.

All runs were done only on the off-peak (S70) case and were not optimized in any form, but to be used as a reference. The line was tested at 2000, 2500, 3000 and 3500 MW. The cases used in the review were:

2000 MW	MRITS2028-S70-R19-S2-HVDC-2000.sav
2500 MW	MRITS2028-S70-R19-S2-HVDC-2500.sav
3000 MW	MRITS2028-S70-R19-S2-HVDC-3000.sav
3500 MW	MRITS2028-S70-R19-S2-HVDC-3500.sav

Figure 4-10 is a map showing the HVDC line location and the four terminals (red dots).

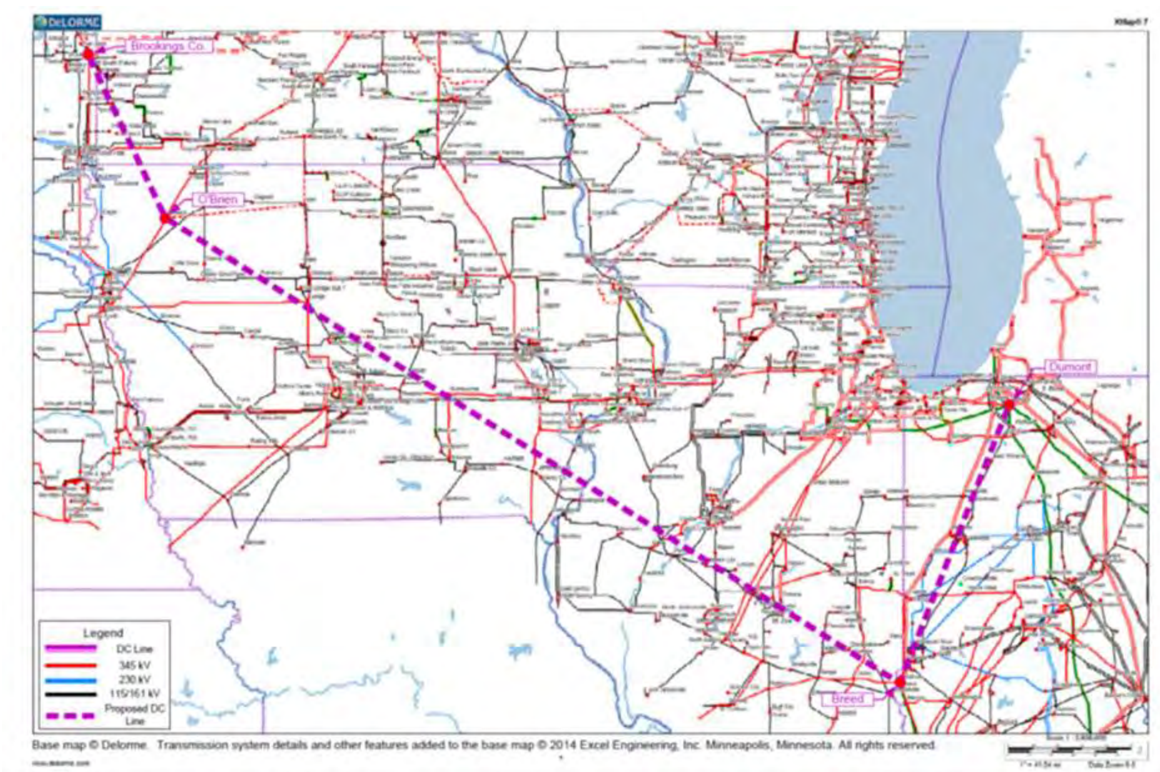

Figure 4-10 HVDC Transmission Map

The HVDC line transferred a significant amount of power from the converter terminals in the west, where a major amount of the MRITS Wind-Solar Siting were located at or near those terminals. If future wind would be developed further away from the HVDC terminals, the HVDC Transmission Expansion option would not be as efficient at transferring power from Western MISO to Eastern MISO and other transmission upgrades would likely be needed to get the new wind to the HVDC terminals. Contingency or Outage of the HVDC line as full, two-pole, or partial, single pole was not evaluated during this study. These outages would require an extensive study and thus was not conducted. We do know from previous work in this study that the ac transmission system could not accommodate all the S2 generation without some additional transmission, so some level of generation runback/tripping or ac transmission expansion would be required in the case of a single or double pole HVDC outage. The estimated cost for a four terminal 3500 MW HVDC for this distance would be approximately $3 Billion. See the Appendix for the full listing (available from GRE upon request).

An undetermined portion of the HVDC estimated cost could be allocated to central and eastern portions of MISO to help meet their respective RPSs.

Table 4-5 lists the ac transmission mitigation required beyond S1 mitigation and the HVDC at 3500 MW. This is an increase in $280M of mitigation beyond the S1 mitigations. This table does not include mitigations for the outage of the HVDC.

Table 4-5 S2 AC Transmission Mitigations required with HVDC Option

Branch Violation	Contingency	COST ($M)
Hazelton-Mitchell Co. 345 kV line	ITC/ MEC Upgrade- 1464 MVA	201.60
McHenry-Coal Creek Tap 230 kV line	GRE upgrade- 637 MVA	78.08
McHenry-Balta 230 kV line	GRE upgrade- 480 MVA	69.44
Big Stone-Big Stone South 230 kV line	OTP upgrade- 831 MVA	5.00
Oakes-Ellendale 230 kV line	OTP upgrade- 480 MVA	38.40
Blair-Watertown 230 kV line	WAPA upgrade- 480 MVA	46.40
Briggs Road-Mayfair 161 kV line	XEL upgrade- 434 MVA	10.00
Lacrosse-Mayfair 161 kV line	XEL upgrade- 434 MVA	4.63
Wheaton-Elk Mound 161 kV line	XEL upgrade-434 MVA	4.50
Beaver Creek-Adams 161 kV line	DPC upgrade- 434 MVA	18.88
Wabacco-Alma 161 kV line	DPC upgrade- 434 MVA	25.38
Swan Lake-Fort Ridgely 11 kV line 5	XEL upgrade- 232 MVA	13.20
Franklin-Redwood Falls 115 kV line	XEL upgrade- 232 MVA	12.80
MN Valley-Redwood Falls 115 kV line	XEL upgrade- 232 MVA	27.80
Lawrence Creek-Shafter 115 kV line	XEL upgrade- 350 MVA	6.10
Lindstrom-Shafer 115 kV line	XEL upgrade- 319 MVA	2.80
Big Stone-Highway 12 115 kV line	OTP upgrade- 319 MVA	2.00
Highway 12-Ortonville 115 kV line	OTP upgrade- 319 MVA	4.50
Hoot Lake-Fergus Falls 115 kV line	OTP upgrade- 232 MVA	4.20
OTP Forman-WAPA Forman 115 kV line	OTP upgrade- 232 MVA	0.20
Devils Lake SE-Ramsey 115 kV line	OTP upgrade- 232 MVA	0.20
Aberdeen Jct-Ellendale 115 kV line	NWE upgrade- 232 MVA	39.00
Iron Range 500/230 Tx	MP upgrade- 1043 MVA	0.00
Forman 230/115 Tx	WAPA replace w/ 180 MVA transformer	2.00
Big Stone South 345/230 Tx #1 & 2	OTP replace BOTH w/ 800 MVA transformer	15.00
Big Stone South 230/115 Tx	OTP replace with 390 MVA transformer	6.00
	Total Cost	**630.60**

4.3 Conceptual Transmission Conclusions

The model building for the steady state thermal analysis involved significant transmission and generation additions and load increases to reflect the Baseline assumptions of the present MISO state RPSs in a 2028-2030 timeframe along with the planned transmission and generation build-outs.

The generation dispatch involved a combination of methodologies to best represent the future system grid which accommodated the lowest fuel cost generation units and future contracts while maintaining system reliability.

The Scenario 1 Transmission Mitigations, as identified with steady state thermal powerflow analysis, to accommodate an increase wind and solar generation necessary to increase the MN RES to 40% involved 54 facilities with a total estimated cost of $373M.

The Scenario 1 mitigations are considered conceptual at this point and thus have not been optimized and thus further study would be required for the upgrading/mitigation of these violations. These 54 mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade the facilities.

To reliably accommodate the addition of 17,245 MW of Scenario 2 generation necessary to increase the MN RES to 50% and MISO states collectively to 25% into the case and alleviate widespread system issues, a significant amount of transmission expansions were identified and included in the S2 models. These expansions involved 9 facilities with a total estimated cost of $2,128M.

Even with the S2 expansions identified above, there were still concerns with the high number of facility overloads and violations, it was noted that several of the wind generation sites from the MRITS Wind-Solar Siting were causing market congestion and it was decided that the top 4 congested non-Minnesota centric generation sites would have generation reduced and moved to the bottom 10 least congested non-Minnesota centric generation sites (T4B10). This generation siting shift assisted in producing a more reliable and efficient market system.

In addition to the S2 Expansions and moving some wind generation from the top 4 congested sites to the bottom 10 least congested non-Minnesota centric generation sites, steady state thermal powerflow analysis still identified Scenario 2 Transmission Mitigations, involving 23 facilities with a total estimated cost of $351M.

The Production Cost Modeling & Analysis showed market congestion caused by the overload of several facilities. These congestion points in the MN Centric area were selected for mitigation and these involved 7 facilities with a total estimated cost of $88M.

The total Scenario 2 expansions and upgrades involved 39 projects at an estimated cost of $2,567M. The cost of the Scenario 1 mitigations should be added to the S2 costs in order to accommodate a MN RES of 50% and a MISO collective RPS of 25%. It should be noted that an undetermined portion the S2 transmission expansions and upgrades are likely due to the non-MN MISO renewables and not exclusively for the MN renewables. No effort was made to separate these costs into those assigned to MN Renewables and those to non-MN MISO renewables.

Table 4-6 Scenario Transmission Cost Breakdown

	Expansion Costs ($M)	Mitigation Costs ($M)	Market Mitigation Costs ($M)	Total Costs ($M)
Scenario 1	$0	$373	$0	**$373**
Scenario 2	$2,128	$351	$88	**$2,567**

An alternative to the above expansions and mitigations, a high level HVDC line was tested as a sensitivity. The modeled 600 kV HVDC line was about 800 miles long and with converter buses located at southeastern South Dakota and northwest Iowa and two inverter buses located northern and southern Indiana. The estimated cost of this HVDC project was approximately $3B and still required 26 mitigations with an estimate cost of approximately $631M for a total HVDC portfolio cost of approximately $3.6B, which is approximately a 40% increase over the ac mitigation portfolio).

The transmission expansions and mitigations are considered high-level and conceptual at this point and thus have not been intensively analyzed nor optimized thus, further study would be required for the identification of the most practicable expansion or upgrade and would likely change as the wind is actually developed. These upgrades would require coordination with MISO and other utilities. These transmission expansions and mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade and build the facilities.

This study builds upon several previous state mandated renewable related studies and the analysis and results have demonstrated the regional nature and benefits of the grid and the operating market.

5 DYNAMIC SIMULATION MODEL

This section documents the data source for the dynamic modeling, benchmarking of the model, modifications made to represent the future high-renewable scenarios and criteria for evaluating stability simulations.

5.1 Data Sources and Benchmarking of Dynamic Models

The original data for dynamic analysis provided by the Minnesota utilities was based on an MTEP 2013 data set. The following files were provided:

Powerflow data in PSS/E raw data format: *2023_SH_2013DPP_August_Pre-DPP.raw*

Case comments:

2023 SHOULDER LOAD CASE

AUG 2013 DPP BASE CASE, PRE DPP

Dynamic data in PSS/E dyre data format: 2018_final_2.dyr

Contingency description files provided in PSS/E response file (.idv) format

These files were converted to GE PSLF format and tested by simulating the benchmark contingencies listed in Table 5-1. Simulations were compared to results obtained using a similar database in PSS/E. Simulation results were reviewed with the MRITS Technical Team. After some minor modifications to the dynamic data (adding mechanically switched capacitor models), the benchmarking results were deemed acceptable.

Note that the PSLF model does not include custom HVDC controls. Rather, it represents a typical HVDC system. Simulation results were reviewed by Technical Team members to ensure that the simulated HVDC response represented expected response. In particular, commutation failure and blocking was reviewed for disturbances near the HVDC terminals.

Table 5-1 Benchmark Contingencies

Name	Description
EI2	CU HVDC Permanent Bipole fault with tripping of both Coal Creek units.
AG1	SLG fault with breaker fail at Leland Olds on the Ft. Thompson 345 kV line
AG3	3 phase fault at Leland Olds on Ft. Thompson 345 kV line, Clear both ends of the line in 4 cycles
NAD	4cycles 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. Runback bi-poles that terminate at Dorsey
PCS	SLG fault t with breaker fail at King with 8P6 stuck. Trips King-EauClaire-Arpin and King-Chisago 345 kV line

5.2 Dynamic Load Model

After obtaining acceptable benchmarking results, the dynamic data set was modified to include a more detailed representation of the study area loads. The objective of adding a dynamic load model was to capture possible fault-induced delayed voltage recovery issues caused by reduced synchronous generation.

The GE PSLF composite load model CMPLDW was added at all loads greater than 5 MW throughout MISO. The topology of the composite load (shown in Figure 5-1) is intended to give more realistic representation of dynamic load behavior than present practice. The model adds distribution transformer and feeder for each load. The load is then modeled at the distribution bus as a composite of different induction motors, electronic load and static load.

In order to develop parameters for the load model, the Minnesota utilities classified all loads in their service territory. Classifications for non-industrial loads are shown in Table 5-2. Classifications for industrial loads are shown in Table 5-3. Loads not identified by the Minnesota utility were assumed to be either power mixed residential/commercial, or power plant auxiliary. Power plant auxiliary loads were assumed if the load was at a generator bus with a rated voltage less than 30 kV.

The load characteristics used for each individual load were based on the load type using the WECC parameters. In total, the CMPLDW model was added to 2045 loads (37.8 GW for the shoulder period). Note that a different set of parameters was used for the light and shoulder load cases and the peak load case. This was intended to represent the higher level of motor load, particularly air conditioning, during the summer peak load than during spring and fall.

The parameters of the four equivalent motors are particularly important for dynamics, as the tendency for motor groups to stall (or not) during major voltage depressions has a substantial impact on system stability. One of the key features of the composite load model includes the ability to control whether stalled motors trip (by contactors opening) or continue to stay attached drawing starting current. Since the motor stalling behavior in the composite load has such a major and acutely non-linear effect on stability results, for this study, all motor tripping in the composite model is disabled. This is very conservative, and it allows for simpler and more illuminating comparison between dynamic simulation cases.

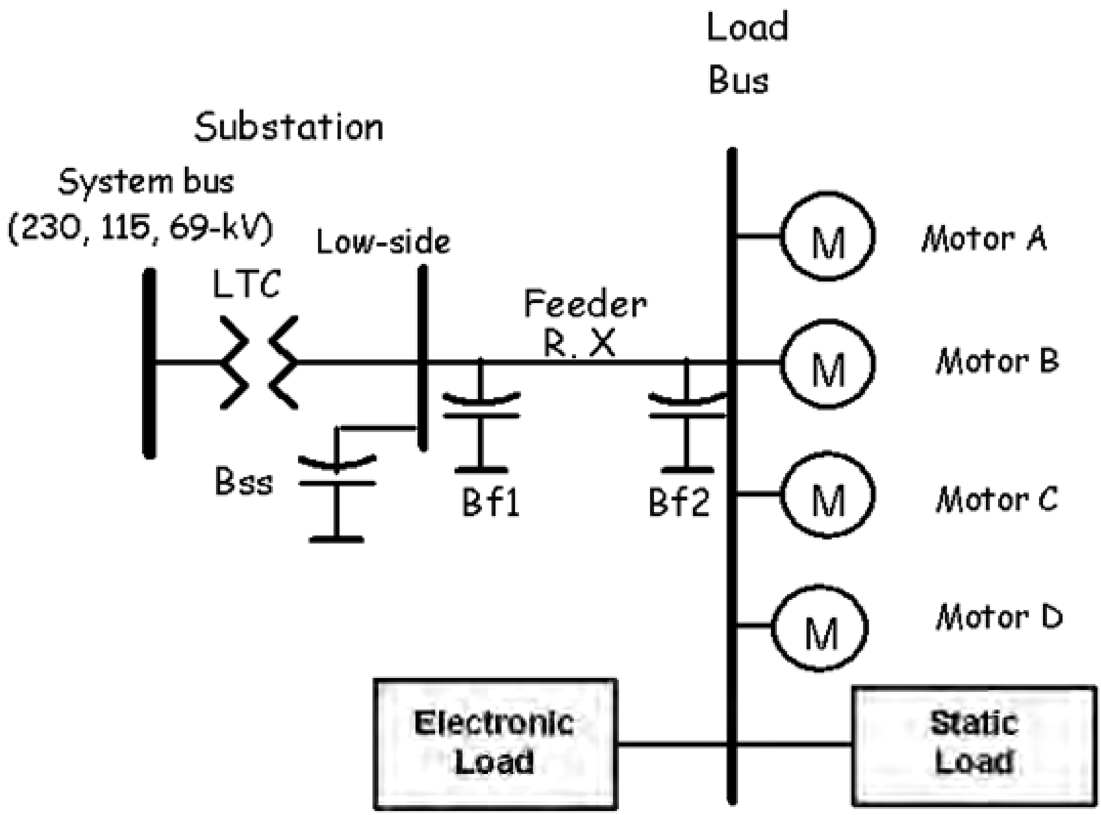

Figure 5-1 GE PSLF Composite Load Model CMPLDW

Table 5-2 Non-industrial Load Types

ID	Feeder Type	Residential	Commercial	Industrial	Agricultural
RES	Residential	70 to 85%	15 to 30%	0%	0%
COM	Commercial	10 to 20%	80 to 90%	0%	0%
MIX	Mixed	40 to 60%	40 to 60%	0 to 20%	0%
RAG	Rural	40%	30%	10%	20%

Table 5-3 Industrial Load Types

ID	Feeder Type
IND_PCH	Petro-Chemical Plant
IND_PMK	Paper Mill – Kraft process
IND_PMT	Paper Mill – Thermo-mechanical process
IND_ASM	Aluminum Smelter
IND_SML	Steel Mill
IND_MIN	Mining operation
IND_SCD	Semiconductor Plant
IND_SRF	Server Farm
IND_OTH	Industrial – Other
AGR_IRR	Agricultural irrigation loads
AGR_PMP	Large pumping stations with synchronous motors
PPA_AUX	Power Plant Auxiliary

5.3 2028 Study Data Sets

The original MTEP data set represented a 2023 shoulder load condition. This data set was modified to establish the 2028 light load, shoulder load and peak load cases. This involved adjusting the load in the MISO areas appropriately to represent 2028 conditions and adding the conceptual transmission plans identified in the thermal and voltage analysis. In going from shoulder load 2023 to 2028, a 0.5% annual load growth was assumed for Minnesota and 0.75% annual load growth was assumed for rest of the MISO. The load in the 2028 shoulder case was then modified to develop a 2028 light load and 2028 peak load case. The new wind and solar generation for each scenario (baseline, S1 and S2) were then added to the 2028 cases.

5.4 Dynamic Models for Renewables

The powerflow topology was modified to interconnect the new wind and utility-scale PV plants and distributed PV. These new plants have two transformations, one for the substation transformer and an equivalent for the unit transformer (from collector voltage to inverter voltage) with an intervening equivalent of the collector system. The arrangement is shown in Figure 5-2.

For dynamic modeling, the utility-scale PV plants are modeled with full four quadrant dynamic models (based on the Type 4 wind turbine generator [WTG] model) with voltage regulation and zero-voltage ride-through (ZVRT). The utility-scale PV plants are modeled with a power factor of ±0.90 at the inverter transformer. This gives an MVA rating of 1.11 times the plant MW rating, and reactive capability of ±0.436pu, based on the MVA rating. New wind plants were split roughly 50/50 between Type 3 double fed asynchronous generator (DFAG) and Type 4 (full converter) with voltage regulation and ZVRT. The new wind plants are modeled with a power factor of ±0.90 at the 690V bus. This gives an MVA rating of 1.11 times the plant MW rating, and reactive capability of ±0.436pu, based on the MVA rating. Both wind and utility-scale PV were set to regulate the 690 V terminal bus. Although advanced WTG controls such as inertial response and frequency response were available in the models, they were assumed to be inactive. Furthermore, they were not required for mitigation during the dynamic analysis task.

Distributed PV was modeled as lumped generation in central locations, based on the siting work. The distributed PV was modeled with no reactive/voltage regulation capability. The ability of the distributed PV generation (DPV) to ride through voltage and frequency excursions is handled by a separate logic. The model allows selection of different levels of voltage and frequency excursion that will result in the DPV blocking. A further part of the logic allows specification of how much DPV will recover if the excursion returns within the user input bounds. The result is a high level of flexibility for modeling fault ride-through. However, the model does not support user input time delays on the blocking functions, and so is limited in its ability to reflect deliberate time thresholds for tripping (e.g., of the type in NERC low voltage ride through (LVRT) and IEEE 1547 standards).

Voltage ride through settings used for the DPV maintained full PV output between 0.90 pu and 1.10 pu voltage. Between 0.90 pu and 0.88 pu voltage, the DPV active power is run back linearly to zero. Below 0.88 pu voltage the PV is blocked. When voltage recovers above 0.9 pu the active power is restored. Similar logic is used for high voltage conditions between 1.1 and 1.2 pu.

Frequency ride through/blocking was modeled similar to voltage ride through/blocking. The DPV retains full output between 59.70Hz and 60.30 Hz. Between 59.70 Hz and 59.50 Hz the DPV active power runs back and is fully blocked below 59.5 Hz. However, unlike the voltage ride-through function, the PV active power does not recover after being blocked due to high or low frequency. There were no time delays model for the voltage or frequency ride through/blocking logic.

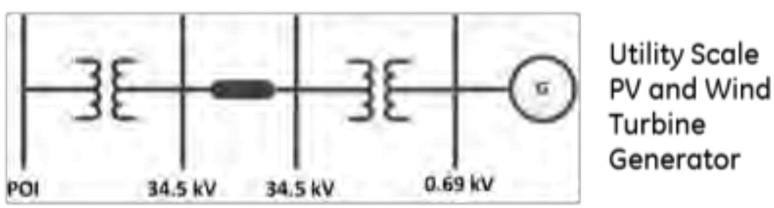

Figure 5-2 Renewable generation topology in powerflow Model

5.5 Monitoring Models and Performance Metrics

In order to quantify the effect of increased renewable generation on the system performance, several sets of metrics are developed. The metrics are geared towards identifying first swing stability, power swing damping and voltage response and recovery following a fault. Rotor angle of generators in the entire Eastern Interconnect are monitored to ensure if the system is transiently stable following each disturbance. Voltages are monitored for 220 kV and above buses throughout MISO.

In addition, a region-wide monitoring approach is used to identify issues that are not apparent from traditional stability plots. In this regard, a new dynamic model is developed to monitor regional performance. Regional metrics include measures such as, total rated MVA, rated MW, actual MW and MVAR and reactive reserves for on-line synchronous generation and renewable generation. System measures such as regional load and interface flows are also monitored. The regional synchronous generation provides information about the short circuit strength of the region while the regional load and generator reactive power provides the understanding about regional voltage recovery following a disturbance. The percentage non-synchronous generation is also calculated from these measurements. These metrics are monitored dynamically and used to compare the high renewable system performance under various load conditions.

The geographical sub-regions and corresponding boundaries are defined based on the group of geographically coherent machines regardless of ownership and state boundaries. Altogether ten geographical subregions are defined for the study wherein six subregions constitute Minnesota Centric Region. Figure 5-3 shows the geographical subregion mapping with the regions shaded green being the Minnesota-Centric region. The assignment was confirmed after discussion with Technical Team members. The subregion assignment is used to evaluate the production simulation (Plexos) output for challenging periods as well as for obtaining the regional metrics for dynamic simulation. The geographical subregion is assigned to every generator in the entire Eastern Interconnect. Furthermore, all equipment including buses, generators, loads, lines, transformers are assigned subregion based on where they fit in the map shown in Figure 5-3. Table 5-4 lists the subregions and the names used to identify them.

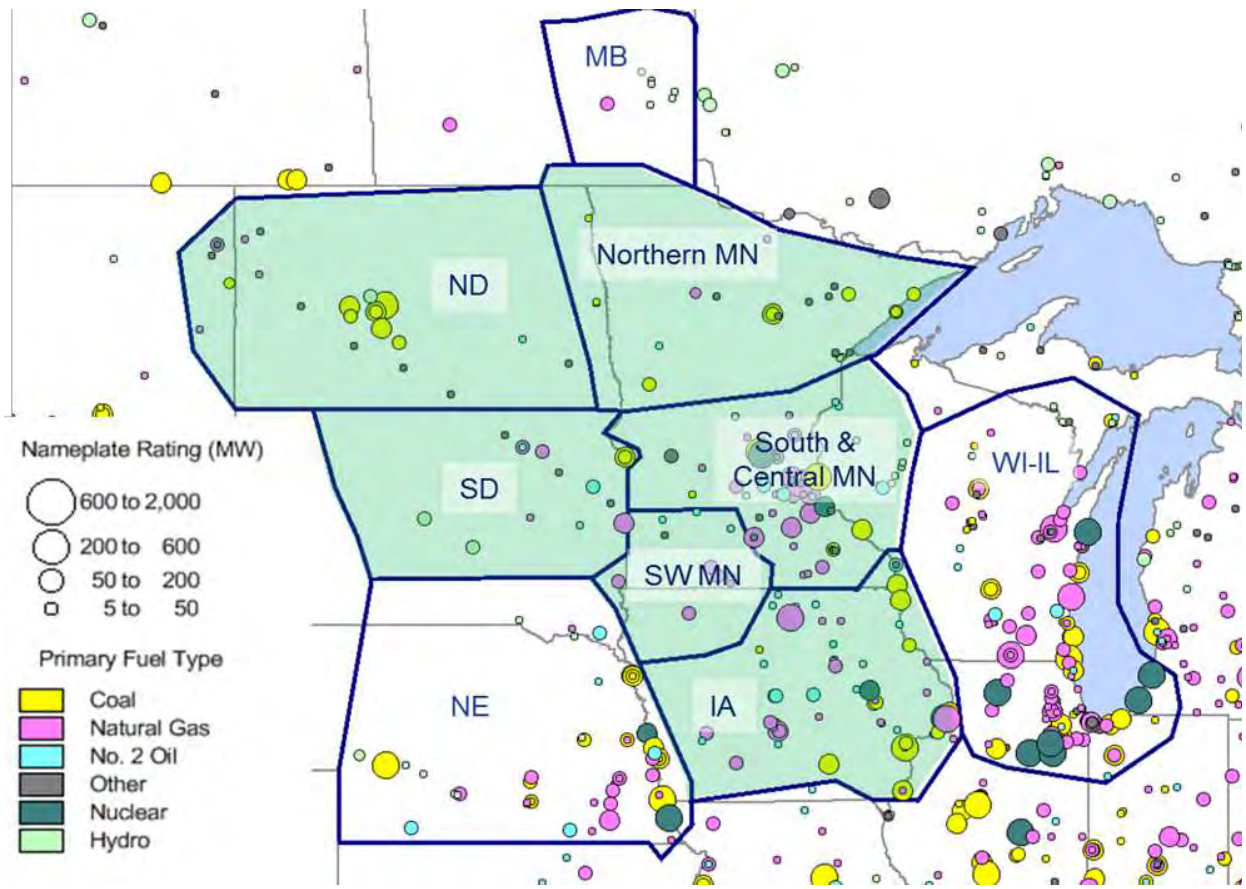

Figure 5-3 Geographical subregions

Table 5-4 Sub region assignment

Sub-Region No.	Name
1	Iowa
2	North Dakota
3	Northern Minnesota
4	South Dakota
5	South & Central Minnesota
6	SW Minnesota
7	Nebraska
8	Wisconsin & Illinois
9	Manitoba
10	Outside

A generic impedance relay model is used on all 220 kV and above the transmission lines throughout Eastern Interconnect. This model is used only for monitoring purpose and will not trip the lines in response to post fault voltage and current.

The instantaneous primary protection zone (Zone 1) is set to cover 85% of the primary line length. Zone 2 protection is delayed by 0.5 seconds and set for 125% of the primary line length. This model was used to identify possible system separation and voltage collapse issues in regions that were not explicitly monitored.

Figure 5-4 shows voltage performance criteria used by WECC. Worst conditions analysis is carried out to identify critical buses with respect to voltage dip and fault induced delayed voltage recovery. All 220 kV and above buses throughout MISO are monitored. With the idea of capturing large post fault transient voltage dip, buses with voltage dip below 20% of initial value for more than 20 cycles are identified. Another criterion is used to screen buses with voltage below 0.7 p.u. after fault clearing. In order not to capture low voltage during stuck breaker faults, where the fault clearing times are longer, the latter criterion is applied 0.15 sec after fault application.

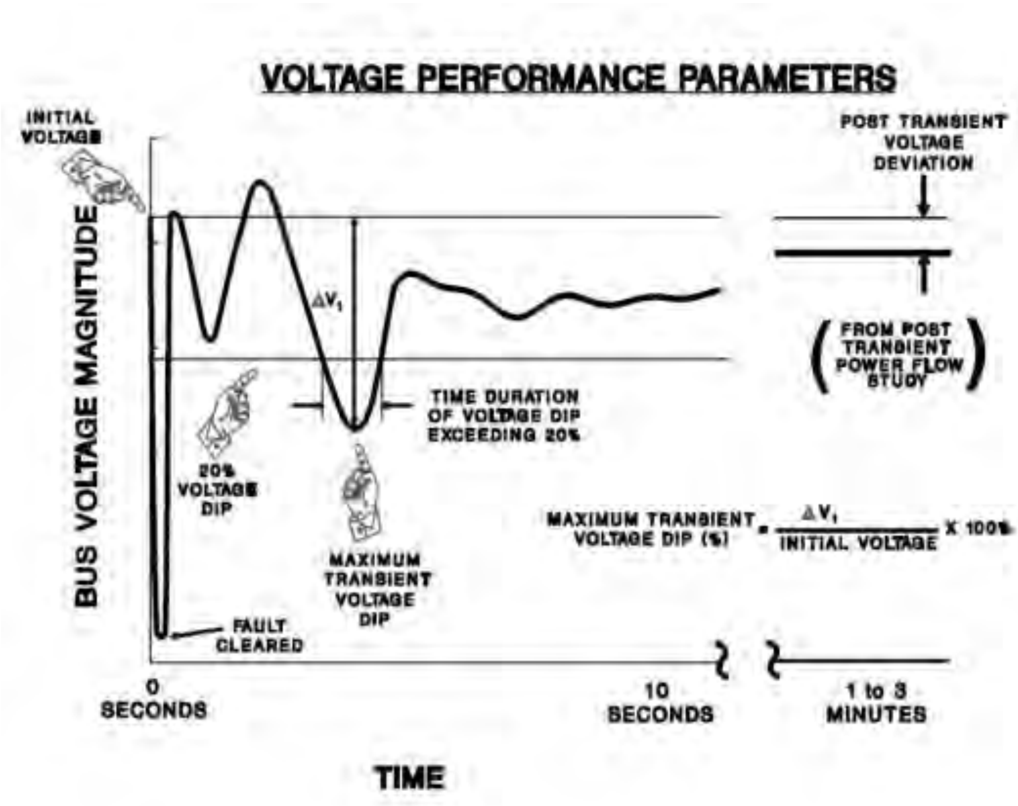

Figure 5-4 Voltage performance metrics

6 PRODUCTION SIMULATION MODEL

6.1 Overview of Production Simulations

The Minnesota Renewable Energy Integration and Transmission Study (MRITS) analyzed three scenarios (Baseline, S1, and S2). The baseline scenario represents the generation, transmission and market system in 2028 if current industry and economic trends continue. S1 represents a future where baseline trends continue, along with Minnesota increasing its renewable penetration to 40% along with small Non-MN distributed solar in MISO. S2 represents a future where baseline trends continue, along with Minnesota increasing its renewable penetration to 50%, and MISO North/Central increases its renewable penetration to 25%.

PLEXOS™, an integrated energy model, was used to do the production simulations. The PLEXOS model was constructed from the existing 2013 MTEP Business As Usual (BAU) dataset for the study year 2028. Then S1 was built from the Baseline by adding new wind and solar generation and transmission upgrades, and S2 was built from S1 by adding yet more wind and solar generation, removing some expansion gas generation and adding additional transmission.

6.2 PLEXOS Overview

PLEXOS was chosen because it can utilize a Day-Ahead Security Constrained Unit Commitment (SCUC) and Real-Time Security Constrained Economic Dispatch (SCED) interleaved market dispatch solution. This type of interleaved modeling, with one simulation feeding into the other, more accurately captures the forecast uncertainties realized between a Day-Ahead and Real-Time markets. Modeling the forecast uncertainty becomes increasingly important when dealing with significant levels of wind resource output which tends to be more stochastic in nature.

Performing an economic production simulation was a principal aspect of the MRITS study to correctly model how the MISO system operates. The vast amount of hourly output such an analysis generates can be crucial in understanding which time periods are the most significant to analyze further. It also provides valuable insight into transmission system utilization, power system flows, and renewable unit curtailment.

6.3 MRITS Production Simulation Model – Source Dataset

MISO used the 2013 MTEP Business as Usual (BAU) future as the source dataset (starting point) for the MRITS analysis. The BAU future is considered the status quo future and continues current economic trends. This future models the power system as it exists today with reference values and trends. Renewable portfolio standards vary by state and 12.6 GW of coal unit retirements are modeled. The MTEP futures are created by MISO and vetted by the MISO Planning Advisory Committee (PAC) stakeholder committee. Information for the dataset is sourced from Ventyx and updated through an extensive internal MISO process to bring it into line with the most current data.

The PLEXOS model footprint includes all areas in the Eastern Interconnect, with the exception of Florida, ISO New England and Eastern Canada as shown in Figure 6-1. Figure 6-2 shows the MISO market footprint. MISO is modeled using membership information dated as of January 2014.

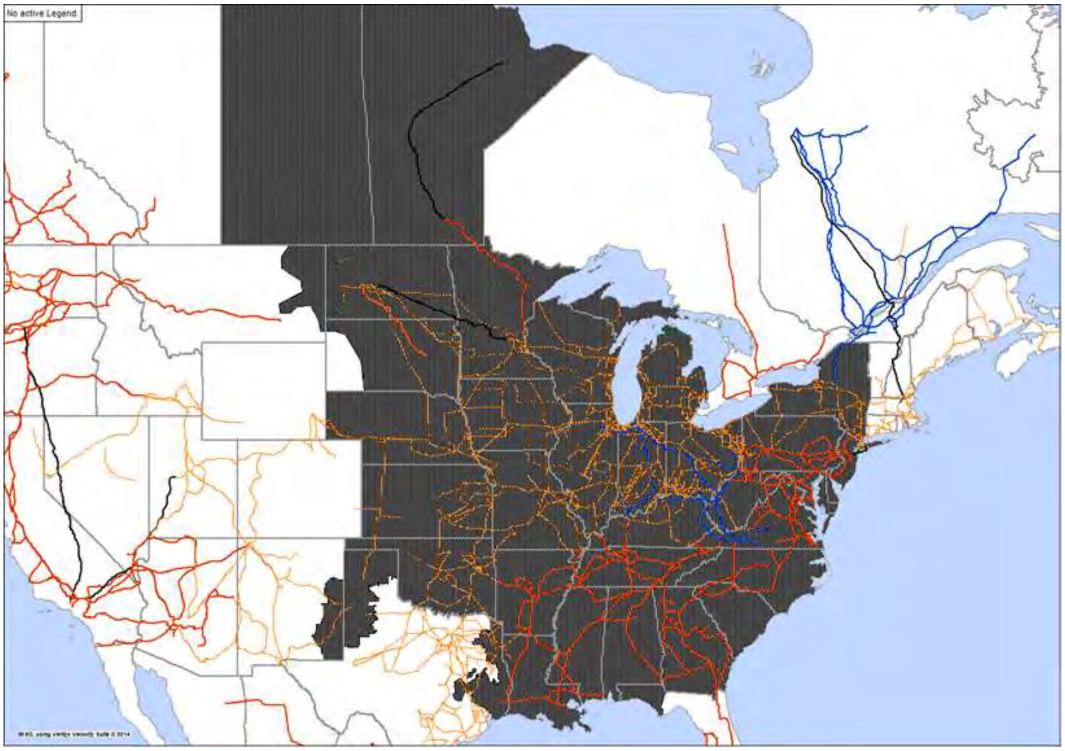

Figure 6-1 Study Footprint

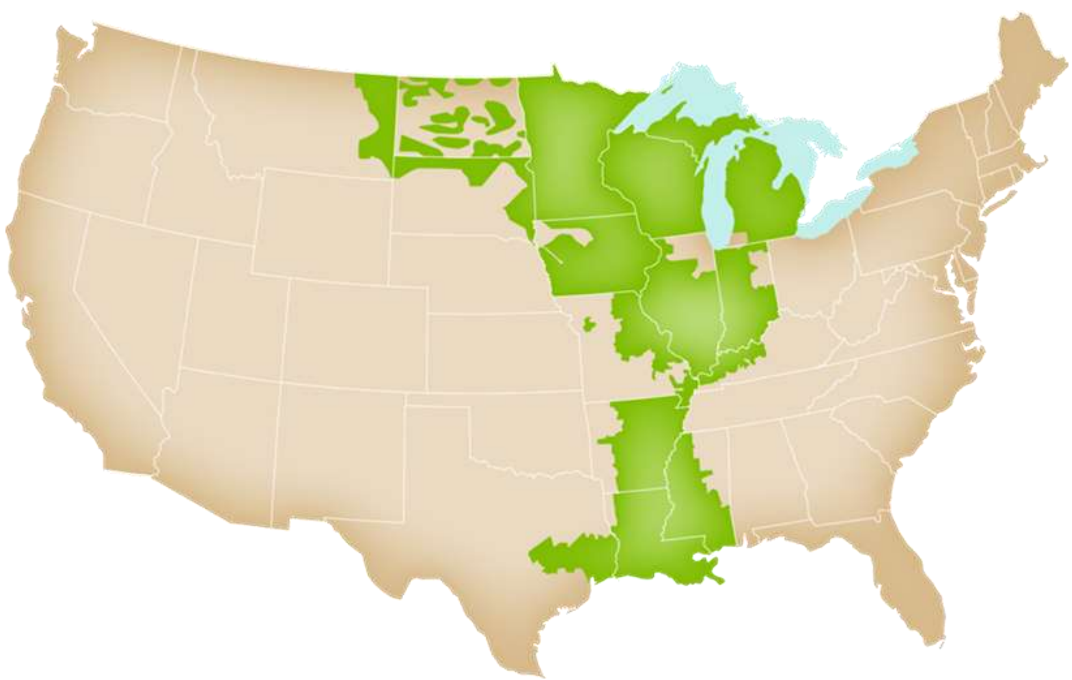

Figure 6-2 MISO's Market Footprint

As part of the MTEP BAU future development process, capacity was added to meet the various planning reserve margin requirements. Renewable resources were added to meet the various state renewable portfolio standards, shown in Figure 6-3, throughout the Eastern Interconnect.

Also between 2013 and 2028, 24,900 MW of capacity was added to MISO to meet the planning reserve margin (14.2%), and 12,200 MW of coal was retired in MISO due to the forecasted effects of prior EPA regulations as shown in Figure 6-4. This does not include coal plant retirements that may result from the EPA's proposed Clean Power Plan (111d).

Capacity additions include wind and demand side resources to meet state mandates along with gas units because of the low natural gas price. Demand and Energy Growth Rate was 1.06%, and all prices escalate at an inflation rate of 2.5%.

Wind and solar plant output was modeled at specific locations with each site having a unique historically based output as demonstrated in Figure 6-5.[1].

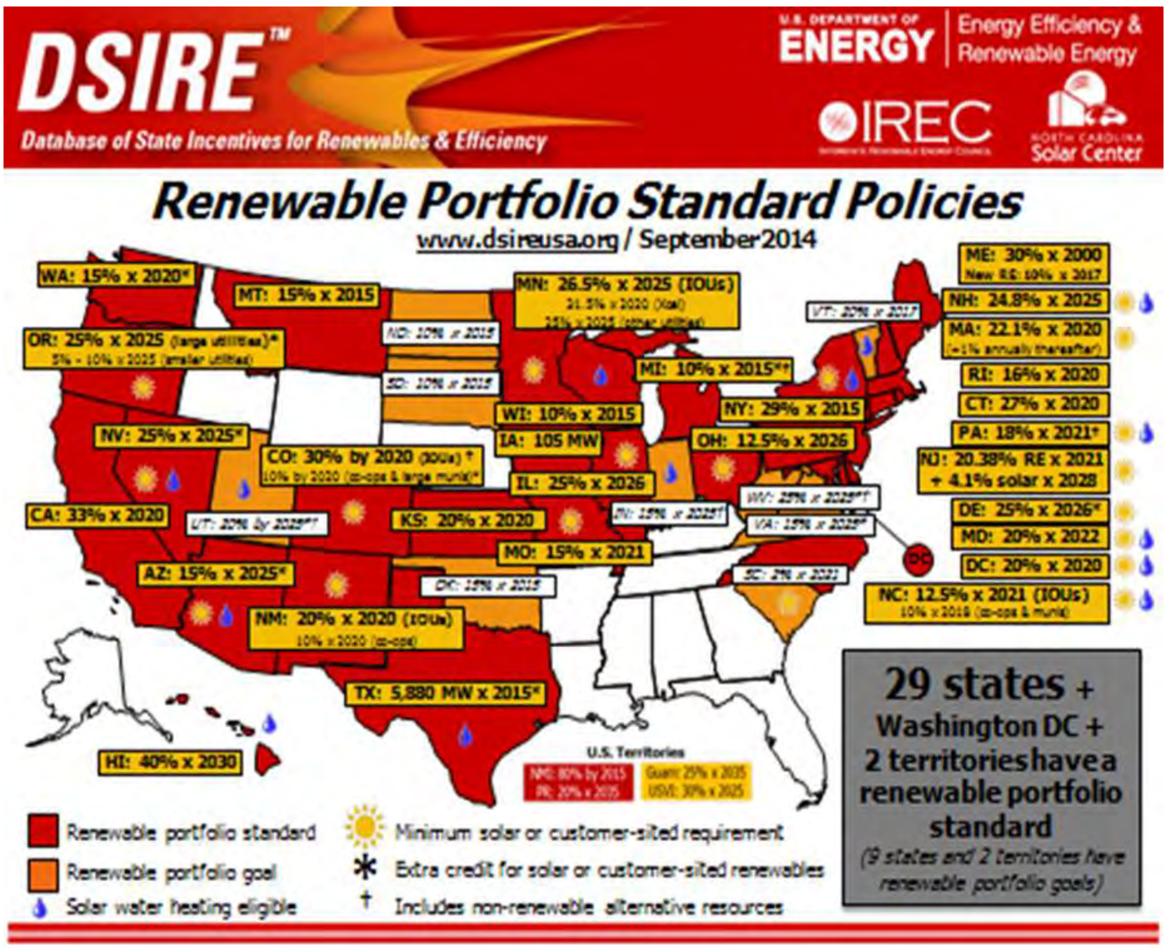

Figure 6-3 State Renewable Portfolio Standard Policies used in the MTEP13 Model

[1] http://www.dsireusa.org/summarymaps/index.cfm?ee=0&RE=0

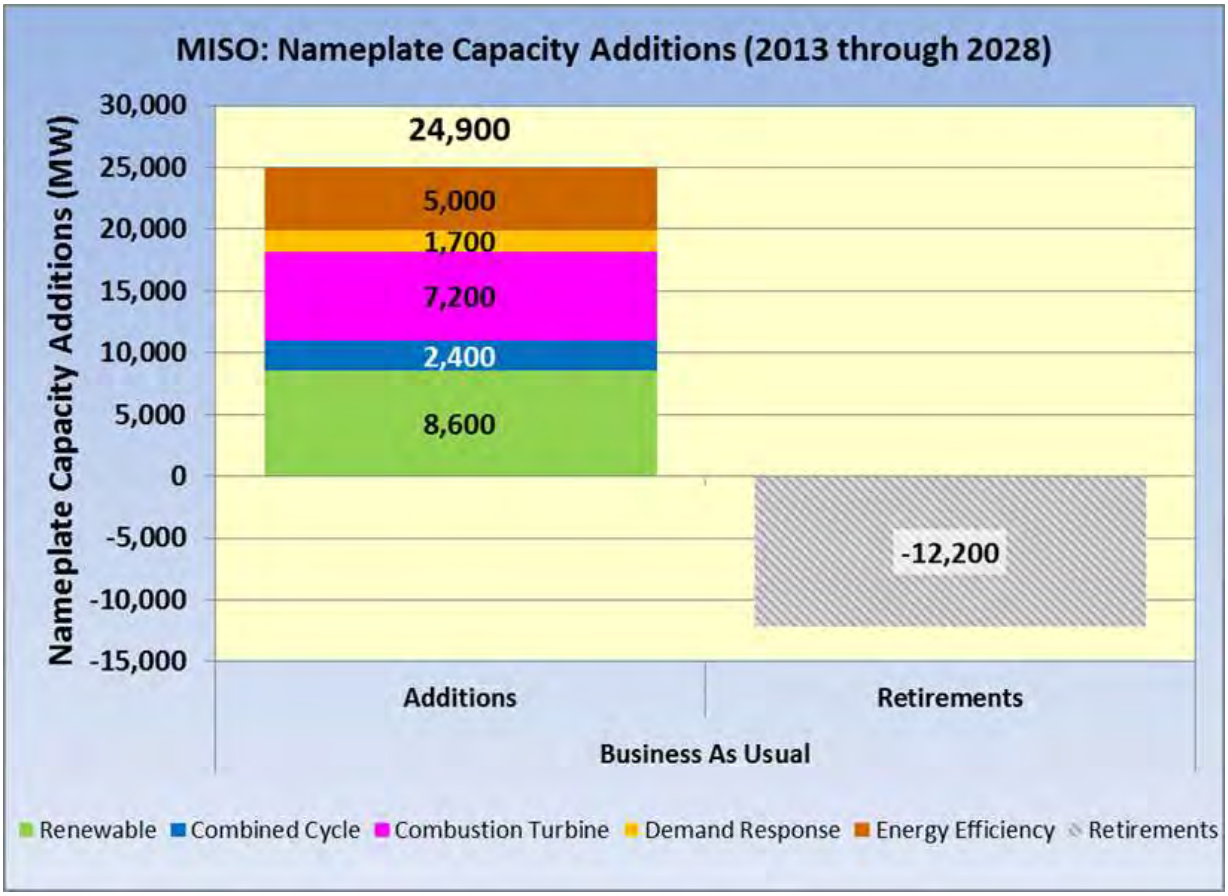

Figure 6-4 MISO's MTEP13 BAU capacity additions and coal Retirements
before changes were made as shown in Figure 6-6 (2013-2028)

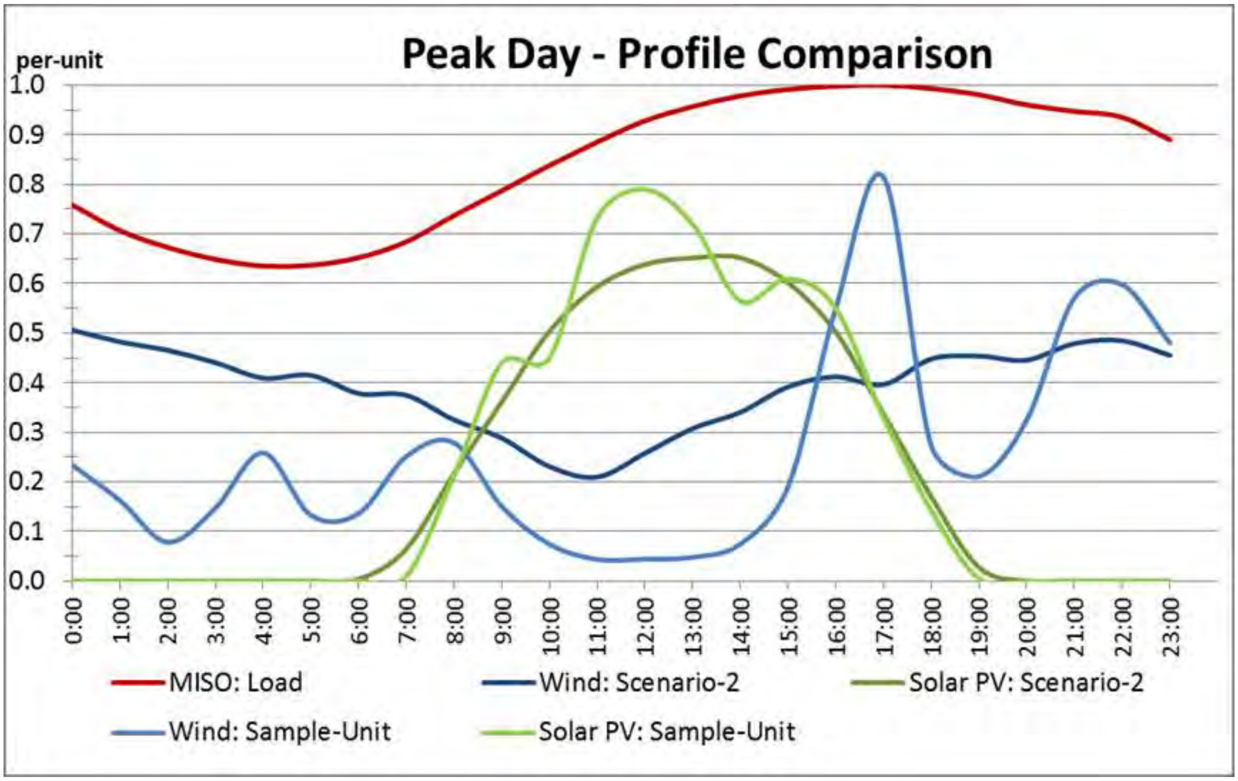

Figure 6-5 Illustration of site specific renewable output

6.3.1 Baseline Scenario

MRITS held slightly different assumptions than the 2013 MTEP BAU future, thus the baseline database needed to be modified to reflect these new assumptions. Wind resources used the same assumptions that the MTEP BAU future did, but solar units were adjusted. The forecasted solar units, totaling 1725 MW, in MISO were removed and 1509 MW of new solar generation was added to the Baseline model per MRITS assumptions.

The siting locations of these units were also changed to reflect a more realistic distribution of solar resources which is explained in the Siting Section. A proxy expansion hydro unit in Manitoba Hydro was removed and replaced with Keeyask, a 695MW unit that has become certain (approved and under construction) since the 2013 MTEP models were built. The 500kV Great Northern transmission line was also added to deliver this hydro power.

6.3.2 Scenarios 1 and 2

Scenario 1 and 2 had different capacity assumptions than the baseline case did so a new capacity expansion was done to reflect these different assumptions. Renewable capacity was increased and thermal capacity was decreased to maintain the same capacity reserve margins as shown in Figure 6-6. The treatment of capacity credit for wind and solar resources is discussed in the following subsection.

Thermal capacity was not reduced for Scenario 1 because capacity reserves were slightly over the requirement in 2028 given the lumpiness of capacity additions, in other words, the generation is not added in smooth incremental amounts but rather the generation is added in larger blocks. In scenario 2, enough renewables were added to warrant the reduction in thermal capacity.

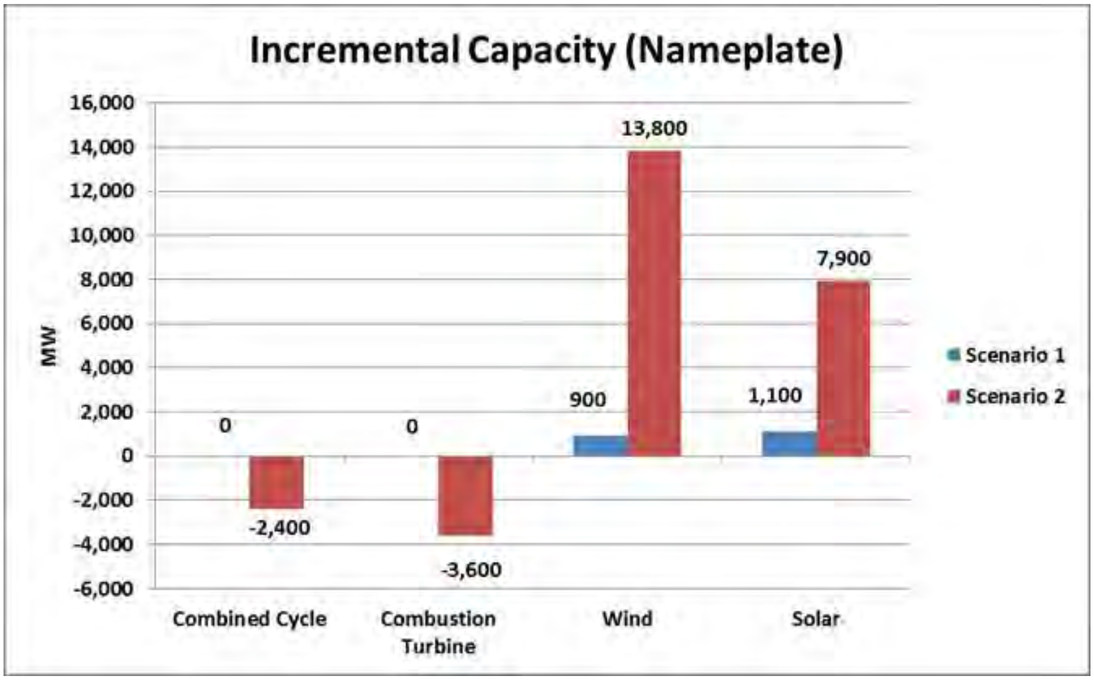

Figure 6-6 Resource Capacity Changes for Scenarios 1 and 2

6.3.3 Capacity Credit for Wind and Solar Resources

A capacity credit value was needed for the wind and solar renewables in order to perform the resource forecasting capacity expansion. For each of those resource types a currently developed MISO process was utilized to determine what capacity value to use for the MRITS study.

The resulting capacity credit values were:

Baseline and S1 Wind:	14.1%
S2 Wind:	11.8%
Solar:	40 %

6.3.3.1 Wind Capacity Value

For the wind capacity credit, this study referred to the MISO report[2] findings.

Both the Baseline and Scenario1 models used the value of 14.1% of nameplate. Those cases both have levels of wind energy penetration, 14% and 15.2% respectively, which are close to the current MISO system amount of 13%, installed.

[2]Planning Year 2014-2015, Wind Capacity Credit, https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf

But for Scenario 2 which had a significant increase in the MISO penetration of wind to 23.8%, the Figure 6-7 from the report[3] was used to interpolate a capacity value of 11.8% for wind. In the higher wind penetration regions, 15%+, as the figure shows, the wind capacity credit decreases due to a saturation of wind energy during peak times. Note that the figure shows only the 20 GW and 30 GW penetration data points and these were converted to 21.2% and 31.8% penetration, respectively, based on the 94,298 MW 2013 MISO Peak Load used for that figure.

6.3.3.2 Solar Capacity Value

For the solar capacity value, this study referred to the MISO Resource Adequacy Business Practice Manual[4] rules for non-wind, intermittent resources. The manual[5] indicates that the following be used:

> "Intermittent Generation and Dispatchable Intermittent Resources that are not powered by wind must supply MISO with the most recent consecutive three years of hourly net output (in MW) for hours 1500 – 1700 EST from June, July and August. For new resources, or resources on qualified extended outage where data does not exist for some or all of the previous 36 historical months, a minimum of 30 consecutive days' worth of historical data during June, July or August for the hours of 1500 - 1700 EST must be provided."

So using only data during that prescribed time period and the 2006 NREL solar set of information provided for the sites used in the MRITS study, a capacity value of 40% of solar nameplate was calculated based on the capacity factor deterministic approach.

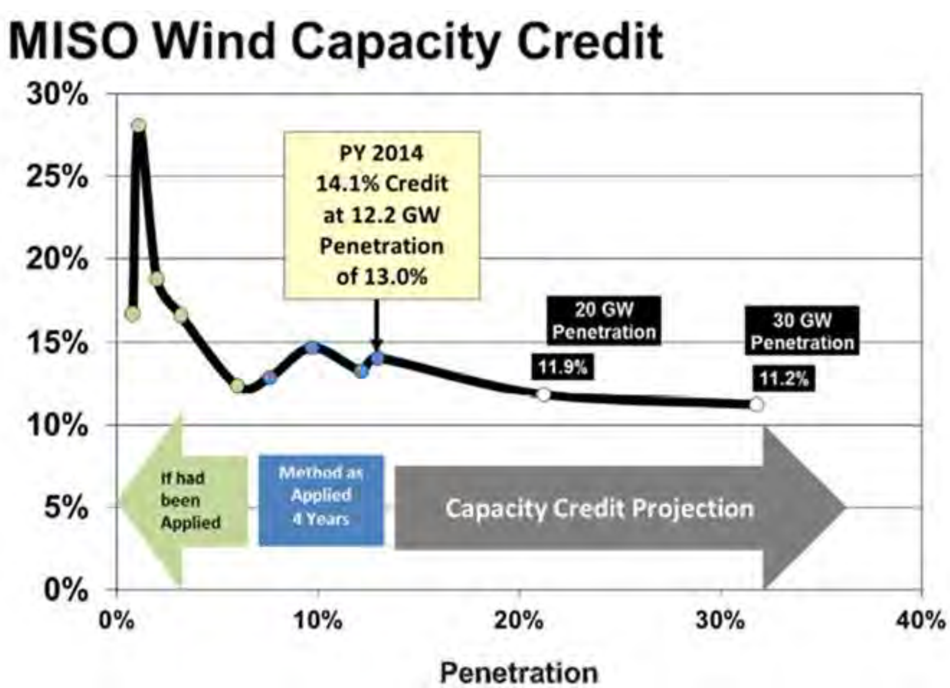

Figure 6-7 Plot of Wind Capacity Credit versus Penetration Level, from MISO Report

[3] https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf
[4] https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19206
[5] Ibid. Section 4.2.2.1 (page-34)

The 40% capacity factor for solar was used in the resource forecasting step when determining which and how many other non-renewable resources to add to maintain the planning reserve margin in the future year.

For the load-flow analysis, it was decided to further stress the transmission system with a higher value of solar output beyond its capacity factor rating. A scatter plot of wind vs. solar output was compiled which can be seen in Figure 6-8. This figure shows that when the wind output is in the range of 20% as during peak load-flow type conditions or when it's at a 90% range during off-peak load-flow type conditions, solar output could be in the high range of 60%. Based on that high range level value, 60% was chosen as the load-flow assumption level for solar.

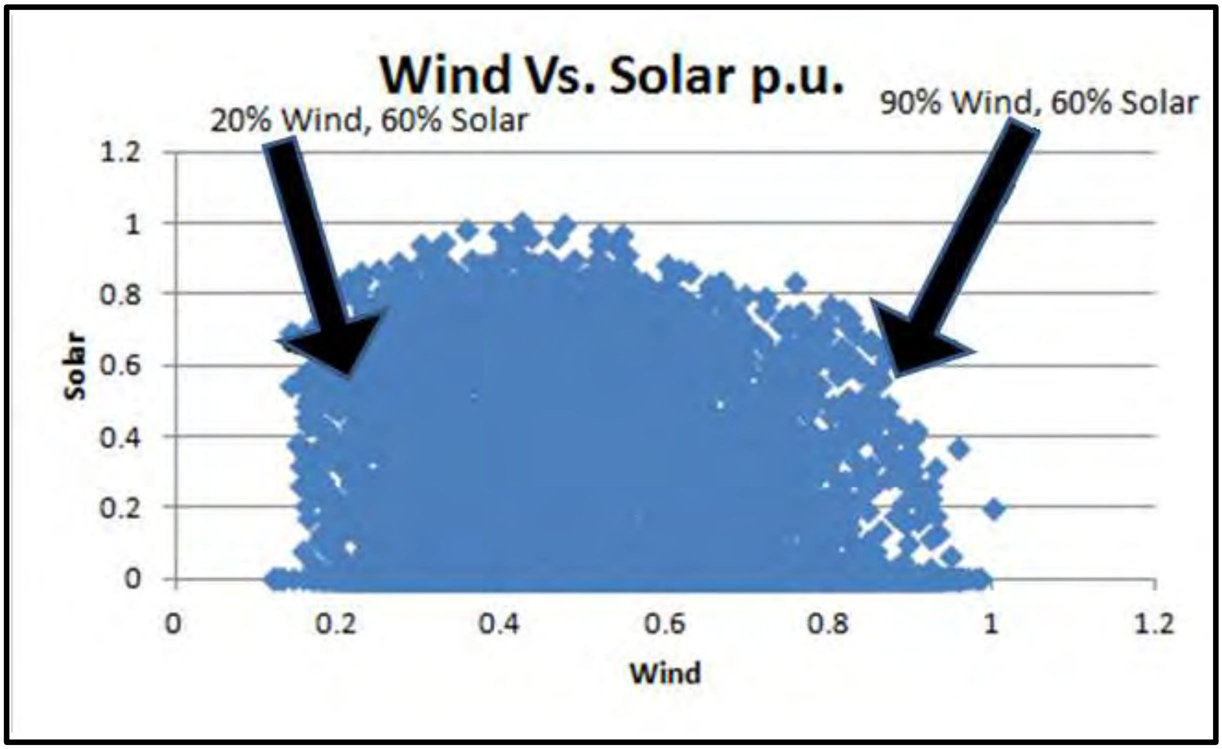

Figure 6-8 Scatter Plot of Wind versus Solar Output

6.3.4 Forecast Uncertainty

The MRITS study incorporates wind, solar and load uncertainty to more accurately reflect the challenges associated with large scale renewable integration. Renewable profiles were provided by the National Renewable Energy Lab (NREL).

Wind uses the NREL EWITS wind dataset:	Unit commitment uses the 4-hour ahead wind profile Dispatch uses the actual wind site output
Solar uses the NREL ERGIS solar dataset:	Unit commitment uses a MISO aggregate solar profile. Dispatch uses the actual solar site output
Load uses historic load data:	Unit commitment uses a stochastic load profile. Dispatch uses the historic actual profiles

6.3.4.1 Wind

All 2006 wind data comes from the NREL EWITS wind data set. Two separate wind forecasts were considered, the Next Day (ND) and the 4-hour ahead (4HR) as shown in Figure 6-9. The plot shows normalized traces of hourly wind power for one week. The 4 hour wind forecast provided by NREL was used as this more accurately approximates the final generation commitment MISO would have going into the Real Time market. The Actual output is the estimated wind that was actually produced for the given hour as provided by NREL[6]..

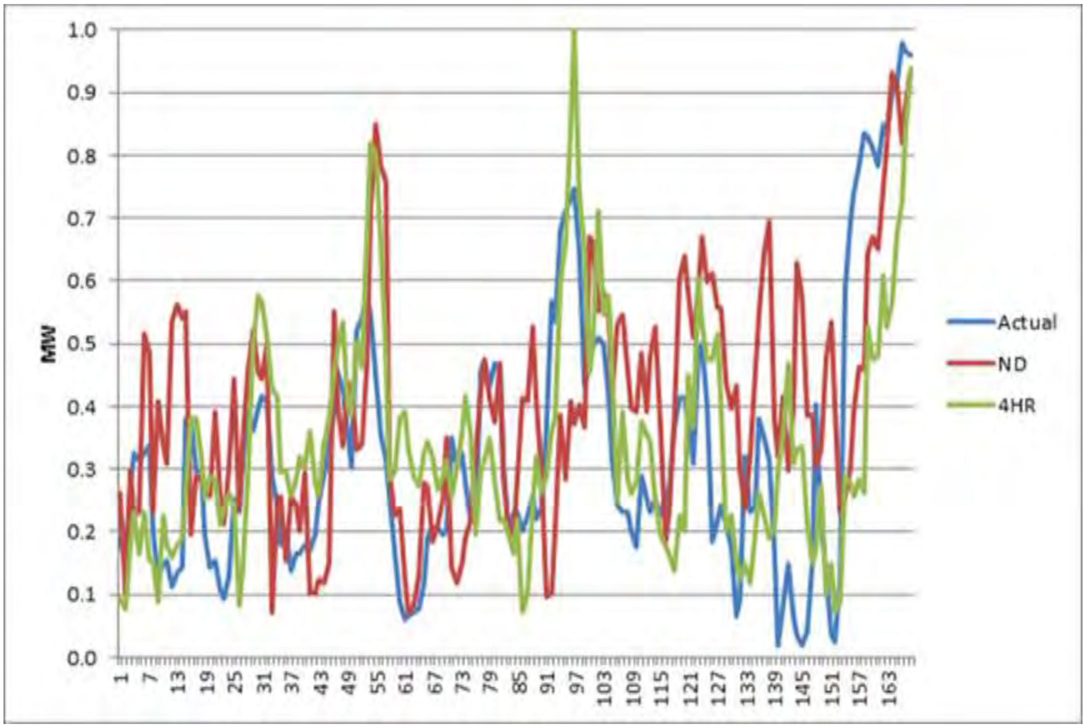

Figure 6-9 Sample of Hourly Forecast and Actual Wind Site Output (1st week of July)

[6] http://www.nrel.gov/electricity/transmission/wind_integration_dataset.html

6.3.4.2 Solar

Actual real time solar data comes from NREL. It is a combination of Eastern Renewable Generation Integration Study (ERGIS) data for non-Minnesota sites and newly created data for Minnesota sites. The forecast is created by summing all profiles together and creating a single shape for the entire region. This shape is scaled back down to the size of each individual solar site.

The forecast will take into account wide spread cloudiness since it is the aggregate of the actual profiles, but spotty clouding will be washed out because of the aggregation. The solar arc can be perfectly forecasted but cloud cover creates the uncertainty in the forecast.

Figure 6-10 shows the output of 2 Solar Sites, and demonstrates the differences between individual locations, and how they each compare to the forecast. Solar output is shown as a percentage of its Direct Current rating.

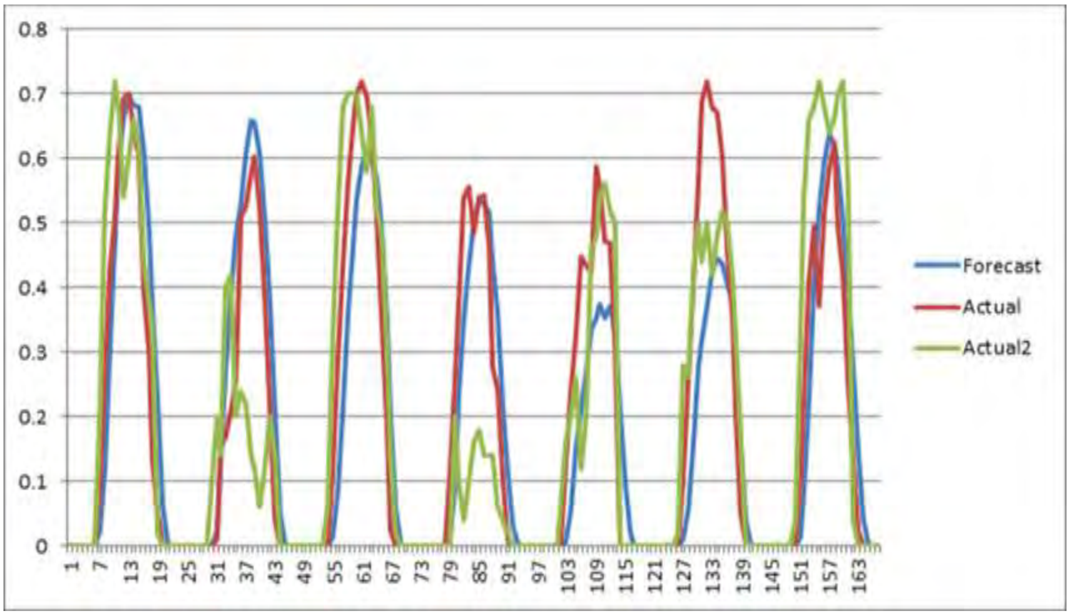

Figure 6-10 Sample of Hourly Forecast and Actual Solar Site Output (1st week of July))

6.3.4.3 Load

Actual load profiles are historic 2006 shapes. Forecasts are created by compiling statistics from the MISO market between 2008 and 2011 and applying those to the actual shapes. A random draw was done using these statistics to simulate the historic differences between the forecast and the actual load. The day-ahead load forecast was used and not a 4-hour forecast because the day-ahead is a discrete and separate forecast while the 4 hour is simply a snapshot of the rolling forecast.

Figure 6-11 shows a sample of load for a week, along with the random draw forecast which was used for this study.

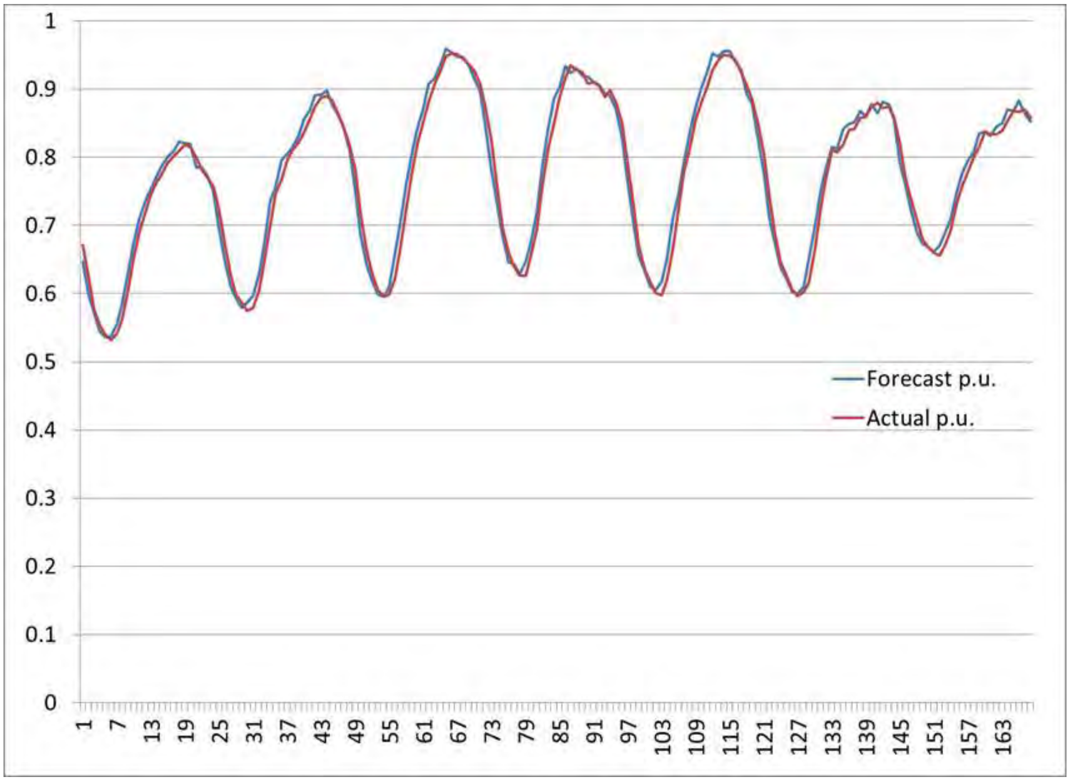

Figure 6-11 Sample Minnesota Load Output (1st week of July)

7 OPERATIONAL PERFORMANCE RESULTS

7.1 Scenarios for Production Simulation Analysis

As described in Chapter 2, the study was designed to evaluate scenarios with three levels of renewable energy (RE) penetration in Minnesota (see Table 7-1). These 3 levels of RE penetration were analyzed with five production simulation cases. Two of the five cases had different assumptions for coal plant commitment, forced outage modeling, coal unit retirements, and modeling of the Missouri River hydro plants. The modeling assumptions for each case are summarized in Table 7-2. Scenario 1a is a sensitivity case with respect to Scenario 1. That is, Scenarios 1 and 1a have the same renewable energy penetration, but with different system operating assumptions. Similarly, Scenario 2a is a sensitivity case with respect to Scenario 2. Thus, the original three scenarios expanded to five scenarios for this aspect of the technical analysis.

Table 7-1 Study Scenarios

Scenario	Minnesota RE Penetration	MISO Wind & Solar Penetration (including MN)
Baseline	28.5%	14.0%
Scenario 1	40.0%	15.0%
Scenario 2	50.0%	25.0%
Note: MISO has an additional 3% renewable energy penetration in all scenarios from existing small biomass and small hydro.		

Table 7-2 Major Assumptions for Production Simulation Analysis of Study Scenarios

	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Coal plants modeling: Must-run (MR) or Security-Constrained Economic Commitment (SCEC)	MR	MR	SCEC	MR	SCEC
Forced outages included in generation modeling	No	No	Yes	No	Yes
Nine Minnesota-Centric coal units retired	Yes	Yes	No	Yes	No
Improved modeling of Missouri River hydro generation	No	No	Yes	Yes	Yes

Minnesota load is served by a group of utilities and cooperatives with service territories that extend beyond the boundaries of the State of Minnesota. Therefore, the results of the production simulation analysis are summarized for the “Minnesota-Centric Region”, which consists of all generating resources operated by and system loads served by the Minnesota utilities.

Figure 7-1 shows a map of the Minnesota-Centric Region. The dots represent generating stations owned and operated by the Minnesota Utilities. The individual utilities are listed in the figure.

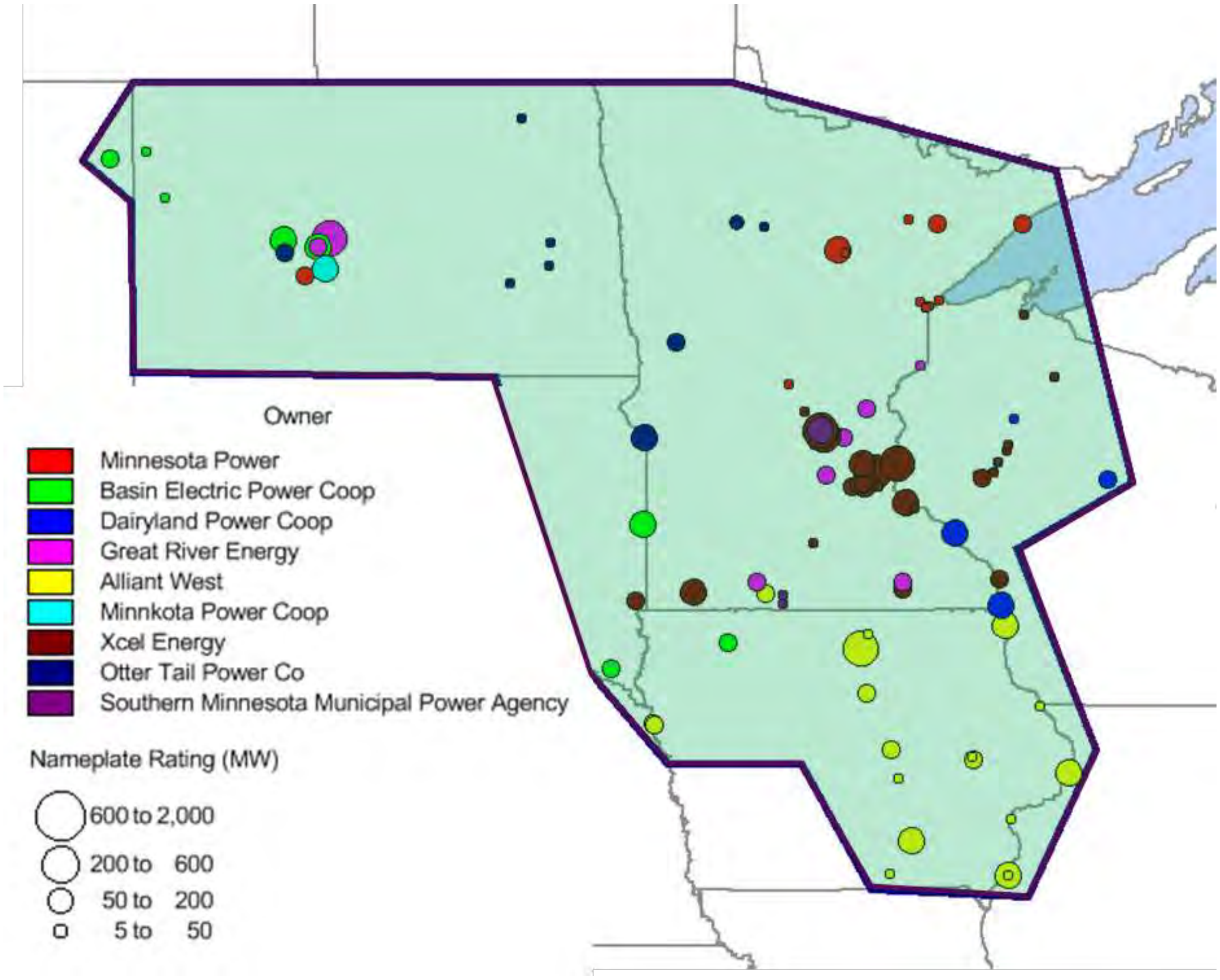

Figure 7-1 Minnesota-Centric footprint for production simulation (Plexos) Analysis Dots indicate generating plants owned by Minnesota Utilities.

7.2 Annual Energy

Table 7-3 shows annual load, wind and solar energy for the Minnesota-Centric region for the study scenarios. The system load energy is, of course, the same for all scenarios. The bottom two rows show the MW rating of assumed wind and solar generation resources in the Minnesota-Centric region, which increase from the Baseline, to Scenarios 1/1a, and then further increase to the values in Scenarios 2/2a.

Note that the wind and solar energy penetration levels shown in this table are for the Minnesota-Centric Region and not specifically for the State of Minnesota. The amount of wind and solar generation resources included in the system models was calculated to meet the Minnesota RE penetrations specified in the study objectives (see Chapter 3).

In the production simulation analysis, the energy is summarized by "owner" (i.e., the utility which owns the bus where the generation is connected) consistent with the operation of the system. Therefore, the wind and solar energy penetration levels shown in the table are calculated for the entire Minnesota-Centric region, which includes all generating resources operated by and system loads served by the Minnesota utilities.

The results show that wind and solar curtailment is relatively small in all the scenarios. The levels of curtailment are considered to be within reason and not sufficient to be of concern. Experience from grid operations and from other renewable integration studies has shown that it is not economically justifiable to eliminate all causes of curtailment for all hours of the year. A small amount of curtailment is to be expected for any system.

Further analysis of wind and solar curtailment is presented in a subsequent section of this report.

Table 7-3 Annual Load, Wind and Solar Energy for Minnesota-Centric Region

	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Load Energy (MWh)	147,807,020	147,807,020	147,807,020	147,807,020	147,807,020
Available Wind Energy (MWh)	37,286,193	45,753,928	45,753,928	61,789,277	61,789,277
Delivered Wind Energy (MWh)	37,129,632	45,298,460	45,025,066	60,467,557	60,799,826
Curtailed Wind Energy (MWh)	156,561	455,468	728,862	1,321,700	989,451
Curtailed Wind Energy	0.42%	1.00%	1.59%	2.14%	1.60%
Available Solar Energy (MWh)	702,562	2,002,969	2,002,969	6,870,164	6,870,164
Delivered Solar Energy (MWh)	701,936	2,002,869	1,998,268	6,841,300	6,853,503
Curtailed Solar Energy (MWh)	626	100	4701	28,864	16,661
Curtailed Solar Energy	0.09%	0.00%	0.23%	0.42%	0.24%
Wind Penetration	25.12%	30.65%	30.46%	40.91%	41.13%
Solar Penetration	0.48%	1.36%	1.35%	4.63%	4.64%
Wind+Solar Penetration	25.60%	32.00%	31.81%	45.54%	45.77%
MW Rating of Wind Fleet	11,039	12,970	12,970	18,140	18,140
MW Rating of Solar Fleet	470	1367	1367	4588	4588

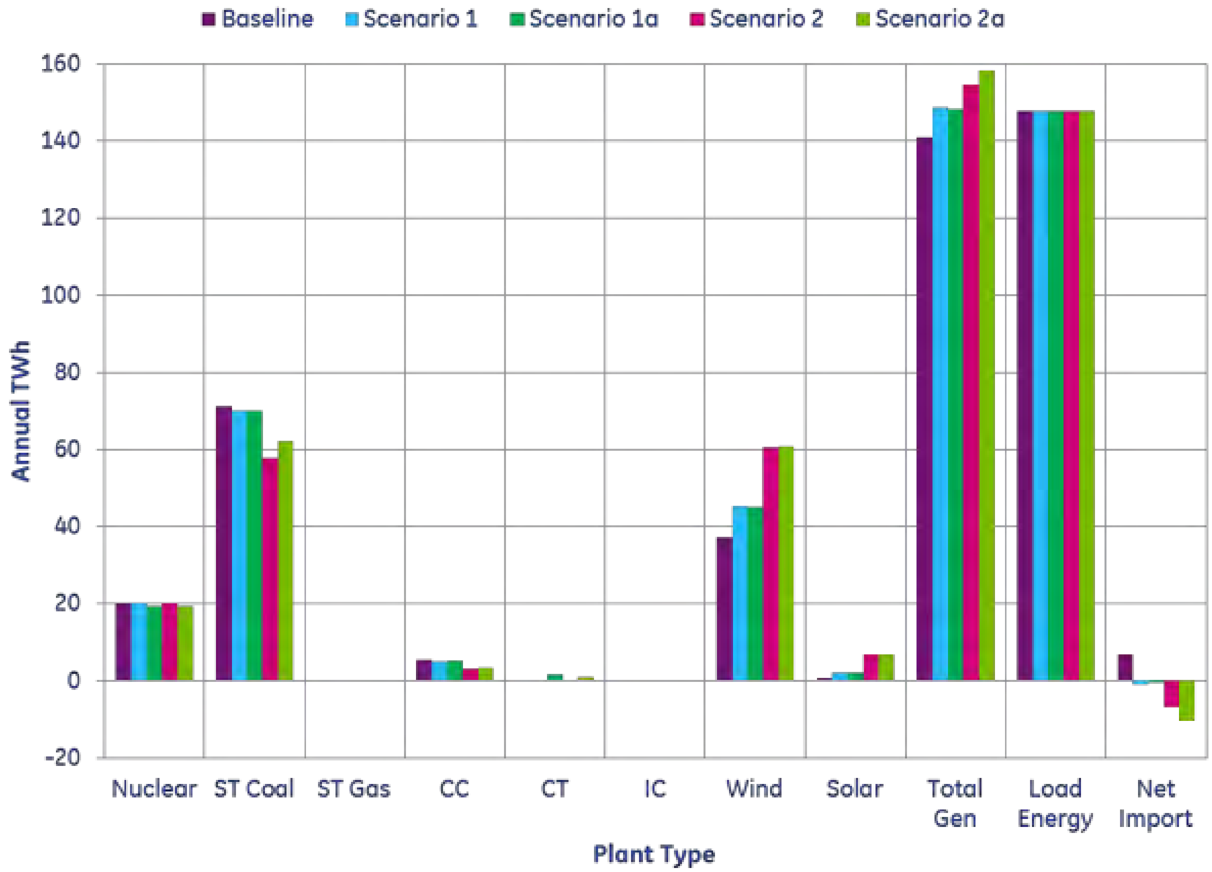

Figure 7-2 Annual generation in TWh by unit type for Minnesota-Centric region

Figure 7-2 shows the annual load and generation energy by type for the Minnesota-Centric region. Comparing Scenarios 1 and 1a (40% MN renewables) with the Baseline,

- Wind and solar energy increases by 8.5 TWh, all of which contributes to bringing Minnesota from 28.5% RE penetration to 40% RE penetration
- There is very little change in energy from conventional generation resources.
- Most of the increase in wind and solar energy is balanced by a decrease in imports
- The slight reduction in nuclear energy in Scenario 1a is due to forced outages.

Comparing Scenarios 2 and 2a (50% MN renewables) with Scenarios 1 and 1a (40% MN renewables),

- Wind and solar energy increases by 20 TWh. Of this total, 4.8 TWh brings Minnesota from 40% to 50% RE penetration and the remainder contributes to bringing MISO from 15% to 25% RE penetration
- Most of the increase in wind and solar energy in the Minnesota-Centric region is balanced by a decrease in coal generation and imports from neighboring regions

- Gas-fired combined-cycle generation declines from 5.0 TWh in Scenario 1 to 3.0 TWh in Scenario 2

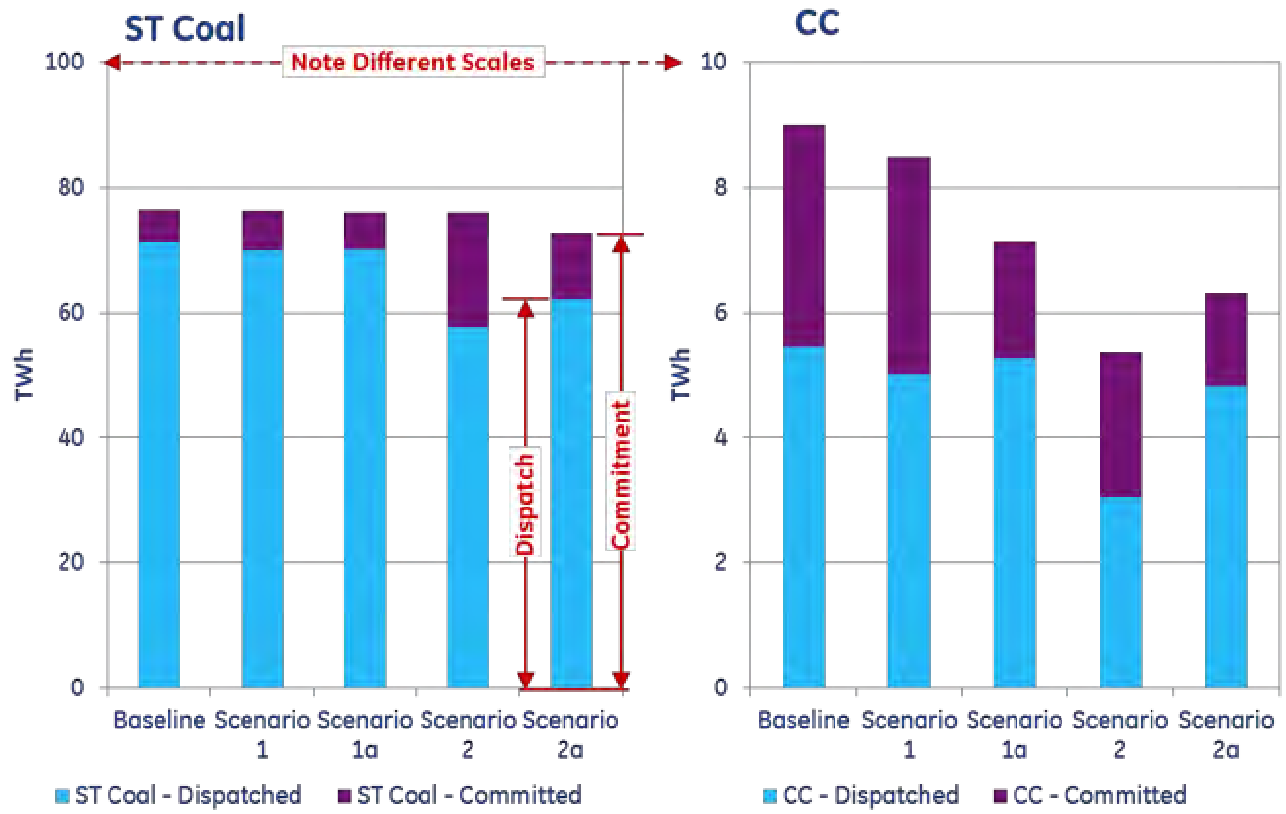

Figure 7-3 Annual Committed Capacity and Dispatch Energy for Coal and Combined-Cycle Units in the Minnesota-Centric Region

The left side of Figure 7-3 shows annual committed capacity and dispatched energy for coal units. In this figure, the total height of each bar indicates total annual coal unit committed capacity for the Minnesota-Centric Region. This is calculated by multiplying the hours online by the unit rating for each coal unit, and then totaling the values for all coal units. The light-blue segment of each bar is the energy dispatched (generated) from the coal units (i.e., the sum of energy output for all hours for all coal units). Comparing the Baseline with Scenarios 1 and 1a, there is no significant difference in coal unit commitment or dispatch. In Scenario 2, the dispatched energy from the coal units declines relative to the previous scenarios due to the increase in wind and solar generation. However, the coal fleet commitment remains nearly the same because many coal units in Scenario 2 are assumed to be must-run and are not decommitted during periods of high wind and solar generation. In Scenario 2a, all coal units are economically committed/decommitted per market signals, so the overall commitment of the coal fleet is lower than in Scenario 2. Note that the coal fleet dispatch in Scenario 2a is higher than Scenario 2. This is because Scenario 2 assumes that 9 coal units in the Minnesota-Centric region would be retired and Scenario 2a assumes that those units would be available to operate.

The right side of Figure 7-3 shows similar information for the combined-cycle fleet. Comparing Scenarios 1 and 1a with Scenarios 2 and 2a, it is evident that utilization of the combined cycle fleet declines as wind and solar energy increases.

The figure also indicates that CC fleet operation is more efficient in Scenario 1a (with coal units economically committed) than in Scenario 1 (with coal units assumed to be must-run). That is, the dispatched CC fleet energy output is a higher percentage of the CC fleet commitment. A similar observation can be made by comparing Scenario 2a with Scenario 2.

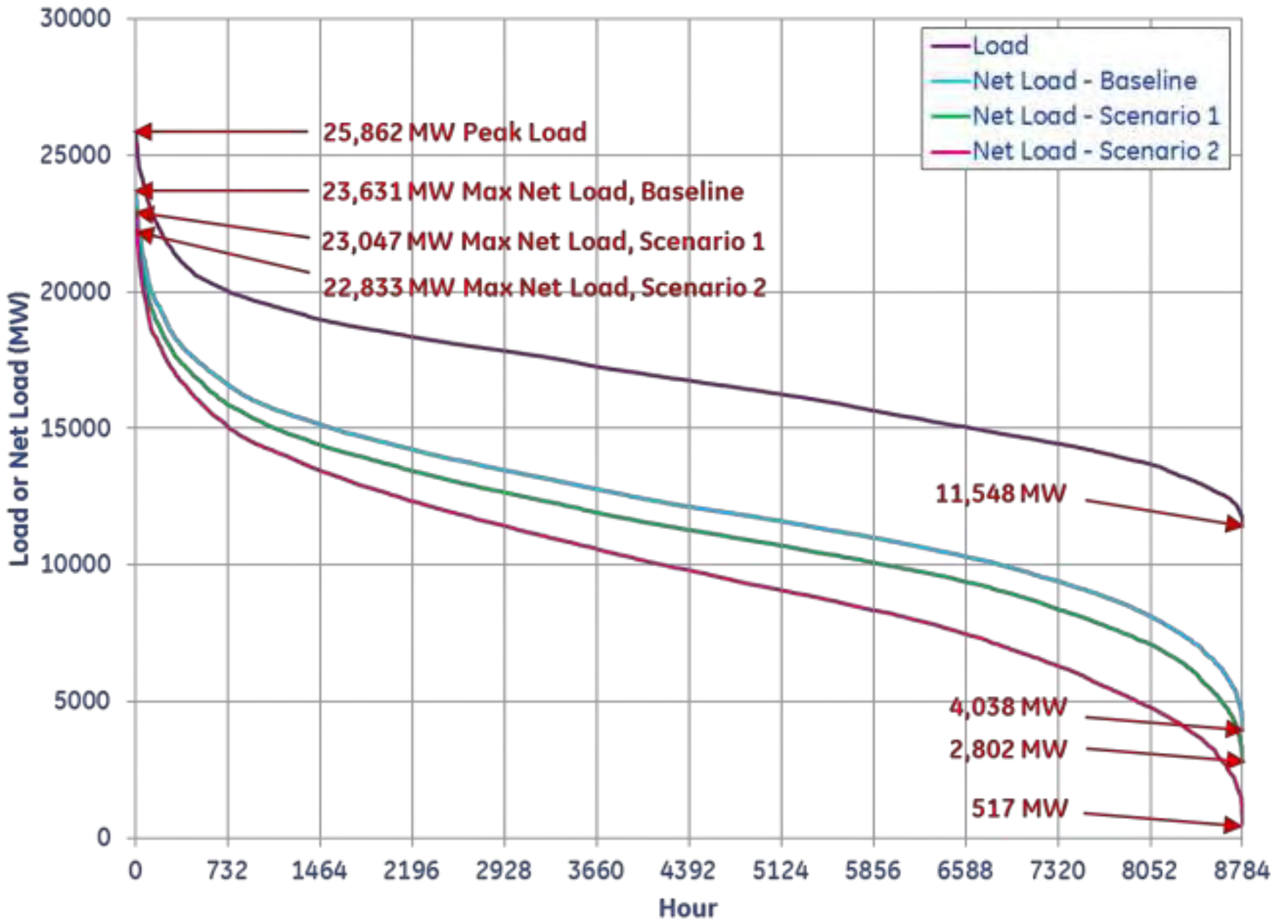

Figure 7-4 Annual Load and Net Load Duration Curves for Minnesota-Centric Region

The annual load and net load[1] duration curves for the Minnesota-Centric region are shown in Figure 7-4 for the different scenarios. (Note, the net loads for scenarios 1a and 2a are essentially unchanged from scenarios 1 and 2 and are not shown here.) The areas between the curves represents the impact of the increasing renewable energy penetrations. The addition of over 11,000 MW of renewable capacity from the Baseline Scenario to Scenario 2 reduced the peak net load by less than 800 MW while the minimum load was reduced by over 3,500 MW. The entire fleet of almost 23,000 MW of renewable capacity reduced the net peak load by about 3,000 MW while the minimum load was reduced by slightly more than 11,000 MW.

[1] Net load is calculated as hourly load energy minus wind and solar generation

It is this fact that makes the cycling capability and minimum stable operating points of the conventional generation critical factors in the analysis.

The timing of the renewable energy is also reflected in Figure 7-5, which shows the annual duration curves of the net energy imports for the Minnesota-Centric region. The overall region is initially a net importer for the year but the increasing amounts of renewable energy shifts it to a net exporter. However, it can be seen that there is little change in the peak imports while the maximum exports increase from a little over 3,500 MW to 6,650 MW.

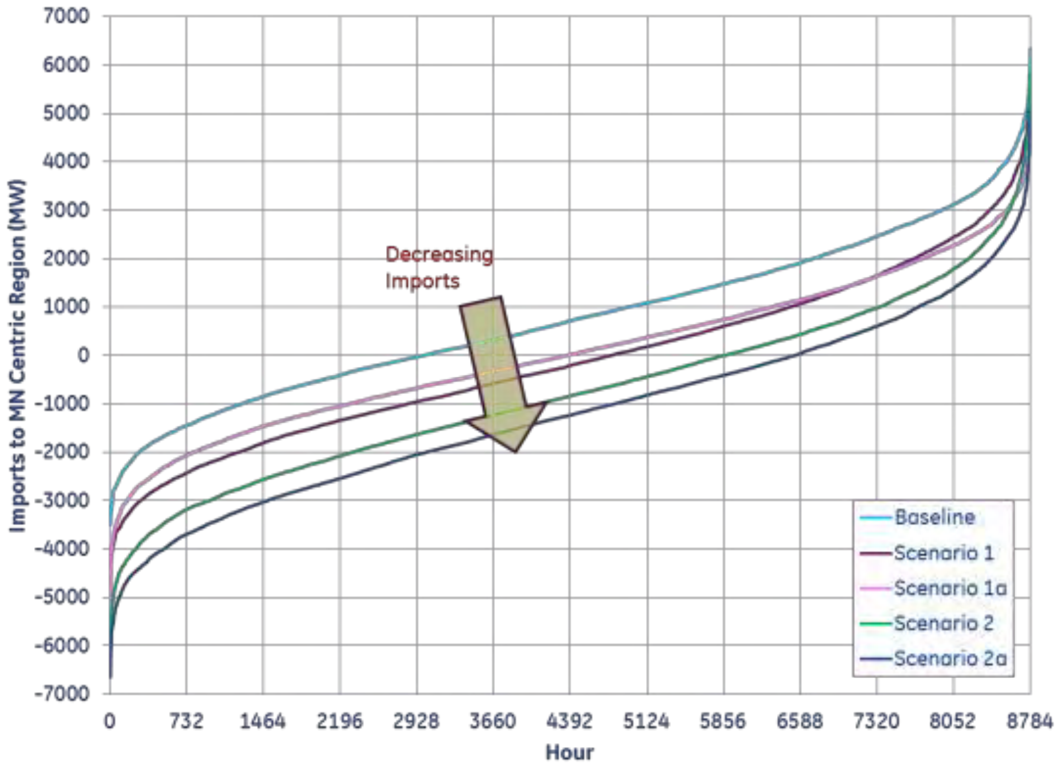

Figure 7-5 Annual Duration Curves of Energy Imports for Minnesota-Centric Region

7.2.1 Aggregate Wind and Solar Plant Capacity and Power Output

The dashed curves in Figure 7-6 show duration curves of the aggregate wind energy from all wind plants in the Minnesota-Centric region. Comparing the curves for the three scenarios shows the increase in wind energy from the Baseline to Scenario 1 to Scenario 2. The solid lines are duration curves of the aggregate ratings of the wind plants on-line. If a wind plant has no power output, then it is considered to be off-line with its power converters idle. If a wind plant is producing power, then it is considered to be on-line and all of its wind turbines and power converters are in-service and connected to the power grid. The flat shapes of these curves indicate that nearly all of the wind plants are on-line for nearly all hours of the year. The importance of this observation is discussed further in Section 7.7.1 (% non-synchronous generation and its impact on relative system strength).

Figure 7-7 is a similar plot for PV solar plants. The solid curves showing aggregate capacity on-line are essentially flat at full fleet rating for the daytime hours and flat at zero for nighttime hours.

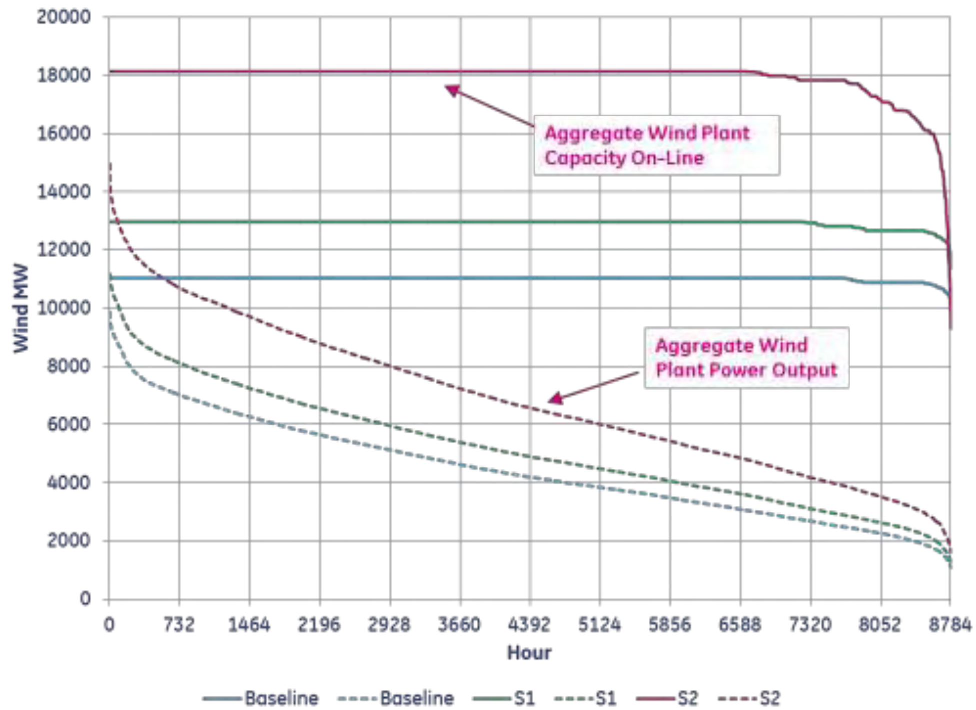

Figure 7-6 Duration Curves of Aggregate Wind Plant Capacity On-Line and Aggregate Wind Plant Power Output for Minnesota-Centric Region

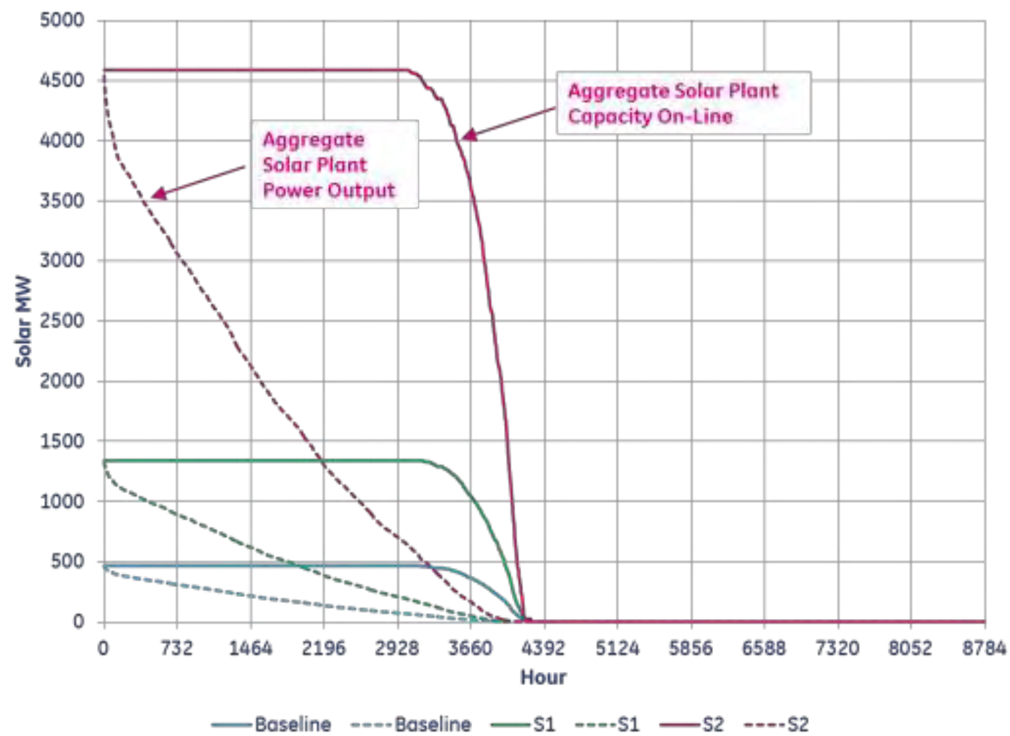

Figure 7-7 Duration Curves of Aggregate Solar Plant Capacity On-Line and Aggregate Solar Plant Power Output for Minnesota-Centric Region

Comparisons of Generation Fleet Utilization for Study ScenariosTable 7-4 gives a more detailed breakdown of the commitment and dispatch by generation type for Scenarios 1 and 1a. As explained earlier, the "MWh Committed" reflects the entire rating of the plants whenever they are on line while the "MWh Dispatched" only reflects the actual energy output. The column "CF" is the capacity factor, which is the energy output divided by the capacity of the fleet times 8784 hours in the year. The next column, "Online CF", is the average capacity factor over just those hours when the units are on. The clearest example of these terms is with the Combined Cycle units (CC). While the overall capacity factor only change slightly between the two scenarios, from 15% to 16%, the online CF, or average operating level, increased from 59% to 74% reflecting a much more efficient level of operation when the coal plants are permitted to cycle. Note, only units that operated at some time during the year were counted in the fleet, so the capacities could change slightly between scenarios.Table 7-5 shows a similar comparison for Scenarios 2 and 2a. Allowing the coal plants to cycle reduced their average capacity factors from 69% to only 58% but their average level of operation increased from 76% to 85%. The combined cycle units also increased the overall efficiency of their operation.

Table 7-4 Comparison of Minnesota-Centric Generation Fleet Utilization Scenarios 1 and 1a

	S1				S1a					
Unit Type	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Δ (S1a-S1)	% Change in Dispatch
Wind	113,516,032	45,298,460	40%	40%	112,894,006	45,025,066	40%	40%	(273,394)	-1%
ST Coal	76,285,799	69,984,409	65%	92%	75,904,870	70,043,841	65%	92%	59,432	0%
CT Gas	428,220	187,010	0%	44%	2,281,544	1,503,340	2%	66%	1,316,330	704%
CC	8,478,103	5,024,030	15%	59%	7,134,913	5,266,709	16%	74%	242,680	5%
Nuclear	20,209,392	20,036,836	96%	99%	19,414,416	19,246,693	93%	99%	(790,143)	-4%
Solar PV	5,175,211	2,002,869	15%	39%	5,164,167	1,998,268	15%	39%	(4,600)	0%
Conventional Hydro	1,817,899	1,225,371	30%	67%	4,110,912	1,606,155	39%	39%	380,784	31%
ST Renewable	3,965,527	3,952,032	99%	100%	2,808,218	2,783,508	70%	99%	(1,168,524)	-30%
ST Gas	184,918	82,764	6%	45%	173,067	78,786	6%	46%	(3,978)	-5%
ST Other	641,604	635,462	92%	99%	614,174	607,706	88%	99%	(27,756)	0%
IC Renewable	226,844	226,138	100%	100%	158,898	157,210	69%	99%	(68,929)	-31%
IC Gas	2,826	1,742	1%	62%	2,443	1,975	2%	81%	233	13%
Grand Total	***230,932,414***	***148,657,123***	**-**	**-**	***230,662,037***	***148,319,353***	**-**	**-**	***(337,770)***	***0%***

Table 7-5 Comparison of Minnesota-Centric Generation Fleet Utilization Scenarios 2 and 2a

	S2				S2a					
Unit Type	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Δ (S2a-S2)	% Change in Dispatch
Wind	157,339,652	60,467,557	38%	38%	157,943,346	60,799,827	38%	38%	332,270	1%
ST Coal	75,987,045	57,743,667	69%	76%	72,743,109	62,072,265	58%	85%	4,328,598	8%
CT Gas	388,393	175,805	0%	45%	1,241,682	867,191	1%	70%	691,387	393%
Solar PV	17,666,794	6,841,300	17%	39%	17,694,013	6,853,504	17%	39%	12,203	0%
CC	5,375,617	3,052,716	11%	57%	4,823,291	3,344,478	10%	69%	291,762	10%
Nuclear	20,207,026	20,036,836	96%	99%	19,414,416	19,246,693	93%	99%	(790,143)	-4%
Conventional Hydro	4,110,444	1,606,234	39%	39%	4,110,912	1,606,218	39%	39%	(16)	0%
ST Renewable	3,974,220	3,715,592	93%	93%	2,808,218	2,708,547	68%	96%	(1,007,045)	-27%
ST Gas	184,170	82,437	6%	45%	172,413	77,529	6%	45%	(4,908)	-6%
ST Other	641,526	632,029	92%	99%	614,174	606,931	88%	99%	(25,098)	-4%
IC Renewable	227,041	212,182	93%	93%	158,898	153,244	67%	96%	(58,938)	-28%
IC Gas	2,068	1,215	1%	59%	1,534	1,177	1%	77%	(38)	-3%
Grand Total	***286,103,995***	***154,567,570***	-	-	***281,727,049***	***158,338,290***	-	-	***3,770,720***	***2%***

7.3 Wind and Solar Curtailment

Curtailment of wind or solar generation occurs when the system is not able to accommodate all of the wind and solar generation in a given hour. The two most common reasons for curtailment are:

- The available power at particular wind or solar plant (or group of plants) is higher than the capacity of transmission lines transmitting the power to the bulk grid. This is often referred to as "local congestion". Given that the system operates with security-constrained economic dispatch, the limitation could reflect an N-1 and/or a prior outage condition.
- The aggregate wind and solar power generation over a wide area exceeds what the grid can accommodate, even after all committed conventional power plants are dispatched at their minimum power levels and regional exports are maximized. This is sometimes referred to as a "minimum generation" condition.

In general, a small amount of curtailment is to be expected in any system with a significant level of wind and solar generation. There will be occasional operating conditions where it is economically efficient to accept a small amount of curtailment (i.e., where mitigation of that curtailment would be disproportionately expensive and not justifiable).

Table 7-6 shows annual curtailment of wind and solar energy as a percentage of the total available wind and solar energy. In all scenarios the level of curtailment in the Minnesota-Centric region is relatively small. Figure 7-8 shows annual duration curves of hourly solar curtailment. An inset in the figure shows an expanded view of the hours with the most curtailment. Curtailment occurs for only a very few hours of the year. Scenario 2 has the most curtailment of solar energy; more than 800 MW is curtailed during the worst hour. Further investigation of curtailment by plant revealed that the majority of all solar energy curtailment in Scenario 2 occurred in only two specific plants, indicating that it is likely caused by local congestion. Nonetheless, only 3% of total available solar energy is curtailed in these plants.

Figure 7-9 shows annual duration curves of hourly wind curtailment. In the Baseline and Scenario 1, there are a few hours where wind curtailment approaches 1000 MW. But for the rest of the year, curtailment is very low. In Scenario 2, there are several hours where wind curtailment exceeds 3000 MW. Figure 7-10 shows total curtailed wind energy by hour of day. In all scenarios, there is higher curtailment in nighttime hours (when many baseload generators are dispatched to their minimum output levels) than in daytime or evening hours. The trend most prominent in Scenario 2. This suggests that a portion of the overall curtailment is likely due to system-wide minimum generation conditions. This type of curtailment could be reduced by decommitting some baseload generation via economic market signals. The effectiveness of this mitigation option is illustrated by comparing Scenario 2 (coal units must-run) with Scenario 2a (economic coal commitment). Wind curtailment decreases from 2.14% to 1.60% (a reduction of 332 GWh).

Figure 7-10 also illustrates that there is some wind curtailment during daytime and evening hours, when conventional generation could likely be dispatched down if needed. This suggests that a portion of the wind curtailment is due to local transmission congestion at wind plants. In fact, further investigation revealed that the majority of wind curtailment in the Baseline and Scenario 1 occurred in just a few wind plants. This cause for curtailment could be mitigated by transmission modifications, if economically justifiable.

Table 7-6 Annual Wind and Solar Energy Curtailment

	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Wind Curtailment	0.42%	1.00%	1.59%	2.14%	1.60%
Solar Curtailment	0.09%	0.00%	0.23%	0.42%	0.24%

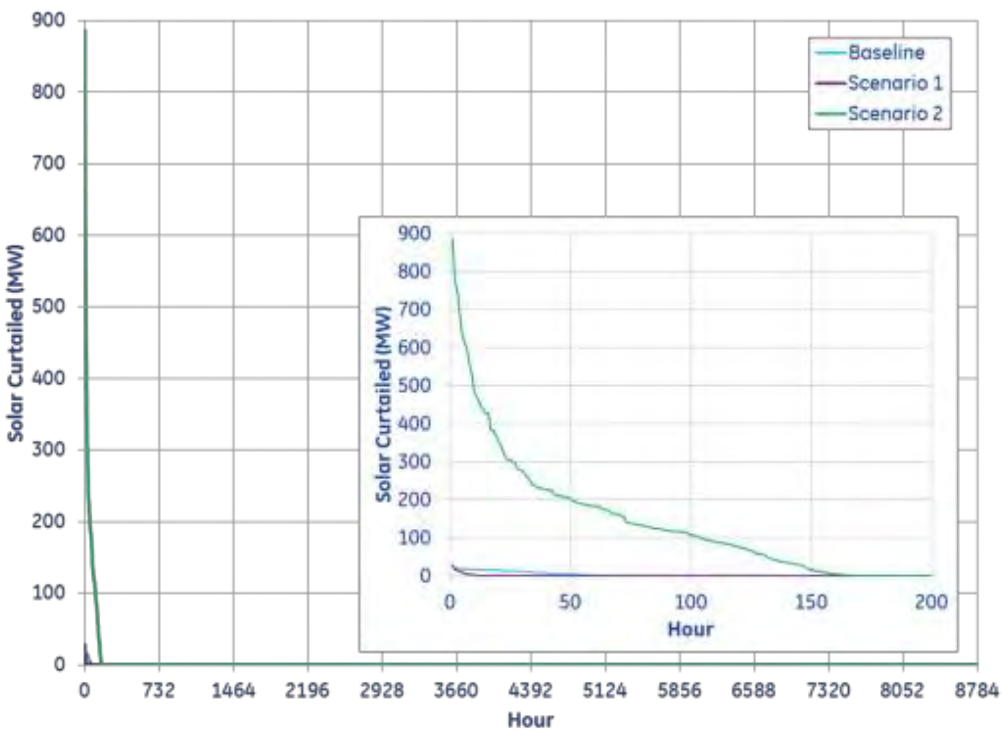

Figure 7-8 Annual Duration Curves of Solar Curtailment for Minnesota-Centric Region

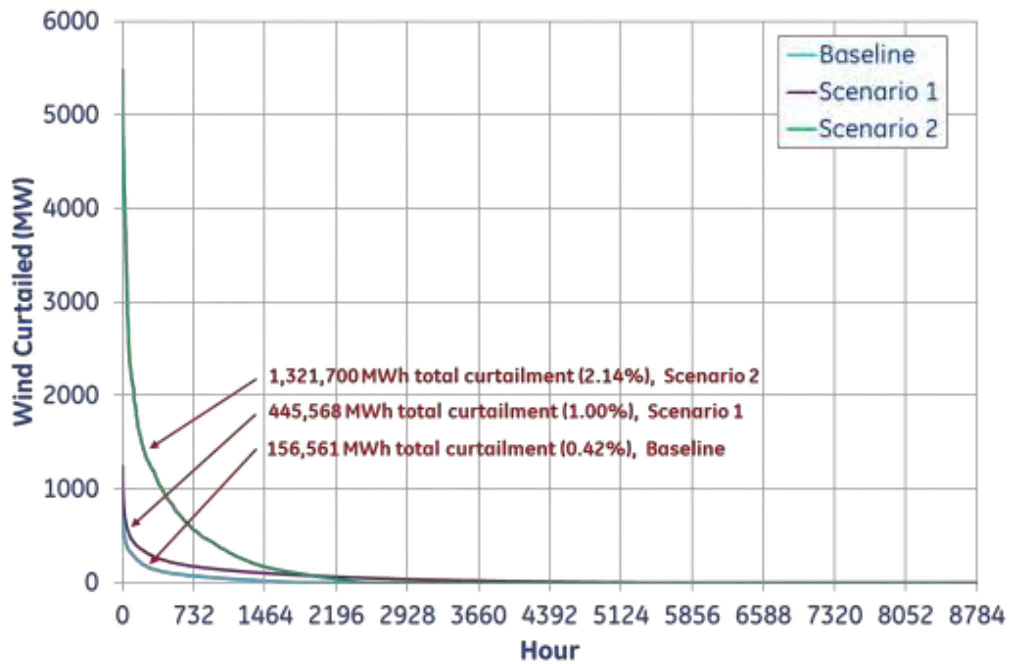

Figure 7-9 Annual Duration Curves of Wind Curtailment for Minnesota-Centric Region

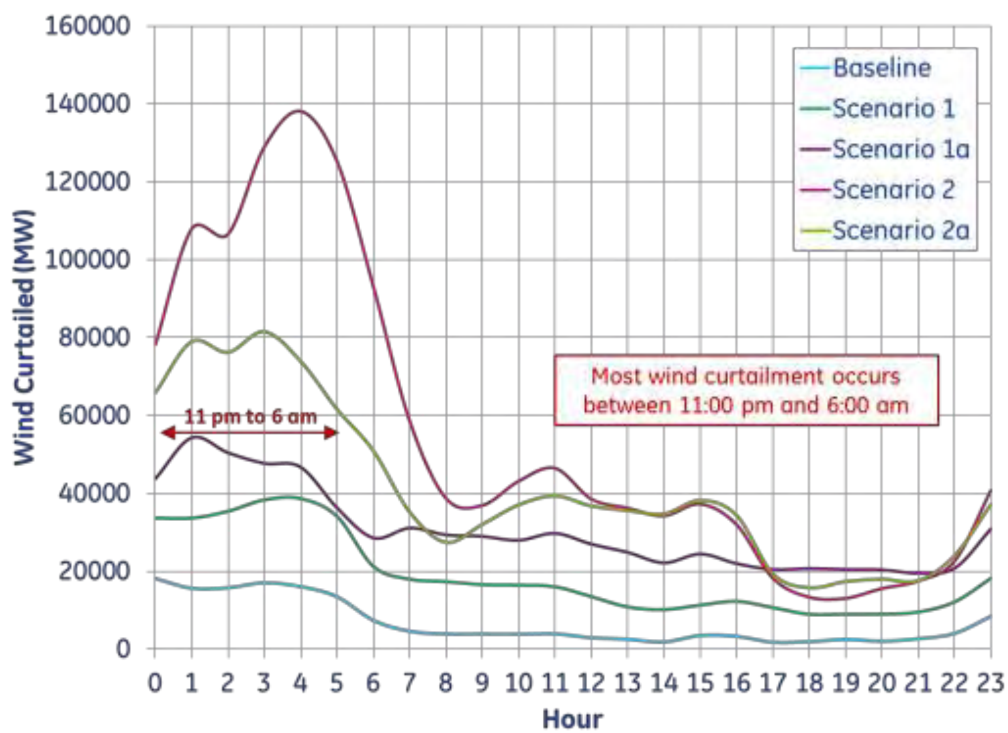

Figure 7-10 Wind Curtailment by Hour of Day for Minnesota-Centric Region

7.4 Thermal Plant Cycling

7.4.1 Coal Units

Shutting down and then restarting generating units is called “cycling”. Increased cycling of conventional generation is a natural side effect of increased wind and solar generation. Some conventional generators are shut down during periods of high wind and solar energy production, and then restarted afterwards.

Some types of units are designed to withstand multiple shutdown/startup cycles (eg., combustion turbines, hydro generators, combined cycle units). However, most coal plants were originally designed for baseload operation; that is, they were intended to operate continuously with only a few start/stop cycles in a year (mostly due to scheduled or forced outages). Increased cycling duty could impact wear and tear on these units, with corresponding impacts on maintenance requirements.

Many coal plants in MISO presently are designated by the plant’s owner to operate as “must-run” to avoid start/stop cycles that would occur if they were economically committed by the market. Figure 7-11 through Figure 7-15 illustrate the amount of cycling for coal plants in the Minnesota-Centric region.

- Figure 7-11 shows total annual starts plotted as a function of unit rating for Baseline, Scenario 1 and Scenario 2. In these scenarios, all but three coal units were assumed to be must-run, consistent with existing operating practices for those units. Hence, those units show only one start per year, following a scheduled maintenance period. The three economically committed coal units experienced from 50 to 230 starts per year.
- Figure 7-12 shows total annual starts for Scenarios 1 (with must-run assumption) and Scenario 1a (with economic commitment and forced outages). In Scenario 1a, coal units experience significantly more cycling duty than in Scenario 1. The plot also shows a general trend where smaller coal units have more annual starts than larger units.
- Figure 7-13 shows a similar comparison for Scenarios 2 and 2a. The trends are similar to the pervious figure.
- Figure 7-14 shows a comparison of total annual starts for Scenarios 1a and 2a. In both scenarios, the coal unit modeling assumptions are the same (economic commitment, forced outages). The only difference is that Scenario 2a has higher wind and solar penetration than Scenario 1a. The plot shows that nearly all coal units experience higher cycling duty when the penetration of wind and solar energy increases.
- The previous figures showed total annual starts due to scheduled outages, forced outages, and economic commitment. Figure 7-15 shows only “operational” starts due to economic commitment. This figure enables a direct comparison of how increased wind and solar penetration affects the cycling duty if the coal units are economically committed by the energy market. Cycling duty increases significantly on nearly all coal units.

Note on Coal Plant Modeling: In this study, coal plants were modeled using data that was derived from the publically available Ventyx dataset, and further vetted by MISO for use in their production simulation analysis studies. Data affecting plant cycling (minimum down time, startup time, startup cost, etc) are representative values for the types of plants modeled. A more thorough analysis of coal plant cycling performance would require use of proprietary plant specific data for individual coal units, which was beyond the scope of this study.

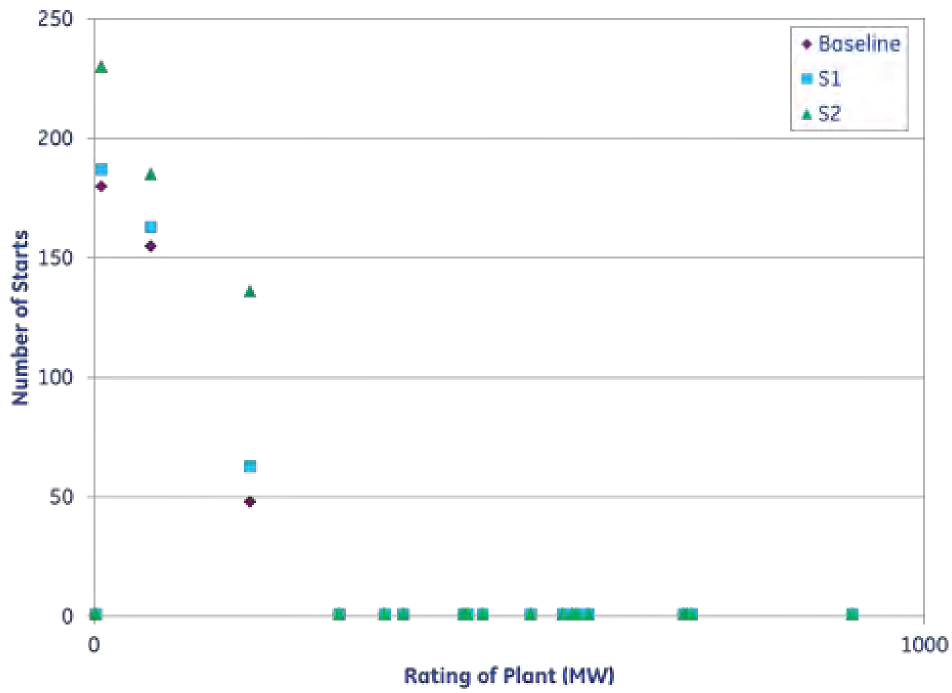

Figure 7-11 Coal Unit Total Annual Starts for Baseline, Scenario 1 and Scenario 2

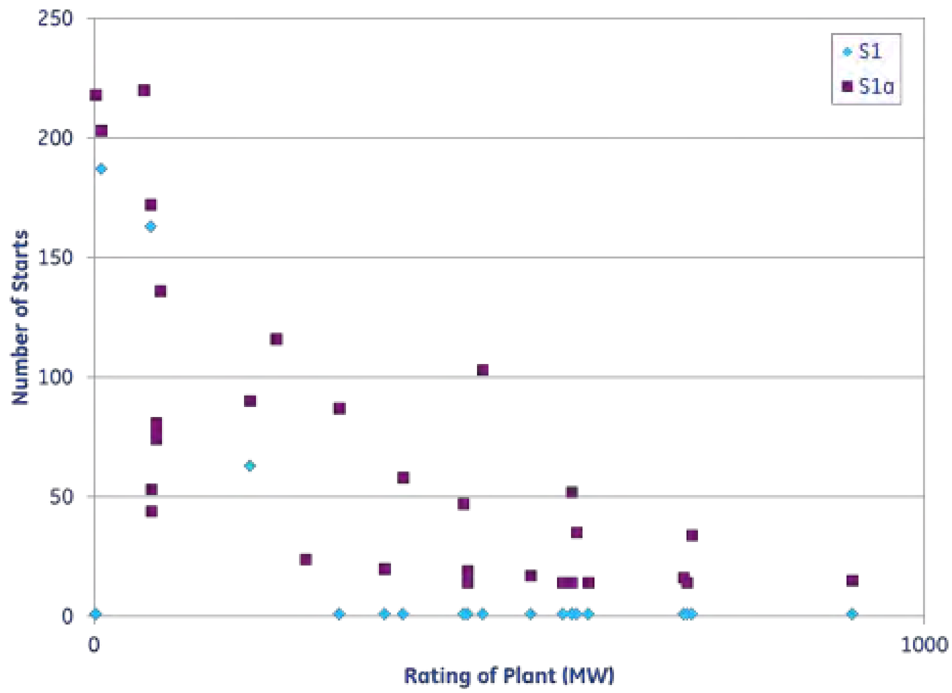

Figure 7-12 Coal Unit Total Annual Starts for Scenario 1 and Scenario 1a

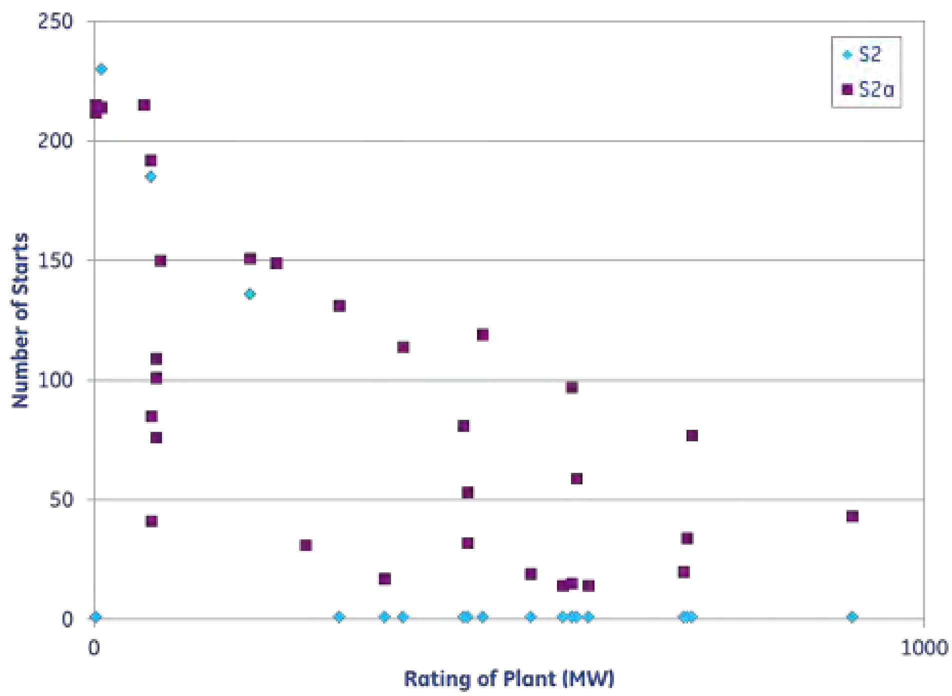

Figure 7-13 Coal Unit Total Annual Starts for Scenario 2 and Scenario 2a

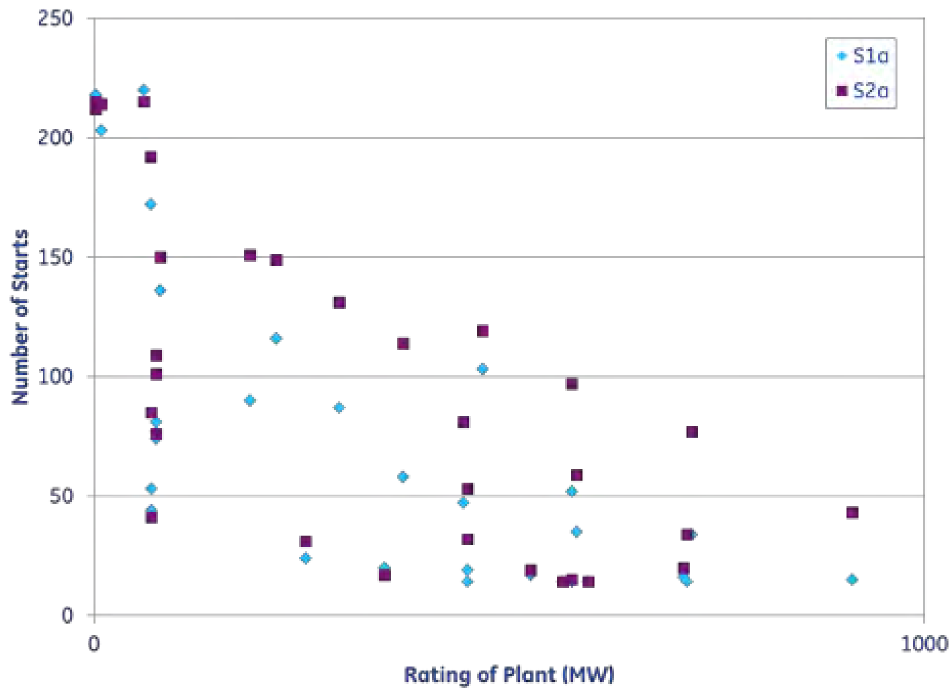

Figure 7-14 Coal Unit Total Annual Starts for Scenario 1a and Scenario 2a

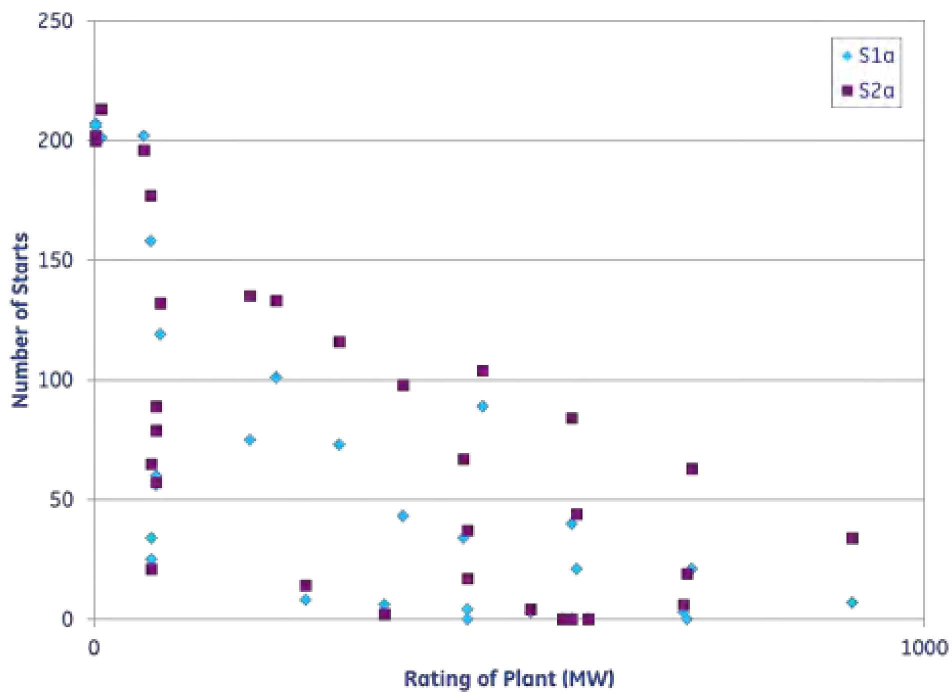

Figure 7-15 Coal Unit Annual "Operational" Starts due to Economic Commitment for Scenario 1a and Scenario 2a

7.4.2 Combined-Cycle Units

Combined-cycle (CC) units are better able to accommodate cycling duties than coal plants. Figure 7-16 is a plot of annual CC unit starts for all 5 scenarios. The data shows that some CC units in the Minnesota-Centric region experience as many as 200 start/stop cycles per year, while other units experience only a few cycles per year. In general, cycling of CC units declines slightly as wind and solar penetration increases. This decline is primarily due to a decrease in CC plant utilization as wind and solar energy increases.

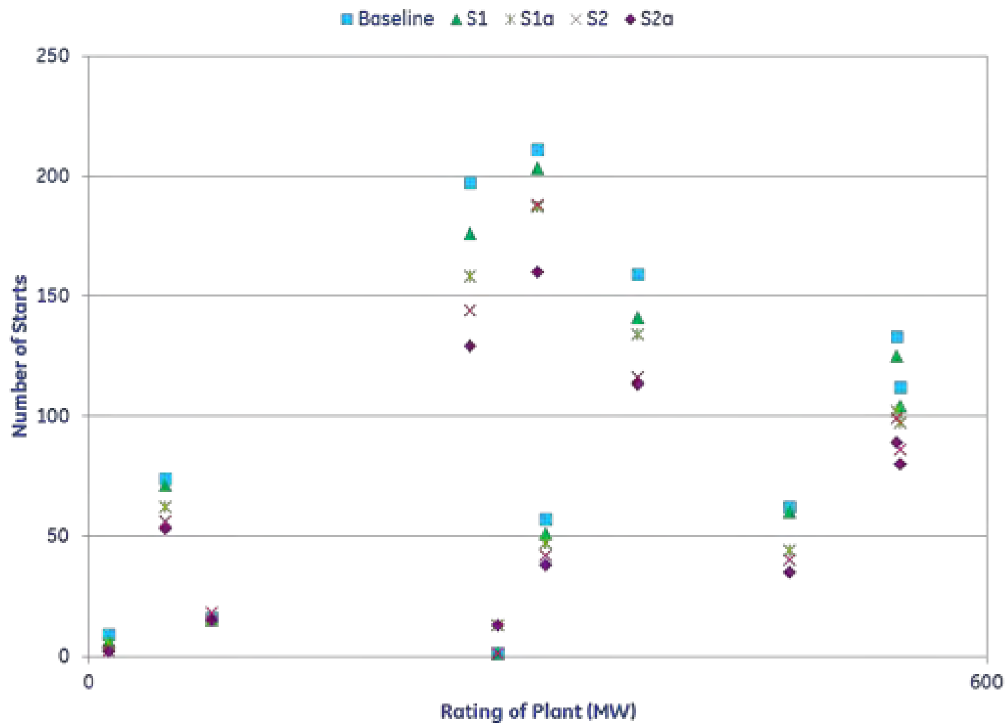

Figure 7-16 Combined-Cycle Unit Total Annual Starts for Baseline, Scenario 1, Scenario 1a, Scenario 2 and Scenario 2a

7.5 MISO Ramp-Range and Ramp-Rate Capability

Ramp-range and ramp-rate capabilities of a balancing area's conventional generation fleet are measures of its ability to accommodate the variability and uncertainty associated with wind and solar generation (i.e., the fleet's ability to follow changes in wind plant output or to compensate for forecast errors in system load and wind/solar energy production. This analysis was conducted for all of MISO Central-North, since this capability is only relevant for a balancing area.

Figure 7-17 shows range-up capability for the MISO conventional generation fleet for the Baseline, Scenario 1 and Scenario 2. Figure 7-18 shows ramp-rate up capability for the same scenarios. Ramp-range-up and ramp-rate-up capability of the MISO conventional generation fleet increases with increased penetration of wind and solar generation. Conventional generation is generally dispatched down rather than decommitted when wind and solar energy is available, which gives those generators more headroom for ramping up if needed.

Figure 7-19 shows range-down capability for the MISO conventional generation fleet for the Baseline, Scenario 1 and Scenario 2. Figure 7-20 shows ramp-rate down capability for the same scenarios. Ramp-range-down and ramp-rate-down capability of the MISO conventional generation fleet decreases with increased penetration of wind and solar generation. In Scenario 2, there are 500 hours when ramp-rate-down capability of the conventional generation fleet falls below 100 MW/min. As shown in Figure 7-21, periods of low ramp-down capability coincide with periods of high wind and solar generation (see regions within red boxes). Wind and solar generators are capable of providing additional ramp-down capability to MISO during these periods. MISO's existing Dispatchable Intermittent Resource (DIR) process already enables this for wind generators. It is anticipated that MISO would expand the DIR program to include solar plants in the future.

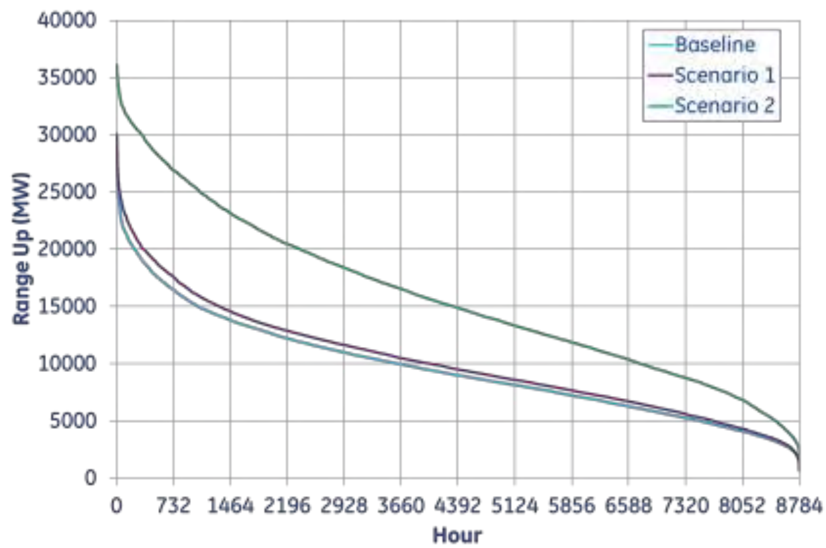

Figure 7-17 Annual Duration Curve of Range-Up Capability for Conventional Generation within MISO Central-North

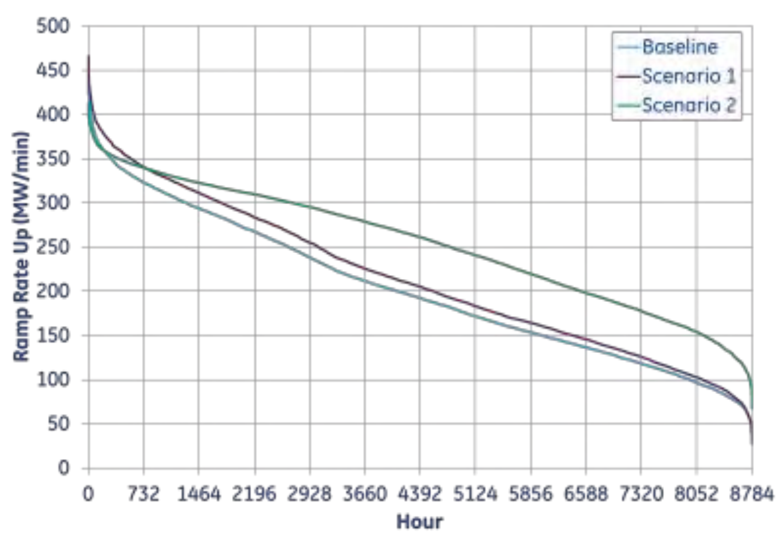

Figure 7-18 Annual Duration Curve of Ramp-Rate-Up Capability for Conventional Generation within MISO Central-North

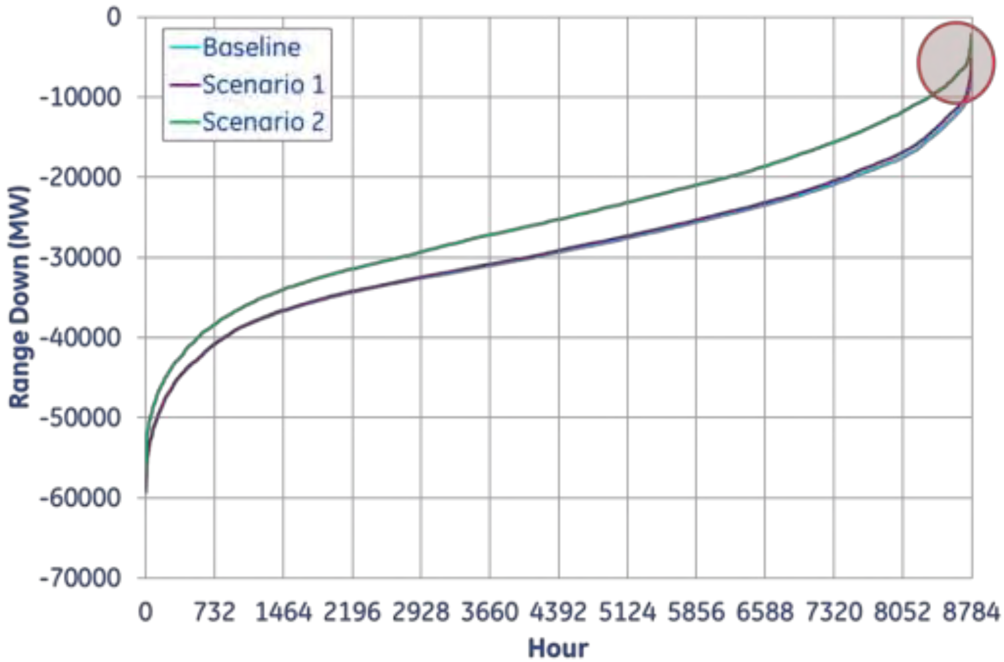

Figure 7-19 Annual Duration Curve of Range-Down Capability for Conventional Generation within MISO Central-North

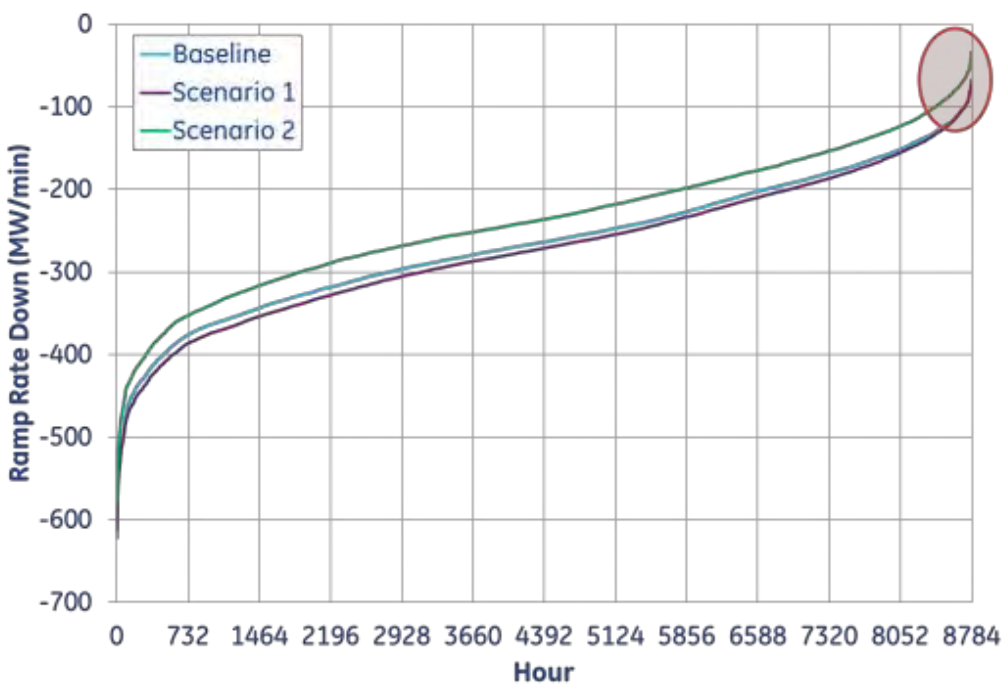

Figure 7-20 Annual Duration Curve of Ramp-Rate-Down Capability for Conventional Generation within MISO Central-North

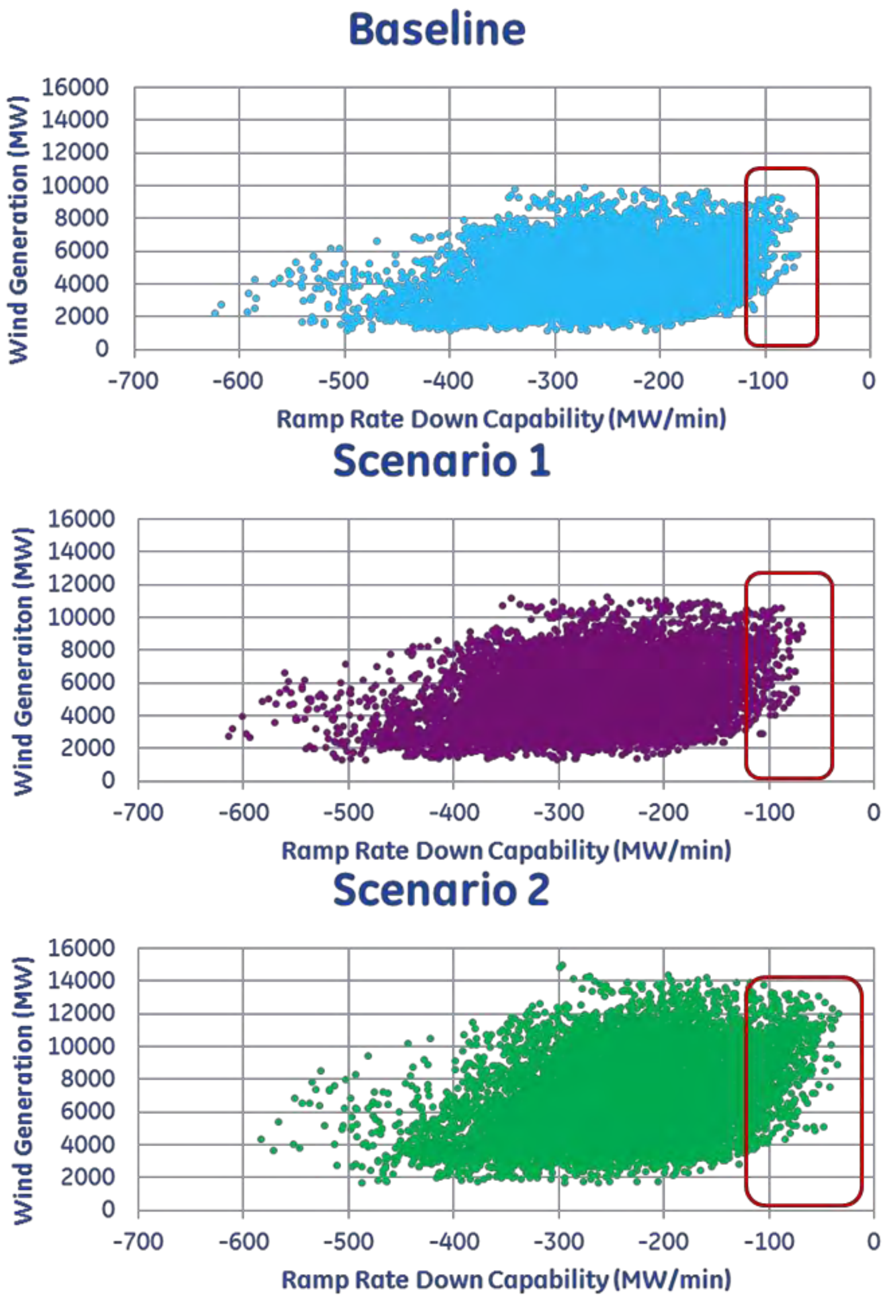

Figure 7-21 Scatter Plot of Ramp-Rate Down Capability of MISO Conventional Generation Fleet vs Wind Generation in Minnesota-Centric Region

7.6 Carbon Emissions

Table 7-7 shows total annual carbon emissions for the study scenarios. Overall, the CO_2 emissions are closely related to the amount of ST Coal committed in the system. Scenario 1a has nine more coal plants than Scenario 1. As a result, Scenario 1a has a higher level of CO_2 emissions. Similarly, Scenario 2a has higher CO_2 than Scenario 2 because of the nine additional coal plants.

Table 7-7 CO_2 Emissions for the Minnesota-Centric Region

	Baseline	S1	S1a	S2	S2a
Tons of CO2	83,627,254	82,055,702	84,027,816	67,882,045	73,991,430
Reduction Versus Baseline (Tons CO2)		1,571,551	(400,562)	15,745,209	9,635,823

7.7 Screening Metrics for Stability/Control Issues

The results of the production simulation analysis were screened to select challenging operating conditions for dynamic performance, and these operating points were subsequently analyzed with fault simulations in the dynamics task. This section describes the three screening metrics and the process for selecting specific system operating conditions for dynamic simulation analysis.

7.7.1 Percent Non-Synchronous Generation (% NS)

In order to assess the stability of the power system, focusing only on generation owned by the Minnesota utilities was no longer sufficient. To evaluate stability issues, it is necessary to consider <u>all</u> generation located within the geographic area of interest. Thus, for this metric, the definition of the Minnesota-Centric region was modified to include all generation, regardless of owner or type, within the regions shown in Figure 7-22. The Minnesota-Centric region for calculating % non-synchronous (NS) is defined by the shaded area of the figure, and includes six sub-regions; Northern Minnesota, South and Central Minnesota, Southwest Minnesota, North Dakota, South Dakota and Iowa. Based on the physical location of the generation, the % NS metric was calculated for the Minnesota-Centric region and the six sub-regions.

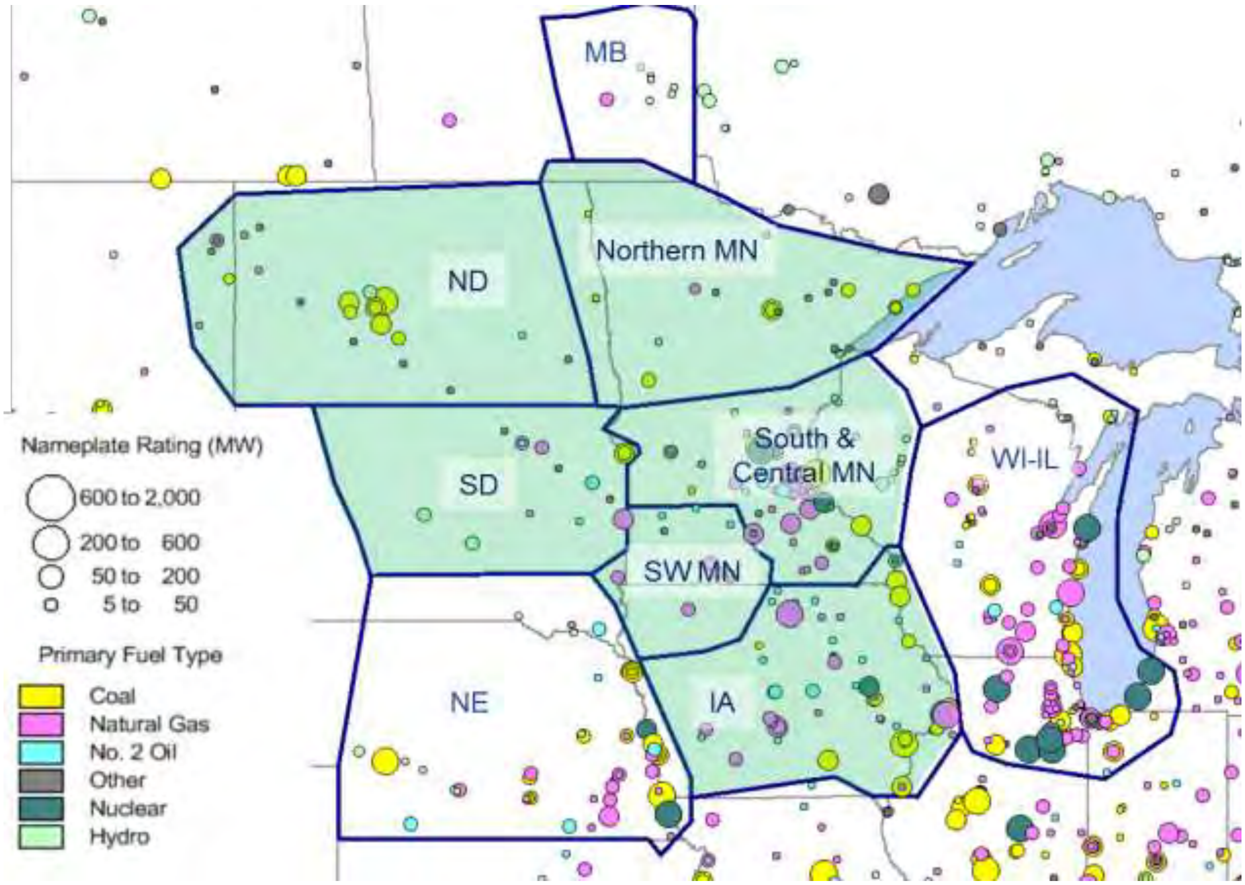

Figure 7-22 Geographic Footprint of Minnesota-Centric Region for % NS Metric

The % NS metric is the ratio of non-synchronous inverter-based generation (i.e. wind and solar) MW rating to the total generation (i.e. wind, solar and all conventional generation) MW rating within a given geographic boundary.

$$\% \, NS = \frac{Total\ online\ wind + solar\ MW\ rating}{Total\ online\ generation\ MW\ rating}$$

This metric is an indicator of ac system strength or weakness. Synchronous generators are pure voltage sources and therefore contribute short-circuit current and support the "strength" of the ac transmission system. Inverter-based generators do not contribute to system strength. Inverter-based generators depend on the system strength provided by synchronous machines (either generators or synchronous condensers) to operate in a stable manner. Low % NS indicates strong system conditions and high % NS indicates potentially weak system conditions. Hence, this metric can be used to identify periods of weak system conditions for further evaluation using dynamic analysis methods.

HVDC converters are also affected by system strength in a similar manner. HVDC converters have similar internal controls that can experience degraded stability under weak system conditions. However, given the scope of this study, the analysis reported here only considers weak system issues related to wind and solar generation.

7.7.2 Percent Renewable Penetration (% RE)

The % RE metric is the ratio of all wind and solar generation MW output to the total MW output of all generation (including wind and solar) within a given geographic boundary:

$$\%\,RE = \frac{Wind + Solar\ MW\ dispatched}{Total\ Generation\ MW\ dispatched}$$

This metric was applied to the Minnesota-Centric region as defined in Figure 7-1. The % RE metric was selected as it is one of the traditional metrics used to identify periods of the year where there are high levels of renewable generation supplying the load in the system, and where the dynamic performance of the overall system is more dependent on the dynamic performance of the wind and solar resources.

7.7.3 Transmission Interface Loading

This metric was used to identify periods of high loading on three interfaces that are important to the dynamic performance of the Minnesota region. High loading on these interfaces stresses the overall transmission system, and provides appropriate operating conditions for testing system resilience to transmission system faults.

North Dakota Export (NDEX): This interface consisted of 23 lines that provided most of the power transfer out of the North Dakota sub-region. The geographic representation of this interface is seen in Figure 7-23.

Figure 7-23 NDEX Transmission Interface

Buffalo Ridge Outlet: This interface consisted of four selected transmission lines that transfer energy out of the wind rich Buffalo Ridge region. The physical location of the lines is seen in Figure 7-24.

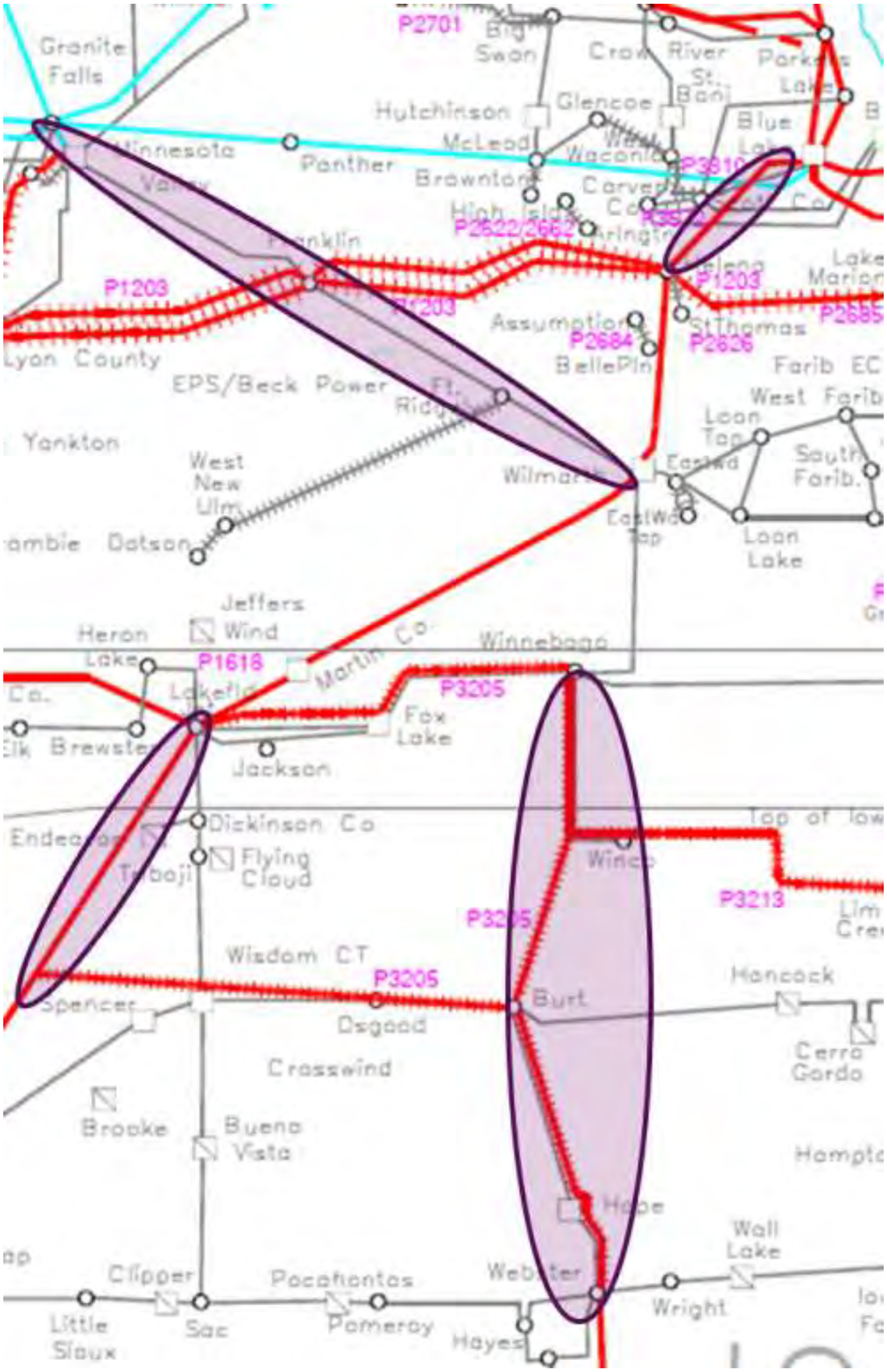

Figure 7-24 Buffalo Ridge Outlet Lines

Minnesota-Wisconsin Export (MWEX): This interface monitored the flows across three major transmission lines from Minnesota into Wisconsin(see Figure 7-25).

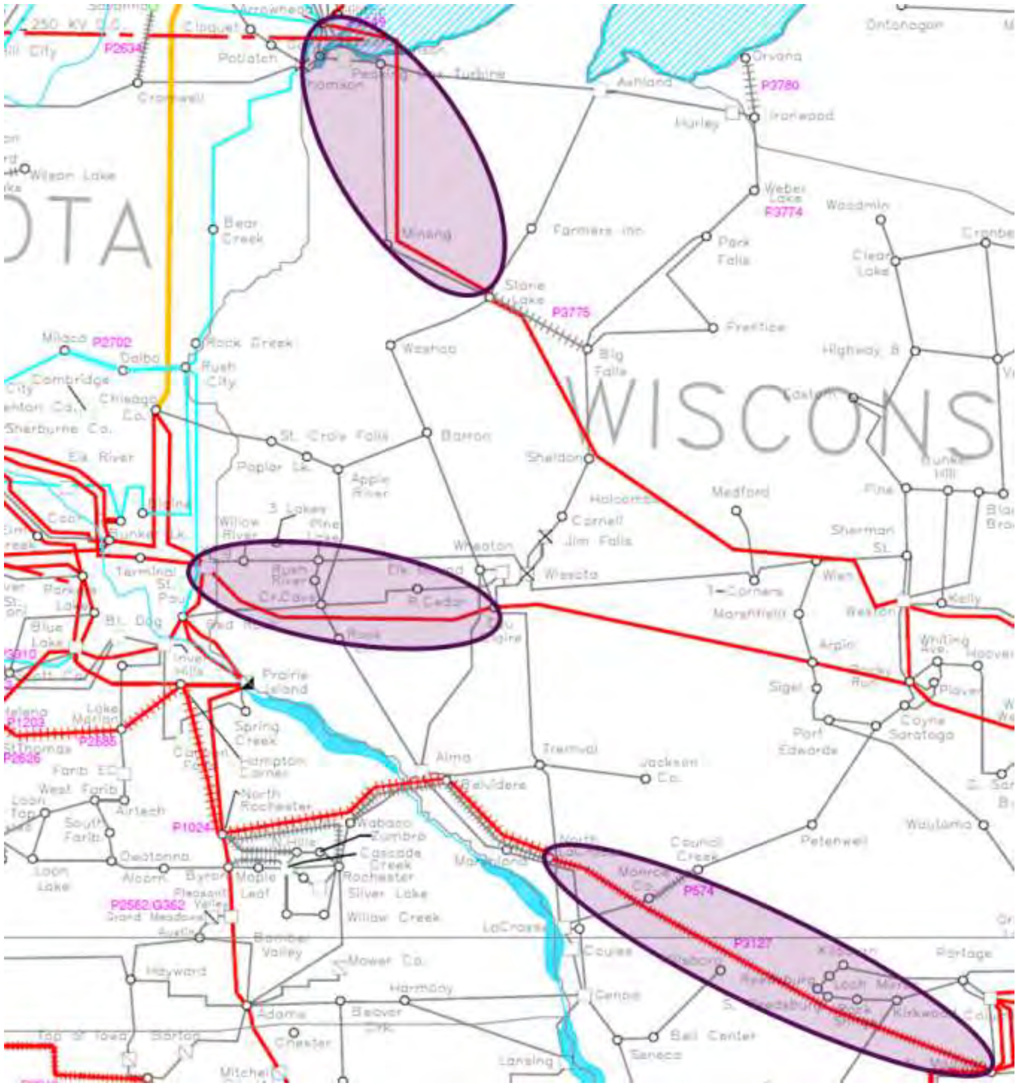

Figure 7-25 MWEX Transmission Interface

7.7.4 Analysis of Percent Non-Synchronous Generation

The % NS metric was calculated for each hour of the year and plotted as duration curves for the Minnesota-Centric region as well as its six subregions (per Figure 7-22). The results are plotted in Figure 7-26 through Figure 7-30.

The % NS varies greatly across the five scenarios. The general trend is that % NS gradually increases from the Baseline (Figure 7-26) to Scenario 1 (Figure 7-27) and finally to Scenario 2 (Figure 7-29). This correlates with the increased wind and solar generation displacing some of the conventional synchronous generation in the region. With lower levels of conventional plant online, the % NS values increase on average.

Different trends are observed when comparing Scenario 1 with Scenario 1a (Figure 7-28). In Scenario 1a, there were nine additional coal plants (existing plants not retired), all of the coal plants were given more operational flexibility (i.e., not must-run), and the forced outage rates of the conventional plants were enforced. As a result, the tails of the duration curves show significant differences. The periods of higher % NS and lower % NS both increase. These same trends can be observed by comparing Scenario 2 with Scenario 2a in Figure 7-30. Table 7-8 provides the maxima and minima of % NS for each of the scenarios studied.

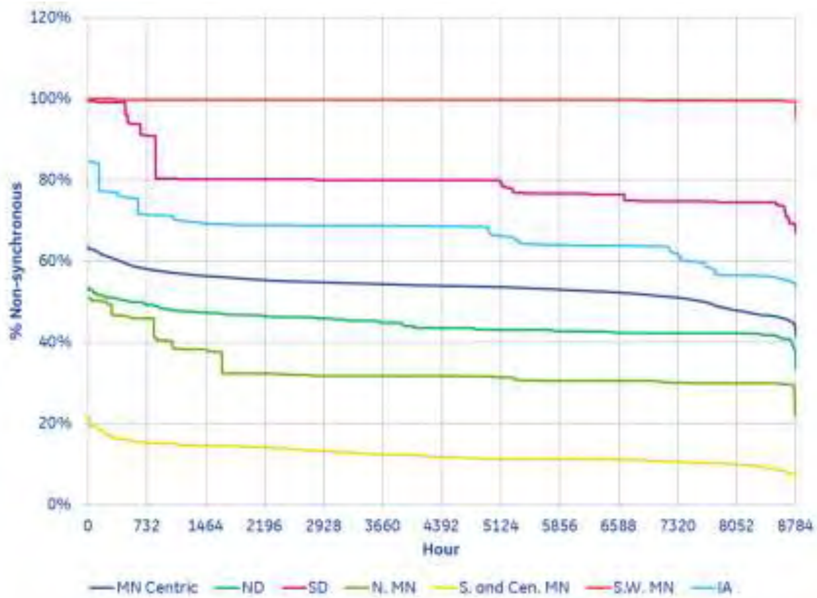

Figure 7-26 Baseline % NS Duration Curves

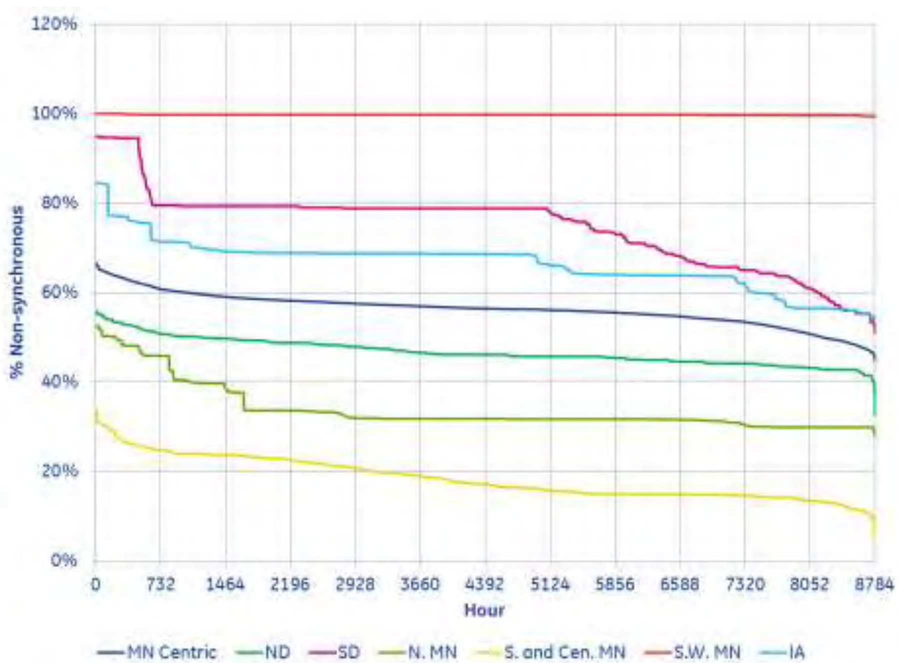

Figure 7-27 Scenario 1 % NS Duration Curves

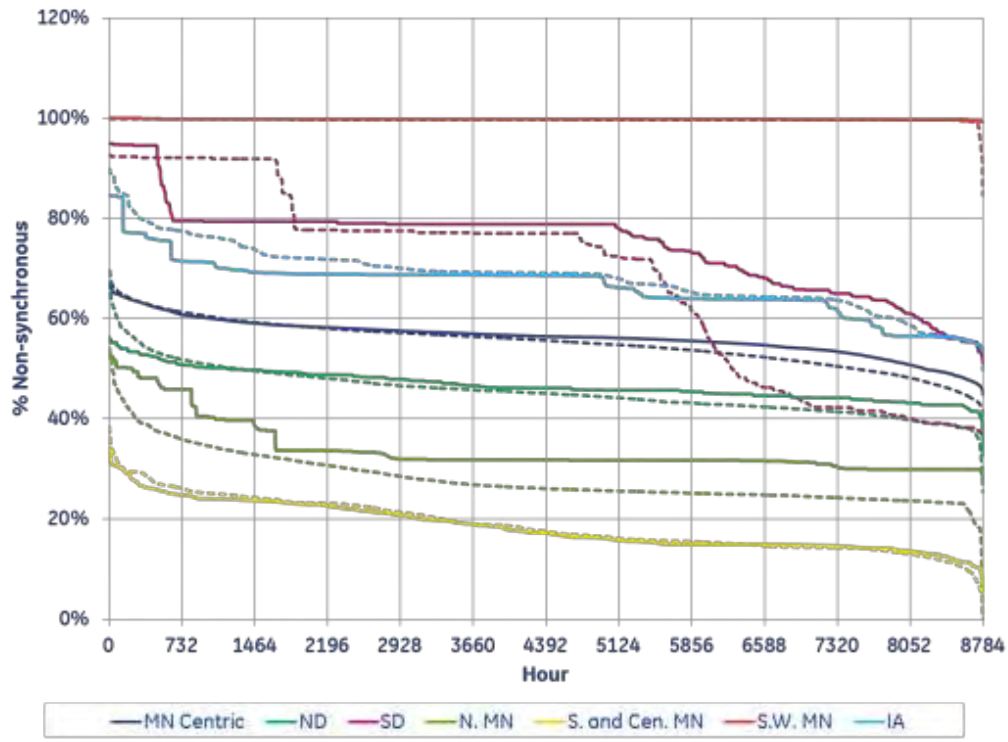

Figure 7-28 Scenario 1 (solid) and 1a (dashed) % NS Duration Curves

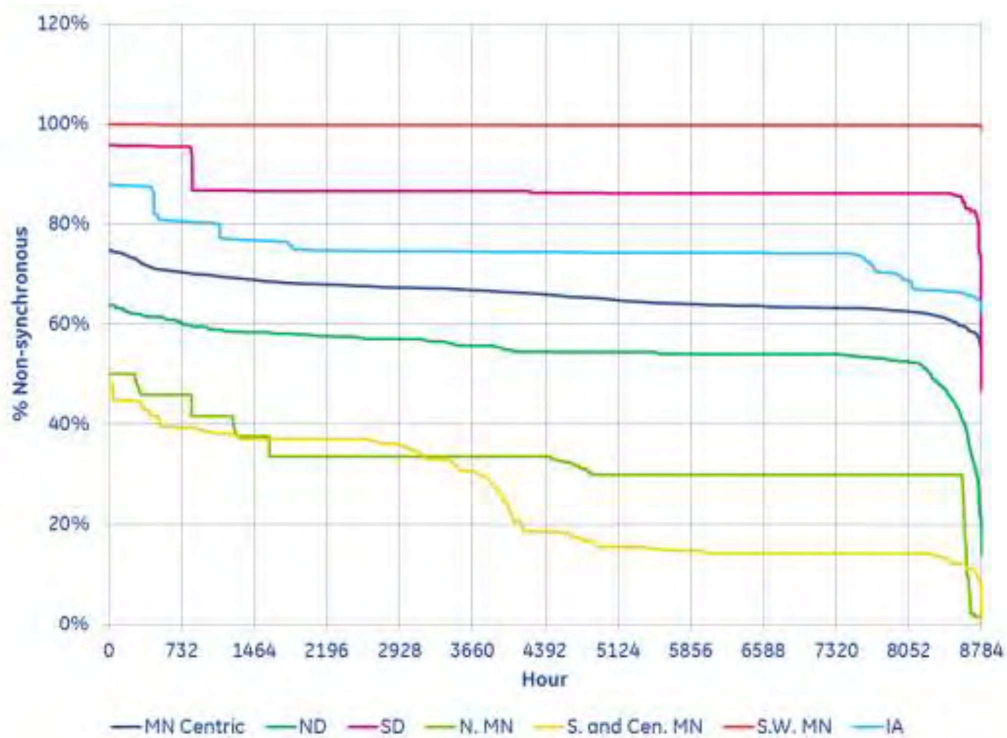

Figure 7-29 Scenario 2 % NS Duration Curves

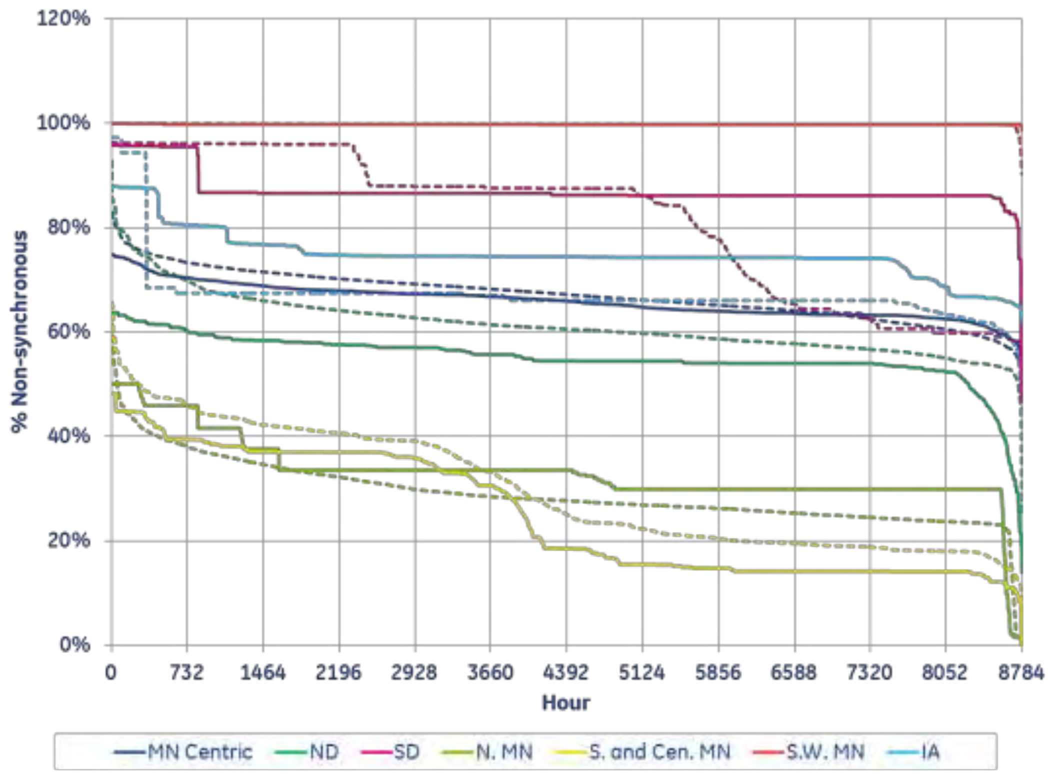

Figure 7-30 Scenario 2 (solid) and 2a (dashed) % NS Duration Curves

Table 7-8 Maximum and Minimum % NS Values

Scenario	Minnesota Centric	Northern Minnesota	South & Central Minnesota	Southwest Minnesota	North Dakota	South Dakota	Iowa
Baseline	Max: 64% Min: 42%	Max: 51% Min: 22%	Max: 22% Min: 6%	Max: 100% Min: 95%	Max: 53% Min: 34%	Max: 99% Min: 67%	Max: 85% Min: 53%
Scenario 1	Max: 67% Min: 45%	Max: 53% Min: 28%	Max: 34% Min: 6%	Max: 100% Min: 99%	Max: 56% Min: 33%	Max: 95% Min: 51%	Max: 85% Min: 54%
Scenario 1a	Max: 70% Min: 40%	Max: 56% Min: 0%	Max: 38% Min: 0%	Max: 100% Min: 85%	Max: 70% Min: 25%	Max: 93% Min: 37%	Max: 90% Min: 50%
Scenario 2	Max: 75% Min: 52%	Max: 50% Min: 0%	Max: 48% Min: 0%	Max: 100% Min: 99%	Max: 64% Min: 14%	Max: 96% Min: 47%	Max: 88% Min: 62%
Scenario 2a	Max: 83% Min: 52%	Max: 62% Min: 0%	Max: 66% Min: 9%	Max: 100% Min: 90%	Max: 93% Min: 25%	Max: 96% Min: 45%	Max: 97% Min: 44%

7.7.5 Percent Renewable Penetration Analysis

Figure 7-31 shows duration curves of the % RE metric for the Minnesota Centric region for all five scenarios. The general trend from Baseline to Scenario 1 to Scenario 2 is an increase in the % RE penetration as the wind and solar levels increase and conventional generation is backed down to accommodate the increased output.

Scenario 1a has a slightly higher % RE than Scenario 1, consistent with the change in % NS between the two scenarios. Conversely, Scenario 2a has a significantly lower % RE than Scenario 2. This is contrary to % NS which is higher for Scenario 2a than Scenario 2. This is primarily related to the changes in modeling assumptions for the coal units. In Scenario 2a where coal units are economically committed, fewer MW of ST Coal and CC generation are committed over the course of the year, but when a plant is committed it is run at a higher capacity factor. This behavior is documented in Section 7.4, where the transition from Scenario 2 to Scenario 2a, sees fewer TWh of ST Coal and CC generation being committed, but the dispatched TWh increasing.

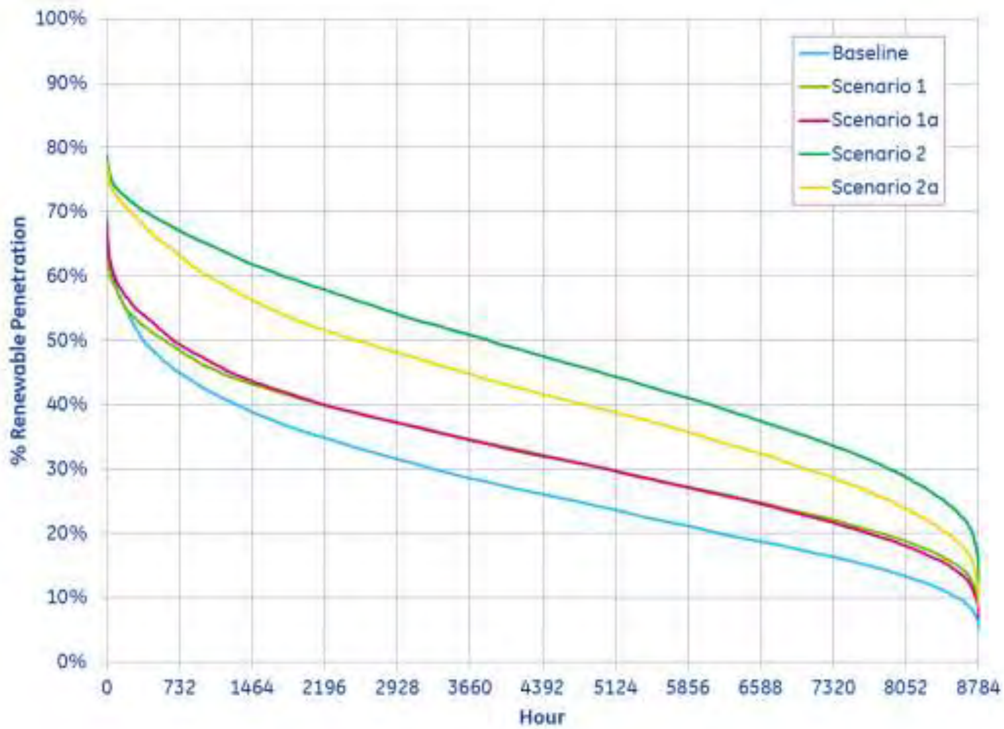

Figure 7-31 % RE Penetration for the Minnesota-Centric Region

7.7.6 Transmission Interface Loading

During periods of high transmission interface loading, the grid could be more vulnerable to power swings after transmission system faults.

In Figure 7-32 through Figure 7-34, the interface loading duration curves are compared for Scenario 1 and Scenario 1a. These were the only two scenarios that were analyzed as they were the only ones that were studied for the dynamic analysis.

For each of the three interfaces an increase in interface loading is observed as the dispatch and commitment moves from Scenario 1 to Scenario 1a for the NDEX (Figure 7-32) and MWEX (Figure 7-34) interfaces. This is due to the fact that there is an overall increase in the ST Coal in the sub-regions close to the interfaces. Both NDEX and MWEX see increases due to additional coal energy in North Dakota and Northern Minnesota from plants that were retired in Scenario 1 but were part of the ST Coal fleet in Scenario 1a. The Buffalo Ridge Outlet flow (Figure 7-33) is nearly the same in Scenarios 1 and 1a because these lines are primarily loaded with wind and solar power, which is nearly the same in both scenarios.

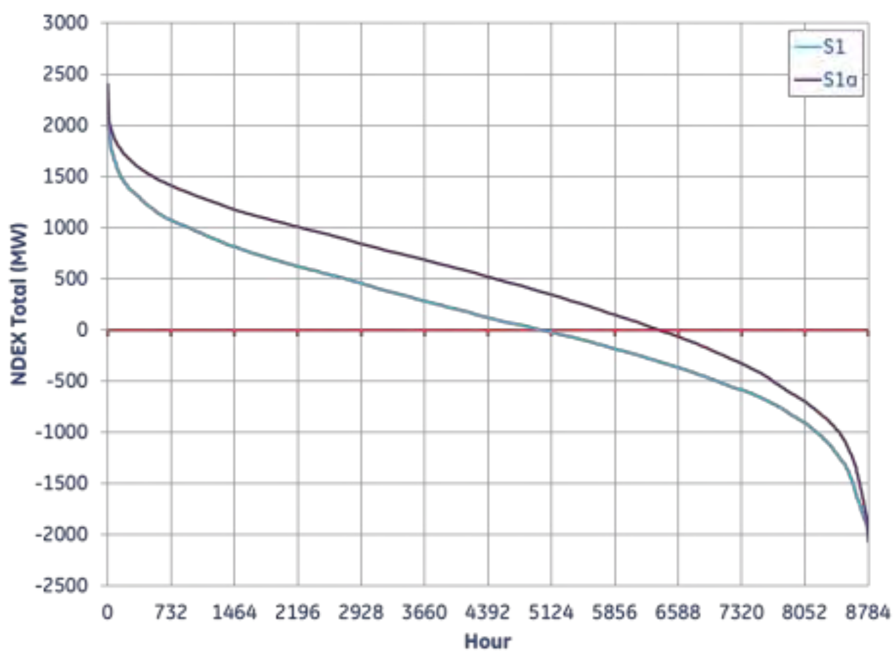

Figure 7-32 NDEX Total Loading for Scenario 1 and Scenario 1a

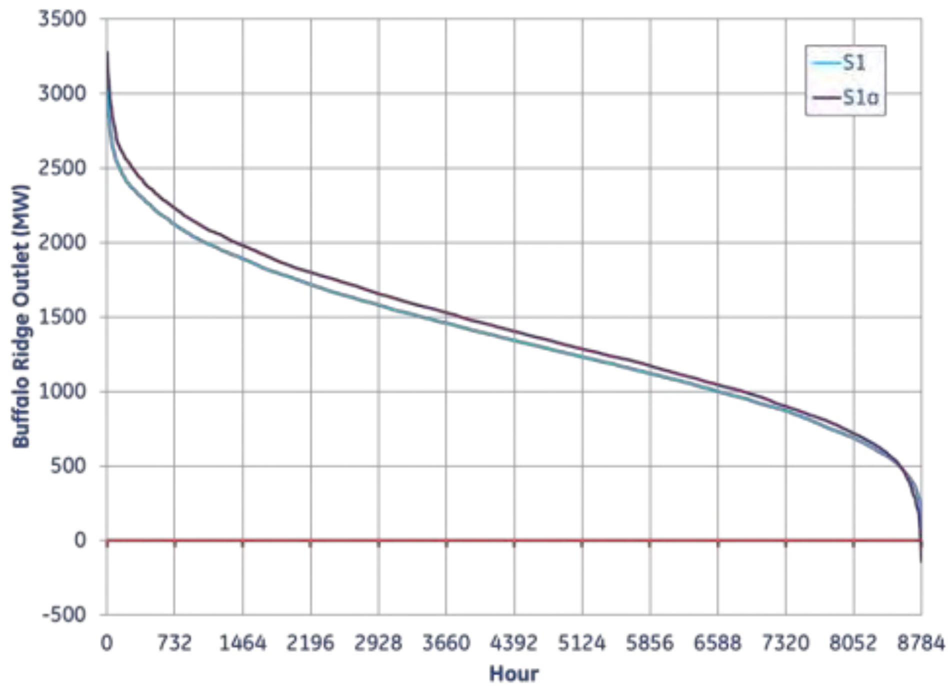

Figure 7-33 Buffalo Ridge Outlet Loading for Scenario 1 and Scenario 1a

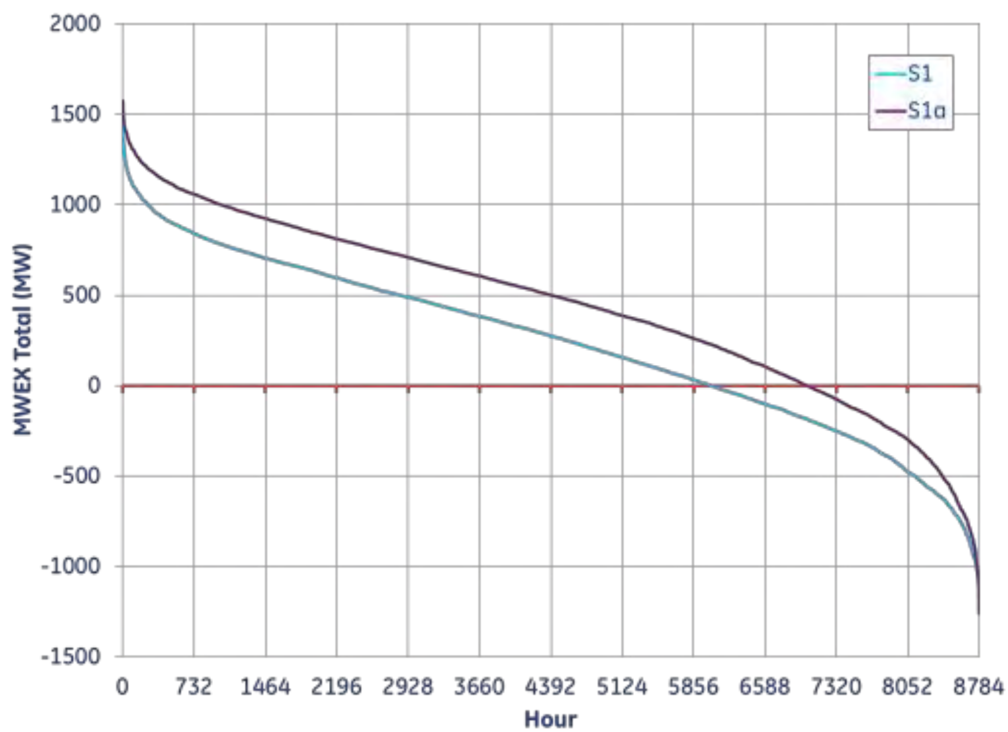

Figure 7-34 MWEX Total Loading for Scenario 1 and Scenario 1a

7.8 Selection of Operating Conditions for Dynamic Analysis

Using the three metrics described in the previous section, seven stability cases were selected for each of the two studied scenarios, Scenario 1 and Scenario 1a, for a total of 14 cases. First they were screened based on the Scenario 1 data followed by a secondary screening and adjustment if necessary based on the Scenario 1a data.

This section describes the process of using the metrics to identify the stability cases. The goal of the screen process was to filter down the 8784 hours of operation from the production simulation results into small groups of hours with common operating conditions that would facilitate in building a commitment and dispatch in the appropriate power flow case.

The first metric used to screen for stability cases was the % NS measure. The following process was used to identify appropriate cases to feed into the dynamic stability assessment.

1. The hourly % NS data for the scenario is plotted against the load duration curve for the Minnesota-Centric region. The load curve is segmented into 3 regions (peak, shoulder, light) that correspond to the power flow cases (Figure 7-35). This provided system load levels that would serve as filters for the next step.

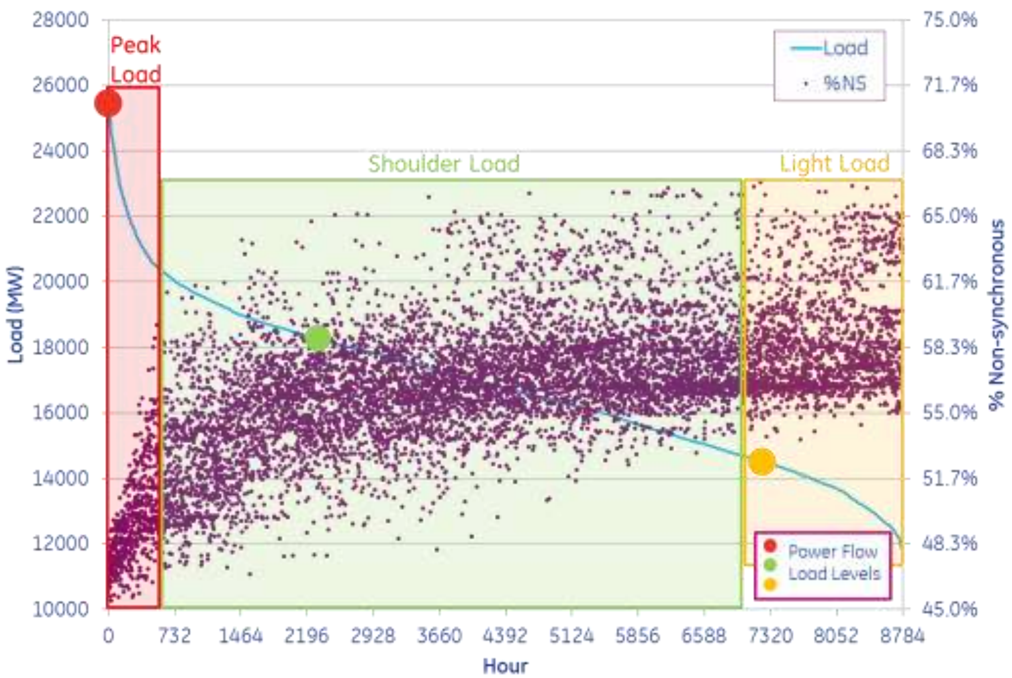

Figure 7-35 Load Duration Curve and % NS for the Minnesota-Centric Region

2. Next, the load and corresponding hourly % NS values were plotted chronologically (as in Figure 7-36). Once again, loading levels that corresponded to the power flow cases (peak, shoulder, light) were identified and used to refine the loading windows in hours with similar characteristics.

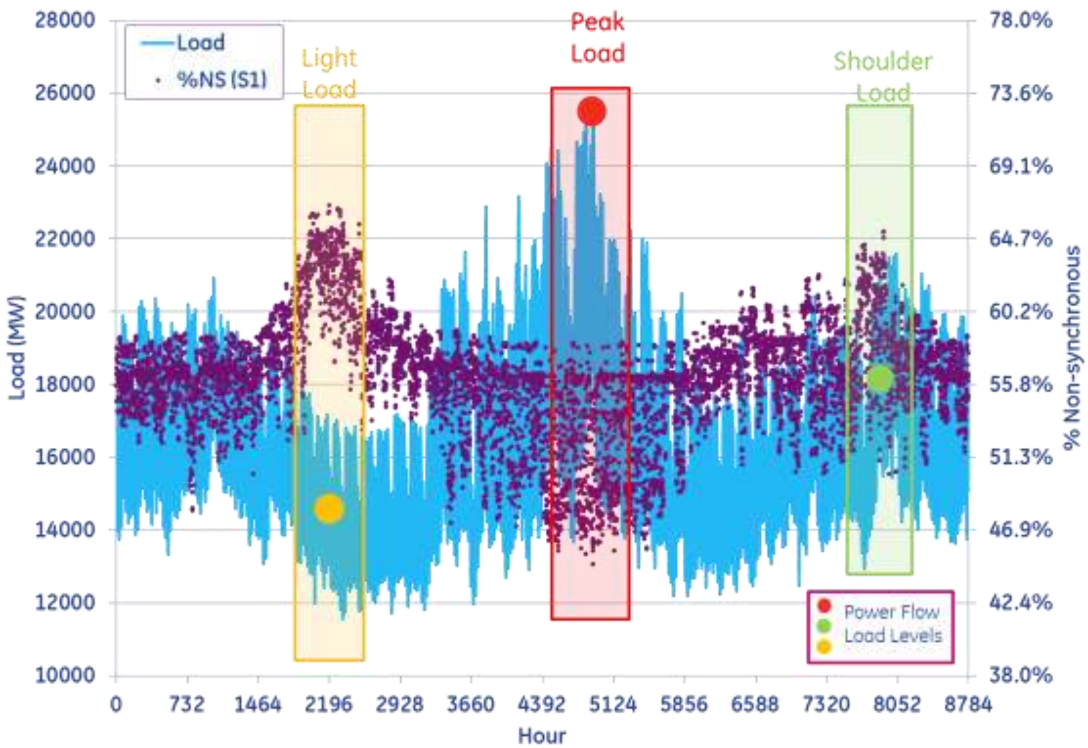

Figure 7-36 Chronological Load and % NS for the Minnesota-Centric Region

3. To identify a group of hours with similar operating conditions, the data was filter by time of year (fall), system load level (shoulder) and highest % NS (>55%). The result was 118 hours that satisfied the criteria (Figure 7-37).

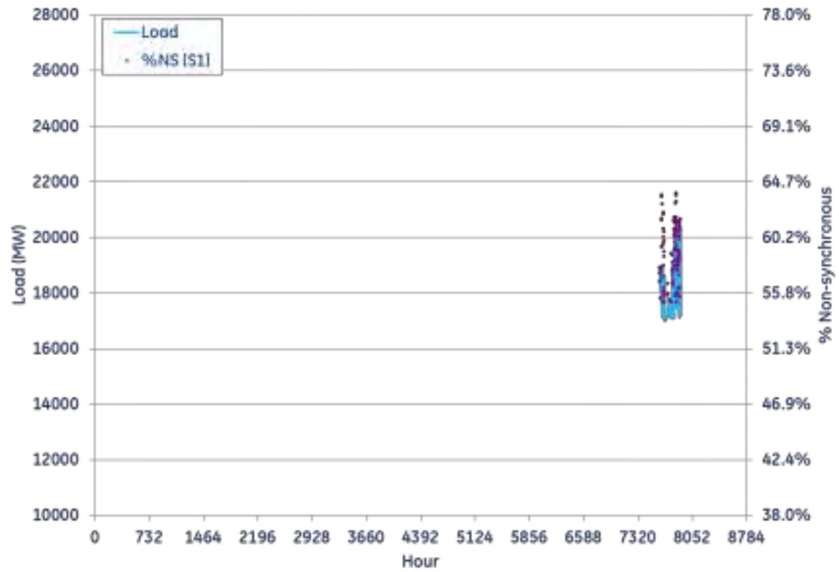

Figure 7-37 Filtered Load and % NS to the Fall Shoulder-Load Window

4. These 118 hours were then sorted by time of day to ensure that the hours with online solar (daytime hours) were captured and allowed for consistent hours in the commitment and dispatch (Figure 7-38). This resulted in 15 hours where the commitment and dispatch had very high % NS levels during a very small window.

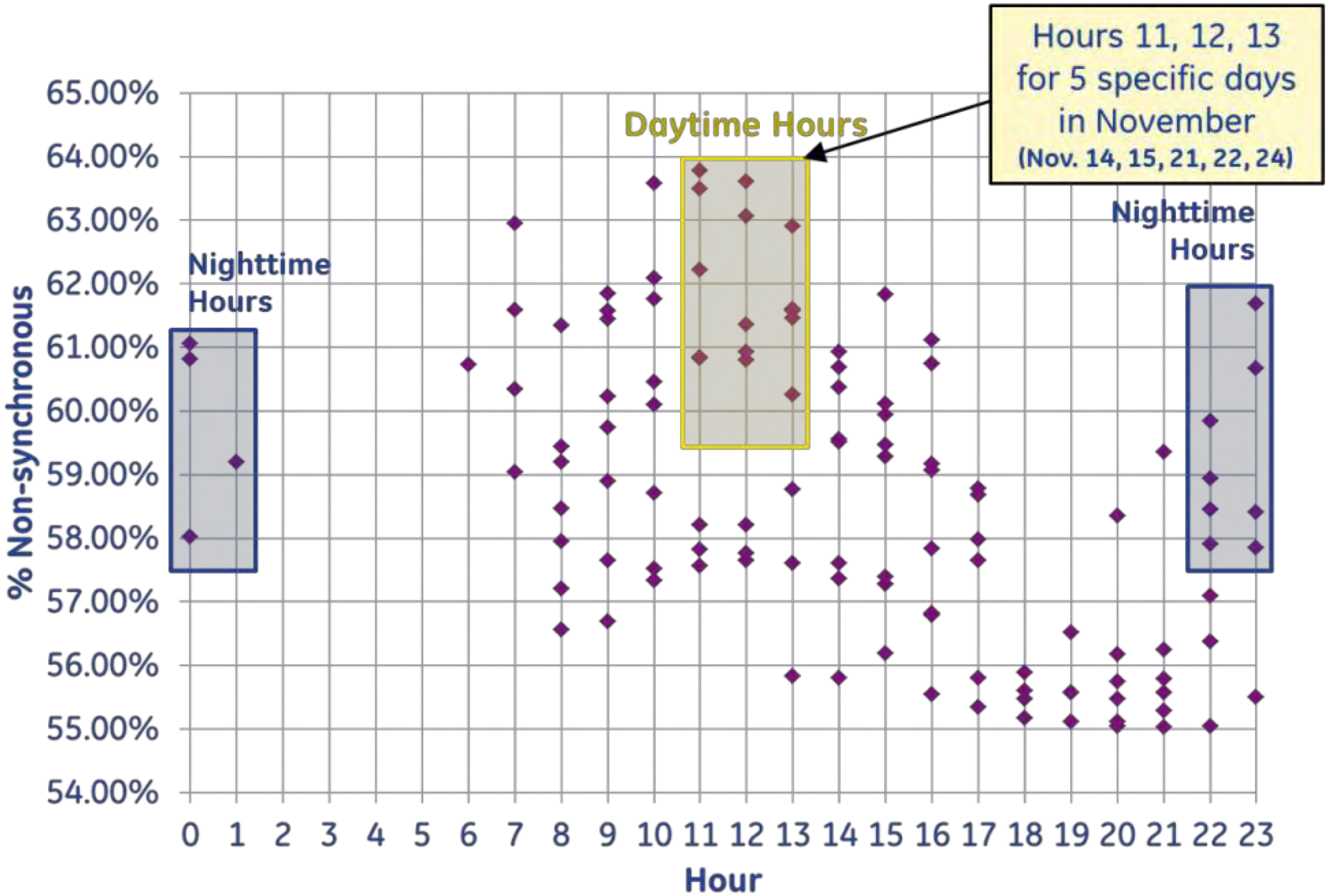

Figure 7-38 Further Filter Fall Shoulder Hours for Scenario 1 Stability Analysis

Through this same methodology a further two stability cases were selected for the % NS case that corresponded to the peak load and light load periods and a high % RE case that corresponded to a light load period. Three additional cases were selected using the interface loading metric for a total of seven Scenario 1 stability cases (Table 7-9).

Table 7-9 Stability Cases for Scenario 1

Case	Criteria	Load	Day / Night	Notes
1	High % NS	Shoulder	Day	55% - 64% NS, 5 days in Nov., 11am – 1pm
2	High % NS	Light	Night	%NS > 60%, April 2-8, 12am-7am
3	High % NS	Peak	Day	46% - 51% NS, July 21-27, 2pm-7pm
4	High % RE Penetration	Light	Night	%RE > 55%, Avg. 71% Oct. 1, 5-7, 12am - 7am
5	High Transmission Loading NDEX	Shoulder	Night	Path Loading>1900 MW, Oct. 25 – 30
6	High Transmission Loading Buffalo Ridge Outlet	Shoulder	Night	Path Loading>2800 MW, May 20 – 22
7	High Transmission Loading MWEX	Light	Day	Path Loading>1400 MW, June 8, 11, 14

Next, the seven cases were re-screened to ensure that the commitment and dispatch windows still corresponded to the limits of the defined stability metrics. For the interface loading metric, the three cases for Scenario 1, corresponded with the new data for Scenario 1a for the NDEX (Figure 7-39), Buffalo Ridge Outlet (Figure 7-40) and the MWEX (Figure 7-41) interfaces.

For the NDEX interface, the period highlighted in Figure 7-39, indicates an interface loading greater than 1900 MW. For the Buffalo Ridge Outlet interface, the highlighted period in Figure 7-40 indicates an interface loading greater than 2800 MW. Finally, for the MWEX interface, the highlighted period in Figure 7-41 indicates an interface loading greater than 1400 MW. These values are based on the highest observed flows on the interfaces and do not correlate with a particular stability limit for the system.

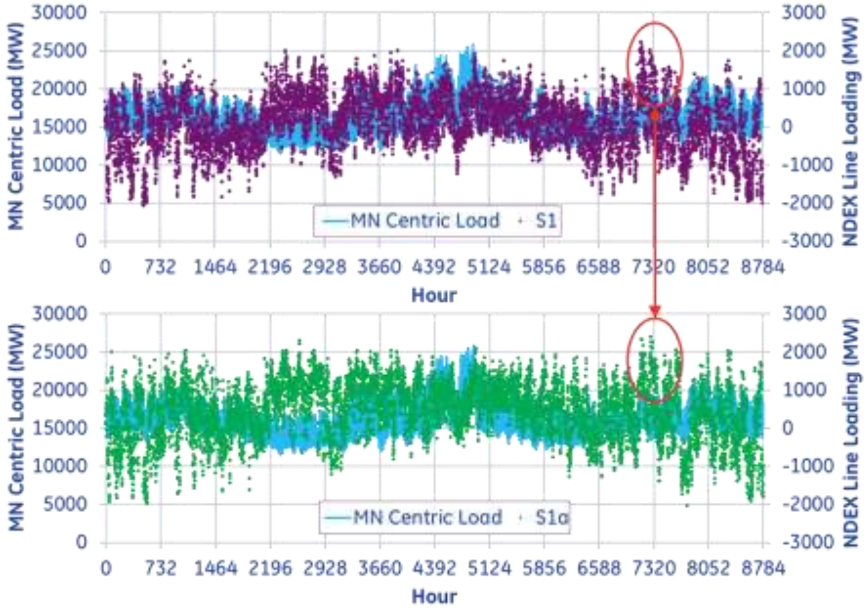

Figure 7-39 NDEX Interface Screening for Scenario 1 and Scenario 1a

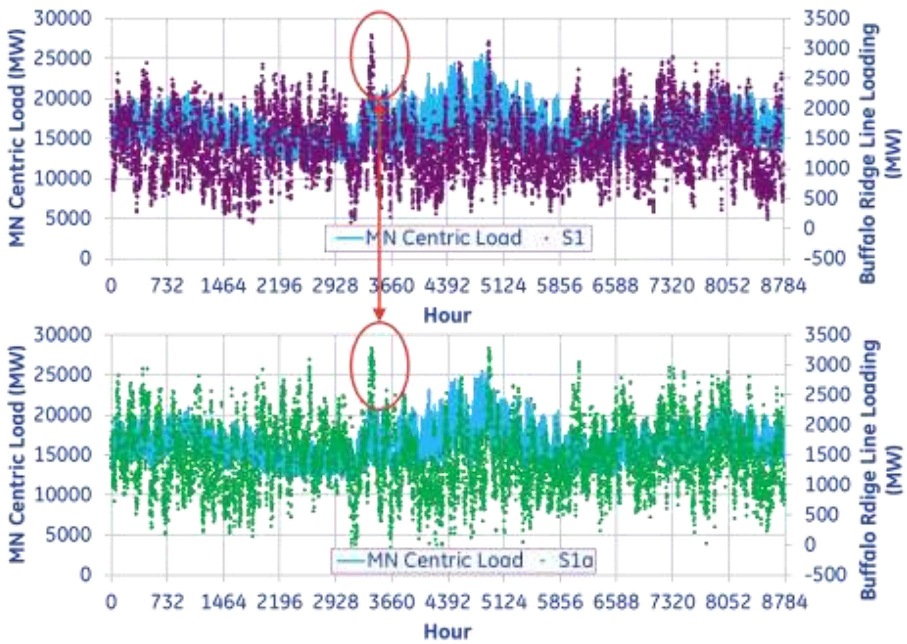

Figure 7-40 Buffalo Ridge Outlet Interface Screening for Scenario 1 and Scenario 1a

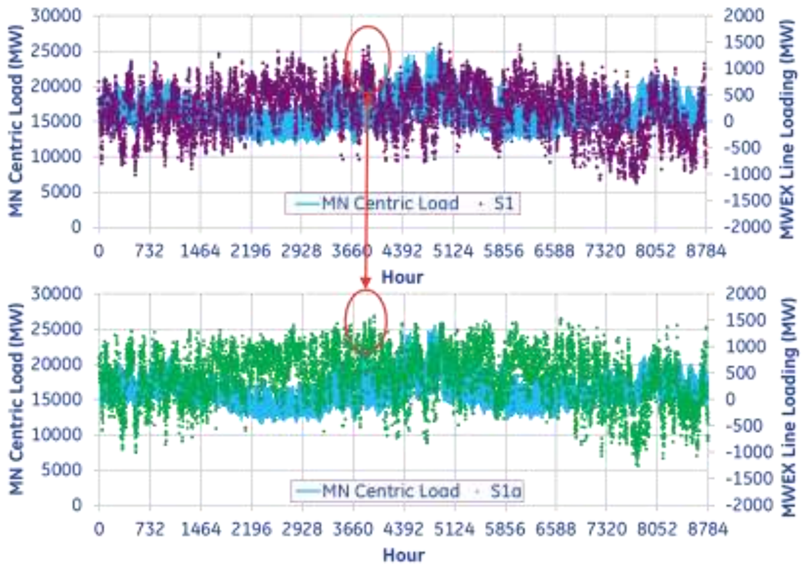

Figure 7-41 MWEX Interface Screening for Scenario 1 and Scenario 1a

For the remaining four cases, Cases 1, 3 and 4 showed close correlation between Scenario 1 and Scenario 1a. As a result, the dispatches between these cases were compared and the power flow for the cases was adjusted according to the new Scenario 1a commitment and dispatch. Case 2 was the only case that required an adjustment of the stability window.

As seen in Figure 7-42, a new peak in % NS for the light load case was observed around hour 3000 in Scenario 1a. As such, the methodology described previously in this section was applied and new commitment and dispatch for Case 2 was developed based on the Scenario 1a data. Overall, the new commitment and dispatch from Scenario 1a for Case 2 resulted in a net increase of 1288 MW of non-synchronous generation commitments.

Figure 7-42 Case 2 Stability Screening for Scenario 1 and Scenario 1a

8 DYNAMIC SIMULATION RESULTS

The objective of this analysis was to tests the dynamic performance of the system under the most challenging system conditions observed in the scenario S1 and S1a production simulation analysis with respect to renewable generation.

The dynamic study cases developed for the S1 analysis represent a full spectrum of operating conditions cover light load, shoulder load and peak load. Every wind plant was on line for each of the study cases. All PV plants and distributed PV were on line for daytime cases and off line for nighttime cases. Renewable generation levels were set based on the production simulation results for the condition being simulated.

The cases cover a wide range of synchronous generation commitment and dispatch due to the different screening metrics used to select challenging hours. In addition, two different production simulation runs were used (S1 and S1a), with their different assumptions on must-run status, generation retirement and forced outages. The study cases represent hours with lower than average commitment and dispatch of synchronous generation, giving a high percentage of renewable energy and non-synchronous generation on line. These cases also stress several critical interfaces and transfer paths with high Manitoba Hydro exports and high Buffalo Ridge Outlet, NDEX and MWEX interface flows.

8.1 Dynamic Performance Study Conditions

Power flow study cases were developed for the seven different system conditions described in the previous section. The commitment and dispatch of all generators (both conventional and renewable) throughout and outside of MISO was set based on unit operation during the corresponding hours in the production simulation analysis. Conventional units that were on line less than 25% of the sample hours were decommitted in the power flow case. Conventional units on line more than 25% of the sample hours were committed and operated at or above their average dispatch for those hours. Renewable generation was committed and dispatched based on the average of the sample hours from production simulation.

These dynamic study cases, listed in Table 8-1, include three light load, three shoulder load and one peak load condition Case 4 was used to test high MWEX transfers at light load. The table lists the case number from the production simulation analysis, the stability case name, the selection criteria, load level and comments. The notes include the percentage of non-synchronous generation (%NS) and percentage of renewable energy (%RE) for the Minnesota-centric region. These are calculates as:

$$\%NS = \frac{Total\ online\ wind + Solar\ MW\ rating}{Total\ online\ generation\ MW\ rating}$$

and

$$\%RE = \frac{Wind + Solar\ MW\ dispatched}{Total\ Generation\ MW\ dispatched}$$

The notes also include information on high transmission loading where applicable. Note that analysis of high MWEX loading (case 7, light load) was performed using the light load case with high percentage of renewable energy (case 4), since this case has very high MWEX loading. Additional contingencies on the highest loaded MWEX lines were simulated to focus on the impact of high transfers.

Table 8-1 Stability Case Description

	Name			
1	S1_SH_D01	High % NS	Shoulder	49% NS Generation 37% Renewable Energy
2	S1_LL_D02	High % NS	Light	48% NS Generation 36% Renewable Energy
3	S1_PK_D03	High % NS	Peak	37% NS Generation 21% Renewable Energy
4	S1_LL_D04	High % RE Penetration	Light	47% NS Generation 40% Renewable Energy
5	S1_SH_D05	High Transmission Loading NDEX	Shoulder	47% NS Generation 37% Renewable Energy 2334 MW NDEX Loading
6	S1_SH_D06	High Transmission Loading Buffalo Ridge Outlet	Shoulder	48% NS Generation 41% Renewable Energy SW Minn Renewables at 95% Pmax
7	S1_LL_D04*	High Transmission Loading MWEX	Light	47% NS Generation 40% Renewable Energy 2424 MW MWEX Loading

*** Note:** Case 4 has MWEX loading above 1400 MW (max value from production simulation). The impact of MWEX loading was tested using this case, subject to additional contingencies on MWEX lines.

The MW dispatch of all Minnesota-centric generation is illustrated in Figure 8-1. This bar graph shows the total on-line generation in MW by type for each of the six study cases. Figure 8-2 shows the same information, but in the form of pie charts of the percentage of generation by type. This is similar to the percent renewable energy measure (%RE) used for the production simulation screening. The dispatches are shown in order of increasing generation, from light load to shoulder load to peak load.

The reporting of %RE for the stability cases is lower than that reported in the production simulation analysis due to differences in the grouping of generation. However, the generation dispatch for each case matches the average dispatch for the selected time period in the production analysis.

Figure 8-3 shows the total MVA of committed Minnesota-centric generation by type for the six study cases. This measure sums the rated MVA of each on-line unit. It does not consider the MW output of the machine, only if the unit is on-line or not. Figure 8-4 presents the same information, but groups the generation as synchronous and inverter-based. The inverter-based generation us made up of all wind, solar PV and distributed PV since most of this generation is power electronic inverter based. Inverter-based generation is also referred to as non-synchronous. This figure shows the rated MVA of each type as a percentage of total on-line MVA. This measure is similar to the percent non-synchronous generation (%NS) used for production simulation screening. Note that HVDC converter stations are not included in the calculation of percent non-synchronous.

The measure of %NS for the light and shoulder load study cases is between 47% and 48% across the Minnesota-centric area. The measure of %NS for the peak load case is 37%. These measures are lower than the %NS reported in the production simulation analysis. This difference is due to three factors:

1. These calculations are based on the sum of rated MVA of on-line generators, where the production simulation analysis is based on the sum of rated MW. In general, a synchronous machine will have a higher MVA rating than a wind or PV plant with the same MW capability. This will lower the measure of percent non-synchronous.
2. There are over 2700 MVA of synchronous units that were not included in the %NS calculations for production simulation, but are included in the calculations for stability analysis. This includes the two Quad Cities nuclear units (1068 MVA each).
3. Over 4600 MW of the renewable generation added for Baseline and S1 scenarios was located at buses outside the Minnesota-centric footprint. These are modeled and included in the stability analysis but not accounted for in calculating the %NS measure.

While the calculation of %NS differs between the production simulation and stability cases, the actual commitment/dispatch in the stability simulations matches that of the production simulation.

Figure 8-5 shows the percentage of on-line synchronous and non-synchronous generation (based on rated MVA) for each of the six regions in the Minnesota-centric footprint for each study case. The same information is shown in Figure 8-6, but shown as total MVA. SW Minnesota is nearly 100% non-synchronous generation for all of the dispatches. South Dakota averages over 60% NS, and is as high as 80% NS for the two light load cases. Iowa and North Dakoda have between 40% NS and 50% NS across the cases, and Northern, Central and South Minnesota have 20% or less %NS.

Figure 8-7 shows the dynamic reactive reserves from synchronous, non-synchronous and static var compensator SVC (labeled "Other") sources for each region. The dynamic reactive reserves are calculated as the difference in the maximum reactive capability minus the reactive output of a unit. This calculation does not include mechanically switched capacitors.

The dynamic reactive reserves closely follow the on-line MVA for each region. The renewable generation provides a significant portion of the dynamic reactive reserves in Iowa, North and South Dakota. All of the reactive reserves in SW Minnesota are from renewable generation sources. The ±60 MVAr SVC at Lake Yankton was not included in this analysis.

The reactive reserves in Northern Minnesota are from synchronous generators and the Forbes SVC. The SVC is critical to supporting imports from Manitoba Hydro (MH). One objective in developing the power flow cases was to maintain over 350 MVAr of dynamic reserves from the SVC. This was achieved using the mechanically switched shunt capacitors associated with the SVC.

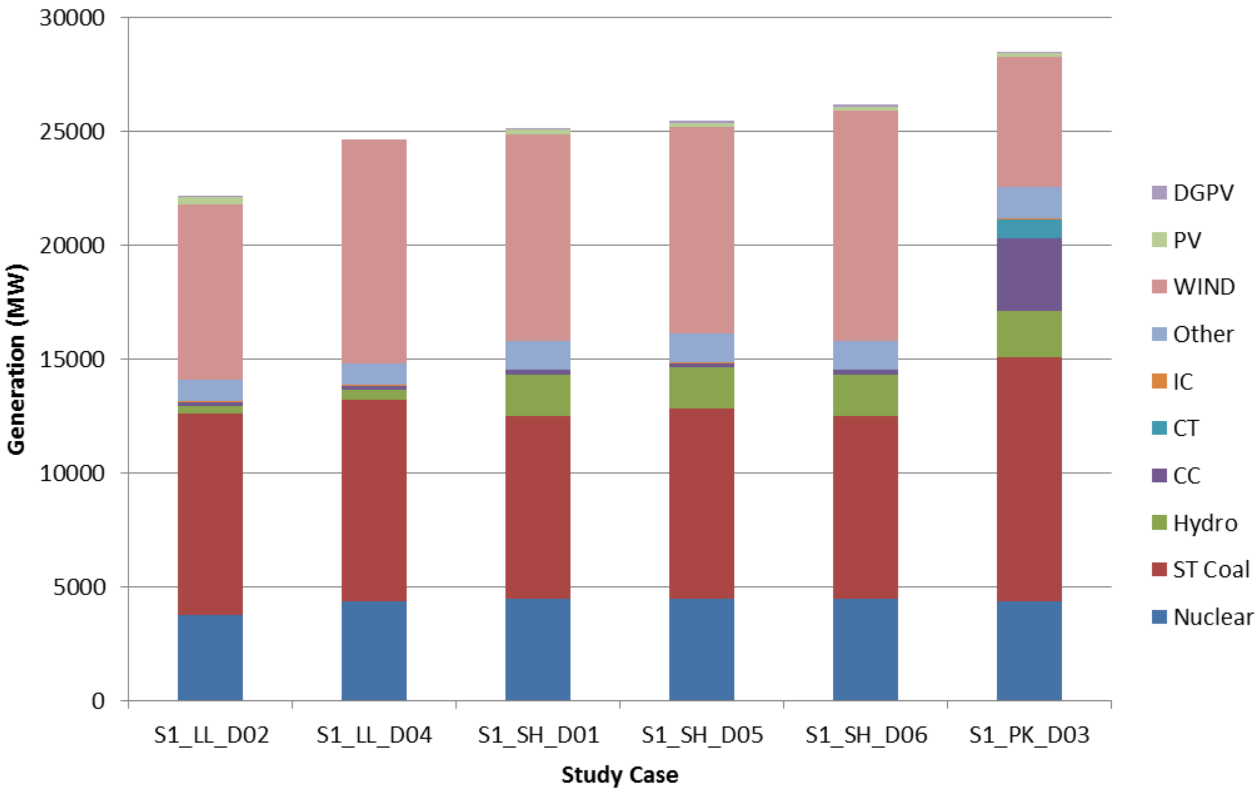

Figure 8-1 Minnesota Centric Dispatch (MW) By Unit Type

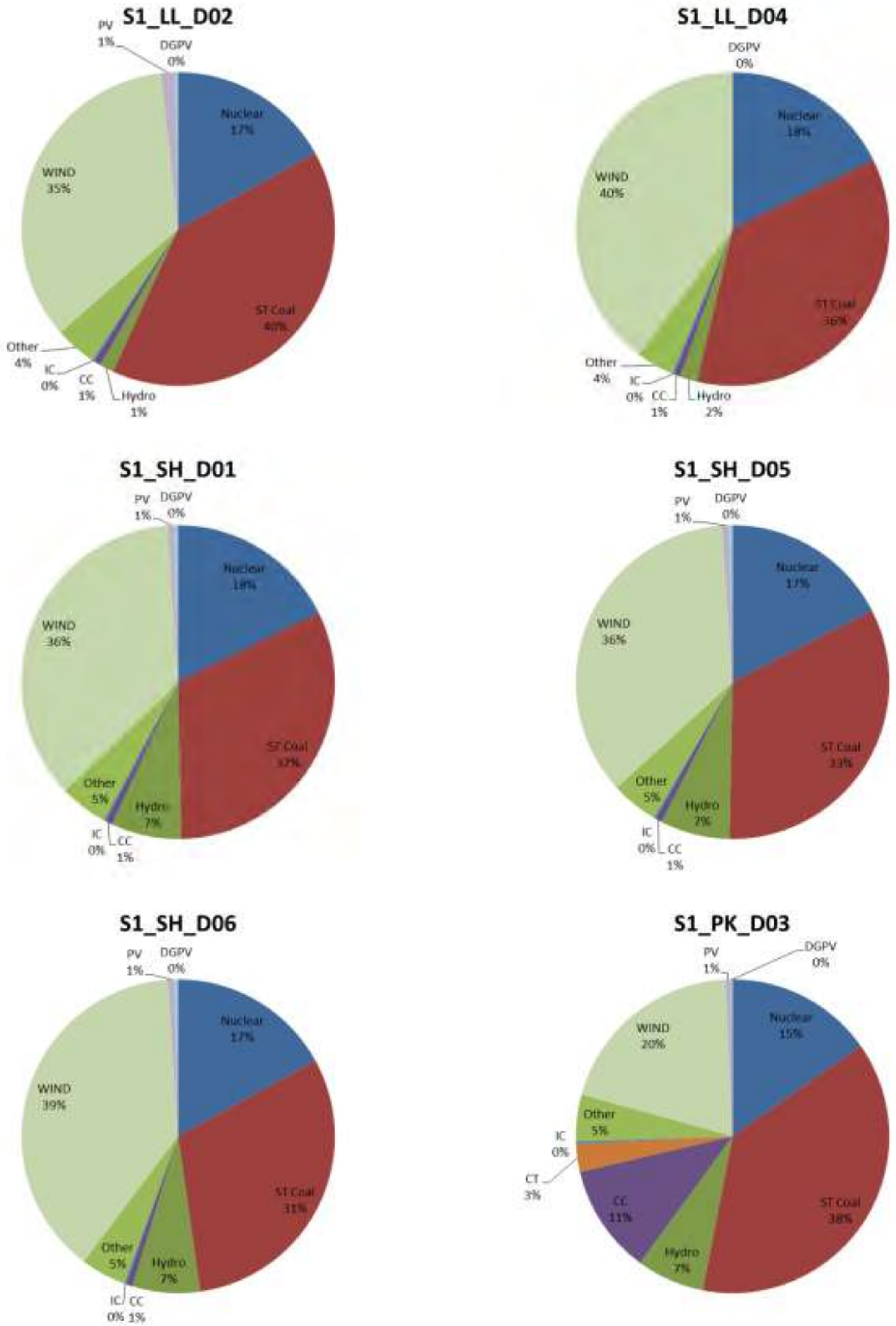

Figure 8-2 Minnesota Centric Percentage Generation Dispatch by Type

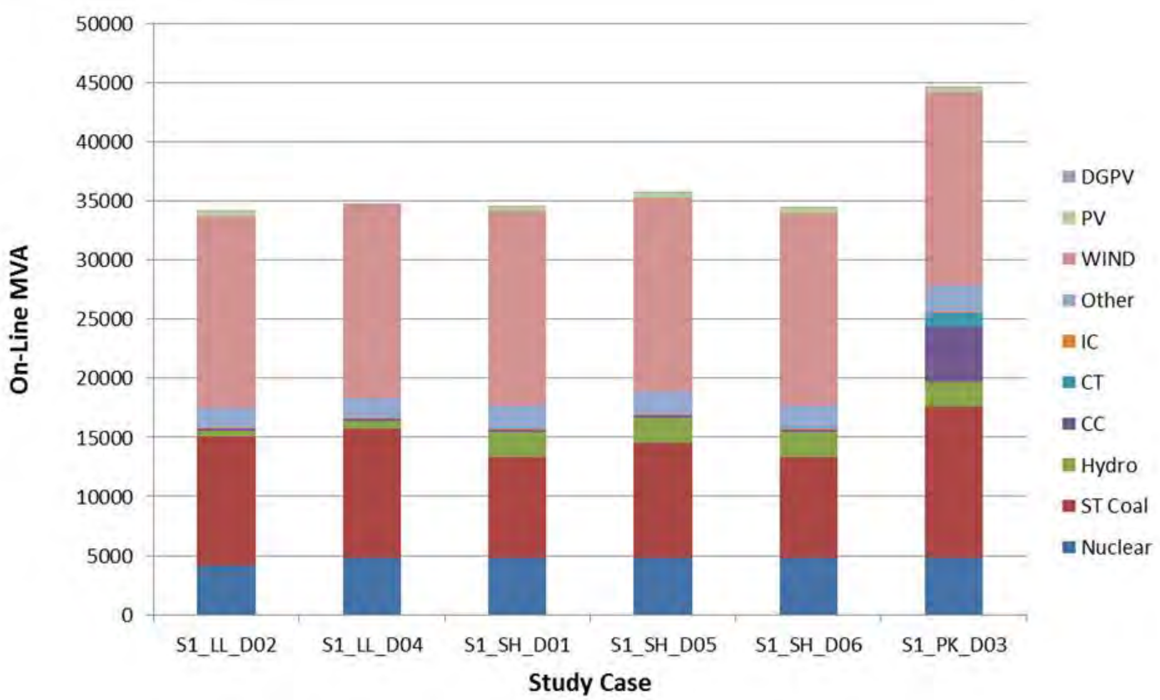

Figure 8-3 Minnesota Centric Commitment (MVA) by Unit Type

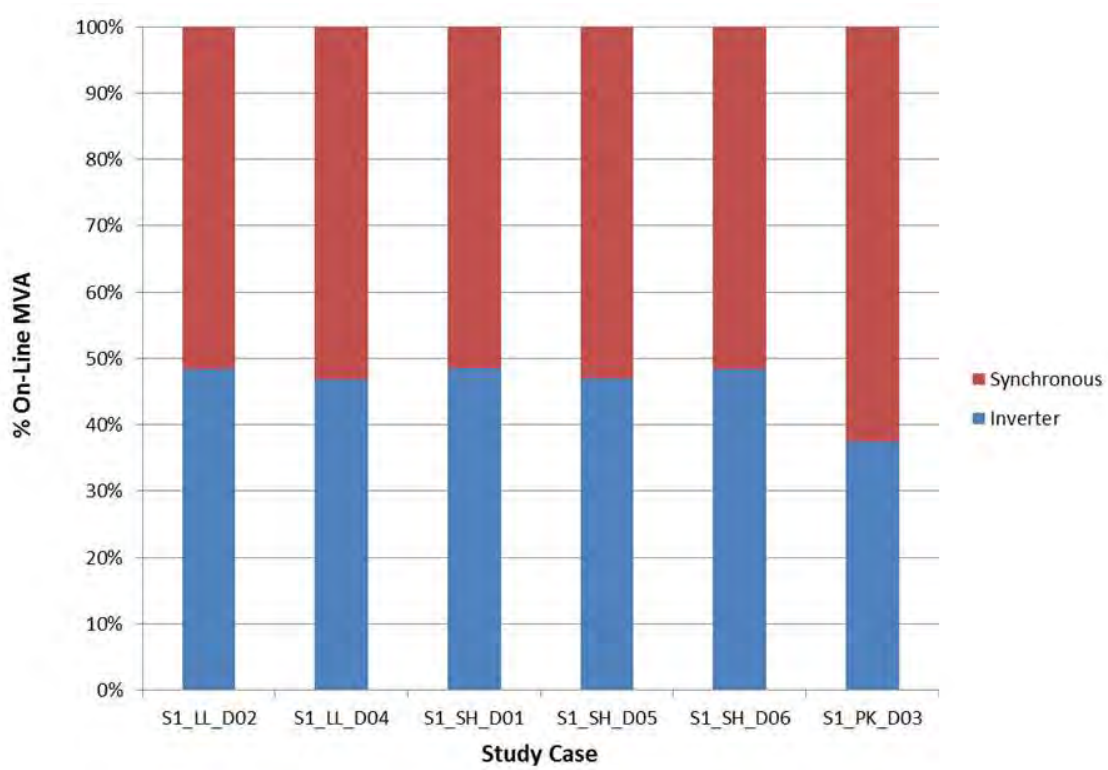

Figure 8-4 Percentage of On-line Non- vs Synchronous MVA

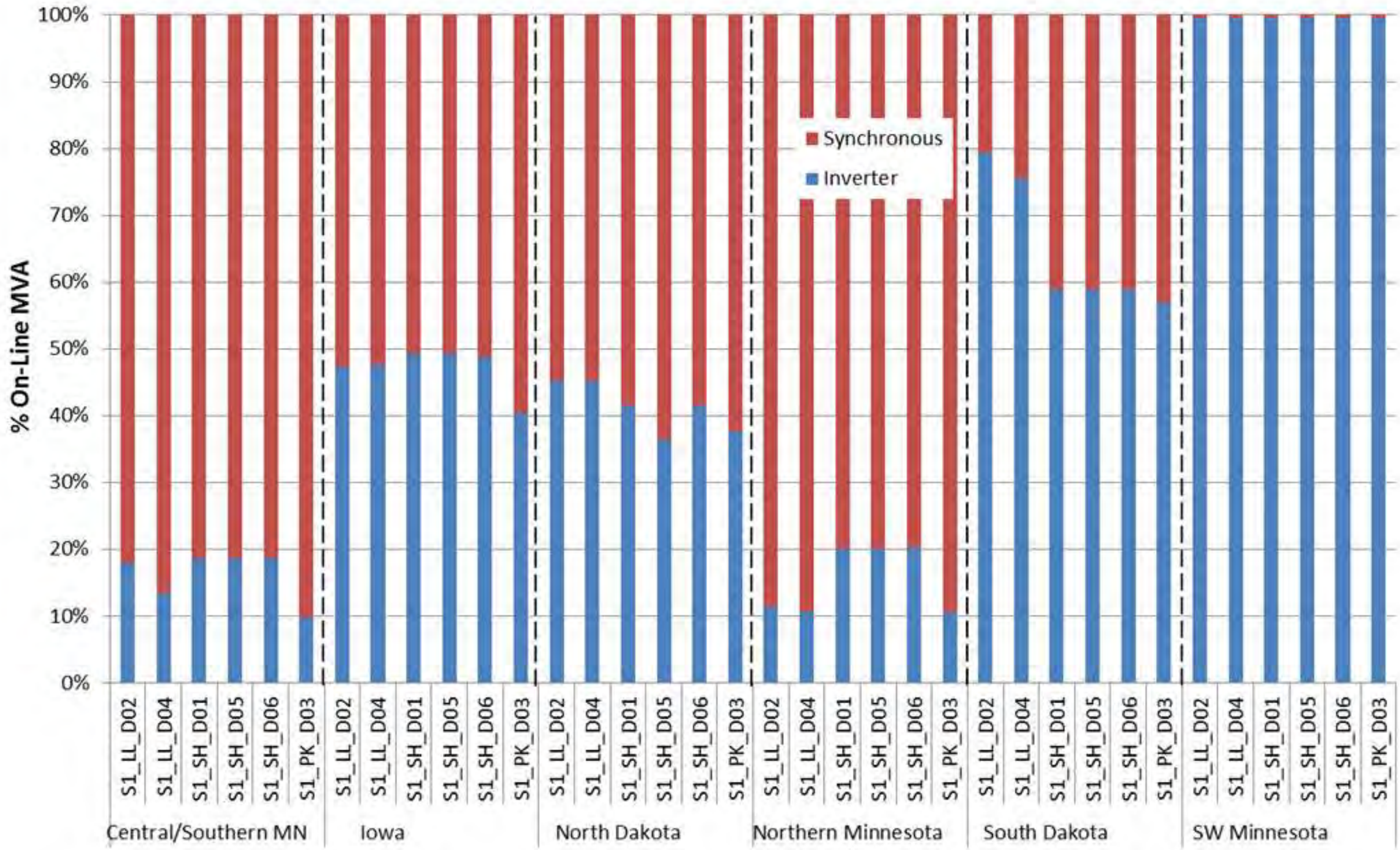

Figure 8-5 Percentage of online, non- and synchronous MVA by Sub-Region

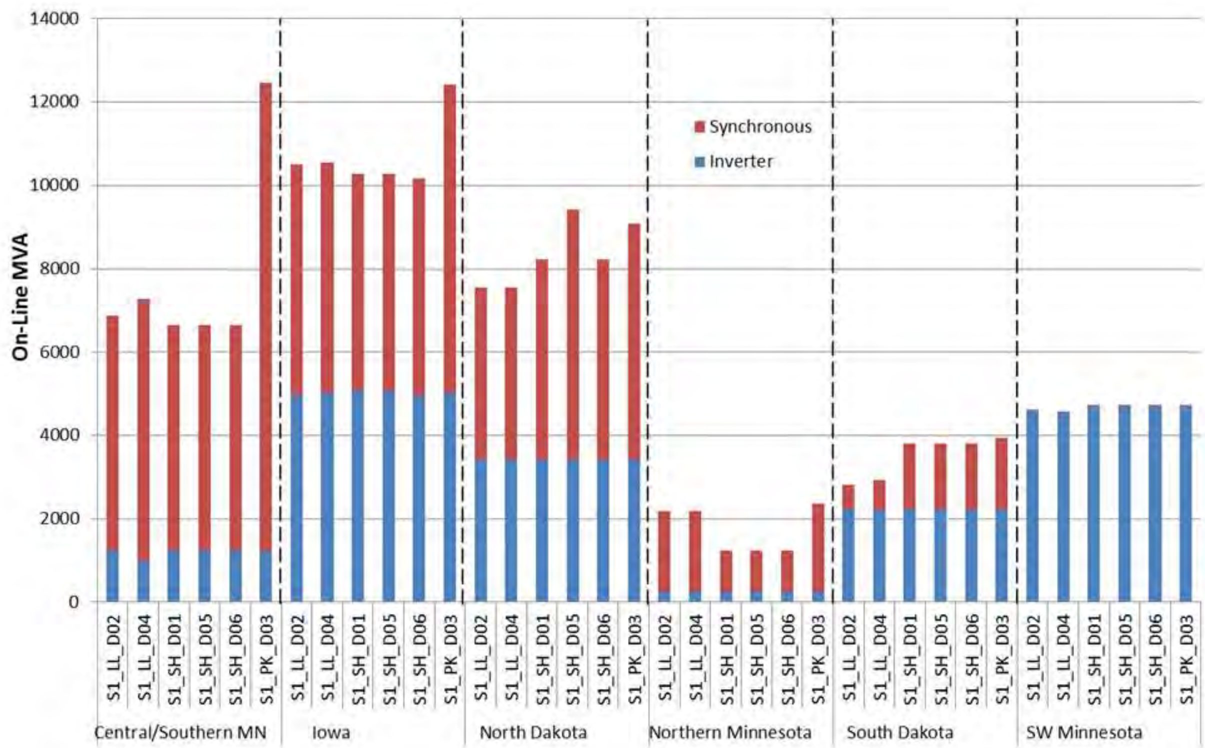

Figure 8-6 Online MVA of synchronous and non-synch Generation by Region

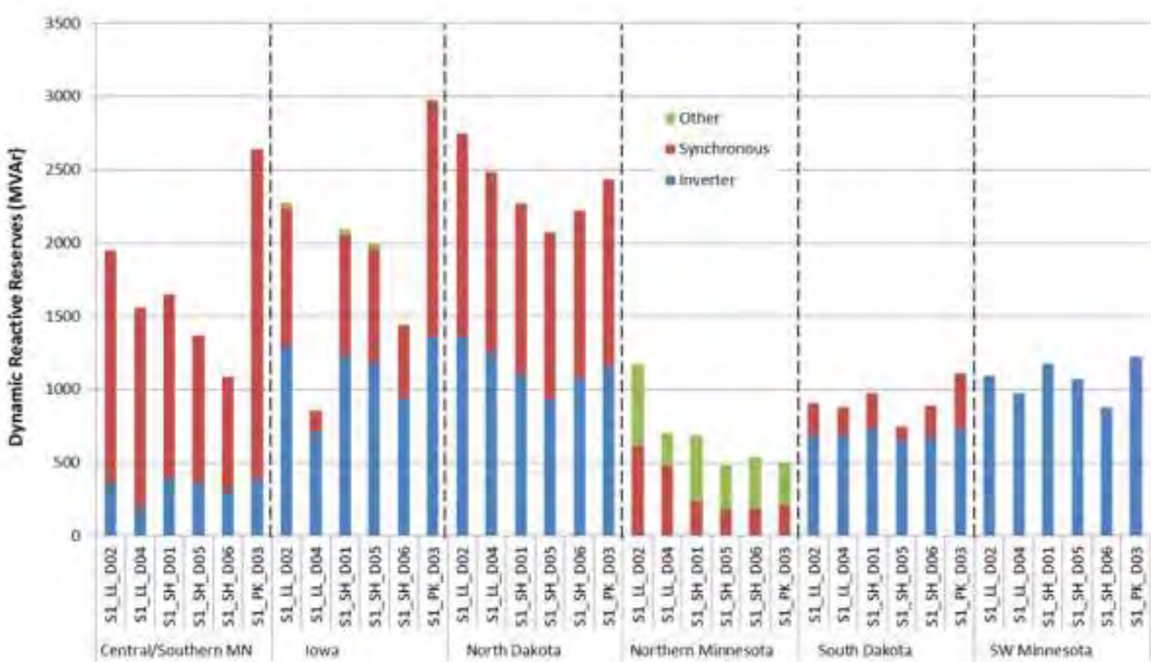

Figure 8-7 Dynamic Reactive Reserves of synchronous and non-synch Generation by Region

8.2 Voltage Regulation & Stability Analysis

8.2.1 Disturbances

This study considers a wide range of contingencies, listed in Table 8-2. The list of faults covers reference disturbances, disturbances in areas with low short circuit strength and faults along transmission interfaces. Faults 1 through 5 are established contingencies that test the traditional stability limitations of the system. Faults 6 through 10 (LSC1 through LSC5) and 16 were selected based on the weak system (low short circuit strength) analysis. These lines have the highest contribution to short circuit strength of the SW Minnesota region. Fault 11 tests the stability and voltage recovery of the Twin Cities area and Fault 12 tests a fault with generation tripping near SW Minnesota. Faults 13 through 16 were developed for high transmission loading cases (cases 5 through 7) only.

Table 8-2 Fault Description for Stability Analysis

No.	Fault Name	Description
1	EI2	CU HVDC Permanent Bipole fault with tripping of both Coal Creek units
2	AG1	SLG fault with breaker fail at Leland Olds on the Ft. Thompson 345 kV line
3	AG3	3 phase fault at Leland Olds on Ft. Thompson 345 kV line, Clear both ends of the line in 4 cycles
4	NAD	4cycles 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. Runback bi-poles that terminate at Dorsey
5	PCS	SLG fault t with breaker fail at King with 8P6 stuck. Trips King-EauClaire-Arpin and King-Chisago 345 kV line
6	LSC1	3Φ Fault at Nobles on Lakefield Jct 345 kV line, clear both ends of the line in 4 cycles
7	LSC2	3Φ Fault at Fallow on Grimes 345 kV line, clear both ends of the line in 4 cycles
8	LSC3	3Φ Fault at Brookings Co. on Big Stone South 345 kV line, clear both ends of the line in 4 cycles
9	LSC4	3Φ Fault at Split Rock on White 345 kV line, clear both ends of the line in 4 cycles
10	LSC5	3Φ Fault at Split Rock on Sioux City 345 kV line, clear both ends of the line in 4 cycles
11	Trip_DEERCK	3Φ Fault at Deer Creek 345 kV bus, clear fault in 4 cycles followed by tripping Deer Creek CC generator
12	Term_King	3Φ Fault at KOLMNLK3 on Terminal 345 kV line, clear both ends of the line in 4 cycles
13	AG1_v2	Single-line-to-ground fault with breaker fail at Leland Olds on the Groton 3 345 kV line
14	AG3_v2	Three-phase fault at Leland Olds on the Groton 3 345 kV line. Clear both ends of the line in 4 cycles
15	briggs	Three-phase fault at Briggs on the NMA 345 kV line. Clear both ends of the line in 4 cycles
16	sheas	Three-phase fault at SHEAS LK3 on the HELENA 3 345 kV line. Clear both ends of the line in 4 cycles

8.2.2 Overall Results

Transient stability analysis evaluated system response to all fault listed in Table 8-2 . Faults 1 through 12 were tested on all cases while faults 13 through 16 were tested on high transmission loading cases (cases 5 through 7) only.

All stability simulations were evaluated using the criteria describe in Section 5. This includes first swing and angular stability, possible system separation and cascading outage conditions based on operation of the system-wide generic impedance relay and post-fault voltage recovery. Transient response was considered stable if all units maintain stable response, voltage recovery meets testing criteria and there were no inadvertent impedance relay operations. The results of transient stability analysis are summarized in the Table 8-3. All tested scenarios produce transiently stable response with acceptable voltage recovery.

Table 8-3 Transient Stability Analysis Results

No	Fault Name	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
1	EI2	stable	stable	stable	stable	stable	stable	stable
2	AG1	stable	stable	stable	stable	stable	stable	stable
3	AG3	stable	stable	stable	stable	stable	stable	stable
4	NAD	stable	stable	stable	stable	stable	stable	stable
5	PCS	stable	stable	stable	stable	stable	stable	stable
6	LSC1	stable	stable	stable	stable	stable	stable	stable
7	LSC2	stable	stable	stable	stable	stable	stable	stable
8	LSC3	stable	stable	stable	stable	stable	stable	stable
9	LSC4	stable	stable	stable	stable	stable	stable	stable
10	LSC5	stable	stable	stable	stable	stable	stable	stable
11	Trip_DEERCK	stable	stable	stable	stable	stable	stable	stable
12	Term_King	stable	stable	stable	stable	stable	stable	stable
13	AG1_v2	NT	NT	NT	NT	stable	NT	NT
14	AG3_v2	NT	NT	NT	NT	stable	NT	NT
15	briggs	NT	NT	NT	NT	NT	NT	stable
16	sheas	NT	NT	NT	NT	NT	stable	NT

* NT is "Not Tested"

For transient stability analysis in this study new monitoring signals are introduced. These signals include dynamic monitoring of total active and reactive output of different types of generation (i.e. synchronous, wind, PV) and load for each of Minnesota footprint regions. The plots of selected traces of transient stability simulations are presented in the sections below.

Transient stability cases are grouped into three categories based on criteria used for their development. The categories are:

1. High percentage non-synchronous condition;
2. High percentage of renewable conditions
3. High transfer conditions,

In the following section, the system response to selected faults is presented for each category of dispatch conditions.

8.2.3 High % NS conditions

The cases developed for high percentage of non-synchronous generation in Minnesota footprint are case 1, case 2 and case 3. The faults selected to represent system response on these cases are:

Case 1: Terminal King fault (3Φ Fault at KOLMNLK3 on Terminal 345 kV line, clear both ends of the line in 4 cycles)

Case 2: Trip DEERCK fault (3Φ Fault at Deer Creek 345 kV bus, clear fault in 4 cycles followed by tripping Deer Creek CC generator)

Case 3: AG3 fault (3 phase fault at Leland Olds on Ft. Thompson 345 kV line, Clear both ends of the line in 4 cycles)

This section lists plots of total Minnesota footprint as well as Minnesota-centric regions system generation and load response. The plots of system generation include active (left column) and reactive (right column) power of all synchronous generation, wind generation, PV plus DGPV and load. The plots show the total generation/load for the Minnesota-centric region and the six sub-regions. Also post fault voltage recovery of bus voltages close to a fault are presented.

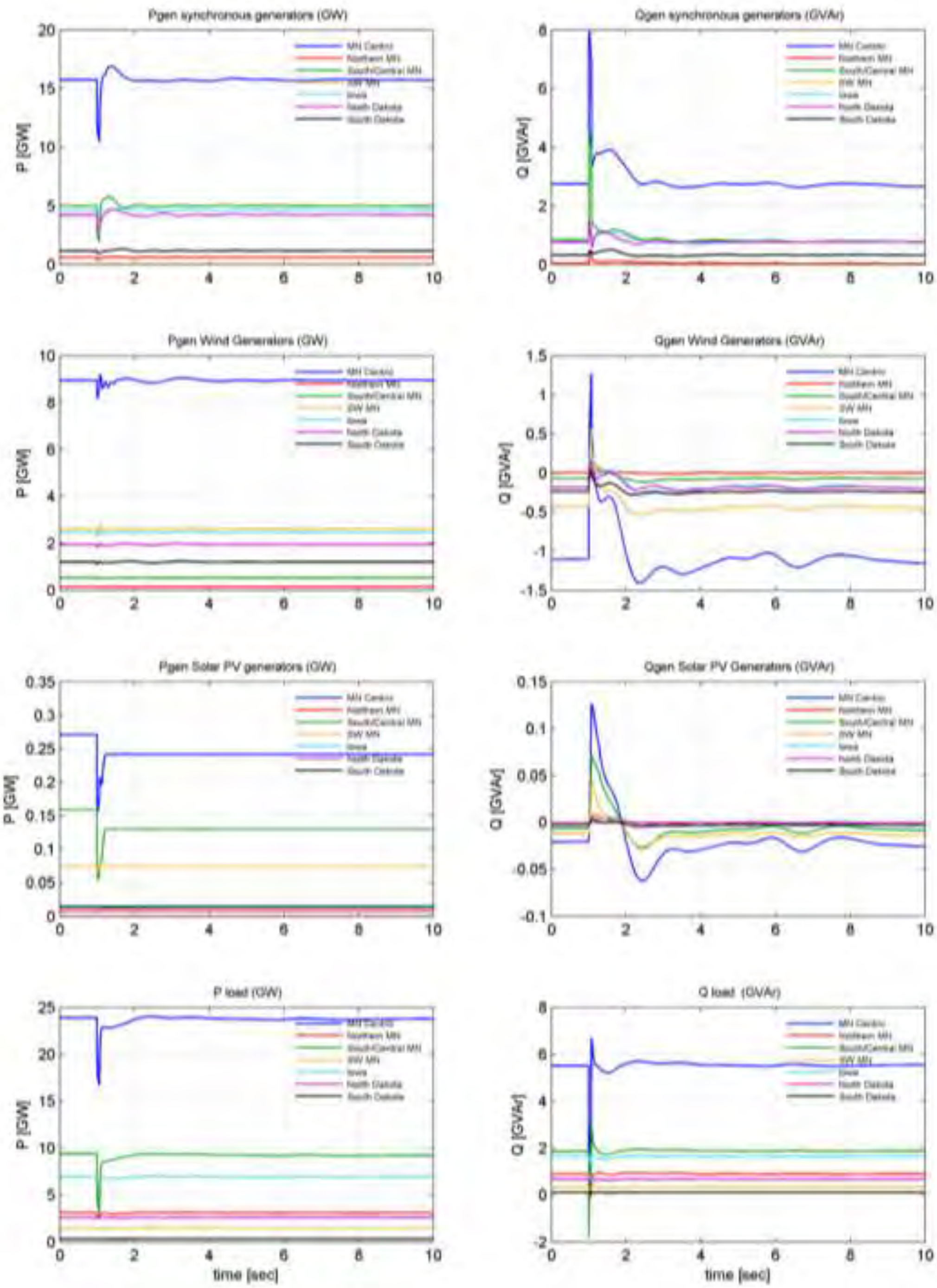

Figure 8-8 Case 1: Terminal King Fault Active and Reactive Response

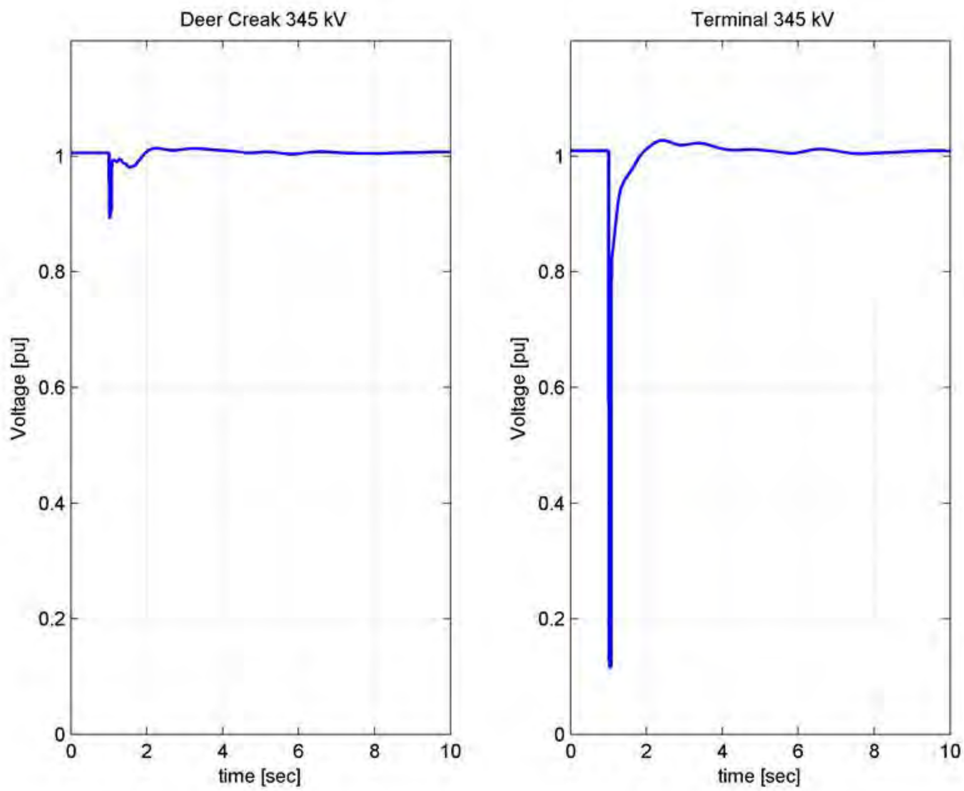

Figure 8-9 Case 1: Terminal King fault Voltage Magnitude

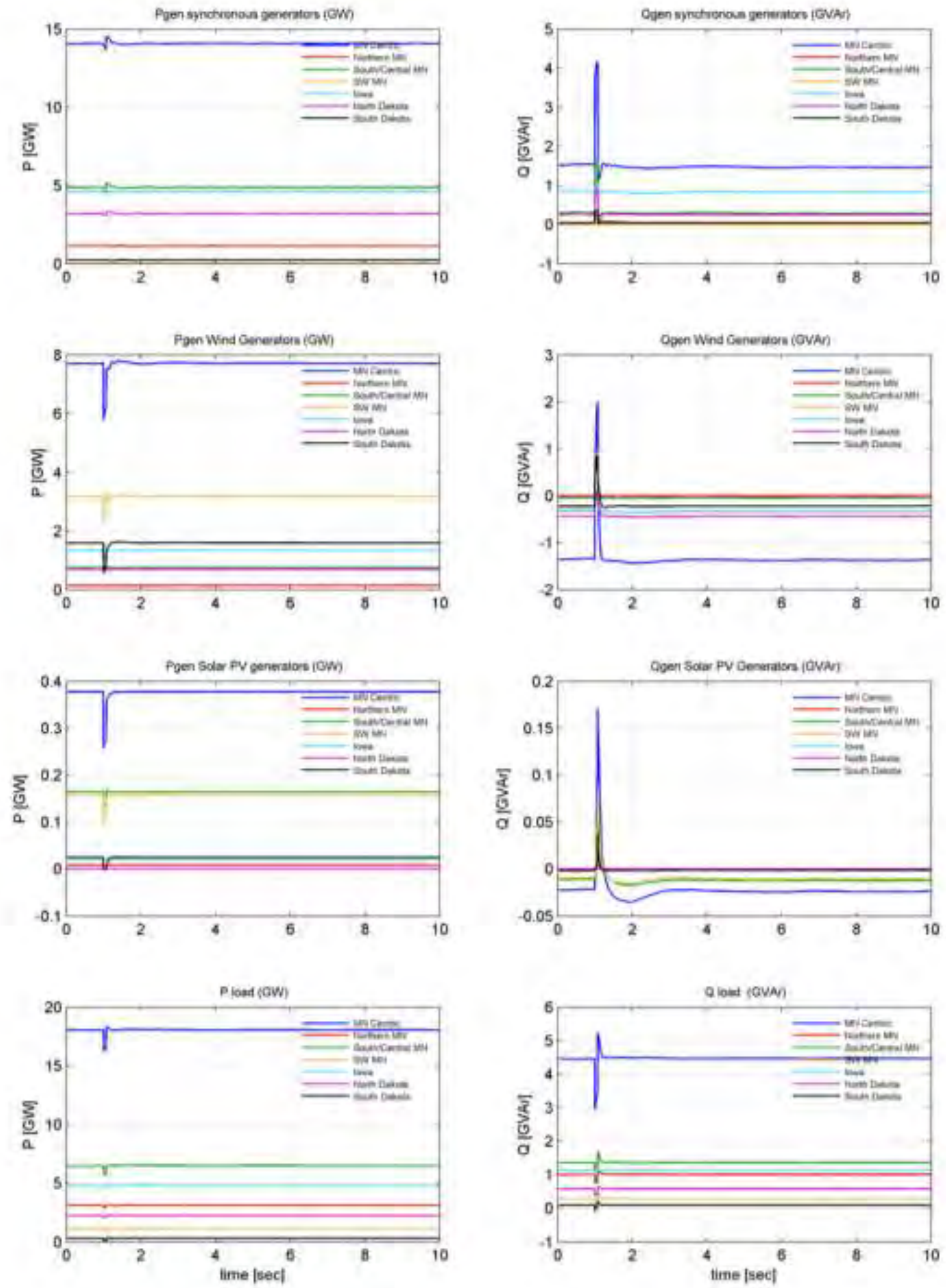

Figure 8-10 Case 2: Trip DEERCK fault Active and Reactive Response

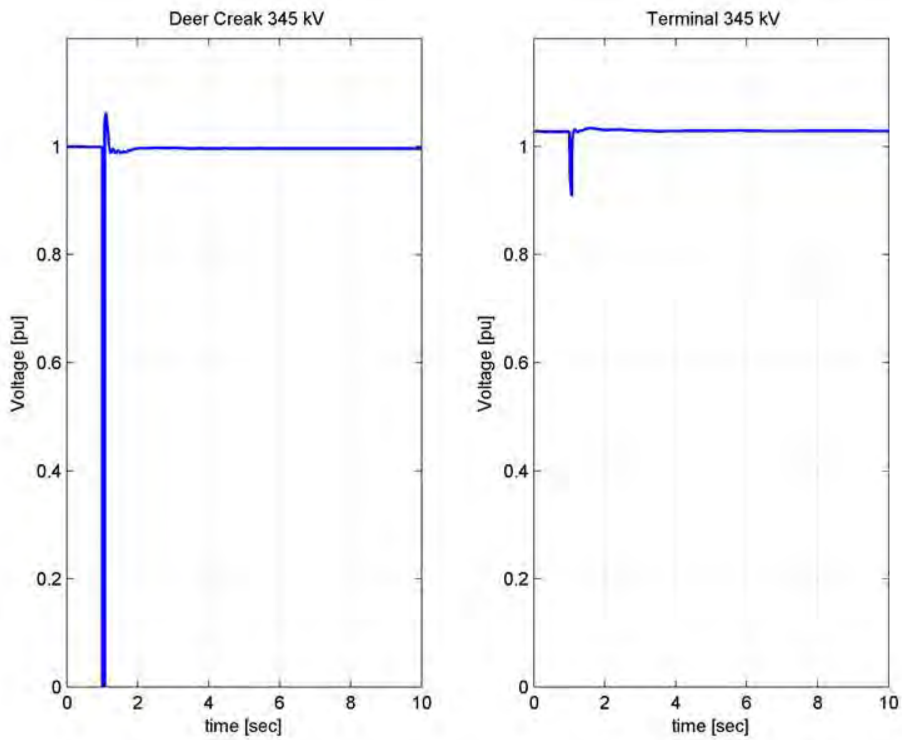

Figure 8-11 Case 2: Trip DEERCK fault Voltage Magnitude

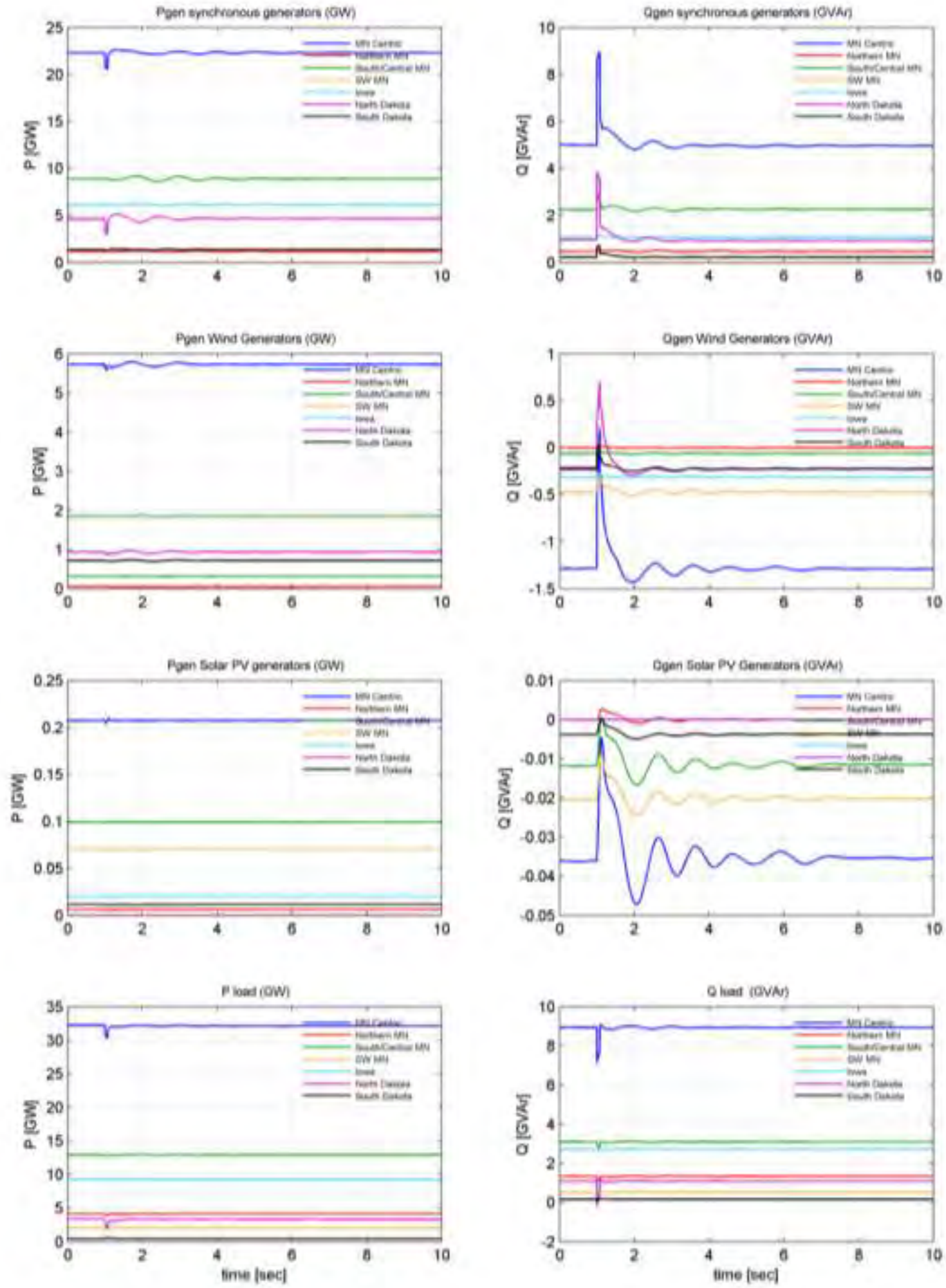

Figure 8-12 Case 3: AG3 fault Active and Reactive Response

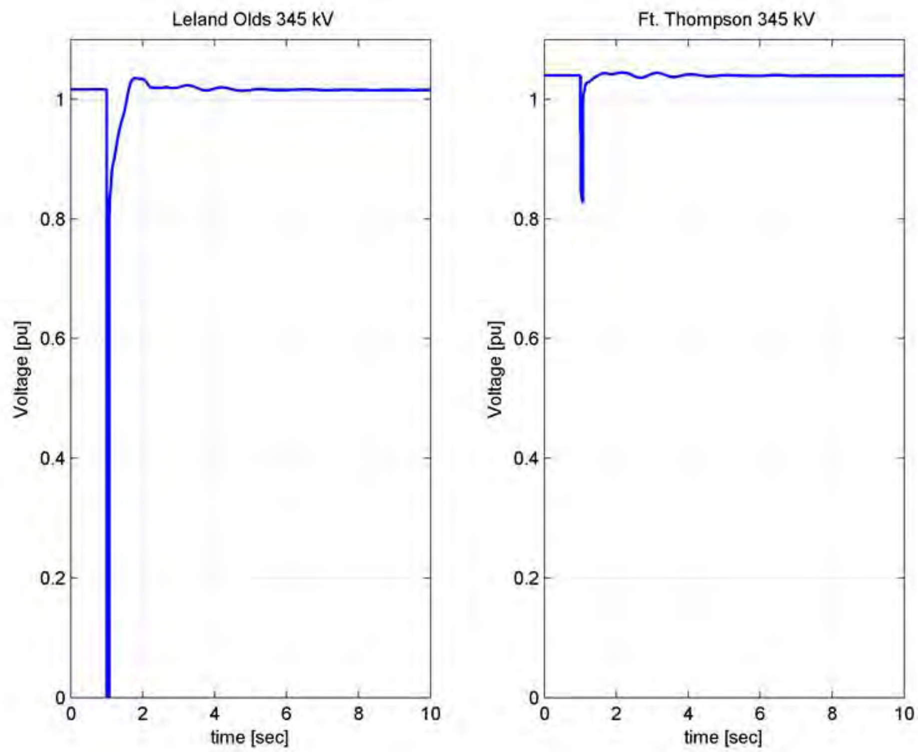

Figure 8-13 Case 3: AG3 fault Voltage Magnitude

8.2.4 High %RE conditions

The case developed to reflect high percentage of renewable penetration in Minnesota footprint is case 4. This is a light load case representing dispatch in early October during night hours between 12am and 7am. The fault selected is NAD fault (4cycles 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. Runback bi-poles that terminate at Dorsey). Minnesota footprint generation and load response to a NAD fault is presented in Figure 8-14. Voltage recovery at 500 kV buses

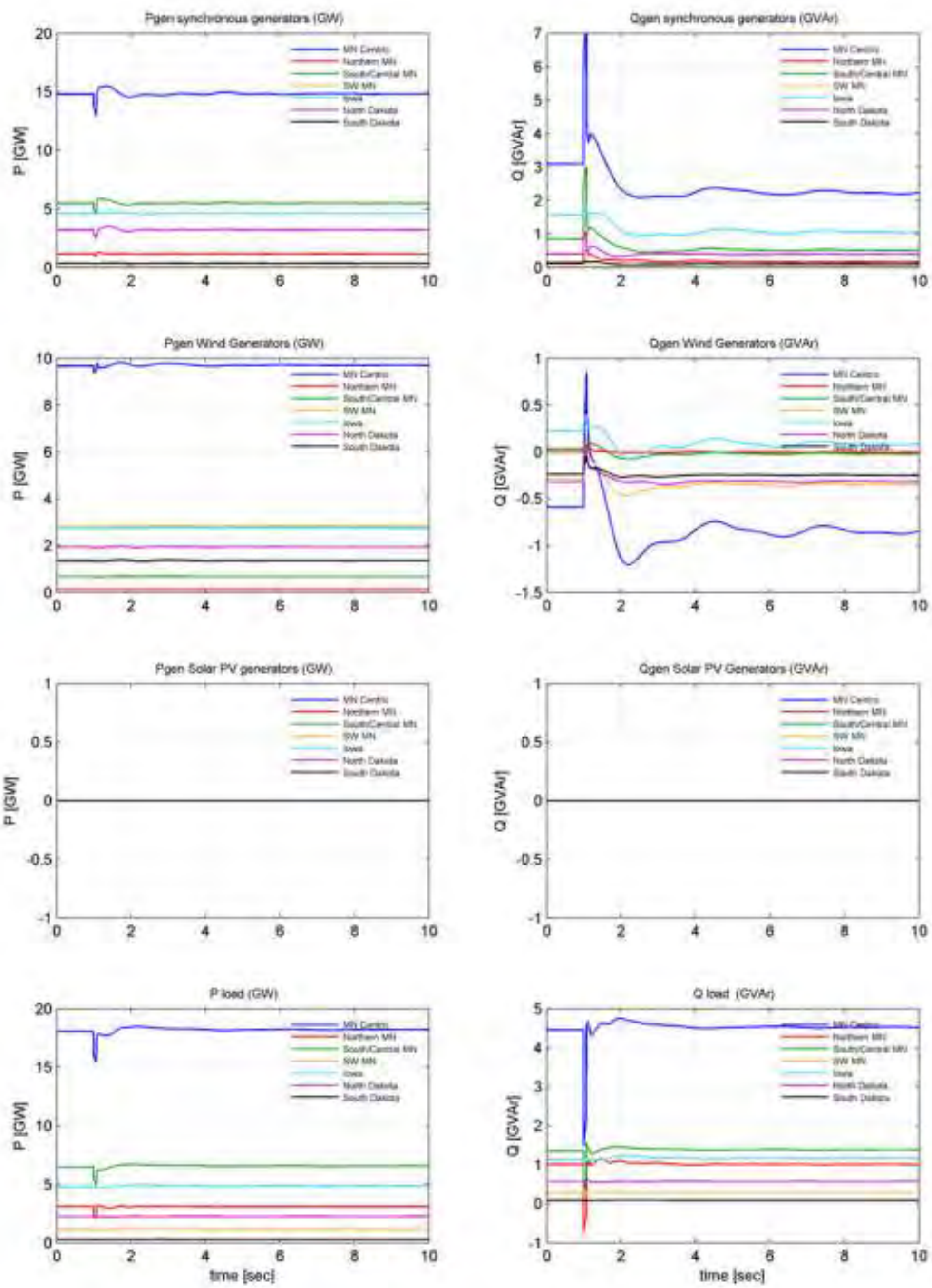

Figure 8-14 Case 4: NAD fault Active and Reactive Response

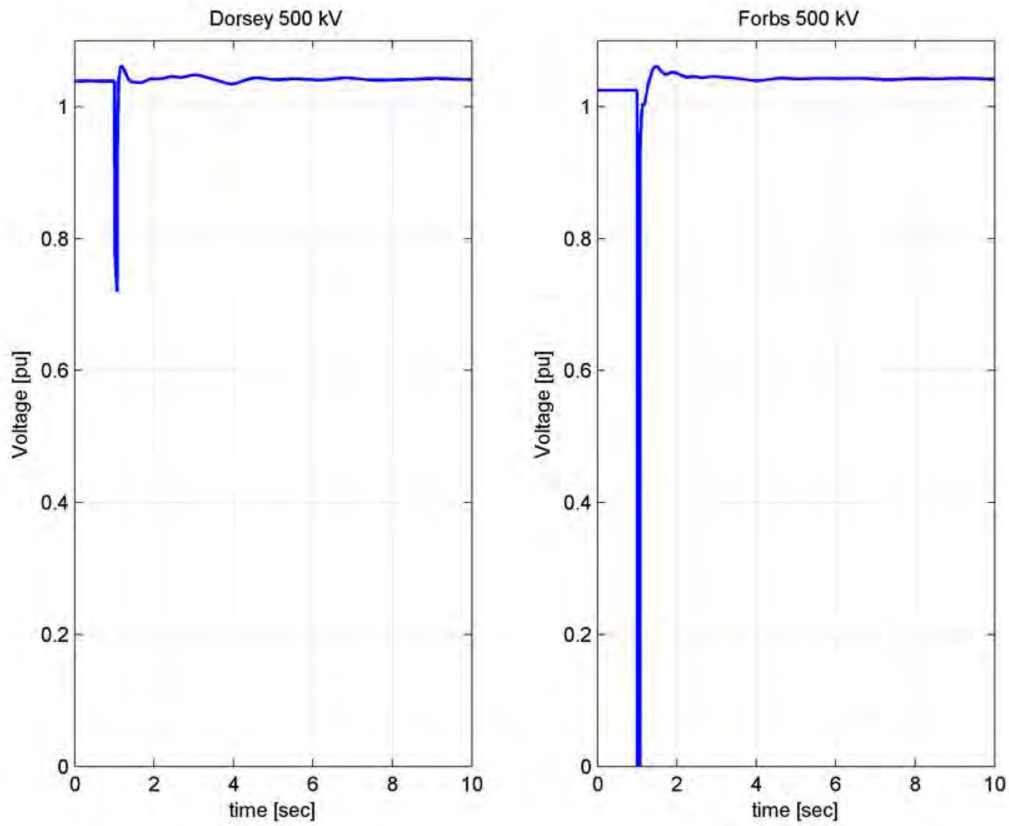

Figure 8-15 Case 4: NAD fault Voltage Magnitude

8.2.5 High Transfer Conditions

The case developed to reflect high transmission loading on NDEX, Buffalo Ridge Outlet and MWEX interfaces are case 5, case 6 and case 7 respectively. The faults selected to represent system response on these cases are:

1. Case 5: AG1_v2 (Single-line-to-ground fault with breaker fail at Leland Olds on the Groton 3 345 kV line)
2. Case 6: SHEAS (Three-phase fault at SHEAS LK3 on the HELENA 3 345 kV line. Clear both ends of the line in 4 cycles)
3. Case 7: BRIGS (Three-phase fault at Briggs on the NMA 345 kV line. Clear both ends of the line in 4 cycles)

Plots of Minnesota footprint area generation and load response as well as post fault voltage recovery is presented in Figure 8-16 through Figure 8-21.

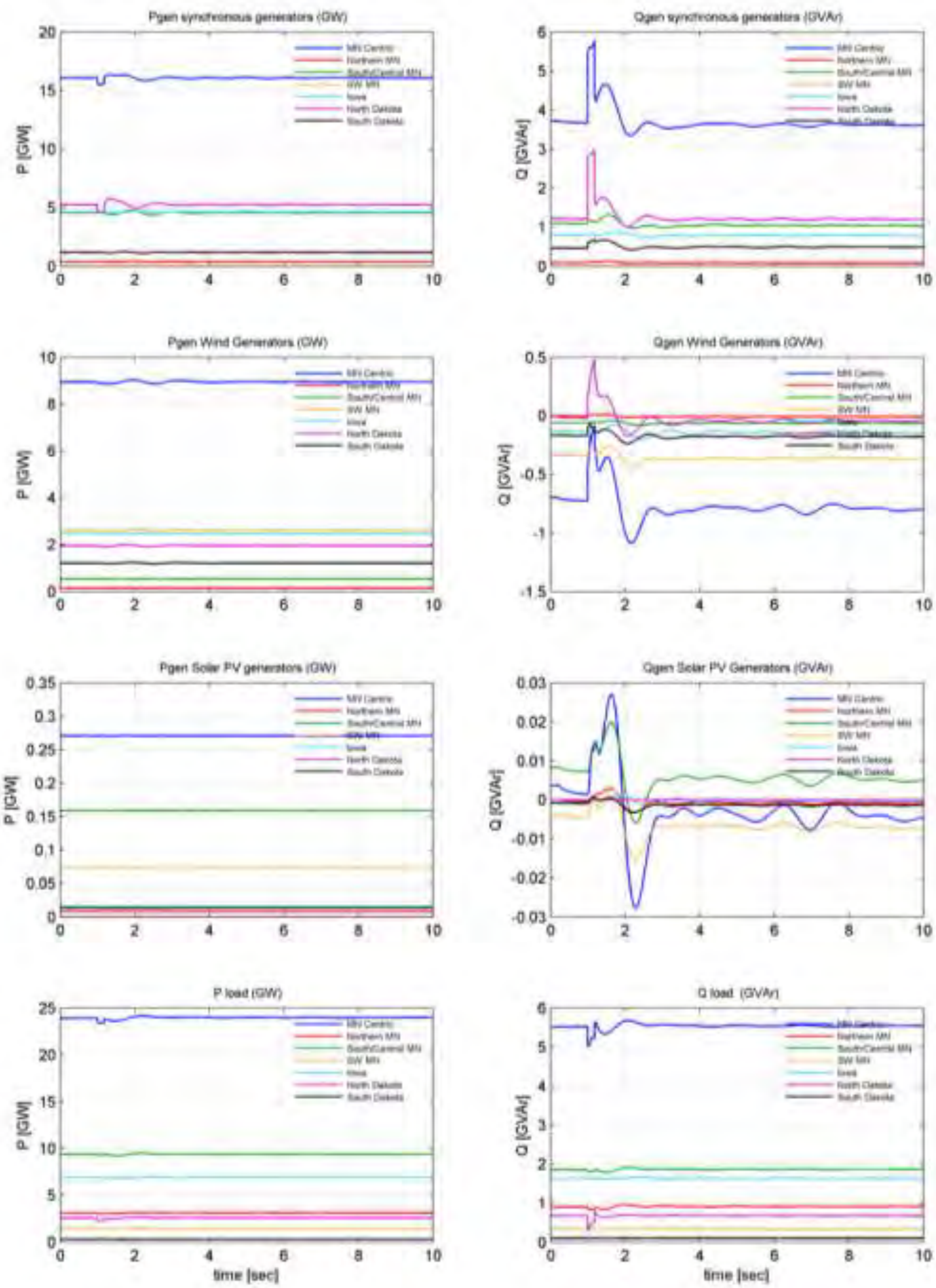

Figure 8-16 Case 5: AG1_v2 fault Active and Reactive Response

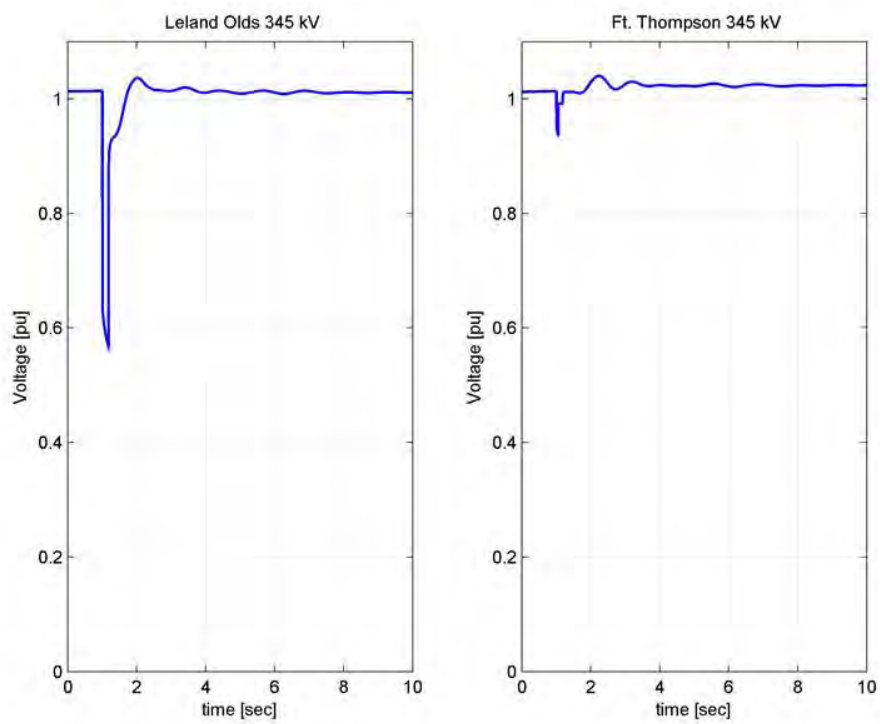

Figure 8-17 Case 5: AG1_v2 fault Voltage Magnitude

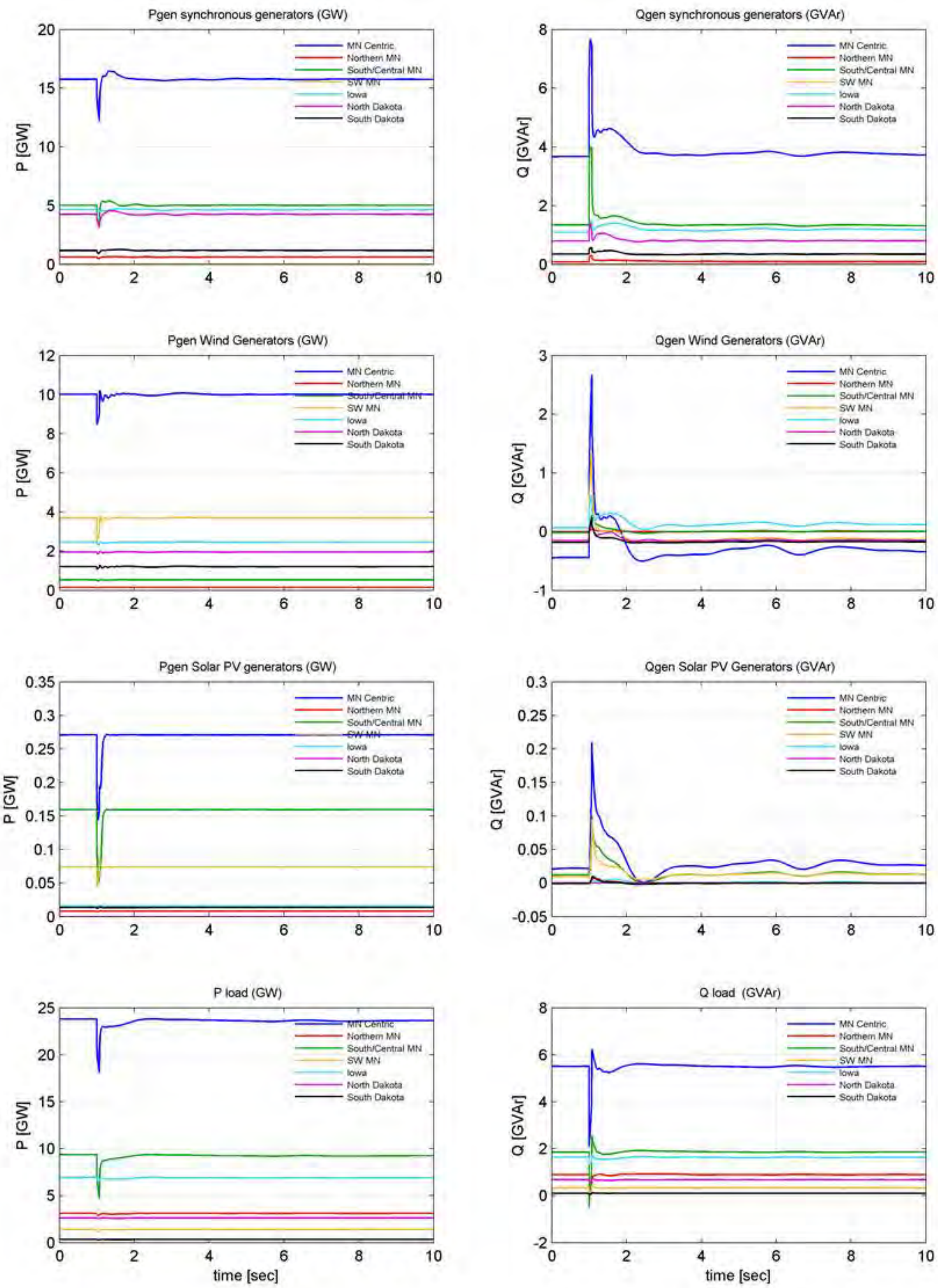

Figure 8-18 Case 6: SHEAS fault Active and Reactive Response

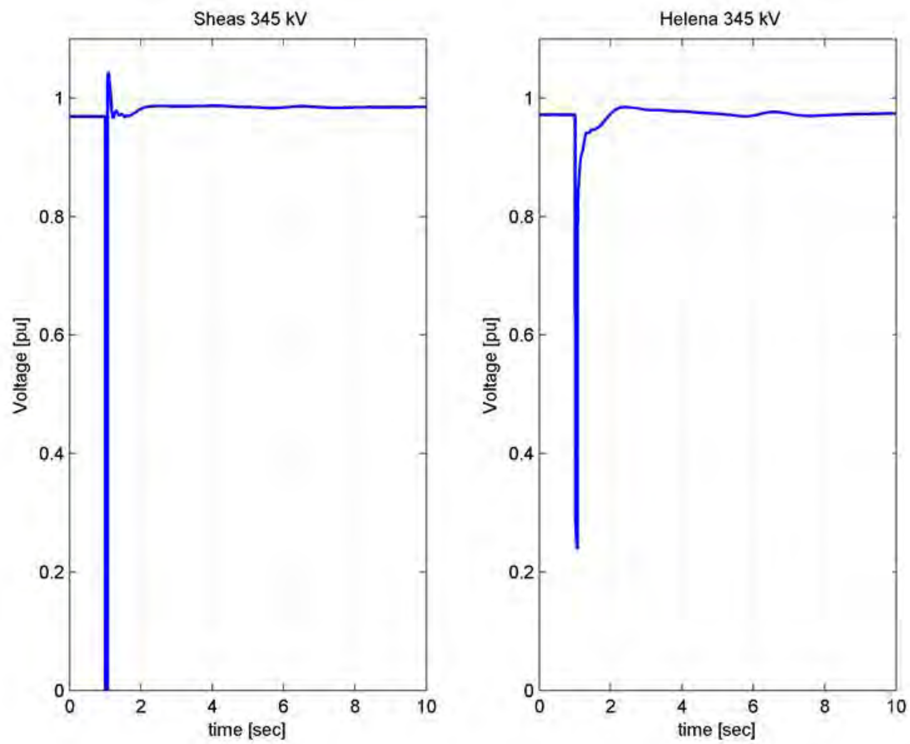

Figure 8-19 Case 6: SHEAS fault Voltage Magnitude

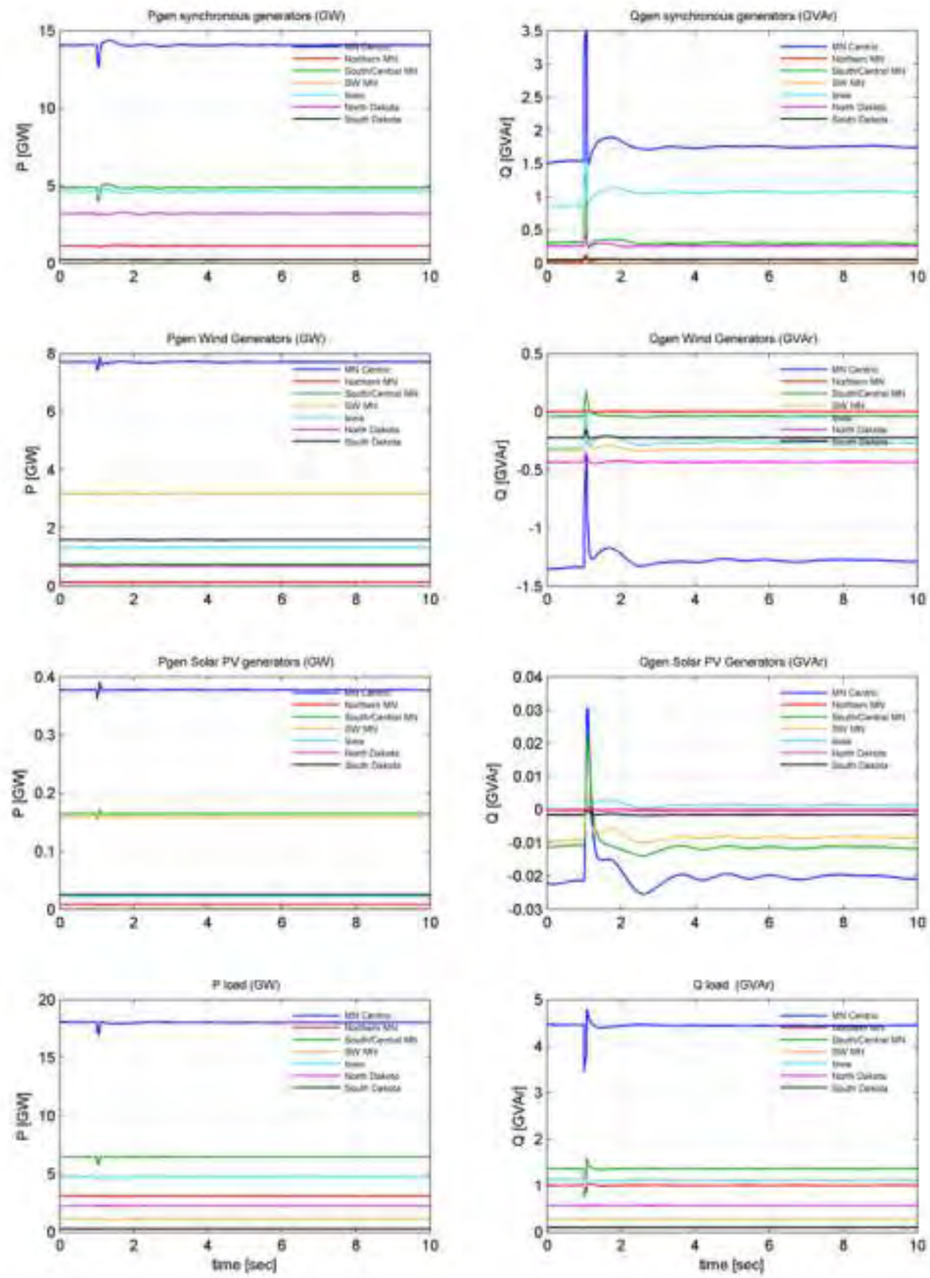

Figure 8-20 Case 7: BRIGGS fault Active and Reactive Response

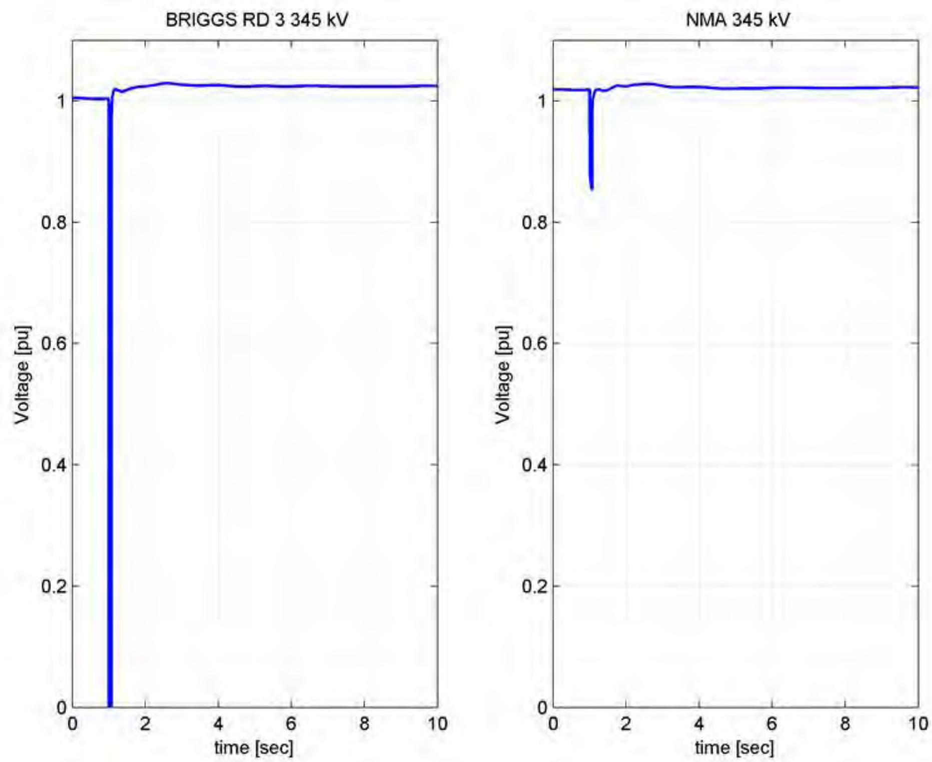

Figure 8-21 Case 7: BRIGGS fault Voltage Magnitude

8.3 Reactive Reserves

The dynamic reactive reserves for all test cases (plotted in Figure 8-7) were sufficient to maintain system stability and allow for acceptable voltage recovery. Both the transient voltage dip and post-transient voltages recovered met all screening criteria.

Sensitivity analysis was performed on two areas to test the response with lower dynamic reactive reserves. The first sensitivity was performed on a localized load pocket. When developing the power flow cases, low voltage and power flow convergence issues were observed in the Tac Harbor / Silver Bay area of Northern Minnesota. This area has a significant amount of industrial load, including over 75 MW of large synchronous motor load. Some of the production simulation hours had all Silver Bay and Tac Harbor units turned off. In most cases, the power flow failed to converge with these units turned off. If the power flow did solve with the generators off, voltages were well below 1.0 pu.

With all local generation off line, the Tac Harbor synchronous motors will be dynamically unstable for faults in the area. Turning on some units, either as generators or synchronous condensers will stabilized the motors. Though not tested, it is likely that new transmission and/or a static var compensator (SVC) would also stabilize the motors.

The second sensitivity was performed on the Manitoba Hydro (MH) HVDC ties and the 500 kV lines from MH to Minnesota. The 2028 power flow cases modeled a new HVDC tie into the Riel station along with reinforcements to the existing 500 kV system near the Iron Range. These reinforcements are intended to support higher MH exports. The HVDC inverter stations at Dorsey and Riel have several synchronous condensers to provide short circuit strength and reactive support. The S1_SH_D01 case has 2975 MW of MH exports. As noted above, all test disturbances are stable with acceptable post-fault voltage recovery for all of the test cases.

Several sensitivity simulations were performed on the shoulder load case (S1_SH_D01) with the Riel condensers turned off and the Dorsey condensers modeled with fixed field voltage. Modeling the Dorsey condensers with fixed field voltages allowed them to provide short circuit strength but not regulate voltages. Under these sensitivity test conditions, faults in Central Minnesota on the Terminal-King line caused a wide-spread instability. In order to stabilize this case, the MH exports had to be reduced by more than 500 MW.

This sensitivity analysis showed that localized dynamic reactive power support is critical to maintaining system stability. The current plans, as modeled in this study, address this issue and are sufficient for the anticipated levels of MH exports. The current practice of operating the Silver Bay and/or Tac Harbor generators to support the local industrial load provides strong local area voltage.

8.4 Weak Grid Analysis

As wind penetration increases and market commitment of synchronous resources decreases, there is a point where the grid is no longer strong enough (i.e. the impedance is too high) to support stable operation of the power electronic converters within the wind generators and PV plants. This can happen for single machines as well as for groups of machines in a wind plant and groups of wind plants in a region.

This is an emerging issue. Very few systems have faced this issue in actual operation (e.g. a few events in Texas before the transmission system was reinforced). Very few transmission engineers understand this issue in depth, as it has its roots within the lowest-level internal controllers of the wind and solar power electronic converter equipment. Knowledge of this issue is built upon converter performance tests and detailed analysis using transient simulation tools such asPower Systems Computer Aided Design (PSCAD) and ElectroMagnetic Transients Program (EMTP). Since such tools and analytical methods are not well suited to studying large-scale risks for many plants over wide geographic areas, the challenge is to take what is learned from detailed analysis of a few plants and extend that learning across larger regions using more practical methods.

8.4.1 Composite Short Circuit Ratio Concepts

Short Circuit Ratio (SCR) is a method used to screen for weak grid conditions near power electronic converters. This method has been used for decades to screen for weak grid conditions near HVDC converters and is currently being applied to wind plants. SCR is the ratio of the available system strength (measured in short circuit MVA) to the MW rating of the wind or PV plant.

While SCR is well established and trusted for HVDC and single-plant wind projects, it is not well suited for areas with multiple wind and solar plants in close proximity. For such cases, the industry is moving towards the Composite Short Circuit Ratio (CSCR) of all plants together.

Like SCR, this is the ratio of available short circuit MVA to plant MW rating. However, it accounts for multiple nearby plants by taking the ratio of composite short circuit MVA to that total MW rating of all plants.

The composite short circuit MVA is calculated by tying together the buses at the low side of the interconnection transformers of all wind and/or PV plants, creating a "composite" bus. The short circuit MVA is then calculated at the composite bus through normal fault calculation methods. CSCR is the ratio of the composite short circuit MVA to the total MW rating of all the wind and PV plants. This is shown in Figure 8-22. The wind and PV plants are assumed to have no fault current contribution when calculating CSCR.

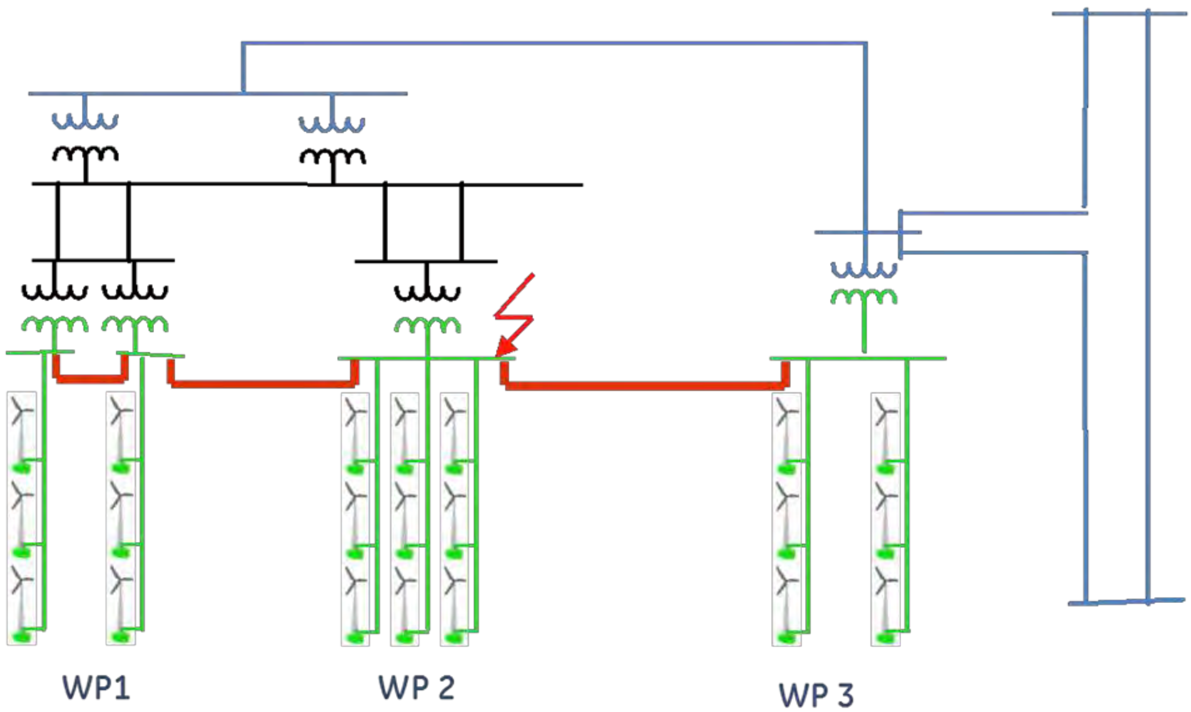

Figure 8-22 Example of composite, short-circuit MVA at Multiple Wind Plants

CSCR is calculated for normal and contingency conditions and considers generation off line. Unlike normal fault calculations, where the object is to determine the strongest system condition and highest fault current, CSCR calculations are intended to determine the weakest conditions the wind and PV will be expected to operate under.

Based on current wind turbine generator technology, a system with a CSCR above about 2.5 to 3 is considered strong. The wind plants should not have control instability issues. CSCR below about 1.7 to 1.5 is considered weak. CSCR below 1.0 would likely require mitigation, either at the plant through control tuning, by strengthening the system (e.g. new transmission or synchronous machines) or a combination of both. There is less experience with an acceptable CSCR level for PV plants.

8.4.2 Identifying Weak Regions

One of the challenges in evaluating weak grid issues for this study was identifying regions of the Minnesota system and the groups of wind and PV plants within those regions that could have low CSCR. The approach used for this analysis was to find relatively weak regions where voltage regulation was impacted more by wind and PV than by synchronous generation.

A measure of voltage regulation ratio was developed as the ratio of Thevenin impedance looking into the terminals of all synchronous generation to the Thevenin impedance looking into the terminals of all wind and PV generation. The Thevenin impedance was calculated taking the MVA rating of each unit into account. A low Thevenin impedance indicates a bus with strong voltage regulation and a high impedance indicates less voltage regulation. Since the voltage regulation ratio was defined as synchronous to non-synchronous Thevenin impedance, a ratio greater than 1.0 points to a bus with higher control from wind and PV than from synchronous generation. This corresponds to the regional measure of %NS, but on a substation level.

The voltage regulation ratio was calculated at all 230 kV and above Minnesota-centric buses. The total short circuit MVA was also calculated at the same buses. These two measures were then plotted for all buses and used to identify possible weak system areas with high renewables. This is shown in Figure 8-23. Each point in the plot represents a transmission bus, color coded by the six Minnesota-centric sub-regions. This plots is for n-0 transmission condition for the shoulder load case 1 dispatch (S1_SH_D01), as this cases had the overall highest percent non-synchronous generation.

Three clusters of buses are highlighted on the plot. Quad Cities 345 kV bus has 16,000MVA of short circuit strength and a voltage regulation ratio less than 0.5. This is to be expected, since both Quad Cities nuclear generating units are in service and dominate the voltage regulation at the transmission bus.

The Ashtabula plant in North Dakota is fed from Pillsbury 230 kV, near Fargo. This group of 230 kV buses, highlighted in the upper left corner of the plot, has a voltage regulation ratio above 3.0 and 710 MVA of short circuit strength. This is clearly a system dominated by wind generation with little short circuit strength. The three Ashtabula wind sites have a total capacity of 377 MW. This gives a CSCR of 1.88 under n-0 transmission conditions (710MVA/377MW). This is in the range of concern, particularly since the CSCR would likely be lower with transmission outages.

The transmission buses in SW Minnesota are shown with orange circles. Four 345 kV buses are highlighted; Obrien, Nobles, Huntley and Lakefield. These buses have a relatively high short circuit strength (5000 to 7000 MVA), but also have a high voltage regulation ratio (1.5 to 2.0). These buses are in the Buffalo Ridge area. The high voltage regulation ratio is due to the large amount of renewables in SW Minnesota (4344 MW total for S1). The short circuit strength is due to the strong 345 kV transmission around the area, connecting it to synchronous generation to the west, south and east. System strength and CSCR calculations in this region are presented in the next section.

The analysis was also used to identify additional contingencies for the stability analysis. Critical transmission lines were identified based on initial loading (i.e. power flow in the base condition) and on the fault current contribution for faults on 345 kV buses around the Buffalo Ridge area. Tripping transmission lines that provide the highest fault current and have the highest initial loading will be most challenging from a weak-system and a transient disruption standpoint. Outages identified from the weak system analysis are identified as LSC1 through LSC5, and SHEAS in Table 8-2.

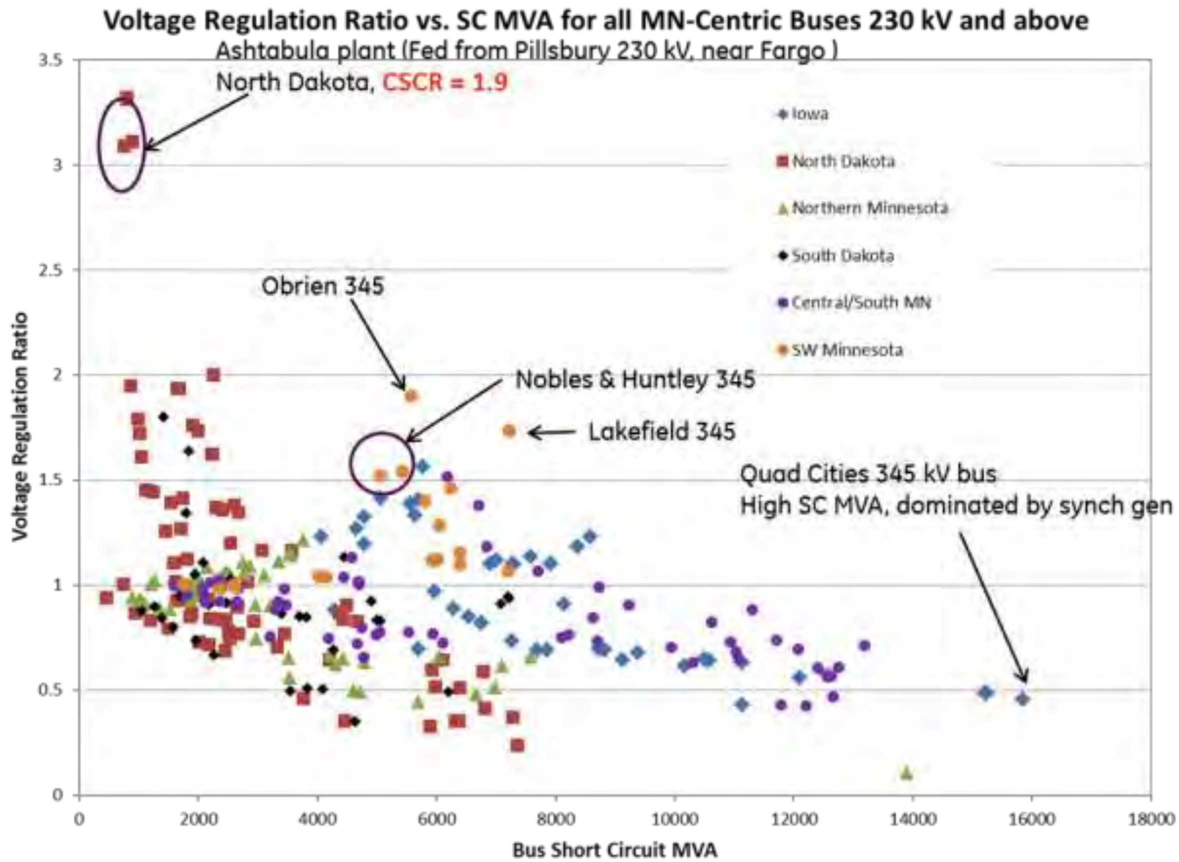

Figure 8-23 SC MVA vs. Voltage Regulation Ratio for Minnesota-Centric Transmission Buses

8.4.3 Southwestern Minnesota CSCR

As discussed above, the SW Minnesota region has a high concentration of renewable generation and relatively high short circuit strength under normal operating conditions. In total, the region has 4344 MW of renewable generation capacity for the S1 system. The rated MW of each plant in this area is listed in Table 8-4. New PV and New Wind represent renewable generation added for the baseline and S1 scenarios.

The CSCR for the composite of all of the SW Minnesota renewable generation was calculated by tying the low side of the interconnection transformers together with all renewable generation disconnected. For the S1_SH_D01 case, the CSCR is 9040 MVA over 4344 MW, or 2.08. This is in the caution region.

The CSCR was calculated with generation throughout the Minnesota-centric region decommitted. In general, no single generator had a significant impact on CSCR. The greatest reduction was seen for decommitting both Prairie Island units (two 659 MVA nuclear units northeast of Buffalo Ridge).

With both of these units off line, CSCR drops to from 2.08 to 2.00. Decommitting Neal 4 (711 MVA unit near Buffalo Ridge) reduced CSCR to 2.04.

Other decommitted units evaluated include Streeter, Ames, Coal Creek, Big Stone, Willmar, Heskett, JP Madgett, Stanton and King. These units were selected based on their commitment across all six stability cases and their operation in all of the selected hours. With all of these units off line, CSCR drops from 2.08 to 1.99. This is not a significant drop in CSCR, given the number of units decommitted. Sensitivity analysis was conducted where Hydro units at Garrison, Big Bend and Oahe were decommitted. These units had very little measurable impact on CSCR in the SW Minnesota region.

Transmission outages play a larger role in CSCR than individual generator status. Loss of the Sheas Lake to Helena 345 kV lines decreases the CSCR from 2.08 to 1.90. All other transmission outages tested has much less impact on CSCR. For example, loss of the Nobles-Lakefield or White-Split Rock 345 kV lines will only reduce the CSCR from 2.08 to 2.07. Several other transmission contingencies were studied but none had a significant impact on CSCR.

8.4.4 Mitigation through Wind/PV Inverter Controls

Standard inverter controls and setting procedures may not be sufficient for weak system applications. Loop gains of internal control functions inherently increase when system impedance increases, thereby reducing the stability margin of the controllers. Developers and equipment vendors must be made aware when new plants are being proposed for weak system regions so they can design/tune controls to address the issue. Wind plant vendors have made significant progress in designing wind and solar plant control systems that are compatible with weak system applications.

This approach becomes somewhat more difficult when there are wind/solar plants from multiple vendors in one region. The level of analysis requires detailed modeling of all affected wind plants at a level of detail that requires the use of proprietary control design information from the vendors. Vendors are very reluctant to share such data, except with independent consultants who can guarantee strict data security. However, this approach is gaining traction and a few projects have made effective implementations. The key to success is that project developers and equipment vendors must be informed beforehand that a given wind or solar plant will be installed at a weak system location. This enables the appropriate control design studies to be initiated before the project is installed.

In the event that such control-based approaches are not sufficient, it would be possible to further improve weak system performance by employing one or more of the system-level mitigations discussed below.

8.4.5 Low CSCR Mitigation

Committing additional generation will increase CSCR, but the increase is not drastic unless large blocks of units are put on line. For example, committing all coal units rated above 50 MVA in the MN centric footprint (7160 MVA total) increases the CSCR from 2.08 to 2.18. This is a very modest increase for such a large amount of committed generation. Therefore, mitigating low CSCR issues through commitment of existing generation is not a reasonable solution.

Two more reasonable methods available to increase CSCR in SW Minnesota are:

1. Add new synchronous machines, either generators or condensers, in the SW Minnesota region.
2. Lower the impedance between the region and the surrounding synchronous generation through new transmission, new 345/115 kV transformers or lower impedance transformers at the renewable generation sites.

Analysis considered the impact of adding synchronous condensers at several 345 kV and 115 kV buses in the Buffalo Ridge region.

Synchronous condensers are synchronous machines that have the same voltage control and dynamic reactive power capabilities as synchronous generators. Synchronous condensers are not connected to prime movers (e.g. steam turbines or combustion turbines), so they do not generate power.

Adding the condensers at the 115 kV level had the greatest increase in CSCR, since they were placed electrically closer to the renewable sites than on the higher voltage buses. For example, adding a 500 MVA of synchronous condensers at Lyon Co 115 kV and another 500 MVA at Nobles 115 kV increased the CSCR to 2.4. Moving the condensers to the 345 kV buses had a much lower improvement in CSCR.

Adding new transmission, particularly in the Sheas Lake area, will increase CSCR. Similarly, lower impedance transformers on the grid or in the renewable plants will increase CSCR. However, the benefits are likely to be modest.

Table 8-4 S1 Renewable Generation in SW Minnesota (Total MW Rating)

Sum of Pmax				
	S1_LL_D02	S1_LL_D04	S1_PK_D03	S1_SH_D01
PV	**160**		**160**	**160**
New PV	160		160	160
WIND	**4076**	**4184**	**4184**	**4184**
BRI3	290	290	290	290
BVIS		108	108	108
CHB3	281	281	281	281
CWS1	16	16	16	16
CWS2	14	14	14	14
DANJ	12	12	12	12
ELMC	151	151	151	151
ERID	10	10	10	10
G162	200	200	200	200
G164	200	200	200	200
G176	100	100	100	100
G255	100	100	100	100
G298	100	100	100	100
G358	35	35	35	35
G375	20	20	20	20
G426	150	150	150	150
G586	30	30	30	30
GRE-	227	227	227	227
JEFF	50	50	50	50
JHND	28	28	28	28
MMU	19	19	19	19
NOB_	200	200	200	200
ODIN	20	20	20	20
SRID	5	5	5	5
UILK	5	5	5	5
WEST	8	8	8	8
New Wind	1781	1781	1781	1781
WOLF	7	7	7	7
WOOD	10	10	10	10
WRID	7	7	7	7
Grand Total	**4236**	**4184**	**4344**	**4344**

9 KEY FINDINGS

This study examined two levels of increased wind and solar generation for Minnesota; 40% (represented by Scenarios 1 and 1a) and 50% (represented by Scenarios 2 and 2a). In the 40% Minnesota Scenario, MISO North/Central is at 15% (current state RESs). The 50% Minnesota Scenario also included an increase of 10% (to 25%) in the MISO North/Central region. Production simulation was used to examine annual hourly operation of the MISO North/Central system for all four of these scenarios. Transient and dynamic stability analysis was conducted for Scenarios 1 and 1a but not on Scenarios 2 and 2a.

9.1 General Conclusions for 40% RE Penetration in Minnesota

With wind and solar resources increased to achieve 40% renewable energy for Minnesota and 15% renewable energy for MISO North/Central, production simulation and transient/dynamic stability analysis results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission mitigations, as described in Chapter 4, to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

Dynamic simulation results indicate that there are no fundamental system-wide dynamic stability or voltage regulation issues introduced by the renewable generation assumed in Scenario 1 and 1a. This assumes:

- New wind turbine generators are a mixture of Type 3 and Type 4 turbines with standard controls
- The new wind and utility-scale solar generation is compliant with present minimum performance requirements (i.e. they provide voltage regulation/reactive support and have zero-voltage ride through capability)
- Local-area issues are addressed through normal generator interconnection requirements

9.2 General Conclusions for 50% RE Penetration in Minnesota

With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO, production simulation results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission upgrades, expansions and mitigations to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

No dynamic analysis was performed for the study scenarios with 50% renewable energy for Minnesota (Scenarios 2 and 2a) due to study schedule limitations and this analysis is necessary to ensure system reliability.

9.3 Annual Energy in the Minnesota-Centric Region

Figure 9-1 shows the annual load and generation energy by type for the Minnesota-Centric region. Comparing Scenarios 1 and 1a (40% MN renewables) with the Baseline,

- Wind and solar energy increases by 8.5 TWh, all of which contributes to bringing the State of Minnesota from 28.5% RE penetration to 40% RE penetration
- There is very little change in energy from conventional generation resources
- Most of the increase in wind and solar energy is balanced by a decrease in imports. The Minnesota-Centric region goes from a net importer to a net exporter.

Comparing Scenarios 2 and 2a (50% MN renewables) with Scenarios 1 and 1a (40% MN renewables),

- Wind and solar energy increases by 20 TWh. Of this total, 4.8 TWh brings the State of Minnesota from 40% to 50% RE penetration and the remainder contributes to bringing MISO from 15% to 25% RE penetration
- Most of the increase in wind and solar energy in the Minnesota-Centric region is balanced by a decrease in coal generation and an increase in net exports to neighboring regions
- Gas-fired, combined-cycle generation declines from 5.0 TWh in Scenario 1 to 3.0 TWh in Scenario 2.

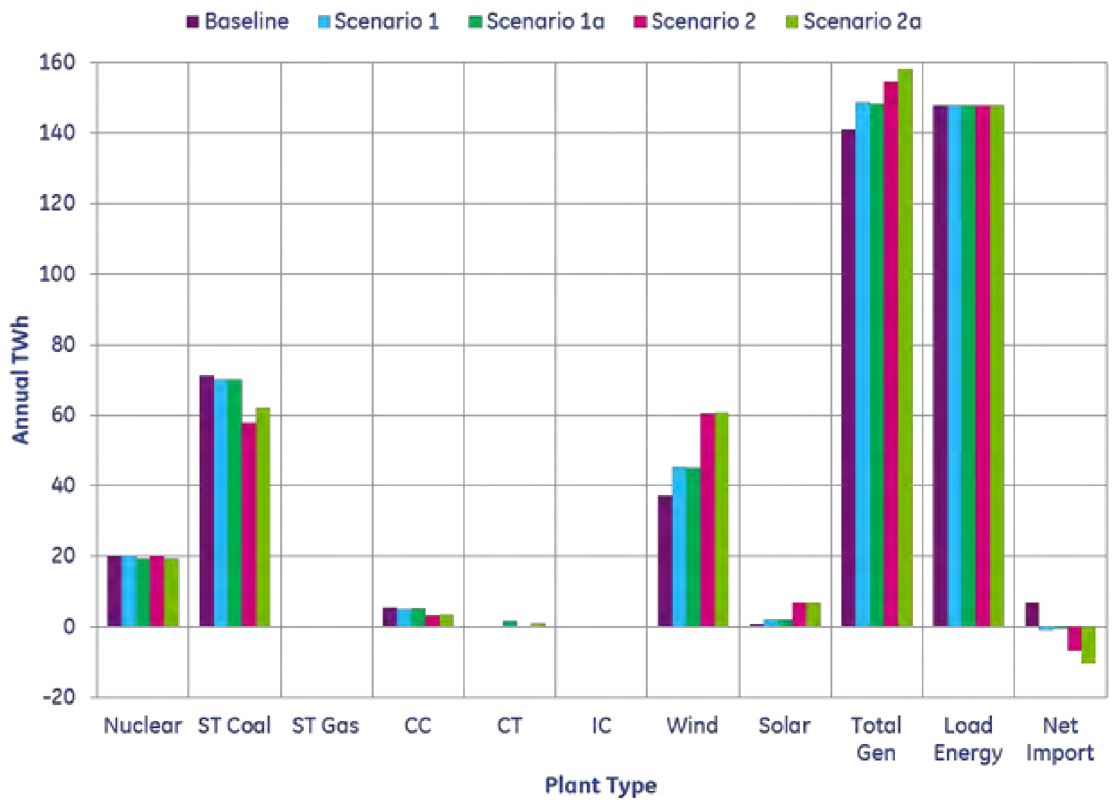

Figure 9-1 Annual Energy by Type in Minnesota-Centric Region for Study Scenarios

9.4 Cycling of Thermal Plants

Most coal plants were originally designed for baseload operation; that is, they were intended to operate continuously with only a few start/stop cycles in a year (mostly due to scheduled or forced outages). Increased cycling duty could increase wear and tear on these units, with corresponding increases in maintenance requirements. Many coal plants in MISO presently are designated by the plant's owner to operate as "must-run" in order to avoid start/stop cycles that would occur if they were economically committed by the market.

Scenarios S1a and S2a assumed that all coal plants in MISO are subject to economic commitment/dispatch (i.e., not must-run) based on day-ahead forecasts of load, wind and solar energy within MISO. Production simulation results show significant coal plant cycling due to economic market signals:

- Small coal units (below 300 MW rating) could have an additional 100 to 200 starts per year, beyond those due to forced or planned outages.
- Large coal units (above 300 MW) could have an additional 20 to 100 starts per year

Scenarios S1 and S2 assumed almost all coal plants would continue to operate as they do today. Coal units were on-line all year (except for scheduled maintenance periods) and were not decommitted during periods of low market prices. The results of these scenarios confirmed that the coal units could remain must-run with minor impacts on overall operation of the Minnesota-Centric region. Coal plant owners could choose to continue the must-run practice to avoid the detrimental impacts of increased cycling as wind and solar penetration increases. Doing so would likely incur some additional operational costs when energy prices fall below a plant's breakeven point. Wind curtailment would also be about 0.5% higher than if the coal plants were economically committed.

An attractive solution to the coal plant cycling issue may exist between the two bookend cases analyzed in this study. Scenarios 1a and 2a assumed that unit commitment was determined on a day-ahead basis, using day-ahead forecasts of wind and solar energy. The result was a high number of start/stop cycles of coal plants, sometimes with down-times of less than 2 days. If the unit commitment process was modified to use a longer term forward market (say 3 to 5 days ahead), then coal plant owners could adjust their operational strategy to consider decommitting units when prolonged periods of high wind/solar generation and low system loads are forecasted. A forward market would depend on longer term forecasts of wind, solar and load energy, consistent with the look-ahead period of the market. Although such forecasts would be somewhat less accurate than day-ahead forecasts, the quality of the forecasts would likely be adequate to support such unit commitment decisions.

This study did not examine the economic or wear-and-tear impacts of increased cycling on coal units. Further information on this topic can be found in the NREL Western Wind and Solar Integration Study Phase 2 report[1] and the PJM Renewable Integration Study report[2].

Combined-cycle (CC) units are better able to accommodate cycling duties than coal plants. Simulation results show that combined cycle units in the Minnesota-Centric region experience from 50 to 200 start/stop cycles per year. Cycling of CC units declines slightly as wind and solar penetration increases. This decline is primarily due to a decrease in CC plant utilization as wind and solar energy increases.

9.5 Curtailment of Wind and Solar Energy

In general, a small amount of curtailment is to be expected in any system with a significant level of wind and solar generation. There are some operating conditions where it is economically efficient to accept a small amount of curtailment (i.e., mitigation of that curtailment would be disproportionately expensive and not justifiable).

Overall curtailment in the Minnesota-Centric region is relatively small in all study scenarios, as shown in Table 9-1. Wind curtailment in Baseline and Scenario 1 is primarily due to local transmission congestion at a few wind plants. This congestion could be mitigated by transmission modifications, if economically justifiable.

Wind curtailment in Scenario 2 is due to system-wide operational limits during nighttime hours, when many baseload generators are dispatched to their minimum output levels. This type of curtailment could be reduced by decommitting some baseload generation via economic market signals. The effectiveness of this mitigation option is illustrated by comparing Scenario 2 (coal units must-run) with Scenario 2a (economic coal commitment). Wind curtailment decreases from 2.14% to 1.60% (reduction of 332 GWh of wind curtailment). Solar curtailment decreases from 0.42% to 0.24% (reduction of 12 GWh of solar curtailment).

[1] http://www.nrel.gov/electricity/transmission/western_wind.html
[2] http://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx

Table 9-1 Wind and Solar Curtailment for Study Scenarios

Scenario	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Wind Curtailment	0.42%	1.00%	1.59%	2.14%	1.60%
Solar Curtailment	0.09%	0.00%	0.23%	0.42%	0.24%

Note: Curtailment is calculated as a percentage of available annual wind or solar energy.

9.6 Other Operational Issues

No significant transmission system congestion was observed in any of the study scenarios with the assumed transmission upgrades and expansions. Transmission contingency conditions were considered in both the powerflow analysis used to develop the conceptual transmission system and the security-constrained economic dispatch in the production simulation analysis.

Ramp-range-up and ramp-rate-up capability of the MISO conventional generation fleet increases with increased penetration of wind and solar generation. Conventional generation is generally dispatched down rather than decommitted when wind and solar energy is available, which gives those generators more headroom for ramping up if needed.

Ramp-range-down and ramp-rate-down capability of the MISO conventional generation fleet decreases with increased penetration of wind and solar generation. In Scenario 2, there are 500 hours when ramp-rate-down capability of the conventional generation fleet falls below 100 MW/min. Periods of low ramp-down capability coincide with periods of high wind and solar generation. Wind and solar generators are capable of providing ramp-down capability during these periods. MISO's existing Dispatchable Intermittent Resource (DIR) process already enables this for wind generators. It is anticipated that MISO would expand the DIR program to include solar plants in the future.

9.7 System Stability, Voltage Support, Dynamic Reactive Reserves

No angular stability, oscillatory stability or wide-spread voltage recovery issues were observed over the range of tested study conditions. The 16 dynamic disturbances used in stability simulations included key traditional faults/outages as well as faults/outages in areas with high concentrations of renewables and high inter-area transmission flows. System operating conditions included light load, shoulder load and peak load cases, each with the highest percent renewable generation periods in the Minnesota-Centric region.

Overall dynamic reactive reserves are sufficient and all disturbances examined for Scenarios 1 and 1a show acceptable voltage recovery. The South/Central and Northern Minnesota regions get the majority of their dynamic reactive support from synchronous generation. Maintaining sufficient dynamic reserves in these regions is critical, both for local and system-wide stability.

Southwest Minnesota, South Dakota and at times Iowa get a significant portion of dynamic reactive support from wind and solar resources. Wind and Solar resources contribute significantly to voltage support/dynamic reactive reserves. The fast response of wind/solar inverters helps voltage recovery following transmission system faults. However, these are current-source devices with little or no overload capability. Their reactive output decreases when they reach a limit (low voltage and high current).

Synchronous machines (either generators or synchronous condensers), on the other hand, are voltage-source devices with high overload capability. This characteristic will strengthen the system voltage, allowing better utilization of the dynamic capability of renewable generation. The mitigation methods discussed below, namely stiffening the ac system through new transmission or synchronous machines, will also address this concern.

Local load areas, such as the Silver Bay and Taconite Harbor area, require reactive support from synchronous machines due to the high level of heavy industrial loads. If all existing synchronous generation in this region is off line (i.e. due to retirement or decommitment), reinforcements such as new transmission or synchronous condensers would be required to support the load.

Dynamic simulation results indicate that it is critical to maintain sufficient system strength and dynamic reserves to support high flows on the Northern Minnesota 500 kV lines and Manitoba high-voltage direct-current (HVDC) lines. Insufficient system strength and reactive support will limit Manitoba exports to the U.S. Existing transmission expansion plans, as modeled in this analysis, address these issues and are sufficient for the anticipated levels of Manitoba exports.

The Manitoba HVDC ties and the 500 kV transmission system in Northern Minnesota require reactive support from synchronous generators, the Dorsey and Riel synchronous condensers, and the Forbes SVC to maintain the expected level of Manitoba exports. Without sufficient reactive reserves, the system could be unstable for nearby transmission disturbances. The current transmission plans, as modeled in this analysis, address this issue.

9.8 Weak System Issues

Composite Short-Circuit Ratio (CSCR) is an indicator of the ability of an ac transmission system to support stable operation of inverter-based generation. A system with a higher CSCR is considered strong and a system with a lower CSCR is considered to be weak. CSCR is calculated as the ratio of the composite short-circuit MVA at the points of interconnection (POI) of all wind/solar plants in a given area to the combined MW rating of all those wind and solar generation resources.

Low CSCR operating conditions can lead to control instabilities in inverter-based equipment (Wind, Solar PV, HVDC and SVC). Instabilities of this nature will generally manifest as growing voltage/current oscillations at the most affected wind or solar plants. In the worst conditions (i.e., very low CSCR), oscillations could become more wide-spread and eventually lead to loss of generation and/or damage to renewable generation equipment if not adequately protected against such events.

This is a relatively new area off concern within the industry. The issue has emerged as the penetration of wind generation has grown. Understanding of the fundamental stability issues is rapidly growing as more wind plants are being installed in regions with weak ac systems. Equipment vendors, transmission planners and consultants are all working to gain a better understanding of the issues. Modeling and simulation tools have already been developed to enable detailed analysis of the phenomena. Wind and solar inverter control systems are being modified to improve weak system performance.

Synchronous machines (either generators or synchronous condensers) contribute short-circuit strength to the transmission system and therefore increase CSCR. Therefore, system operating conditions with more synchronous generators online will have higher CSCR. Also, stronger transmission ties (additional transmission lines or transformers, or lower impedance transformers) between synchronous generation and regions of wind and solar generation will increase CSCR. SVCs and STATCOMs do not contribute short-circuit current, and because they are electronic converter based devices with internal control systems similar to wind/solar inverters, their presence in a weak system region could further reduce the effective CSCR and exacerbate the control system stability issues that occur in weak system conditions.

There are two general situations where weak system issues generally need to be assessed:

- Local pockets of a few wind and solar plants in regions with limited transmission and no nearby synchronous generation (e.g. plants in North Dakota fed from Pillsbury 230 kV near Fargo).
- Larger areas such as Southwest Minnesota (Buffalo Ridge area) with a very high concentration of wind and solar plants and no nearby synchronous generation

This study examined the sensitivity of weak system issues in Southwest Minnesota. Observations are as follows:

The trouble spots identified in this analysis are not very sensitive to existing synchronous generation commitment. While there is very little synchronous generation within the area, the region is supported by a strong networked 345 kV transmission grid. Primary short circuit strength is from a wide range of base-load units in neighboring areas, and interconnected via the 345 kV transmission network. Commitment, decommittment or outages of individual synchronous generators do not have significant impact on CSCR in these identified areas.

Transmission outages will lower system strength and make the issue worse. When performing CSCR and weak system assessments as wind and solar penetration increases, it will be prudent to consider normal and design-criteria outages at a minimum (i.e, outage conditions consistent with MISO reliability assessment practices).

9.9 Mitigations

There are two approaches to improving wind/solar inverter control stability in weak system conditions:

- To improve the inverter controls, either by carefully tuning the equipment control functions or modifying the control functions to be more compatible with weak system conditions. With this approach, wind/solar plants can tolerate lower CSCR conditions.
- To strengthen the ac system, resulting in increased short-circuit MVA at the locations of the wind/solar plants. This approach increases CSCR.

The approaches are complementary, so the ultimate solution for a particular region would likely be a combination of both.

Mitigation through Wind/PV Inverter Controls

Standard inverter controls and setting procedures may not be sufficient for weak system applications. Loop gains of internal control functions inherently increase when system impedance increases, thereby reducing the stability margin of the controllers. Developers and equipment vendors must be made aware when new plants are being proposed for weak system regions so they can design/tune controls to address the issue. Wind plant vendors have made significant progress in designing wind and solar plant control systems that are compatible with weak system applications.

This approach becomes somewhat more difficult when there are wind/solar plants from multiple vendors in one region. The level of analysis requires detailed modeling of all affected wind plants at a level of detail that requires the use of proprietary control design information from the vendors. Vendors are very reluctant to share such data, except with independent consultants who can guarantee strict data security. However, this approach is gaining traction and a few projects have made effective implementations. The key to success is that project developers and equipment vendors must be informed beforehand that a given wind or solar plant will be installed at a weak system location. This enables the appropriate control design studies to be initiated before the project is installed.

In the event that such control-based approaches are not sufficient, it would be possible to further improve weak system performance by employing one or more of the system-level mitigations discussed below.

Mitigation by Strengthening the AC System

CSCR analysis of the Southwest Minnesota region shows that synchronous condensers located near the wind and solar plants would be a very effective mitigation for weak system issues. Synchronous condensers are synchronous machines that have the same voltage control and dynamic reactive power capabilities as synchronous generators. Synchronous condensers are not connected to prime movers (e.g. steam turbines or combustion turbines), so they do not generate power.

Other approaches that reduce ac system impedance could also offer some benefit:

- Additional transmission lines between the wind/solar plants and synchronous generation plants
- Lower impedance transformers, including wind/solar plant interconnection transformers

Series capacitors on transmission lines could be used to increase CSCR and to improve the transmission system's capability to transfer energy out of regions with high concentrations of wind and solar resources. However, series capacitors create subsynchronous frequency resonances in the transmission system which affect the performance of control systems within wind and solar plants. These resonances introduce an additional challenge to wind/solar plant control designs, which must maintain stable operation in the presence of the resonant conditions.Mitigation through "must-run" operating rules for existing generation was found to be not very effective. The plants with synchronous generators are not located close enough to effected wind/solar plants.

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11 APPENDICES

Appendix A1 – AC Input Files

Appendix A2 – Powerflow Case Flow Info

Appendix A3 – Bus Angle Diagrams

Appendix A4 – Contingency Analysis Spreadsheets

Appendix A5 – Maps

Appendix A6 – Transmission Costs

Appendix A7 – HVDC

Note: The Appendices are available upon request from Great River Energy.

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Technical Report
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Executive Summary

Our analysis considers several alternative forms of an energy imbalance market (EIM) proposed in the nonmarket areas of the Western Interconnection. The proposed EIM includes two changes in operating practices that independently reduce variability and increase access to responsive resources: balancing authority cooperation and subhourly dispatch. As proposed, the EIM does not consider any form of coordinated unit commitment; however, over time, it is possible that balancing authorities would develop formal or informal plans to coordinate unit commitment. As the penetration of variable generation increases on the power system, additional interest in coordination would likely occur. Several alternative approaches could be used, but consideration of any form of coordinated unit commitment is beyond the scope of our analysis. This report examines the benefits of several possible EIM implementations—both separately and in concert.

We calculated the need for flexibility reserve for several EIM footprints. This flexibility reserve requirement was estimated using a National Renewable Energy Laboratory method adapted from the Eastern Wind Integration and Transmission Study and is separate and distinct from contingency reserve requirements. The technique uses statistical analysis of simulated historical wind and solar generation to estimate reserve requirements at periods faster than the dispatch interval (regulation) and slower requirements (additional spin and non-spin reserve resources beyond what is needed to satisfy the contingency reserve requirement) to follow longer unforecasted changes in variable generation output. The additional flexibility reserve requirements are physically similar to, but distinct from, the existing reserves that are already required for regulation and contingencies. Each of these reserves is calculated for each hour of the year to create a dynamic reserve that can be deployed to manage forecasting errors over various time scales. Because this report assumes that contingency reserve obligations do not change with the increased use of variable generation, our discussion focuses on additional flexibility reserve throughout. Therefore, any reference to terms using *spin* or *non-spin* apply only to flexibility reserves that can be either spinning or non-spinning resources above and beyond what is needed to satisfy existing contingency reserve obligations.

We used wind data developed for the recent Western Wind and Solar Integration Study, which was managed by the National Renewable Energy Laboratory on behalf of the U.S. Department of Energy [1]. Solar data were developed by the National Renewable Energy Laboratory for the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC) 2020 planning case. The scenario is defined by the TEPPC 2020 Planning Case 0, which includes approximately 8% wind and 3% solar penetration in the Western Interconnection. Although this study used the TEPPC database, it is not associated with the TEPPC process.

Both the wind and solar data sets are based on weather/cloud modeling that explicitly recognizes the temporal and geographic diversity of these resources. In effect, the load, wind power, and solar power data sets “re-create” the weather and load conditions from the year 2006 and apply them to the future year 2020, subject to various TEPPC PC0 assumptions. This approach is state-of-the-art in providing high-quality, simulated time series of wind power and solar power plants that have not yet been built.

Our analysis finds a reduction in required flexibility reserve is made possible by an EIM if it is implemented over the entire areas of the Western Interconnection not currently participating in regional markets. Figure i illustrates the impact of the full-footprint implementation of an EIM on reserves. The business-as-usual (BAU) case represents the current operational paradigm, with limited coordination among balancing authorities. The solid bars show the average hourly reserve deployment, and the whiskers show the maximum and minimum reserve levels over the course of the year for the BAU and EIM cases. Total average regulation is cut from 1669 MW for the BAU case to 1076 in the footprint EIM, while total flex spin and flex non-spin reserves are reduced from 5359 MW to 3083 MW. The figure shows the reserve detail for the footprint EIM compared with the BAU case. The average reserve is reduced 35%–46%.

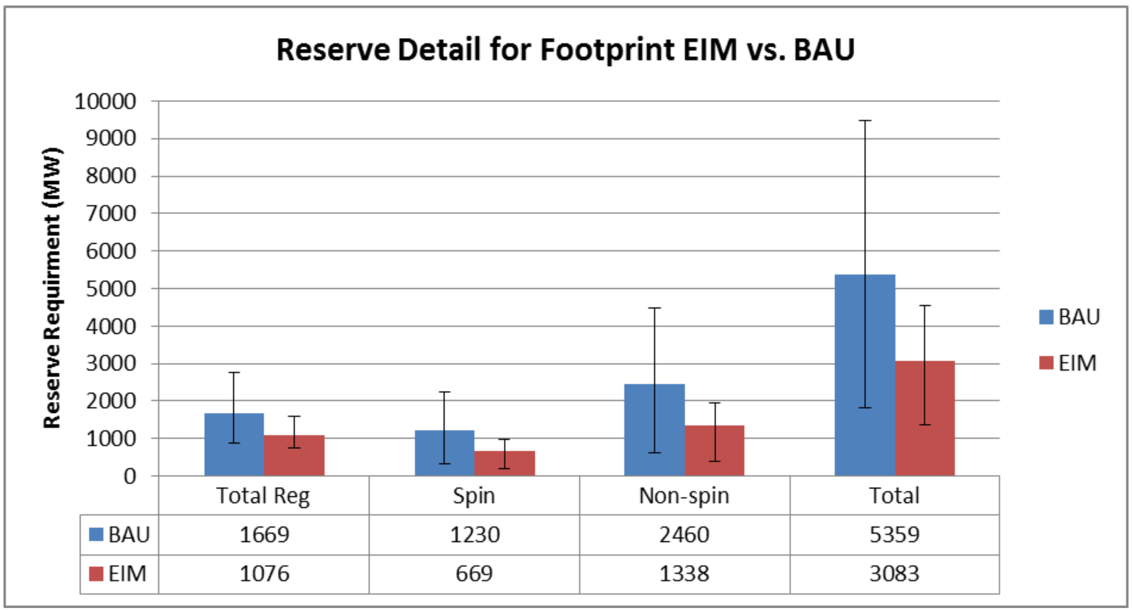

Figure i. The EIM reduces reserve targets by 35%–46%, on average

Table i shows the maximum reductions—ranging from a 42% maximum reduction in regulation to a 56% maximum reduction in spin and non-spin—in each flex reserve type.

Table i. Reduction in Maximum Flexibility Reserve Values

	BAU	EIM	Reduction
Total Regulation	2765	1607	42%
Spin	2236	977	56%
Non-Spin	4472	1955	56%
Total	9473	4539	52%

Total regulation is made up of three components: load, wind, and solar. The relationship among these components is shown in Figure ii. Total regulation is the square root of the sum of the squares of the individual components because they are assumed uncorrelated in the regulation timeframe. Load regulation is the largest contributor to total regulation, but the most significant savings for the EIM occur for the wind component, which is reduced by 54%. Solar impact on regulation is significantly smaller than that of wind, but that is because wind energy penetration is 8% and solar energy penetration is 3% in the TEPPC 2020 case.

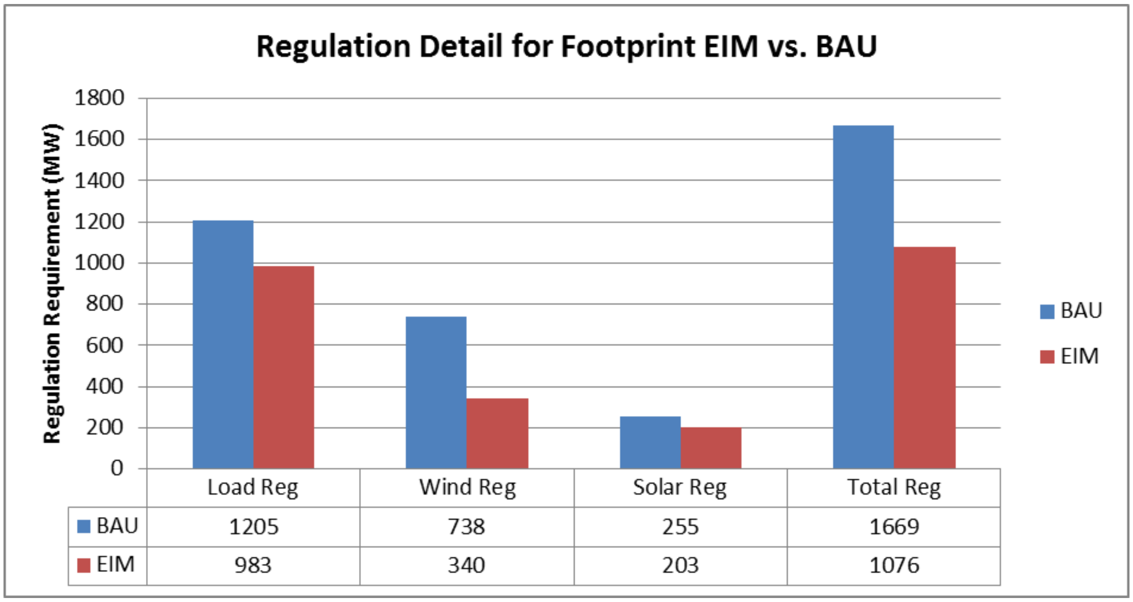

Figure ii. Contributions of load, wind, and solar to average total regulating reserves

Calculating the reduction in total system flexibility reserve requirements that results from increased aggregation is relatively straightforward (as is measuring the benefits once the wind and solar generation is installed); allocating the savings to the individual participants is not as easy. To enable individual balancing authorities to assess the effect of the EIM on their reserves, it is necessary to calculate the balancing authority flexibility reserve needs in the aggregated case. This means that some form of allocation method is needed. We describe several allocation approaches, including incremental allocation, proportional allocation, and vector allocation. We define a very broad notion of “fairness” based on prior work that we use as a framework for discussing the alternative forms of allocation of reserves. We find that incremental and proportional allocations, although possessing some potentially attractive characteristics and simplicity, may result in reserve allocations that do not respect our simple, and hopefully noncontroversial, notions of fairness. Evaluating the reserve reduction potential of the EIM for any particular entity or balancing authority requires the use of some allocation, either implicitly or explicitly.

We also apply general reserve pricing to estimate the potential cost savings of each reserve type by balancing authority and for the market footprint. These estimates are not intended to be precise because we use the same pricing for all balancing authorities and at all times. We find that the full-footprint implementation of the EIM—which comprises the entire Western Interconnection, excluding the California Independent System Operator and Alberta Electric System Operator market areas—would result in savings of approximately $103 million/year because of less flexibility reserve deployment. This benefit is reduced to approximately $77 million/year if the Bonneville Power Administration and Western Area Power Administration, the federal power marketing administrations in the West, do not participate in the EIM.

We also apply this analysis to an alternative renewable energy scenario from the Western Wind and Solar Integration Study that uses a 30% annual wind energy penetration. We find that the reserve benefit for the entire footprint is approximately $221 million, which is reduced to $144 million without the participation of Bonneville Power Administration and Western Area Power Administration.

Our savings estimates are imprecise but provide an order-of-magnitude estimate of benefits. More importantly, this provides a glimpse at how the benefits might be allocated across the participants in the EIM. These results also show the overall sensitivity of the benefits (both in terms of megawatts of reserve and monetized benefits) to the penetration of variable generation. This analysis also shows the danger of relying on specific point estimates of the benefits of the EIM because the difference in results obtained from alternative penetrations is large.

Flexibility reserve requirements are not explicitly specified for each balancing authority area, but they are implicit in the operating reliability requirements for balancing. Each balancing authority must carry enough reserves to meet Control Performance Standard (CPS) 1, CPS 2, and Disturbance Control Standard requirements. Balancing authorities differ in their risk tolerance, and different balancing authorities may elect to carry different reserves to compensate for the same level of variability. One balancing authority may carry enough reserves to maintain a CPS 2 score of 98%, for example, while another may carry fewer reserves because it is comfortable with a 92% CPS 2 score. (Ninety percent or better is required.) For the purposes of this report, and to calculate the specific savings that result from the EIM, it is necessary to assume a common level of risk tolerance and a common reserve criterion to apply to each balancing authority, which we do inside the context of the reserve method discussed in this report. In reality, participation in the EIM and aggregating variability will always reduce the required reserves regardless of the individual balancing authority’s risk tolerance.

Our analysis focuses only on the ramping and flexibility reserve impacts of the EIM. We do not consider or evaluate production costs, nor do we consider the cost of establishing the EIM or operating the EIM. The flexibility reserve calculations in this report also do not consider transmission limitations that might affect the delivery of an EIM transaction across congested transmission interfaces. The flexibility reserves that we calculate here were used as inputs to the WECC benefit study [2] and are also input to production simulation modeling under way using the Plexos production simulation model through a partnership between the National Renewable Energy Laboratory and Energy Exemplar. Both the WECC and Plexos analyses incorporate transmission constraints into the production simulation. The flexibility reserve calculations in this report establish the need for these reserves, and the production simulation provides a means to evaluate whether the demand for energy and reserves can be met.

Acknowledgments

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List of Abbreviations and Acronyms

AVA	Avista
AZPS	Arizona Public Service
BA	balancing authority
BAA	balancing authority area
BAU	business as usual
BCTC	British Columbia Transmission Corp.
BPA	Bonneville Power Administration
CHPD	Public Utility District No. 1 of Chelan County
CPS	Control Performance Standard
DOPD	Public Utility District No. 1 of Douglas County
E3	Energy and Environmental Economics Inc.
EIM	energy imbalance market
EPE	El Paso Electric
ERCOT	Electric Reliability Council of Texas
GCPD	PUD No. 1 of Grant County
GW	gigawatt
IID	Imperial Irrigation District
IPC	Idaho Power Corp.
ISO	independent system operator
ISO-NE	Independent System Operator – New England
LDWP	Los Angeles Department of Water and Power
MISO	Midwest Independent Transmission System Operator
NREL	National Renewable Energy Laboratory
NTTG	Northern Tier Transmission Group
NWE	Northwest Energy
PACE	Pacificorp East
PACW	Pacificorp West
PC	Planning Case
PGE	Portland General Electric
PNM	Public Service Company of New Mexico
PSCO	Public Service Company of Colorado
PSE	Puget Sound Energy
SCL	Seattle City Light
SMUD	Sacramento Municipal Utility District
SPP	Sierra Pacific Power
SRP	Salt River Project
TEP	Tucson Electric Power
TEPPC	Transmission Expansion Planning Policy Committee
TID	Turlock Irrigation District
TPWR	Tacoma Power
VG	variable generation
WACM	Western Area Power Administration – Colorado Missouri Region
WALC	Western Area Power Administration – Lower Colorado Region
WAPA	Western Area Power Administration

WAUW	Western Area Power Administration – Upper Great Plains West
WECC	Western Electricity Coordinating Council
WWSIS	Western Wind and Solar Integration Study

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1 Introduction

The anticipated increase in variable generation (VG) in the Western Interconnection over the next several years has raised concerns about maintaining system balance, especially in smaller balancing authority areas (BAAs).[1] Given renewable portfolio standards in the West, it is possible that more than 50 gigawatts (GW) of wind capacity will be installed by 2020. Significant quantities of solar generation are likely to be added as well. The consequent increase in variability that must be managed by the conventional generation fleet and responsive load makes it attractive to consider ways in which balancing authorities (BAs) can pool their variability and response resources to take advantage of geographic and temporal diversity and increase overall operational efficiency.

Several approaches, each of which involves alternative levels of operational coordination beyond what is done today, could be taken to implement this type of variability pooling. A full pooling of variability could potentially result in fully coordinated unit commitment, after blending load, solar, and wind forecasts. Closer to real time, economic dispatch could be implemented across the entire electrical footprint. An alternative to this fully coordinated operational case is using the existing practice for unit commitment, which is largely uncoordinated among BAs, in most cases, but allows for economic dispatch over a wide area.

Our analysis considers several alternative forms of an energy imbalance market (EIM) proposed in the non-market areas of the Western Interconnection. The proposed EIM includes two changes in operating practices that independently reduce variability and increase access to responsive resources: BA cooperation and subhourly dispatch. As proposed, the EIM does not consider any form of coordinated unit commitment; however, over time, it is possible that BAs would develop formal or informal coordination plans. This report examines the benefits of several possible EIM implementations, both separately and in concert.

Our analysis focuses only on the ramping and flexibility reserve impacts of the EIM. We do not consider or evaluate production costs, nor do we consider the costs to establish the EIM or operate the EIM. The flexibility reserve calculations in this report also do not consider transmission limitations that might affect the delivery of an EIM transaction across congested transmission interfaces. The flexibility reserves that we calculate here were used as inputs to the Western Electricity Coordinating Council (WECC) benefit study and are also input to production simulation modeling under way using the Plexos production simulation model through a partnership between the National Renewable Energy Laboratory (NREL) and Energy Exemplar. Both the WECC and Plexos analyses incorporate transmission constraints into the production simulation. The flexibility reserve calculations in this report establish the need for these reserves, and the production simulation provides a means for evaluating whether the demand for energy and reserves can be met.

Because this report assumes that contingency reserve obligations do not change with the increased use of VG, our discussion focuses on additional flexibility reserves throughout. Therefore, any reference to terms using *spin* or *non-spin* apply only to flexibility reserves that can be either spinning or non-spinning resources above and beyond what is needed to satisfy existing contingency reserve obligations.

Table 1 describes the ancillary services referenced in this report (adapted from [6]). Both contingency reserves and flexibility reserves use regulating, spinning, and non-spinning resources. Flexibility reserves are in addition to contingency reserves.

[1] Balancing the same variable renewable generation penetration percentage is more difficult for numerous small BAAs than for fewer large BAAs because variability partially cancels as BAA size increases while access to flexible resources continues to increase.

Table 1. Ancillary Service Descriptions

Service	Service Description				
	Response Speed	Duration	Cycle Time	Market Cycle	Price Range (Average/Max) $/MWh
Normal Conditions					
Regulating Reserve	Online resources, on automatic generation control, that can respond rapidly to system operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and correct for unintended fluctuations in generator output to comply with CPS 1 and 2				
	~1 min	*Minutes*	*Minutes*	*Hourly*	*33–60*# *300–620*
Load Following or Fast Energy Markets	Similar to regulation but slower; bridge between the regulation service and the hourly energy markets				
	~10 min	*10 min to hours*	*10 min to hours*	*Hourly*	-
Contingency Conditions					
Spinning Reserve+	Online resources, synchronized to the grid, that can increase output or decrease consumption immediately in response to a major generator or transmission outage and can provide full response within 10 min to comply with the North American Electric Reliability Corp Disturbance Control Standard				
	Seconds to <10 min	*10–120 min*	*Hours to days*	*Hourly*	*6–27* *60–2000*
Non-Spinning Reserve*+	Same as spinning reserve but need not respond immediately; resources can be offline but still must be capable of fully responding within the required 10 min				
	<10 min	*10–120 min*	*Hours to days*	*Hourly*	*1–4* *10–2000*
Replacement or Supplemental Reserve	Same as non-spinning reserve but with a 30–60 min response time; used to restore spinning and non-spinning reserves to their pre-contingency status				
	<30 min	*2 hours*	*Hours to days*	*Hourly*	*1–2* *4–244*

#Up and down regulation prices for California and ERCOT are combined to facilitate comparison with the full-range prices of New York and other regions.

*In this analysis, non-spinning reserve is considered to be a 30-min service.

+The flexible reserves defined in this report are in addition to reliability reserves using the same names.

This study extends the analysis by King et al. [10] that quantifies the flexibility reserve requirements for several implementations of the EIM. The prior study used the wind energy penetration assumptions for a 35% renewable penetration scenario from the Western Wind and Solar Integration Study but used only the wind energy at a 30% penetration. This study uses the approximately 8% wind and 3% solar penetration assumptions from the WECC Transmission Expansion Planning Policy Committee (TEPPC) 2020 Planning Case 0 (PC0).

The NREL method uses a technique for estimating flexibility reserve requirements adapted from the Eastern Wind Integration and Transmission Study. This technique uses statistical analysis of simulated historical wind and solar generation to estimate reserve requirements at periods faster than the dispatch interval (regulation) and slower requirements (spin and non-spin reserves) to follow longer unforecasted changes in VG output.

The method is used to calculate the reserve requirements for a business-as-usual (BAU) case and compares those results with calculations for several EIM implementations to estimate the savings in reserves resources.

WECC engaged E3 (Energy and Environmental Economics Inc.) to perform a study using a production cost modeling approach to estimate the production cost savings that would be realized with EIM implementation. This study also used the WECC TEPPC 2020 PC0 assumptions. The E3 analysis used the NREL reserve results (described herein) that consist of one time series for each reserve type, hourly, for the full year, as input to production cost simulations that were carried out using the Gridview production simulation model. The E3 study uses the reduced reserve requirements for the EIM to calculate the value of energy savings due, in part, to those reduced requirements.[2]

Figure 1 shows the relationship between the methods and data presented here and production cost modeling studies that are used to simulate the total savings from the implementation of an EIM. The boxes on the left show the process used to develop the flexibility reserves described in this report, and the boxes on the right show how those results are integrated into production cost simulations. Because Gridview and Plexos both incorporate the WECC TEPPC 2020 PC0 assumptions, transmission is explicitly considered in the production simulations. The flexibility reserves calculated in this report describe the need for those reserve products, and the production simulation provides a way to evaluate the operation of the power system and how the flexibility reserve can be delivered.

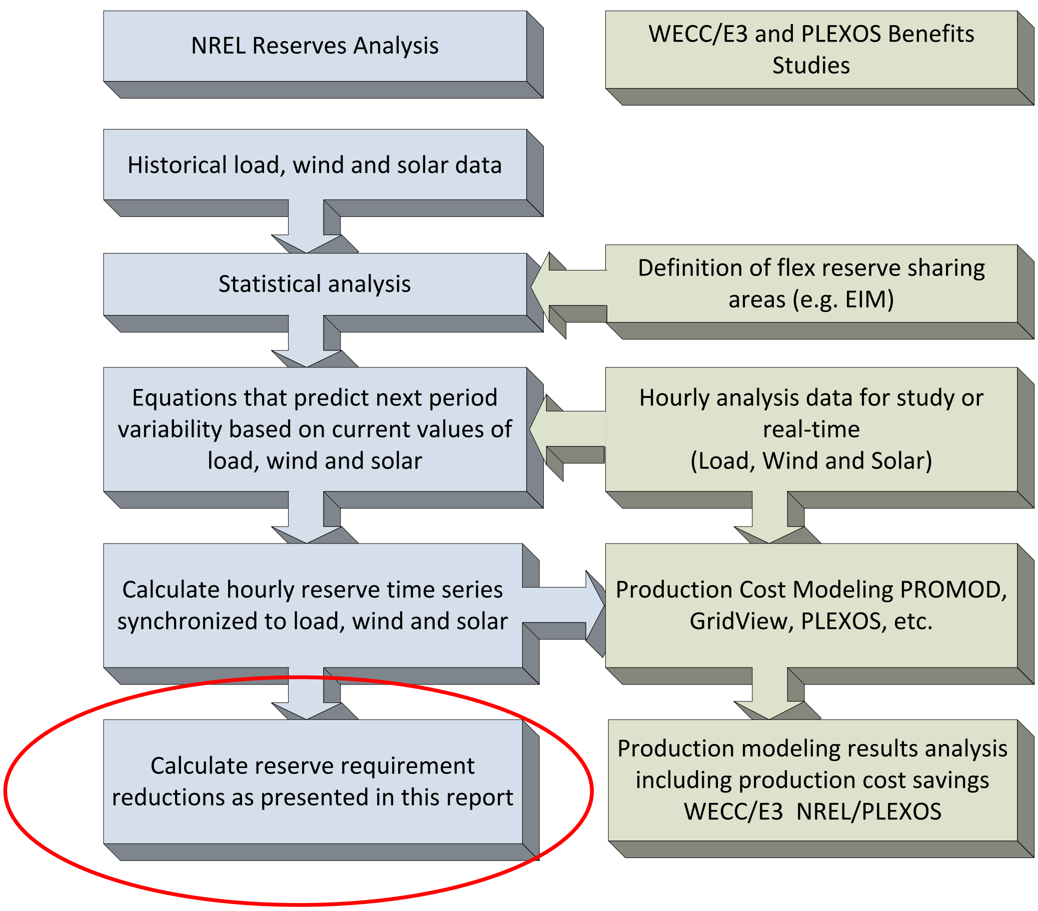


Figure 1. Relationship between reserve calculations and production cost studies

[2]The E3 study provides a point estimate of the benefits of the EIM. It is based on a single scenario. The actual benefits of the EIM would accrue through time and depend heavily on the level of wind and solar generation, along with other assumptions about the remaining components of the power system and the modeling. Interested readers are referred to [13].

2 Data

We used wind data from the recent Western Wind and Solar Integration Study, which was managed by NREL on behalf of the U.S. Department of Energy [1]. Solar data were developed by NREL for the WECC TEPPC 2020 planning case. The scenario is defined by TEPPC 2020 PC0, which includes approximately 8% wind and 3% solar penetration in the Western Interconnection.

Both the wind and solar data sets are based on weather/cloud modeling that explicitly recognizes the temporal and geographic diversity of these resources. In effect, the load, wind power, and solar power data sets “re-create” the weather and load conditions from the year 2006 and apply them to the year 2020, subject to the various TEPPC PC0 assumptions. This approach is state-of-the-art in providing high-quality, simulated time series of wind and solar power plants that have not been built.

The 2006 time series wind data set was paired with the 2006 time series load data so that the common weather impacts on load and wind would be consistent. We aggregated the data into subregional footprints: Columbia Grid, Northern Tier Transmission Group (NTTG), WestConnect, and British Columbia. Other areas within the Western Interconnection (California and Alberta) were not modeled because markets are already in place in those areas and they likely would not participate in the initial EIM analyzed in this report.[3]

2.1 Wind Production Data

3TIER developed a large wind speed and wind power database using a numerical weather prediction model applied to the West. Because the model allows the re-creation of the weather at any time or space, wind speed data were sampled every 10 min for a 3-year period on a 2-km spatial resolution at representative hub heights for modern wind turbines. The resulting data set does a good job of capturing the chronological behavior and geographical diversity of the wind that would occur at locations around the West. The high-resolution data set was then used to construct the various wind scenarios.

The numerical weather prediction model of the Western Interconnection contained geographic and temporal seams that were not possible to resolve. This resulted in unrealistic wind energy ramps near the temporal boundaries, which occurred every 3 days. To make the reserves and ramping analysis complete, a continuous annual record was needed, so a method to smooth those ramps below statistical significance was required. To do this, the wind data were analyzed in detail surrounding the anomalies.

The anomalies occurred at approximately the same time, 3 p.m., every third day starting with the first day of data for all wind plants in the data set. Anomalous data were seen up to 3 hours before this time and 3 hours after—a side effect of the blending of model runs done by the wind data contractor. These anomalous data caused 10-min ramps more than double that seen anywhere else in the data sets. Figure 2 shows a scatter plot of 10-min interval changes verses the interval number out of a 3-day period. The red dots show where the anomalous data are found. The spikes near 90 on the X axis show the peak interval changes. The similar time, 3 p.m., on the second and third days are near 230 and 380 and do not show similar peaks.

The time range in which the anomalies occurred and the magnitude characteristics were observed. Statistics for similar time periods not affected were computed. Several moving average filters were designed to push the magnitude of the anomalies below a threshold consistent with statistics from the nonaffected times. The blue dots show the results of the filtering. Although some artifacts of the filtering are observed, the overall shape of the envelope is similar to the same time on the second and third days of the sequence.

[3] If seams coordination between the EIM with the California ISO and the Alberta ISO allows for real-time border price convergence, the benefits calculated herein would likely increase.

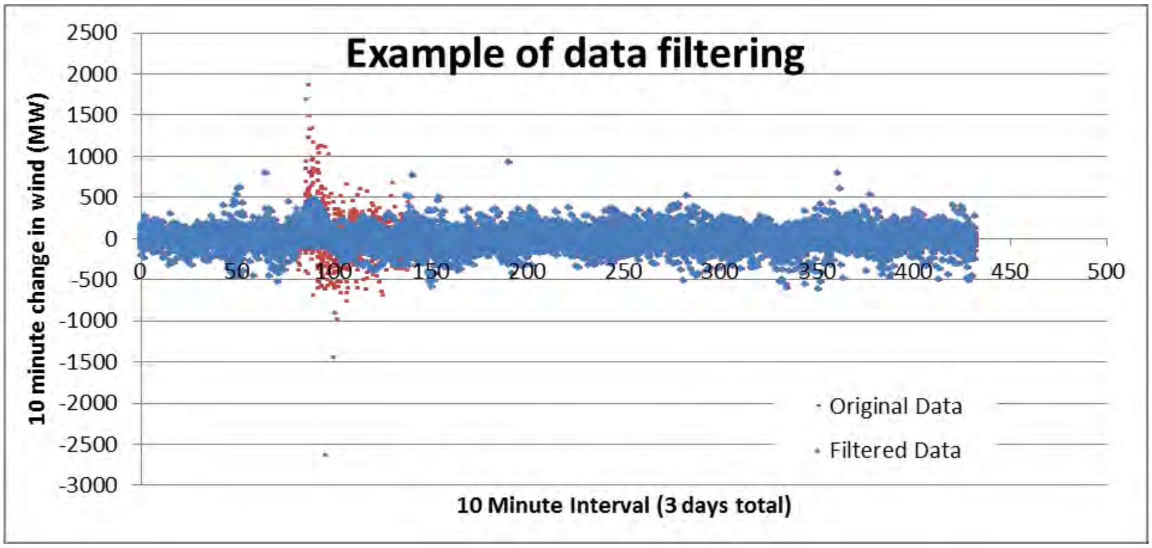


Figure 2. Example correction of the third-day anomaly in the Western Wind and Solar Integration Study wind data set

2.2 Solar Data

Solar data for this study were developed at NREL using satellite-based irradiance data, as described in Orwig [11]. The model produced data for multiple solar technologies, including fixed photovoltaic panels, one-axis tracking photovoltaic panels, and concentrating solar power plants.

The solar data were developed at spatial resolution of 10 km and temporal resolutions of 1, 10, and 60 min for the year 2006. The data were calculated for 1488 grid locations that correspond to Western renewable energy zones. At each of the retained locations, output for nominal 50-MW photovoltaic and 100-MW concentrating solar power plants were calculated at each time interval for the entire year.

TEPPC 2020 PC0 solar locations were mapped to the NREL data. These locations were then used to generate 1-hour resolution regional profiles. These profiles were eventually disaggregated back to the original solar locations to allow the generation of 10-min resolution data compatible with the methods used in the analysis reported here.

2.3 Load Data

Load time series data from 2006 were provided by WECC for each of the load zones in the Western Interconnection. The load data were taken from the TEPPC 2020 PC0 case and reflect forecasted load conditions for the year 2020 based on the load shapes from 2006.

To provide adequate temporal resolution to observe diversity effects and match the resolution of the wind data, 10-min data were synthesized from hourly load data. The intra-hour variability was statistically characterized using multiple high-resolution data sets from BPA and some Eastern Interconnection BA sources. These data sets ranged from 5- to 10-min sampling resolution for BAs ranging from about 2000 MW up to 15,000 MW. The size range was chosen to cover the range of the subset of WECC-member BAs used in the broader analysis discussed later in this report.

2.4 BAAs and Regional Modeling

This study modeled portions of the Western Interconnection not already covered by a market structure. Table 2 shows the BAAs considered as part of the study as well as subregional groupings used for subregional implementations of EIM operations. BAs that do not contain load were not considered for this evaluation.

Table 2. BAAs and Subregional Groups Considered in This Study

Columbia Grid	
	Avista (AVA)
	Bonneville Power Administration (BPA)
	Public Utility District No. 1 of Chelan County (CHPD)
	Public Utility District No. 1 of Douglas County (DOPD)
	Public Utility District No. 1 of Grant County (GCPD)
	Puget Sound Energy (PSE)
	Seattle City Light (SCL)
	Tacoma Power (TPWR)
Northern Tier Transmission Group	
	Idaho Power Corp. (IPC)
	Northwest Energy (NWE)
	Pacificorp East (PACE)
	Pacificorp West (PACW)
	Portland General Electric (PGE)
WestConnect	
	Arizona Public Service (AZPS)
	El Paso Electric (EPE)
	Imperial Irrigation District (IID)
	Public Service Company of New Mexico (PNM)
	Public Service Company of Colorado (PSCO)
	Sacramento Municipal Utility District (SMUD)
	NV Energy [Sierra Pacific Power (SPP), Nevada Power (NEVP)]
	Salt River Project (SRP)
	Tucson Electric Power (TEP)
	Turlock Irrigation District (TID)
	WAPA - Colorado Missouri Region (WACM)
	WAPA - Lower Colorado Region (WALC)
	WAPA - Upper Great Plains West (WAUW)
California Other	
	Los Angeles Department of Water and Power (LDWP)
Canada	
	British Columbia Transmission Corp. (BCTC)

Figure 3 shows a map of the reduced BAA structure considered for this study. The color of the BAA name indicates to which subregional group it belongs. Orange indicates Columbia Grid, light blue is NTTG, white is WestConnect, and black is BCTC and LDWP.

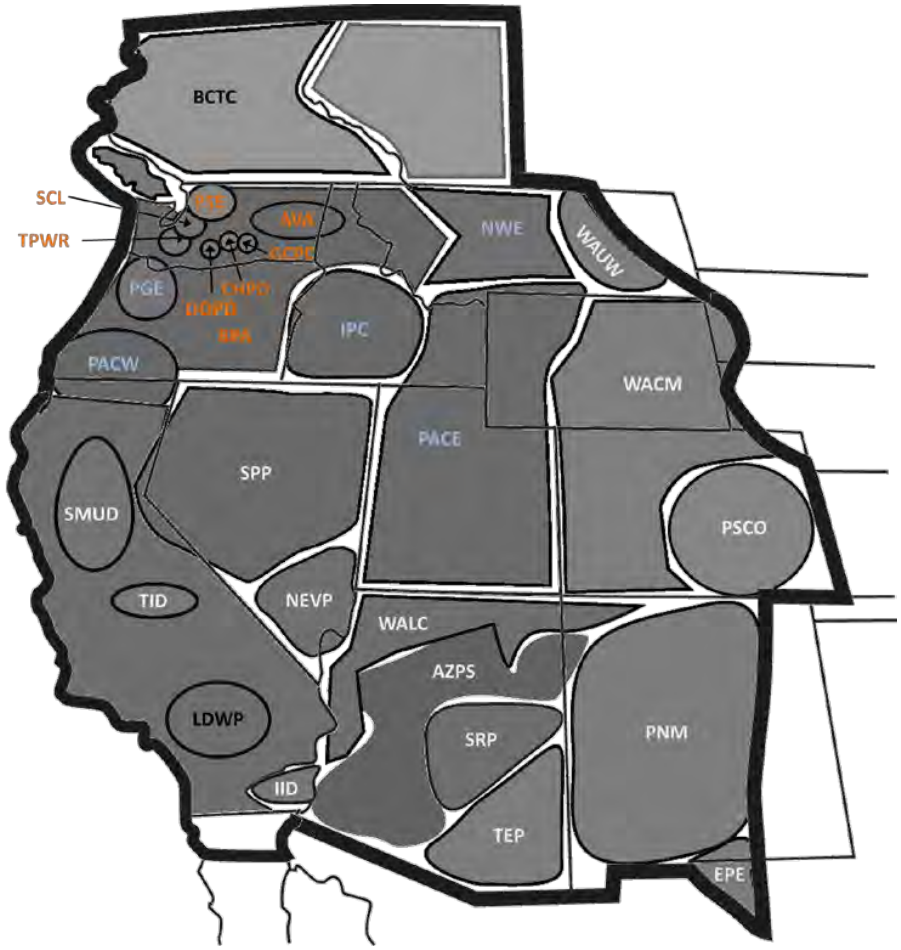


Figure 3. WECC BAA map with subregional groups

3 Overview of the Proposed EIM and Efficient Dispatch Toolkit[4]

In the Western Interconnection, areas outside of California and Alberta do not have a common energy market, although there is bilateral transaction activity in the region. In addition, a joint initiative (www.nttg.biz) provides low-cost, bilateral products that include the intra-hour transaction accelerator platform and the dynamic scheduling system. Stakeholders in the Western Interconnection are investigating an efficient dispatch toolkit that would achieve many of the benefits of a large-scale energy market but without a coordinated unit commitment or regulation market.

The proposed efficient dispatch toolkit would use two primary tools. An enhanced curtailment calculator, which can prioritize and allocate transmission service curtailments based on service priority for power flow impacts on the grid, would evaluate tagged and untagged flows. (Most deliveries inside balancing areas are not tagged.) The enhanced curtailment calculator would pass relevant curtailment information to the second tool: the EIM.

The EIM uses a security-constrained economic dispatch to provide two functions:

[4] This section is adapted from [9].

- Balancing service: This service redispatches generation every 5 min to maintain the balance between generation and load. For deliveries scheduled in advance, the effect is that the market supplies deviations from schedules in generator output and errors in load schedules.
- Congestion redispatch service: This redispatches generation to relieve overload constraints on the grid. Information provided to the EIM from the enhanced curtailment calculator ensures correct allocation of the costs of redispatch service.

Federal Energy Regulatory Commission Pro Forma Tariff Schedules 4 (energy imbalance) and 9 (generation imbalance) provide the approach used by the WECC BAs for balancing services. The proposed EIM replaces part of the BA services and results in a “virtual consolidation” because of a wide-area security-constrained economic dispatch that covers imbalances. The congestion redispatch service is new to the nonmarket portions of the Western Interconnection.

The EIM design includes a feature different from most regional markets in the United States in which internal resources are subject to a “must offer” requirement. Instead, the default operating assumption is that each market participant provides sufficient resources to cover its own obligations (as is the case today) and the regional economic dispatch is provided by any resource that voluntarily offers responsive capability and which is cleared by the security-constrained economic dispatch process. Most transmission service deliveries would continue to use traditional reserved transmission service, but the EIM would not use pre-reserved transmission. Instead, the EIM flow would receive the lowest transmission service curtailment priority. By this mechanism, EIM flows would not displace reserved transmission service.

Unlike other regional markets in which transmission service for market delivery is provided under a regional network service tariff, the EIM flows would pay an imputed service compensation after the fact to participating transmission providers. At this stage of development of the efficient dispatch toolkit, the specific terms for the transmission service revenue target and revenue allocation among participating transmission providers have not been established.

The EIM function adds some operational steps to the practices used in the Western Interconnection today. Functionally, the operating steps for the proposed EIM track closely with the operating process established in the Southwest Power Pool in its Energy Imbalance Service Market. Figure 4 illustrates the timeline for operation of the proposed efficient dispatch toolkit.

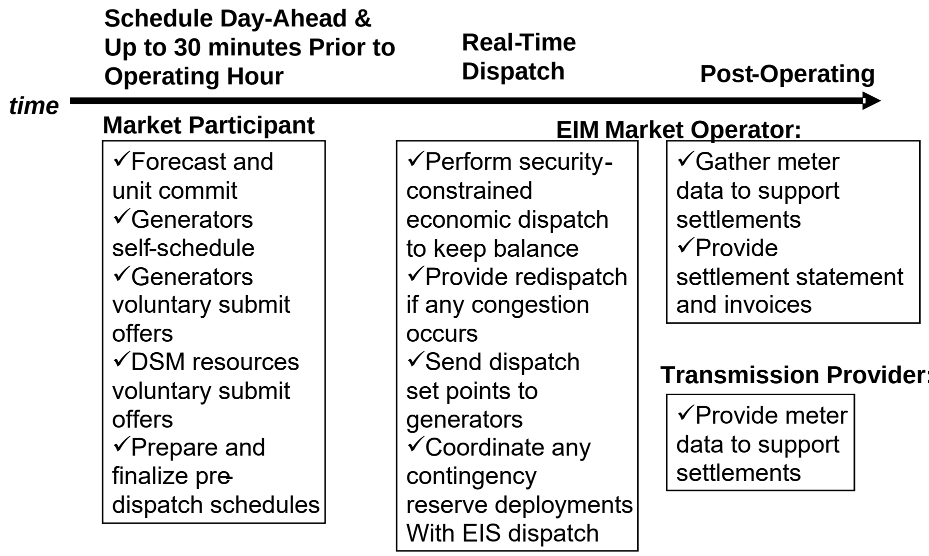


Figure 4. Operation timeline for the EIM toolkit

Figure 5 shows the sequence of taking the system data, calculating the expected conditions and required set points for the next interval, communicating those set points to generators and responsive loads, and then responsive resources moving to the new set points—all in 10 min.

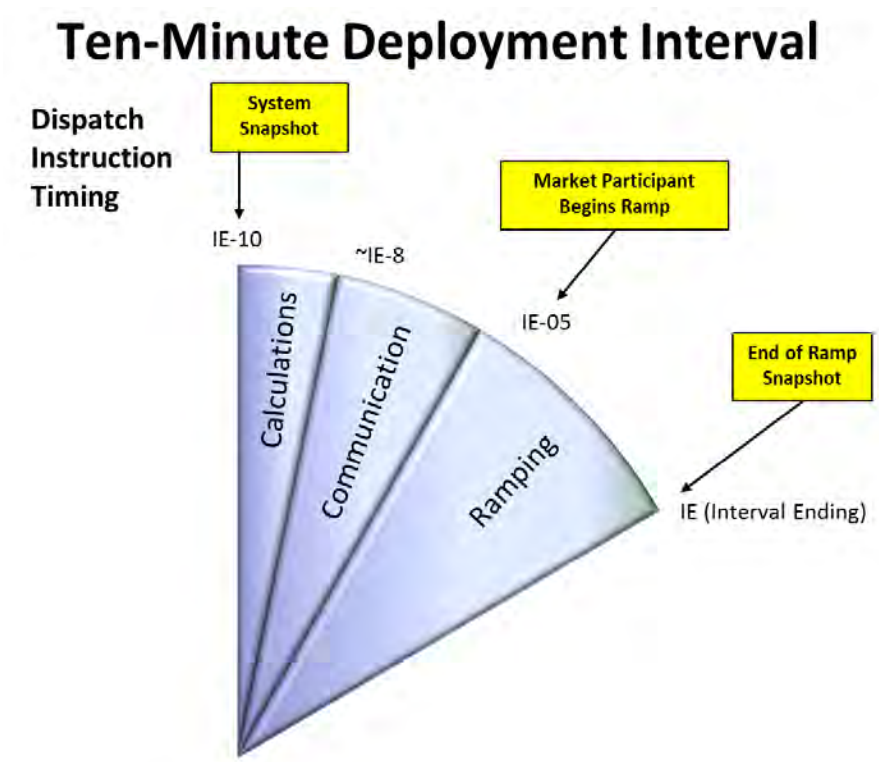


Figure 5. EIM schedule for calculating dispatch set points and moving generation within 10 min

Figure 6 shows how continuously repeating the process shown in Figure 5 results in meeting a new system dispatch point every 5 min, based on information that is only 10 min old.

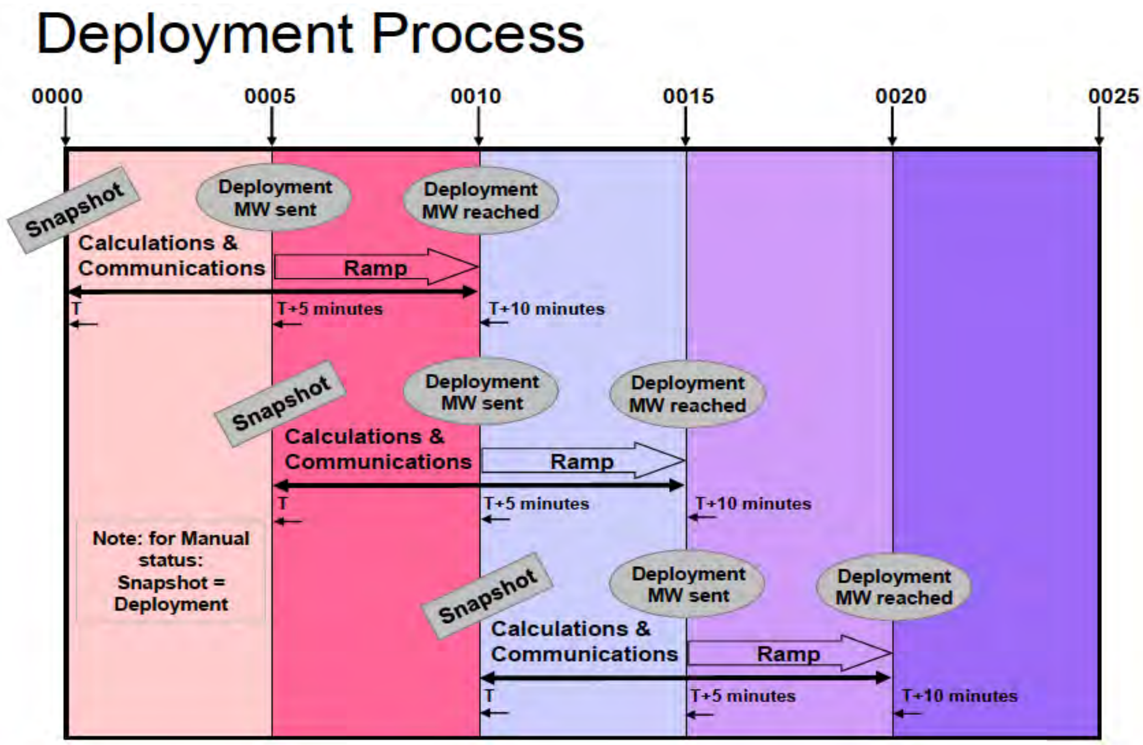


Figure 6. EIM repeats the calculations and unit ramping every 5 min based on system snapshots that are only 10 min old

The EIM would effectively implement some aspects of a virtual BAA across the Western Interconnection. (California and Alberta would not be included because they already have energy markets.[5]) Imbalances would be netted out, much as they would be in a single BAA. As proposed, the EIM does not result in a coordinated unit commitment, nor does it pool regulation, which remains a service at the local BA level. However, the netting of energy imbalance, which would include impacts of load and wind, is expected to be significant.

Figure 7 illustrates the concept, with each of the small bubbles representing a single BAA. The arrows between the BAAs indicate bilateral tagged energy flows that would not be precluded in the EIM. However, under the EIM, only the footprint net imbalance must be managed, resulting in less net variability within the local BAAs and less required ramping across the footprint.

[5] EIM benefits would increase if the California ISO and/or Alberta Electric System Operator coordinated with the EIM.

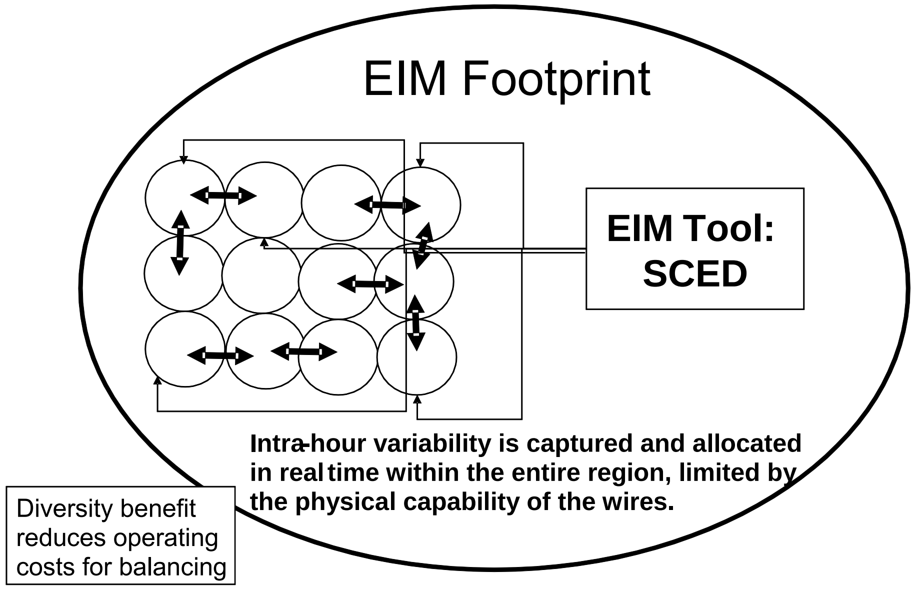


Figure 7. The EIM would effectively pool variability within the operating footprint, similar to a single BAA

4 Analysis Methods

4.1 Reserve Analysis

The increased variability and uncertainty from wind and solar power causes an increase in flexibility reserve requirements that can be provided by some combination of flexible generation and responsive load.[6] Our reserve categories are discussed in more detail in [4].This flexibility reserve is separate and distinct from contingency reserves. Flexibility reserve is discussed in more detail in this section and encompasses both generation and responsive load that may be available to help manage wind and load variability. This reserve is calculated dynamically and is a function of the time-synchronized anticipated variability of the wind and solar power and the load. A method was developed to estimate the increased requirements for regulation with wind variability in the Eastern Wind Integration and Transmission Study [4] and King et. al [10]. The Eastern Wind Integration and Transmission Study method focused on fast dispatch updates of 10 min or faster.

Short-term variability is challenging because it is difficult to anticipate the scheduling changes and fluctuations that must be covered with reserves. In a system with 10-min or faster markets or dispatch updates, a common approach is to forecast a flat value for wind output for the next interval based on the past 10–20 min.[7] This method is known as *persistence forecasting*. The wind varies on that time scale, and an understanding of how it will vary during the forecast interval is needed. Figure 8 illustrates how the forecast error is calculated for 10-min dispatch. The forecast error is the difference between the actual data and the forecast value.

[6] We note that wind power plants do not constitute a contingency because of the relatively slow rate at which wind power changes compared with a unit tripping offline.
[7] The short-term load trend can be forecast somewhat more accurately, but the load regulation movement cannot.

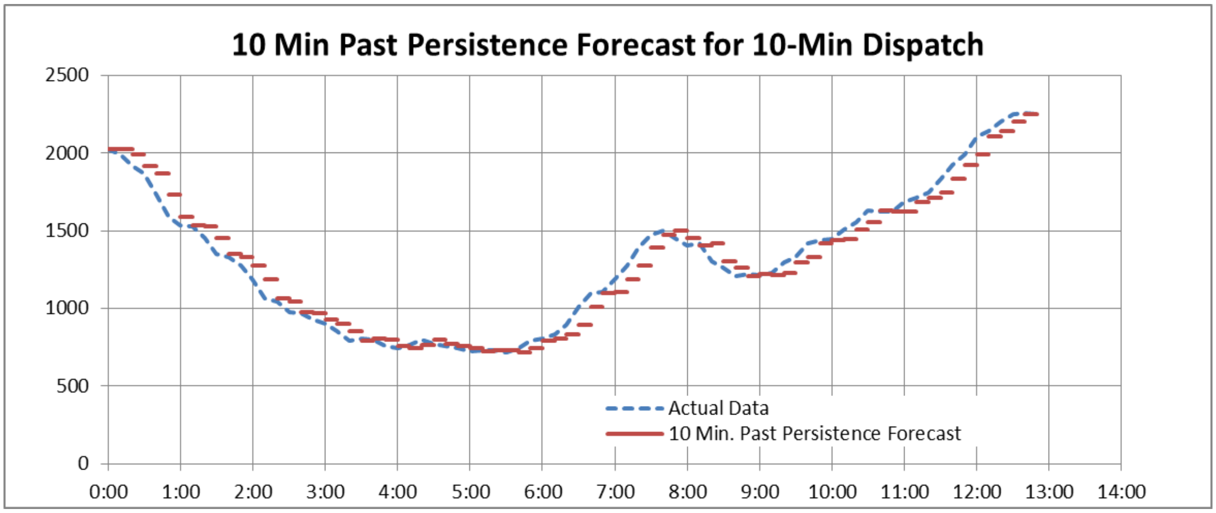


Figure 8. Forecast for 10-min dispatch

With a statistical approach based on detailed wind, solar, and load and forecast data, an estimate of the required reserves can be calculated based on the standard deviation or other variability metric derived from the data.

For our purposes, the flexibility reserve requirements are broken into three classes by the types of resources required to fulfill them.

1. Regulation is required to cover fast changes within the forecast interval. These changes can be up or down and can happen on a minute-to-minute time scale up to the re-dispatch timing for the system. Regulation requires resources on automatic generation control.
2. Spinning reserve is required to cover larger, less frequent variations that are primarily due to longer-term forecast errors. Spinning reserve is provided by resources (generation and responsive load) that are spinning and can respond within 10 min. These resources do not necessarily require automatic generation control.
3. Non-spinning and supplemental reserves are used to cover large, slower-moving, infrequent events such as unforecasted ramping events. Non-spinning reserve can be made available within 10 min and can come from quick-start resources and responsive load. Supplemental reserves can be made available within 30 min.

Note that these additional reserves are separate and distinct from the reserves the power system already requires to address load variability and contingencies. The names are the same (regulation, spinning reserve, and non-spinning reserve) because the same types of resources are required to provide flexibility reserves and contingency reserves. The flexibility reserves are distinct because they address the variability and uncertainty of wind and solar generation (aggregated with load variability and uncertainty) instead of responding to conventional generation contingencies. Large wind and solar ramp events are similar to conventional contingencies in that they are large and infrequent. They are different because they are slower. Similar resources can fulfill both needs and come from the same resource pool (conventional generation and responsive load), but our analysis does not consider the use of contingency reserves to provide flexibility reserves. Flexibility reserves are in addition to contingency reserves. The added spinning and non-spinning flexibility reserves address the wind and solar ramps.

Longer-term (an hour and longer) forecast errors can be dealt with by bringing additional generation on line, which is done via the unit commitment process. Faster-responding spinning and non-spinning reserves are required to bridge from the time when it becomes evident to the system operator that a large, slow ramping event is unfolding until the additional resources are available. The use of slower-responding reserves would reduce reserve costs, but this benefit has not been quantified.

Unless specifically stated elsewhere in this report, all of our references to the term *reserves* are intended to apply to flexibility reserve. We do not discuss contingency reserves further, and the flexibility reserve that is the focus of our analysis is separate and distinct from contingency reserves.

The variability of wind plant output is a function of its production level.[8] The Eastern Wind Integration and Transmission Study method assumes that the short-term variability in wind plant output, and thus short-term forecast error, is a normally distributed value over a large geographic footprint. Through analysis, an equation can be written for the standard deviation (sigma) of variability that varies with production level. That equation is derived by analyzing wind production data over some long period of time (a year or more) and calculating the standard deviation for the variability in various ranges of wind output. This approach does use the simplifying assumption that the data are normally distributed. The underlying data have been shown to be slightly non-normal, with more events in the tails than would be predicted by a normal distribution [12]. Figure 9 shows an example of this function.

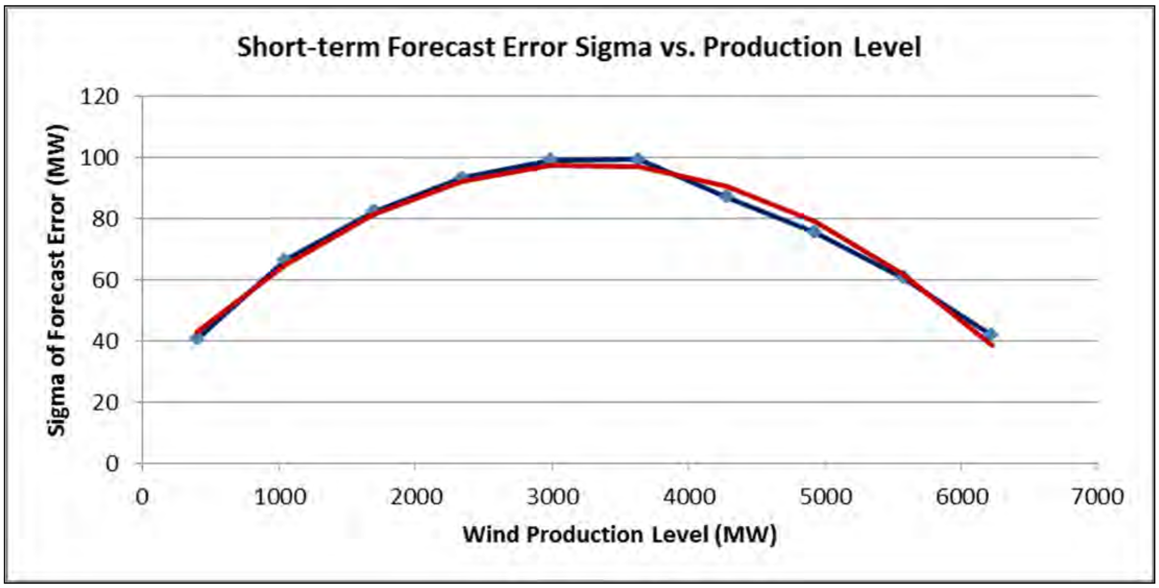


Figure 9. Short-term forecast error sigma as a function of wind production level

The curve fit polynomial shown as the smoothed line, in this example, is shown in Equation 1.

Equation 1. Sample calculation of hourly wind standard deviation

$$\sigma_{WST}\,(Hourly\ Wind) = \ -6.72E-06\ \cdot (Hourly\ Wind)^2 + 0.0437\ \cdot (Hourly\ Wind) + 26.74$$

A similar procedure can be used to obtain an equation that describes the short-term variability of solar output as a function of production level.

The equations are used to calculate the standard deviation (sigma) of the wind and solar power for each hour. A component to cover load variability is calculated as a fixed percentage of the hourly load. That fixed percentage is calculated based on the load size in the BAA as described in the Data section above and is

[8]The minute-to-minute variability has been shown to be uncorrelated between individual wind plants [4]. This results in only a small contribution to regulation requirements and is neglected in this method.

calculated to cover 1 sigma of the load variability. The wind, solar, and load components are scaled to 3 sigma and combined as the square root of the sum of the squares, as shown in Equation 2. This provides us with a common level of implicit risk for each BAA and is similar to maintaining a high Control Performance Standard (CPS) 2 score.

Equation 2. Calculation of intra-hour regulation requirement

$$Total\ Regulation\ Requirement\ (With\ Wind\ and\ Solar) = 3 \cdot \sqrt[2]{\left(\frac{1.5\%\ Hourly\ Load}{3}\right)^2 + (\sigma_{WST}\ (Hourly\ Wind))^2 + (\sigma_{SST}(Hourly\ Solar))^2}$$

The 3-sigma approach estimates reserve values that will cover 99.7% of all short-term variability for normal distributions; for non-normal distributions, adjustments can be made accordingly. Some analysis has indicated that using the normality assumption and 3 sigma yields approximately 99% coverage with actual data. Larger multiples of sigma—for example, 4 or 5—would cover additional events. Analysis of the distribution of events shows that a multiplier of 5 catches all events seen in the database for larger aggregation areas. This component must be covered by regulation-like reserves under automatic generation control.

The component of regulation that is due to VG, referred to here as *flex reserves*, can be isolated from the load regulation. This concept has been used in studies in which the load regulation is calculated and evaluated separately from the VG component. This component must also be covered with resources under automatic generation control.

Equation 3. Calculation of intra-hour "flex only regulation" requirement

$$Flex\ Only\ Regulation\ Requirement\ (With\ Wind\ and\ Solar) = 3 \cdot \sqrt[2]{(\sigma_{WST}\ (Hourly\ Wind))^2 + (\sigma_{SST}(Hourly\ Solar))^2}$$

In general, the analysis in this report uses the total regulation component shown in Equation 2. When "flex only reserves" are used, it will be clearly noted.

An additional uncertainty component related to hour-ahead wind forecasting error was calculated as part of the Eastern Wind Integration and Transmission Study method. This component is calculated in a similar manner to the short-term forecast error described above using an equation to describe the standard deviation of hour-ahead forecast error. Figure 10 shows the development of the equation for hour-ahead forecast error standard deviation.

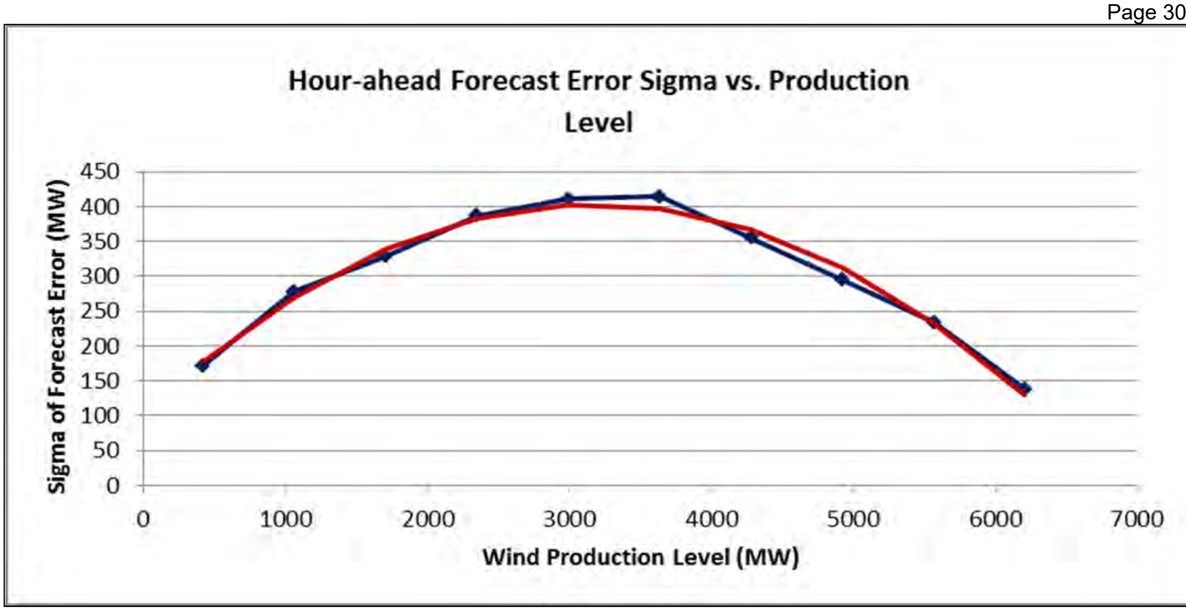


Figure 10. Hour-ahead forecast error sigma as a function of wind production level

The curve fit polynomial shown as the smoothed line, in this example, is shown in Equation 4.

Equation 4. Sample calculation of hour-ahead wind standard deviation

$$\sigma_{HAWind}(Hourly\ Wind) = \ -2.985E-05\ \cdot(Hourly\ Wind)^2 + 0.1895\ \cdot(Hourly\ Wind) + 103.2$$

With that equation, the expected sigma for the forecast error is calculated based on the previous hour's production (persistence forecast). A similar equation can be derived for the solar hour-ahead forecast error using the same procedure.

These components help ensure the system is positioned with enough maneuverability to cover the probable forecast error and divided as 1 sigma assigned to spinning reserves and 2 * sigma assigned to non-spin/supplemental reserves. Equation 5 shows the function for the spinning reserves. The equation for non-spinning/supplemental reserves is the same except that 2 * sigma is used. As before, adjustments can be made for non-normal distributions. Analysis of the available data shows that a total of 5 sigma would capture all events in the data set, which implies a CPS 2 score of 100%.

Equation 5. Calculation of spinning reserve requirement

$$\begin{aligned} &Spinning\ Requirement\ (Hour - Ahead\ Forecast\ Error) \\ &\qquad = \sqrt{\sigma_{HAWind}(Previous\ Hour\ Wind)^2 + \sigma_{HASolar}(Previous\ Hour\ Solar)^2} \end{aligned}$$

Finally, to find the total reserve requirement, each of these three components—regulation, spin, and non-spin—are added arithmetically.

This analysis must be performed for each region or aggregation of regions studied. For instance, in the base or BAU case, each BA within the study footprint is responsible for managing the variability within its boundaries. These calculations are performed on the data specific to each BAA, including the VG production profiles. These profiles are based on the time series of load and wind and solar production aggregated from individually modeled plants and thus fully represent the geographic and temporal diversity of their BAAs. The results of this analysis are 8760 hour vectors of flex regulation, flex spin, and flex non-spin reserves for each BAA that reflect the variability in the BAA load and VG data.

When the EIM is analyzed, the VG for each of the BAAs included in the EIM is aggregated by combining the time series for the resources. Again, the geographic and temporal diversity of the data are preserved. The calculations shown in this section are performed based on the aggregated data, and a different set of flex reserve vectors are obtained that reflect the variability of the combined or aggregated regions. As will be shown later, the effect of aggregating the VG is to reduce the overall variability of the combined regions. This directly leads to lower aggregate reserve requirements.

Both conventional contingencies and the increased variability and uncertainty associated with wind and solar generation increase the need for responsive reserves. Because the response requirements are similar in terms of speed, frequency, and duration, they are expressed in terms of the same set of required reserves: regulation, spinning reserve, non-spinning reserve, and supplemental reserve. The same resources can supply services for either need. That does not mean that dedicated contingency reserves would be used to respond to wind variability or uncertainty. It does mean that wind variability and uncertainty results in an increased need for the same *types* of reserves—spinning and non-spinning—that are required for contingency response. Our analysis does not evaluate contingency reserves, nor do we consider whether resources that provide one type of reserve can be activated to provide another type of reserve. The issue of whether reserve types can be shared among uses is under discussion in several forums, and we do not take a position on this issue. For the analysis in this report, we do not reduce the contingency reserve margin nor deploy contingency reserve to manage the increased variability and uncertainty of wind and solar.

4.2 Ramp Analysis

We followed a similar approach as Milligan and Kirby [3] and King et al. [10] in developing 1-hour ramp-reduction estimates based on the chronological wind and load data available for this study. BAAs that are operated without coordination may have ramps simultaneously occurring in opposite directions. With coordinated operations, such as would be available with the EIM, some of this ramping requirement—and therefore generator and responsive load ramping—could be reduced or eliminated. Similarly, different BAAs can experience peak ramping requirements during different hours or on different days. By combining ramping across the EIM, all participants realize a reduction in ramping reserve requirements.

This analysis was performed in several steps. Individual BAA 1-hour ramps were partitioned into positive and negative ramps, and these were separately combined into estimates of the up-ramps and down-ramps that would be met if the systems were to operate separately (without the EIM). The wind, solar, and load data were then pooled into a single hypothetical BA, and the ramp requirements were recalculated. Ramp savings were calculated by chronologically subtracting the total up-ramps and down-ramps of the individual BAAs from the similar ramps for the combined areas. Figure 11 shows an example of the results for this analysis for an arbitrary week for a sample area.

Contingency Reserves and Ramping Reserves

Contingency reserves and ramping reserves share a number of similarities but also a few differences. The power system maintains a series of contingency reserves in sufficient quantity to ensure it will be able to maintain the generation-load balance even if a large generator or transmission line suddenly fails. These reserves are made up of generating capacity held back from the energy supply and responsive load available to respond.

Contingency reserves are time-synchronized. Spinning reserve begins responding immediately, while non-spinning reserve is fully deployable within 10 minutes, and supplemental operating reserve is typically available within 30 minutes. For our purposes, both non-spin and supplemental reserves must be available in 30 minutes. An important characteristic of these contingency reserves is that they are used relatively infrequently (every few days as opposed to every hour) because contingency events are relatively infrequent. Consequently, the cost to stand ready to respond is more important than the response cost itself. A fast-start combustion turbine may be an economic source of non-spinning reserve even if it has a relatively high fuel cost.

Wind ramping requirements are similar to conventional contingency requirements in that large wind ramp events are relatively rare. The standby costs are often more important than the response costs, just as with conventional contingency reserves.

Wind ramps differ from conventional contingencies both in event speed and duration. A large generator can trip and remove 1000 MW from the power system in a cycle. Because of geographic diversity, even a fast, large wind ramp will take an hour or more to drop 1000 MW. This means that non-spinning and supplemental operating reserves (instead of spinning reserves) can often be used for wind ramps. Wind ramp events are also longer than conventional contingency events. North American Electric Reliability Corp. standards require BAs to restore their contingency reserves within 105 minutes of an event, and they typically restore their reserves much more quickly [6]. Slower wind ramps may require longer reserve deployments.

The important point is that wind ramps require the same *types* of responsive resources as conventional contingencies. Reserves may or may not be sharable between contingencies and wind ramps. The issue is still being investigated. This analysis is agnostic to that point and assumes there is no sharing. Partial sharing may be economic and reliable. Contingency-like reserves, however, are used for wind ramps because they are much lower-cost than alternatives such as regulation.

Table 3 presents annual average prices for regulation and contingency reserves from five regions for 2011. Spinning reserve is only 15%–73% of the cost of regulation, while non-spinning reserve is 5%–38%. These are the annual average hourly prices paid for each ancillary service in dollars for 1 MW of ancillary service capacity for 1 hour. It seems likely that additional reserves, with similar characteristics, will have similar prices and similar price relationships.

Table 3. Ancillary Service Prices From Five Regions Show Contingency Reserves Are Much Less Expensive Than Regulation

	California (Reg = up+dn)	ERCOT (Reg = up+dn)	New York	New England (Reg + "mileage")	MISO
		2011 Annual Average $/MWh			
Regulation	16.1	31.3	11.8	7.16	10.8
Spin	7.2	22.9	7.4	1.04	2.8
Non-Spin	1.0		3.9	0.39	1.2
Replacement		11.8	0.1	0.25	

Note: The California Independent System Operator and MISO do not provide replacement reserve markets. These values are derived from OASIS ancillary services data or communications directly with the ISOs.

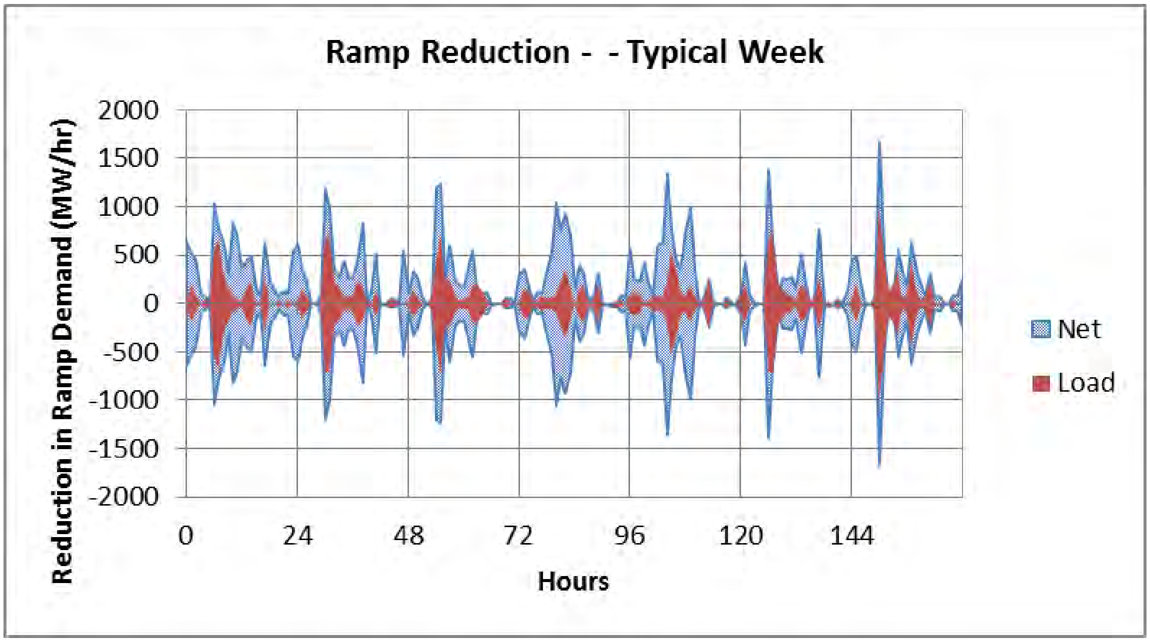


Figure 11. Example of effect of EIM on 1-hour ramps

The red trace shows the reduction in load ramps, and the blue shows the reduction for net load (load – wind – solar). For this sample week, the maximum net load ramp savings is approximately 1600 MW around Hour 150 for the BAAs. The symmetric nature of the graph is because of the simultaneous savings of +1600 MW and -1600 MW at the hour in question.

By tallying the hourly ramp savings over the entire year, we can create a plot that describes the frequency at which ramps of various magnitudes occur. Figure 12 shows that for our sample EIM footprint.

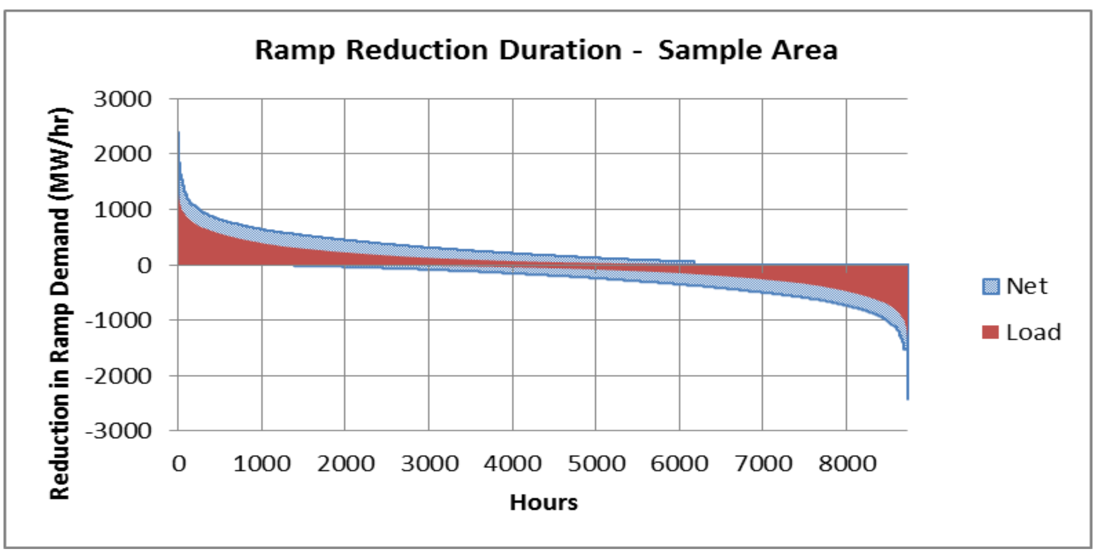


Figure 12. Example of annual ramp savings duration plot

Figure 12 shows that the reduction in net ramp is more than 1000 MW, symmetrically up and down, for approximately 250 hours per year. The peak net ramp reduction is about 2400 MW.

4.3 Allocation of Reserves and Reserve Savings to EIM Participants

Calculating the reduction in total system reserve requirements that results from increased aggregation (combining more load, wind, and solar generation within a balancing footprint) is relatively straightforward (as is measuring the benefits once the wind and solar generation are installed); allocating the savings to individual participants is not as easy. So that individual BAs can assess the impact of the EIM on their reserve savings, it is necessary to calculate the BAA reserve needs in the aggregated case. This means some form of allocation method is needed. This section is motivated by the desire to explore some of the characteristics of simple allocation methods so their behavior and properties can be better understood.

The physical act of coordinating scheduling and dispatch among BAAs, or fully combining them, results in a specific physical outcome. *Allocating* the resulting reduction in flexibility reserve requirements is a policy choice that does not have a single, unique, physical solution. Instead, there are many possible allocation choices. The nonlinear nature of reserves that provide the aggregation benefit also creates the allocation difficulty. A number of allocation methods that at first appear appealing turn out to have undesirable characteristics. We describe one method with appealing properties of “fairness” that avoids the shortcomings of other methods. Because we are attempting to allocate flexibility reserves, which are substantially different from contingency reserves, our method likely differs significantly from approaches used in existing reserve sharing groups. We also note that, under the proposed EIM, there is no proposed method to allocate flexibility reserves among participants; therefore, we are unable to precisely estimate flexibility reserve allocations that would be in effect under the EIM.

One clerical problem needs to be addressed first. Reserve requirements are not explicitly specified for each BAA, but they are implicitly addressed via required balancing/reliability metrics. Each BA must carry enough reserves to meet CPS 1, CPS 2, and Disturbance Control Standard requirements. BAs differ in their risk tolerance, and different BAs may elect to carry different amounts of reserves to compensate for the same level of variability. One BA may carry enough reserves to maintain a CPS 2 score of 98%, for example, while another may carry fewer reserves because it is comfortable with a 92% CPS 2 score. (Ninety percent or better is required.) For the purposes of this report, and to calculate the specific savings that result from the EIM, it is necessary to assume a common level of risk tolerance and a common reserve criterion to apply to each BA. In reality, participation in the EIM and aggregating variability will always reduce the required reserves, regardless of the individual BA’s risk tolerance. Note, too, that this discussion does not address if the source or sink BA is responsible for the cost of carrying reserves. The discussion is written as though the source and sink are the same BAA, which seems reasonable without knowledge of the specific case. Actual implementation of the allocation method can easily account for the desired allocation of responsibility.

4.3.1 A Working Definition of Fairness

To facilitate the discussion that follows, we describe a general notion of fairness. Our definition is not intended to be prescriptive; however, a few simple principles can help guide our discussion. We adapt these from Milligan et al. [12]. To help motivate this discussion, we briefly describe the notion of cost causation and relate that to our simplified notion of fairness.

Some utilities have worked to quantify the impact wind energy has on the operational cost of the power system. (Not much work has been done in this area for solar energy, which reflects its slower pace of development.) There is general agreement that wind energy increases the levels of variability and uncertainty that must be managed by the power system operator. In addition, there is broad recognition that these impacts increase operational cost.[9] A prerequisite for calculating integration cost is the principle of cost causation. If a generator imposes a cost on the system, then it may be financially responsible for mitigating this cost. Conversely, if the generator does not impose a cost, then it should not be assessed a payment. Two corollaries can be derived from these simple principles:

1. Horizontal consistency: Two entities that have the same (or similar) variability and uncertainty in power system operation should be allocated the same (or similar) level of reserve.
2. Vertical consistency: If one entity has less variability and uncertainty than another entity, then it should receive a smaller reserve allocation. A corollary is that if Entity A and Entity B start with the same reserve allocation and then B adds significant wind and/or solar generation, then A's reserve level should not increase (whereas B's should).

These ideas can easily be adapted to reserves analysis:

1. If an entity increases the reserve requirement for the whole, it is *fair* if its reserve obligation increases.
2. If an entity decreases the reserve requirement for the whole, then *fairness* dictates that its reserve obligation be reduced.
3. If an entity has no change in the variability or uncertainty that provide the basis for the need for reserves, the principle of *fairness* implies that its reserve obligation should not change

In the discussion that follows, we use this loose definition of fairness and avoid specific recommendations on allocation of reserves. Instead, our objective is to point out some interesting, and potentially important, issues regarding some rather simple allocation methods and some possible unintended consequences of these methods.

4.3.2 Alternative Allocation Methods Produce Different Results

To illustrate the benefits and complexity of aggregation, we will examine a hypothetical set of BAAs[10] (A–K) that require 100 MW of regulation each when they balance on their own. Later, we will extend this example to spinning, non-spinning, and supplemental reserves. For simplicity, assume that the regulation requirements are identical for each BAA and are completely independent. These assumptions are not necessary, and the math works out for all of the allocation methods discussed for BAAs of differing sizes and when there is some correlation. However, these simple assumptions make the examples easier to follow. We will also examine three subregions (X, Y, and Z) that are each composed of several of the BAAs.

Table 4 shows how aggregating individual BAAs into three subregions and a single region reduces the physical regulation burden—the greater the aggregation, the greater the benefit.

[9]There is some disagreement among experts about whether the cost impact of one generator, or type of generator, can be accurately calculated because of the highly nonlinear nature of operation and cost. We ignore that issue in this discussion. Interested readers can consult Milligan et al. [12].
[10]These concepts apply equally well to individual loads and generators and combinations of loads, generators, and BAAs.

Table 4. Physical Benefits of Aggregation

BA	Actual Regulation (MW)	Sub Region	Aggregate Regulation (MW)	Region	Aggregate Regulation (MW)
A	100	X	224	Total Footprint	332
B	100				
C	100				
D	100				
E	100				
F	100	Y	200		
G	100				
H	100				
I	100				
J	100	Z	141		
K	100				
Sum	1100		565		332

The members of subregion X reduce their collective regulation burden by 55% when they cooperate. Members of subregion Y save 50%, and members of subregion Z save 29%. Regional cooperation would reduce the regulation burden by 70%. These physical savings can be directly measured as changes in the area control error (ACE) variability of each of the collections.

How should these savings be allocated? There is no single technically correct answer. Different allocation methods have different properties and provide different results under different conditions. One fundamental principle is that the sum of the allocated amounts should equal the total physical requirement. If the balancing is on a regional basis for all 11 BAAs, for example, then the sum of the regulation amounts allocated to each of the 11 BAAs should equal 332 MW because that is all the regulation that is physically required.

4.3.3 Incremental Allocation

BAA K could offer to join BAA J in the formation of Subregion Z. BAA K could offer to fully protect BAA J and supply all of the extra regulation required when BAA K joined. BAA J would be held completely harmless. BAA J would continue to supply 100 MW of regulation, while BAA K would supply the extra 41 MW required to maintain reliability in Subregion Z.

Clearly, incremental allocation of regulation requirements is not fair when two similarly situated entities are combined, but it can be a reasonable allocation method under other circumstances. A regulatory commission might, for example, determine that it is in the public interest to allocate the incremental regulation burden to a new industrial enterprise if there were significant job creation or tax benefits. The BA customers would be no worse off, and the subregion would gain economic benefits.

Allocating the regulation burden among BAAs on an incremental basis has the very undesirable effect of assigning different amounts to otherwise identical entities based solely on the order that the entities join the aggregation. This would result in the violation of the principle of horizontal consistency. Table 5 shows how an incremental allocation would work if all 11 BAAs were aggregated sequentially. BAA A would see no benefits from regional cooperation, while BAA K would see its regulation requirement drop by 85%. Note that the incremental allocation did result in meeting the total regional requirement of 332 MW. It is only the allocation among individuals that is problematic.

Table 5. Incremental Regulation Allocation Treats Identical Entities Differently

BA	Actual Regulation (MW)	Incremental Regulation Allocation (MW)
A	100	100
B	100	41
C	100	32
D	100	27
E	100	24
F	100	21
G	100	20
H	100	18
I	100	17
J	100	16
K	100	15
Sum	1100	332

4.3.4 Proportional Allocation

Allocating regulation benefits proportionally based on the BAAs' standalone regulation requirements at first appears to be very fair. If the total regulation requirements are reduced by 70%, then one could simply reduce each BAA's regulation assignment by 70%. What could be fairer? Unfortunately, because of the nonlinear nature of the physical aggregation benefit, proportional allocation places a disproportionate burden on the smaller entities. This becomes clear when subregions are considered, which we evaluate below.

Proportional allocation does work when all the individuals are the same size, as shown in Table 6. The left side of the table shows that each BAA is allocated an equal share, 30 MW, of the regional regulation burden. The right side shows that each BAA is allocated an equal share of *its* subregional regulation burden (assuming that the subregions do not aggregate together into an aggregate region). BAAs A–E have less regulation burden than BAAs F–I and BAAs J and K. This is reasonable because there are greater physical benefits for larger aggregations.

The proportional allocation breaks down if the subregions aggregate, as shown in Table 7. The physical regulation requirement drops by 41% from 565 MW to 332 MW (the same as on the left side of Table 6). That reduction is proportionately allocated to each of the subregions based on the subregions' regulation requirements. It only becomes apparent that this may not be the desired outcome when the subregional regulation allocations are further allocated to the individual BAAs. BAAs A–E are allocated a 26-MW regulation burden, while BAAs F–I are allocated a 29-MW regulation burden, and BAAs J and K are allocated a 42-MW regulation burden. Even though balancing is on a regional level and all 11 BAAs are identical, they get allocated different regulation requirements based on an arbitrary listing of the BAAs in subregions in the calculation. The amount of regulation allocated to each BAA depends on any intermediate subgrouping of the BAAs. Had BAAs A–J been grouped together first and had BAA K been considered last, the proportional regulation allocation would have been even more disproportionate, with BAAs A–J supplying 25 MW each and BAA K supplying 80 MW. This, too, violates the principle of horizontal consistency. Note again that, in all cases, the regulation allocation adds up to the 332 MW that is physically required by the aggregate region doing the balancing.

Table 6. Proportional Allocation at First Appears To Work Well

Regional Aggregation				Sub-Regional Aggregation				
BA	Actual Regulation (MW)	Proportional Regulation Allocation (MW)		BA	Actual Regulation (MW)	Sub Region	Aggregate Regulation (MW)	Proportional Allocation Within the Sub-region (MW)
A	100	30		A	100			45
B	100	30		B	100			45
C	100	30		C	100	X	224	45
D	100	30		D	100			45
E	100	30		E	100			45
F	100	30		F	100			50
G	100	30		G	100	Y	200	50
H	100	30		H	100			50
I	100	30		I	100			50
J	100	30		J	100	Z	141	71
K	100	30		K	100			71
Sum	1100	332		Sum	1100		565	565

Table 7. Proportional Allocation Fails When Subregions Aggregate and for Different Sizes of BAAs

Regional Aggregation of Sub-Regions							
One Set of Sub-regions						*Another Set*	
Sub Region	Actual Aggregate Regulation (MW)	Proportional Sub-regional Regulation Allocation (MW)	BA	Proportional Allocation Within the Sub-region (MW)		BA	Proportional Allocation Within the Sub-region (MW)
X	224	131	A	26		A	25
			B	26		B	25
			C	26		C	25
			D	26		D	25
			E	26		E	25
Y	200	117	F	29		F	25
			G	29		G	25
			H	29		H	25
			I	29		I	25
Z	141	83	J	42		J	25
			K	42		K	80
Sum	565	332		332			332

4.3.5 Vector Allocation

Regulation requirements can be allocated such that the allocation does not depend on the number or order of subaggregations. Any number of individual entities (loads, generators, BAAs, etc.) can be disaggregated. Subaggregations can be reordered and redefined without affecting the regulation allocated to other entities.

An allocation method developed by one of us has this appealing property [7].[11] The method has been verified and used by numerous utilities to analyze the regulation burdens imposed by individual loads and subaggregations of loads. The method appropriately handles any amount of correlation between the individual BAAs. The method accommodates a mix of individually allocated entities and subaggregations.

The vector allocation method requires one to know only the reserve requirement of the total system, the reserve requirement of the individual BAA, and the reserve requirement of the system without that BAA.

Equation 6. Allocation of reserve requirements

$$\sigma_{i\_allocation} = \frac{\left(\sigma_{Total}^2 + \sigma_i^2 - \sigma_{Total-i}^2\right)}{2 * \sigma_{Total}}$$

Where:

σ_{Total} is the total system regulation requirement
σ_i is the standalone regulation requirement of entity i
$\sigma_{Total-i}$ is the regulation requirement of the total system without entity i
$\sigma_{i\_allocation}$ is the regulation requirement allocated to entity i

Table 8 shows the vector allocation results when every BAA is allocated its regulation burden, when three subregions are allocated their regulation burdens, and when an alternate pair of subregions is allocated its regulation burdens. The individual BAAs are then allocated their share of the subregions' regulation burden. Note that the regulation allocated to each subregion and each BAA is always the same, regardless of how other BAAs are subaggregated. Only a change in the physical aggregation itself will change the allocation.

Table 8. The Vector Allocation Results Do Not Depend on Subaggregation or Order

Individual BA			*Sub-Region*				*Alternate Sub-Region*			
BA	**Actual Regulation (MW)**	**Vector Allocation (MW)**	**Sub Region**	**Actual Regulation (MW)**	**Vector Allocation (MW)**	**Individual BA in Sub Region**	**Sub Region**	**Actual Regulation (MW)**	**Vector Allocation (MW)**	**Individual BA in Sub Region**
A	100	30	X	224	151	30	A-J	316	302	30
B	100	30				30				30
C	100	30				30				30
D	100	30				30				30
E	100	30				30				30
F	100	30	Y	200	121	30				30
G	100	30				30				30
H	100	30				30				30
I	100	30				30				30
J	100	30	Z	141	60	30				30
K	100	30				30	K	100	30	30
Sum	1100	332		565	332	332		416	332	332

4.3.6 BAAs of Different Size

When two BAAs with identical regulation requirements join, it appears intuitively obvious that each should be allocated an equal share of the net regulation requirement (absent a compelling societal reason to use incremental allocation). It is not nearly as obvious what the regulation allocation should be in the much more usual case when the standalone regulation requirements of multiple BAAs differ. The results shown

[11]The method is based on similarities between regulation allocation and the MW/MVAR/MVA relationship.

above provide some insight into what a "fair" allocation is for entities with different standalone regulation requirements. Subregions X, Y, and Z have different standalone regulation requirements (224, 200, and 141 MW, respectively). Although the sizes cannot be compared easily based on the megawatt regulation requirements, they can be compared because we know why the megawatt requirements differ: Each subregion is composed of a different number of otherwise identical BAAs. So although it is not immediately obvious that subregion Y is twice the size of subregion Z based on their standalone regulation requirements, it is obvious based on subregion Y being composed of four identical BAAs while subregion Z is composed of two identical BAAs. It then makes intuitive sense that the fair allocation of the regional regulation requirement for subregion Y should be twice the allocation of subregion Z. The vector allocation method has the unique property of providing a "fair" allocation. This is in keeping with the principle of vertical consistency, in which the entity that consumes more regulation also provides more regulation.

5 Impact of Energy Imbalance Markets on Reserves and Ramping

Per-unit wind and solar variability are reduced with increased geographic diversity, which reduces the level of reserves needed to compensate for that variability. Forecast errors are also reduced by diversity [7].

5.1 Alternative Market Scenarios

We analyzed a large number of possible market footprints and variations on participation levels based on discussions with WECC. Although the EIM may cover all of the nonmarket areas of the interconnection, there may instead be subregional implementations of the market that correspond to the subregional transmission planning groups (or other alternative footprints that we do not address), which include Columbia Grid, WestConnect, and NTTG. For our study, we did not include wind in British Columbia because no wind data were available. Federal power marketing administrations such as BPA and Western Area Power Administration (Western or WAPA) may not participate in the EIM because of potential institutional constraints.[12] We therefore constructed cases that excluded these entities as variations from the all-inclusive participation cases. The full footprint includes all of the Western Interconnection except for Alberta and the California Independent System Operator market areas of California.

The proposed EIM would operate at the 5-min level, possibly aggregating energy settlements to hourly (similar to the 5-min markets currently operated by the Pennsylvania-New Jersey-Maryland Interconnection, Midwest Independent Transmission System Operator [MISO], New York Independent System Operator, Independent System Operator-New England, Electric Reliability Council of Texas [ERCOT], and California Independent System Operator); however, our analysis evaluated alternative dispatch intervals of 10 min because of data limitations. As discussed in [5], faster markets improve access to generation that may be available to alter its output, whereas slower markets restrict units on economic dispatch so that they cannot respond to demand changes within the dispatch period. Our 10-min analysis therefore understates the benefits of the actual 5-min EIM.

5.2 Variability Analysis

Larger operating footprints improve the ability of the system to respond to variability [2, 3]. This occurs for two reasons:

1. Pooling of variability of loads and wind generation increases diversity, which reduces the overall per-unit variability.

2. A broader resource mix increases ramping capability linearly.

[12] It is also possible that a version of EIM, or an improved interface between EIM and non-EIM areas, may eventually be extended to include all of the Western Interconnection.

The result is that aggregation provides an increased ability to manage variability, which itself is reduced with aggregation. This principle can be applied to many facets of power system operation and is one driver for the formation of reserve-sharing pools that reduce the total contingency reserves needed to maintain reliability. The full footprint in our analysis includes all of the Western Interconnection except for Alberta and California Independent System Operator areas of California.

Table 9. Summary of Load, Wind, and Solar Data Variability

	Footprint	West Connect	NTTG	Columbia Grid	LADWP	BCTC
# of BAAs	29	14	5	8	1	1
Load						
Max Non-Coincident	123720	57240	24644	23645	6778	11393
Max Coincident	110504	55251	22843	22933	6778	11393
Avg	71631	31292	14969	14464	3712	7194
Min Coincident	50577	21866	10284	10005	2172	5091
Min Non-Coincident	46404	20003	9628	9511	2171	5091
Wind						
Max Non-Coincident	18749	5510	4571	8083	585	
Max Coincident	15641	4949	4357	8077	585	
Average	5859	1672	1618	2359	210	
Non-Coincident CF	31%	30%	35%	29%	36%	
Coincident CF	37%	34%	37%	29%	36%	
Solar						
Max Non-Coincident	4546	4205	20	0	321	
Max Coincident	4375	4052	20	0	321	
Average	1250	1172	4	0	74	
Non-Coincident CF	27%	28%	20%	0%	23%	
Coincident CF	29%	29%	20%	0%	23%	
Total VG (Wind and Solar)						
Max Non-Coincident	23116	9601	4584	8083	848	
Max Coincident	18105	8393	4357	8077	848	
Average	7108	2843	1622	2359	285	
Non-Coincident CF	31%	30%	35%	29%	34%	
Coincident CF	39%	34%	37%	29%	34%	
VG Penetration						
Max BAA in Area	300%	300%	82%	126%	34%	
Max Coincident	28%	31%	36%	69%	34%	
Energy	10%	9%	11%	16%	8%	

VG penetration is the ratio of annual VG-produced energy to total generation.

Figure 13 shows the peak load and VG coincidence for all of the Western Interconnection and the three subregions. Aggregation provides a host of benefits for load as well as for VG. Aggregation reduces the peak capacity requirements for load alone. Coincident peak load is 11% lower for the overall footprint than the sum of the non-coincident peak loads that each BAA must support on its own.

Aggregation also benefits VG. Peak Western Interconnection wind is reduced by 20% through aggregation. Footprint VG capacity factor increases by 7% with aggregation. Aggregating VG also reduces the maximum wind penetration. One BAA in WestConnect (Imperial Irrigation District) has a maximum 10-min wind penetration of 300%, which is reduced to a maximum of 31% for the aggregated WestConnect and a maximum 28% for the aggregated footprint.

A detailed table showing the VG for each BAA can be found in Appendix B.

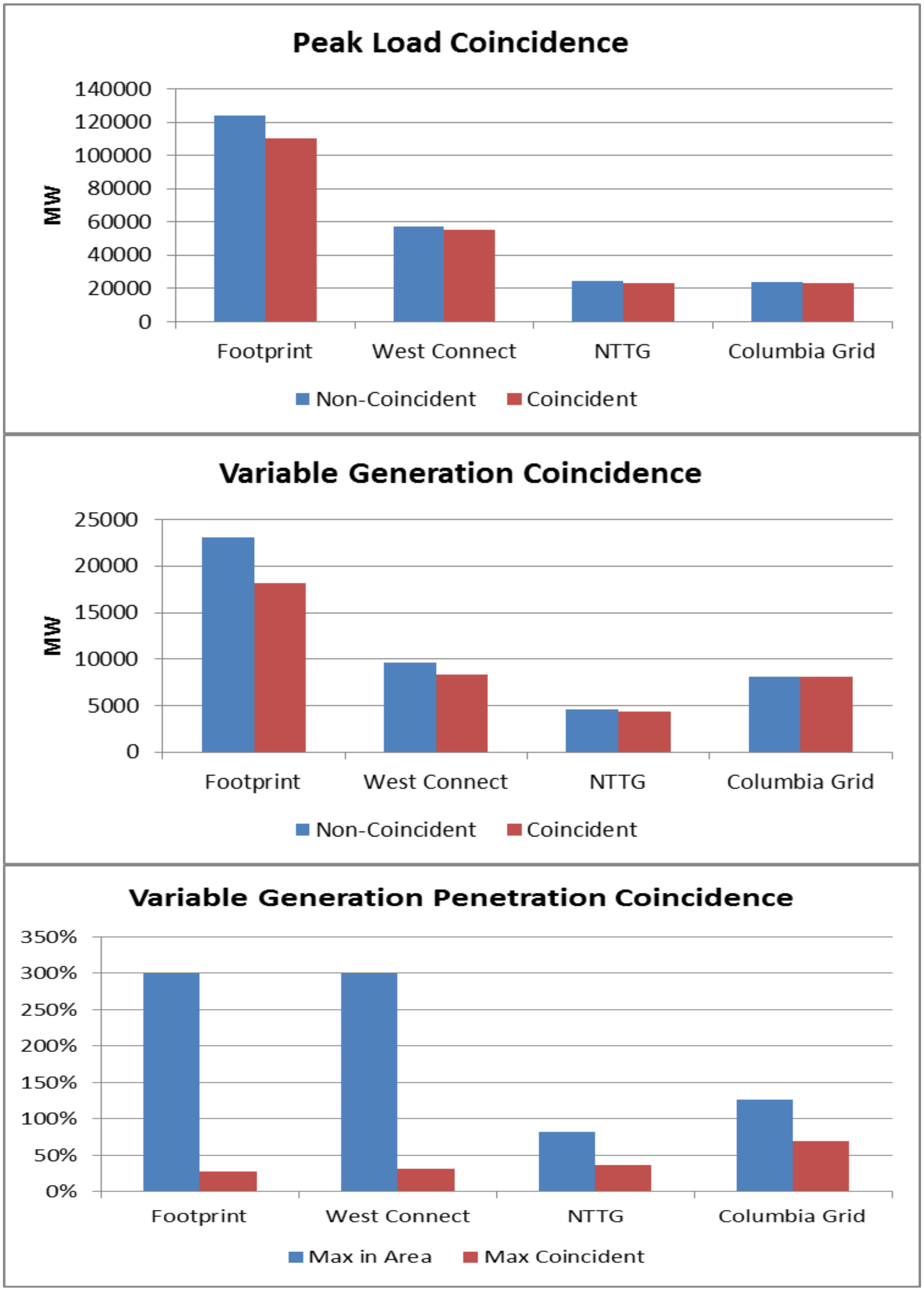


Figure 13. Coincidence of VG, load, and hourly penetration

5.3 Footprint EIM Scenario – Base Case

The base scenario for our analysis compares the footprint-wide EIM with the BAU case. The footprint-wide EIM includes all of the BAAs included in the study cooperating to manage that variability.

For the purposes of this report, the BAU case is defined as follows. Each BA is responsible for balancing the variability, both load and VG, within its borders as defined by WECC TEPPC 2020 PC0. In all cases, we assume that all BAs dispatch every 10 min, even in the BAU. The BAAs included in the footprint are defined in Section 2.4.

Existing reserve sharing groups are not relevant to this analysis because those reserve sharing groups are defined only for contingency reserves, not flexibility reserves. No assumptions are made about deliverability of reserves in this analysis. Production simulation models can verify if the aggregate reserves that result from these calculations can be delivered around the system as required.

5.3.1 Flexibility Reserves

As described in Section 4, Analysis Methods, three categories of reserve requirements were calculated for the footprint EIM and BAU scenarios. Figure 14 shows the comparison of the regulation, spin, and non-spin/supplemental reserves. The whiskers show minimum and maximum values, and the bar shows the average value of all hours of the year.

For each category of reserves, the requirement is reduced 35%–46%, depending on type. Total regulation is cut from 1669 MW for the BAU case to 1076 in the footprint EIM, while total reserves are reduced from 5359 MW to 3083 MW.

Table 10 shows that the reduction in maximum values seen is substantially larger.

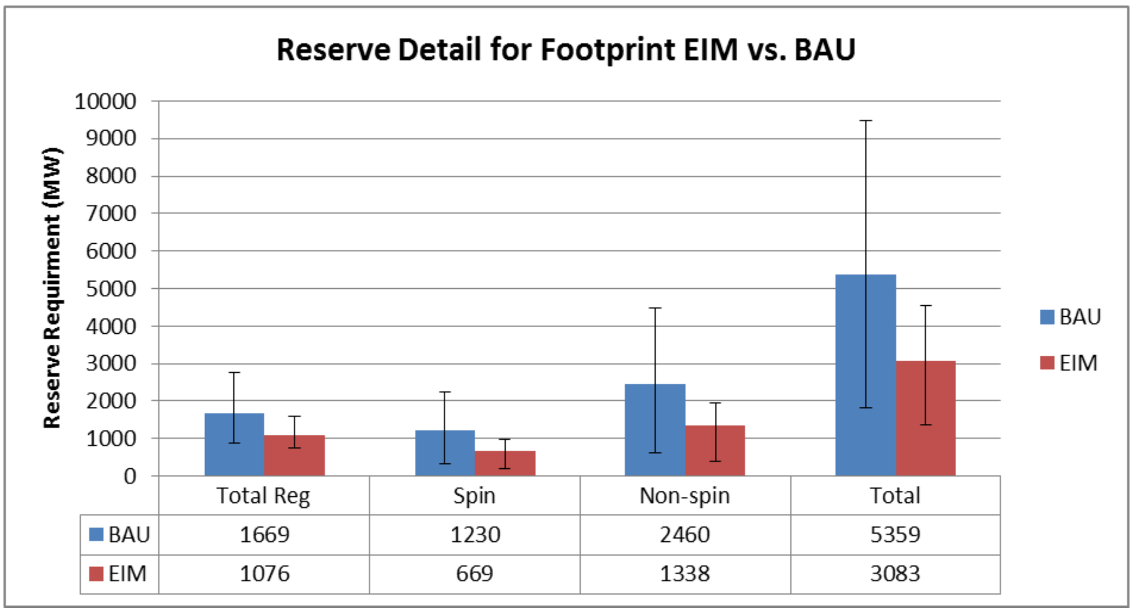
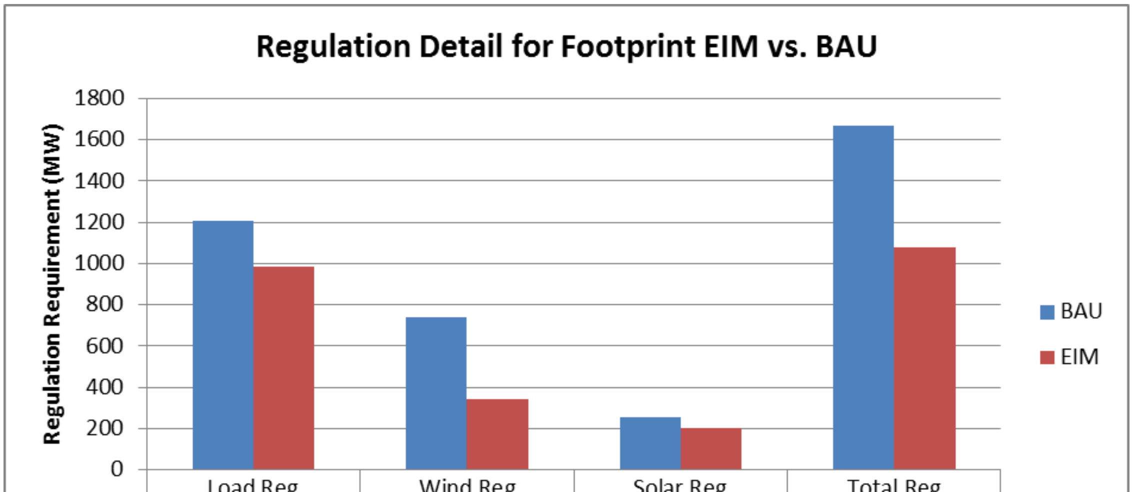


Figure 14. Comparison of reserve requirements for footprint EIM and BAU

Table 10. Reduction in Reserves Maximum Values

	BAU	EIM	Reduction
Total Regulation	2765	1607	42%
Spin	2236	977	56%
Non-Spin	4472	1955	56%
Total	9473	4539	52%

As described earlier, total regulation is made up of three components: load, wind, and solar. The relationship among these components is shown in Figure 15. The total regulation is the square root of the sum of the squares of the individual components because these components are uncorrelated. Load regulation is the largest contributor to total regulation, but the most dramatic savings for the EIM are seen for the wind component, which is reduced by 54%.



	Load Reg	Wind Reg	Solar Reg	Total Reg
BAU	1205	738	255	1669
EIM	983	340	203	1076

Figure 15. Detail of regulation components for footprint EIM

To understand how often various amounts of reserves are required, we developed regulation and total reserves duration plots. Total reserves are the sum of the total regulation, spin, and non-spin requirements. Figure 16 shows total reserves duration for the BAU and footprint-wide EIM case. The black line shows the saving in total reserves that are realized when the footprint EIM is implemented. The plot shows the large decrease in the overall requirements but particularly for the large, infrequent tails events.

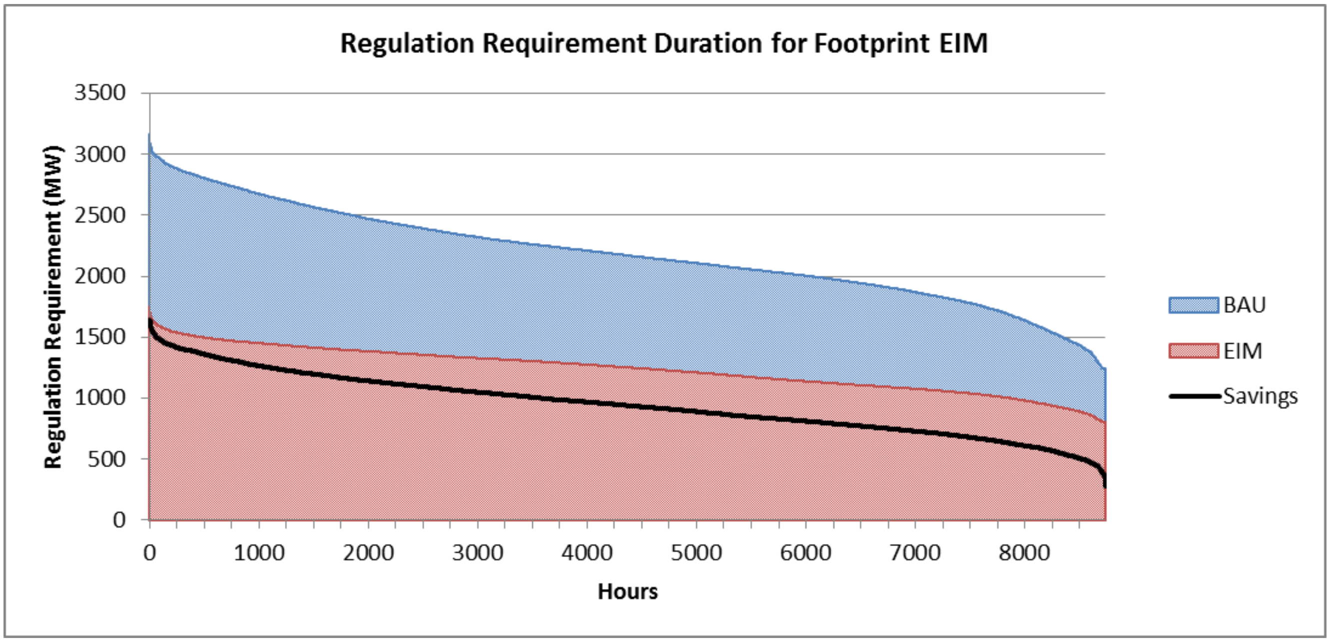


Figure 16. Comparison of footprint-wide EIM and BAU total reserve requirement

Interestingly, the total reserve requirement for the large aggregation is flatter and lower than when reserves are supplied for each BAA individually. The same pattern is seen for regulation for the scenario regions, as show in Figure 17.

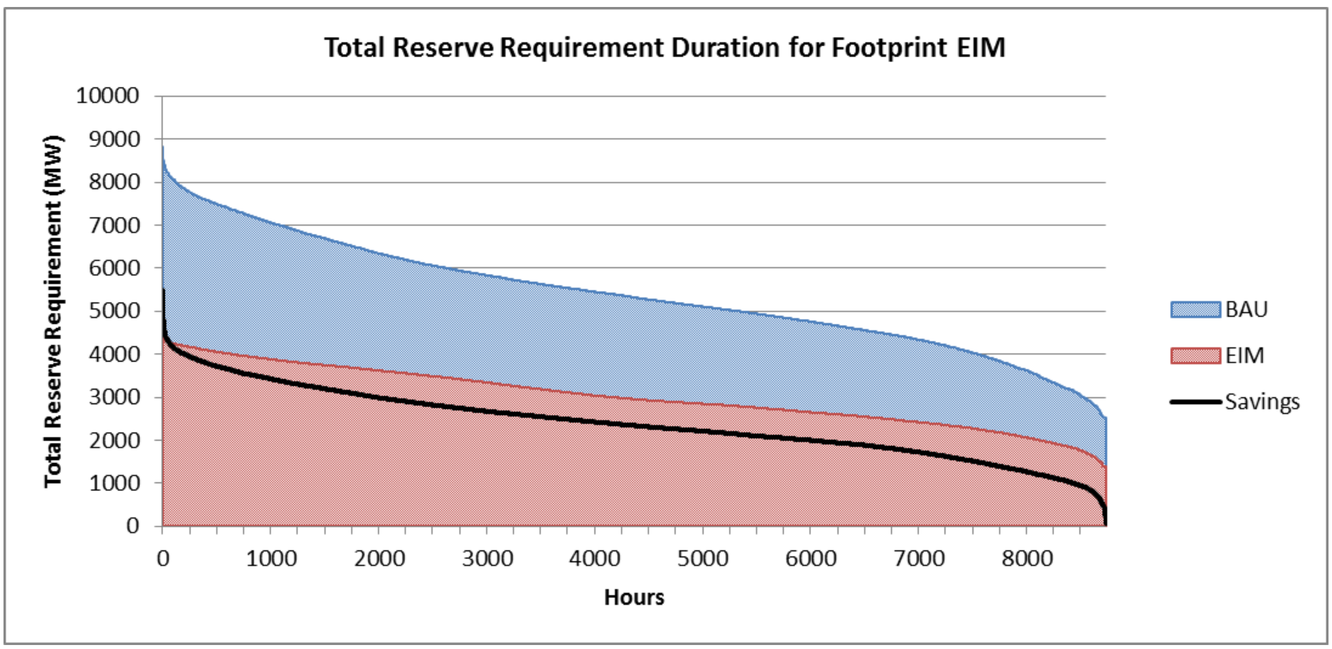


Figure 17. Reduction in total regulation reserve requirements by implementing a footprint-wide EIM

5.3.2 Ramp Demand Reduction

The reduction in variability implies that the need for ramping will be reduced under the various coordination approaches. We followed a similar approach as E3 [2], Milligan and Kirby [3], and King et al. [10] in developing ramp-reduction estimates based on the chronological wind, solar, and load data available for this study. The approach calculates hourly individual area ramp requirements, separating up-ramp and down-ramp demand for load alone and for net load (load minus wind and solar). Balancing areas that operate without coordination may simultaneously have ramps in opposite directions. With coordinated operations, such as would be available with the EIM, some of this ramping requirement, and therefore generator ramping, could be reduced or eliminated.

Figure 18 illustrates the concept for a sample 1-week period. This graph assumes that the EIM would operate across the entire footprint. As shown in the graph, there is a benefit even without any wind because of the load diversity. However, as also shown in the graph, there is a much larger ramp saving at a high wind penetration rate, largely because a high wind penetration will cause a significant increase in ramping demand for many hours of the year and the greater geographic diversity in wind ramps as compared with load ramps.

Figure 19 shows a duration plot for the load and net ramp savings for the entire year (8760 hours). For 248 hours per year, the savings in net ramp exceed 1000 MW. It averages about 275 MW for the year. Load ramp savings over the year average about 144 MW. Again, the effect of aggregation on wind and solar ramp savings is clearly higher than for load alone.

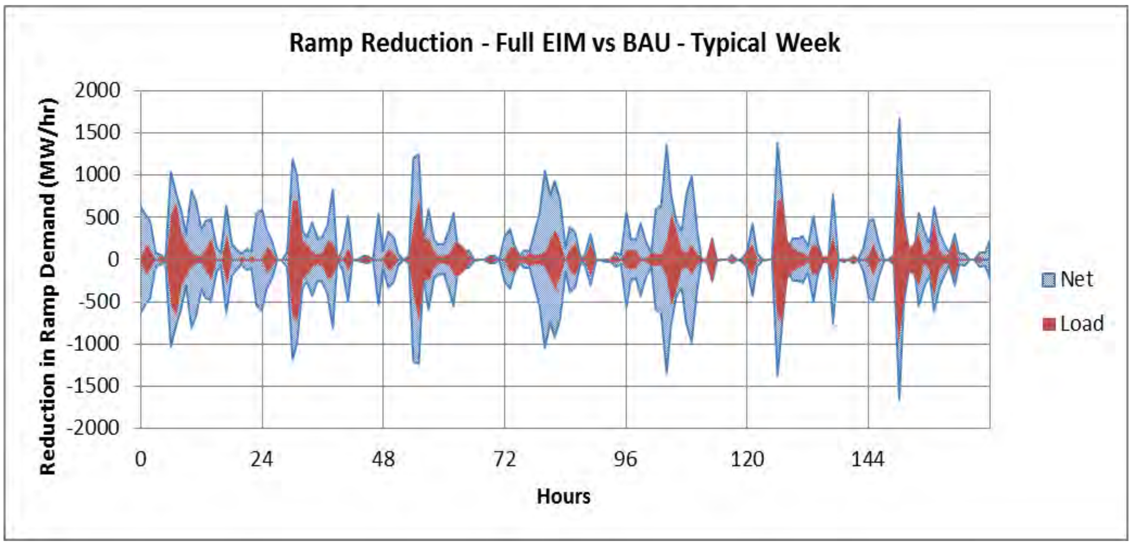


Figure 18. Footprint-wide ramping that can be eliminated by the EIM for a sample 1-week period

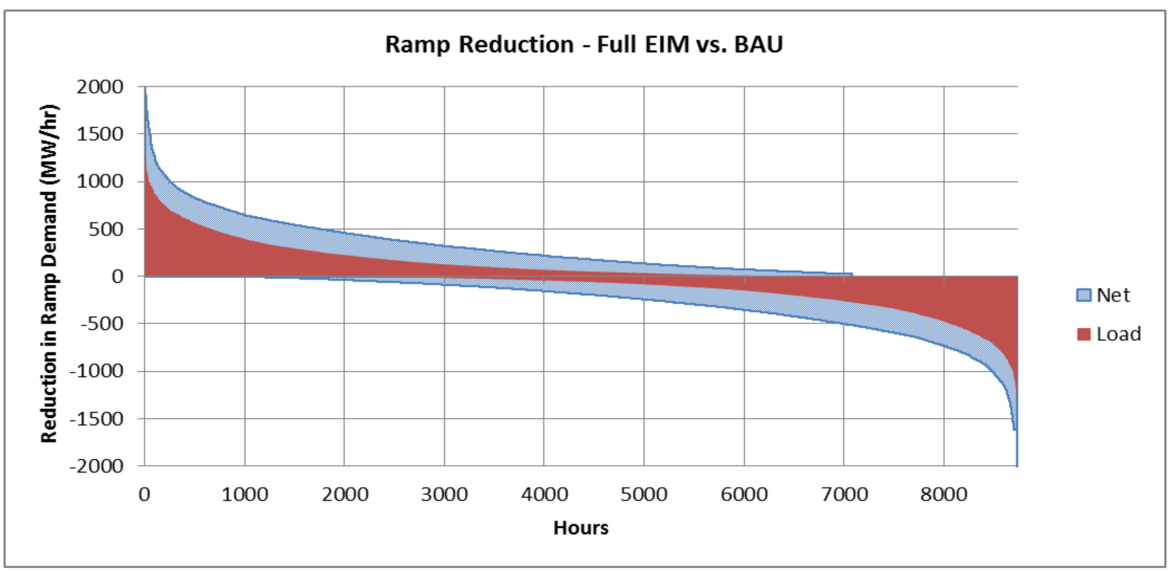


Figure 19. Frequency and magnitude of annual ramping reductions

5.3.3 Allocation of Reserves to Participants

We next applied the allocation procedure discussed in Section 4.3 to the regulation and total reserve requirements for the footprint EIM. This procedure allocates the reserve requirements for various classes of reserves to the areas participating in the EIM based on each area's contribution to variability. Average total reserve requirements are the arithmetic sum of regulation, spinning, and non-spinning components.

The savings for any particular participant are influenced by the diversity that area lends to the aggregate area. An area with a relatively small amount of wind can see a disproportionate savings if that area adds to the diversity of the overall area and lowers overall variability. An area with a large proportion of wind and/or solar energy can experience relatively little savings if its wind/solar resources have a small impact on the overall variability, as happens when a single area dominates the VG. Further, an area with both wind and solar can contribute even more to the overall diversity because the wind and solar variabilities are not correlated at short time frames.

Another factor in the savings for each BA is the VG penetration for that area. As penetration increases, there is a tendency for the savings to also increase. This is primarily because of the relatively low diversity of load variability across the study footprint. Because the load and VG components are combined as root sum squares, the higher load component will dominate the regulation and the savings until VG penetration reaches higher levels.

Finally, the size of the of the overall EIM relative to the size of the participating BAs has a direct influence on the savings seen by each participant. Large aggregation areas maximize the diversity of both load and VG, which, in turn, increases the savings seen by all.

The results for the full EIM compared with the BAU case are shown in Figure 20 for both total reserves and regulation. Based on this allocation method, the average savings is about 47% for total reserves and 42% for total regulation.

The largest BAAs see greatest absolute savings, while smaller BAAs with significant VG penetration can see higher percentage reductions. BAAs with little or no VG see the smallest savings. Tabular data for these charts can be found in Appendix A in Table 24.

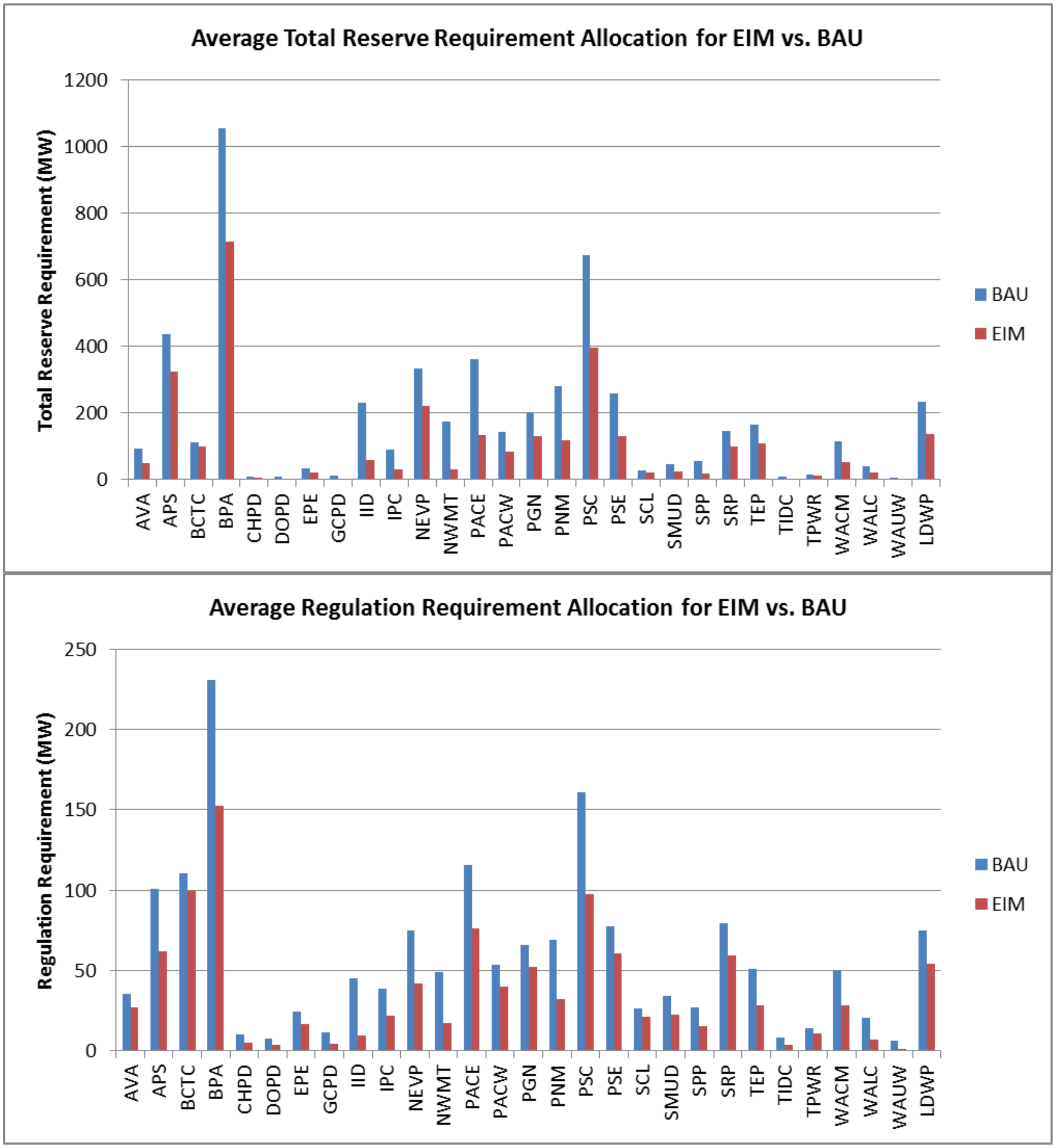


Figure 20. Allocation of reserves in the full-footprint EIM

We also calculated the value of the reserve savings by assuming a price for each class of reserves. The assumed prices are shown in Table 11. These prices are typical for these services in various parts of the country and are derived from Table 3 as rough averages for the three classes. We acknowledge that these prices may not be representative for some areas; however, we provide additional information in the appendices that allow individual BAs to assess their own benefits using the reserve reductions calculated herein and their own reserve pricing.

Table 11. Prices Assumed for Valuing Reserve Savings

Reserve	Price $/MW-hour[13]
Regulation	$12.00
Spin	$6.00
Non-Spin	$1.00

By applying the values in Table 11 to the reserve savings for full-footprint EIM, we find a total savings of about $103 M. Table 12 shows the allocation of these savings to each of the BAAs participating in the EIM. Note that the values are in millions of dollars.

Table 12. Value of Annual Flexibility Reserve Savings by BAA for Footprint EIM ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$4.08	$1.27	$0.42	$5.77
AVA	$0.90	$0.62	$0.21	$1.72
BCTC	$1.18	$0.00	$0.00	$1.18
BPA	$8.22	$4.44	$1.48	$14.14
CHPD	$0.53	$0.00	$0.00	$0.53
DOPD	$0.40	$0.00	$0.00	$0.40
EPE	$0.83	$0.05	$0.02	$0.90
GCPD	$0.76	$0.00	$0.00	$0.76
IID	$3.70	$2.38	$0.79	$6.87
IPC	$1.75	$0.74	$0.25	$2.73
LDWP	$2.17	$1.37	$0.46	$3.99
NEVP	$3.47	$1.38	$0.46	$5.30
NWE	$3.36	$1.92	$0.64	$5.91
PACE	$4.17	$3.32	$1.11	$8.60
PACW	$1.43	$0.78	$0.26	$2.47
PGE	$1.41	$0.96	$0.32	$2.68
PNM	$3.92	$2.14	$0.71	$6.77
PSCO	$6.68	$3.72	$1.24	$11.63
PSE	$1.79	$1.91	$0.64	$4.34
SCL	$0.59	$0.00	$0.00	$0.59
SMUD	$1.25	$0.20	$0.07	$1.51
SPP	$1.27	$0.46	$0.15	$1.89
SRP	$2.07	$0.50	$0.17	$2.74
TEP	$2.39	$0.54	$0.18	$3.11
TID	$0.49	$0.00	$0.00	$0.49
TPWR	$0.31	$0.00	$0.00	$0.31
WACM	$2.29	$0.72	$0.24	$3.25
WALC	$1.43	$0.12	$0.04	$1.59
WAUW	$0.53	$0.00	$0.00	$0.53
Total	$63.34	$29.52	$9.84	$102.70

[13] Ancillary service prices are often given as dollars per megawatt-hour because there is no energy content inherent in the reserves.

5.4 Subregional EIM Scenario Results

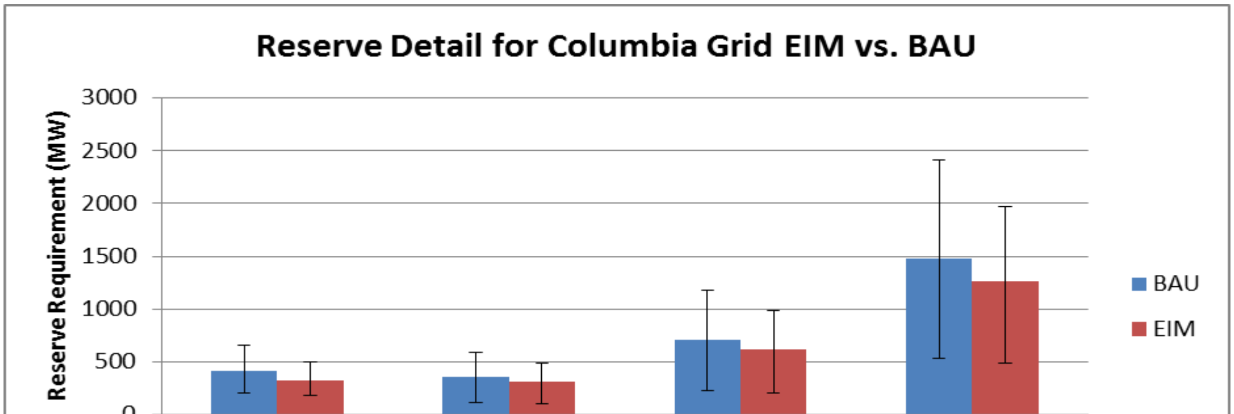
Results in the previous section show how reserves are affected when the entire study footprint operates as a single EIM. We also evaluated the effect of operating three distinct subregional EIMs from the same regional footprint. These subregional footprints are defined in Section 2.4.

5.4.1 *Columbia Grid EIM*

Columbia Grid was evaluated as a standalone EIM with all the members participating and also with BPA not participating (Section 5.6.1). Figure 21 shows the net reserve requirement reduction results for Columbia Grid with all the members participating in the EIM.

Reserve reductions for the Columbia Grid EIM are relatively modest compared with the full footprint and other subregional EIMs. This is primarily due to the relatively high correlation among wind sites in the footprint, with approximately 83% of the nameplate (measured as maximum zonal output, not actual machine nameplate) located in the BPA.[14] This dilutes much of the advantage of aggregating the wind across the subregional EIM.

Total regulation is reduced by 20% for each of the Columbia Grid BAs operating independently. Total reserves are reduced from 1476 MW to 1263 MW, or about 14%.



	Total Reg	Spin	Non-spin	Total
BAU	413	355	709	1476
EIM	328	312	623	1263

Figure 21. Net reserve savings for Columbia Grid EIM

Figure 22 shows the load and net load ramp savings from implementing the subregional EIM. The savings are relative to ramping that would be seen in the same set of BAAs without the EIM.

For net ramps, the maximum up-ramp reduction is about 20% and down-ramp is about 25%. Ramping energy or average ramp saving is about 8.3%, and the savings exceed 250 MW/hr for at least 130 hours per year. The average ramp is reduced by 27 MW. For load ramps, the maximum up-ramp reduction is 13% and down is 8%. The average ramp savings is about 3%, or 8 MW, and the savings exceed 100 MW/hr for at least 46 hours per year.

[14]We note that BPA does not calculate a dynamic reserve for wind energy and uses a different approach, as presented here.

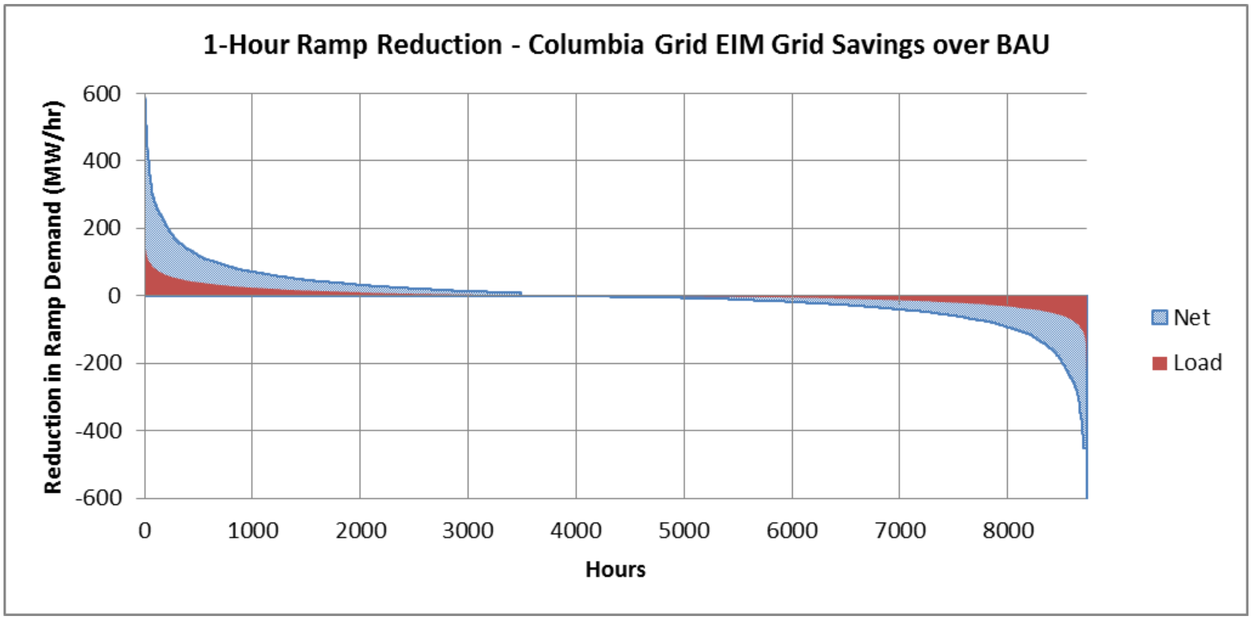


Figure 22. Columbia Grid EIM 1-hour ramp savings

Figure 23 shows the ramp savings for a typical week. The net savings are much larger than the load only because the load in Columbia Grid is highly correlated and the wind is less so, making net ramp reductions greater in magnitude.

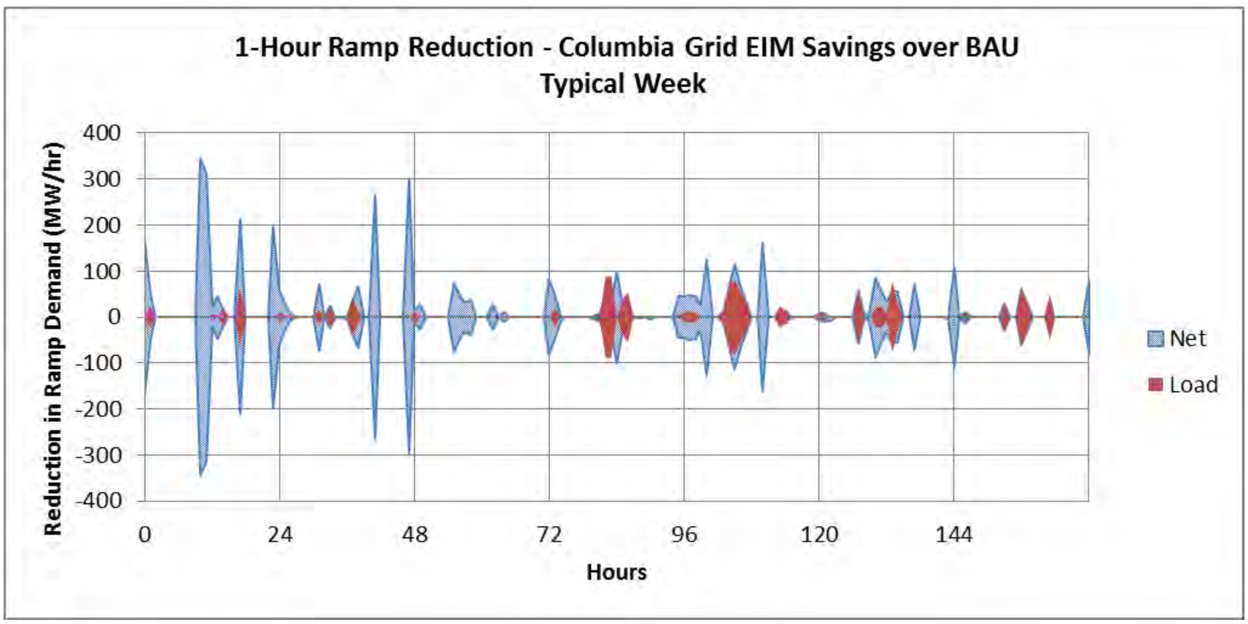


Figure 23. Columbia Grid EIM ramp savings over a typical week

Figure 24 shows the allocation of average total reserves and average regulation for the Columbia Grid EIM. The method for calculating these allocations is discussed in Section 4.3.

BPA dominates the Columbia Grid for load, VG, and variability. This leads to relatively small savings for BPA in the EIM because the diversity effects from the EIM aggregation are small. BPA saves about 41 MW of total reserve, on average, and about 12 MW of regulation. PSE sees larger savings in absolute terms—97 MW total reserves and 21 MW of regulation, on average—because PSE has a relatively large load (approximately half of BPA) but a significant amount of VG that adds to the diversity of the EIM.

There is also a reduction for Avista of 36 MW of total reserves, on average, and 12 MW of regulation. There is no VG in the remaining BAAs, so all the reduction in reserves is due to load aggregation effects. If load were not included in the calculations, their portion of the reserves would be zero, so savings would be zero. Tabular data for this table can be found in Appendix A in Table 25.

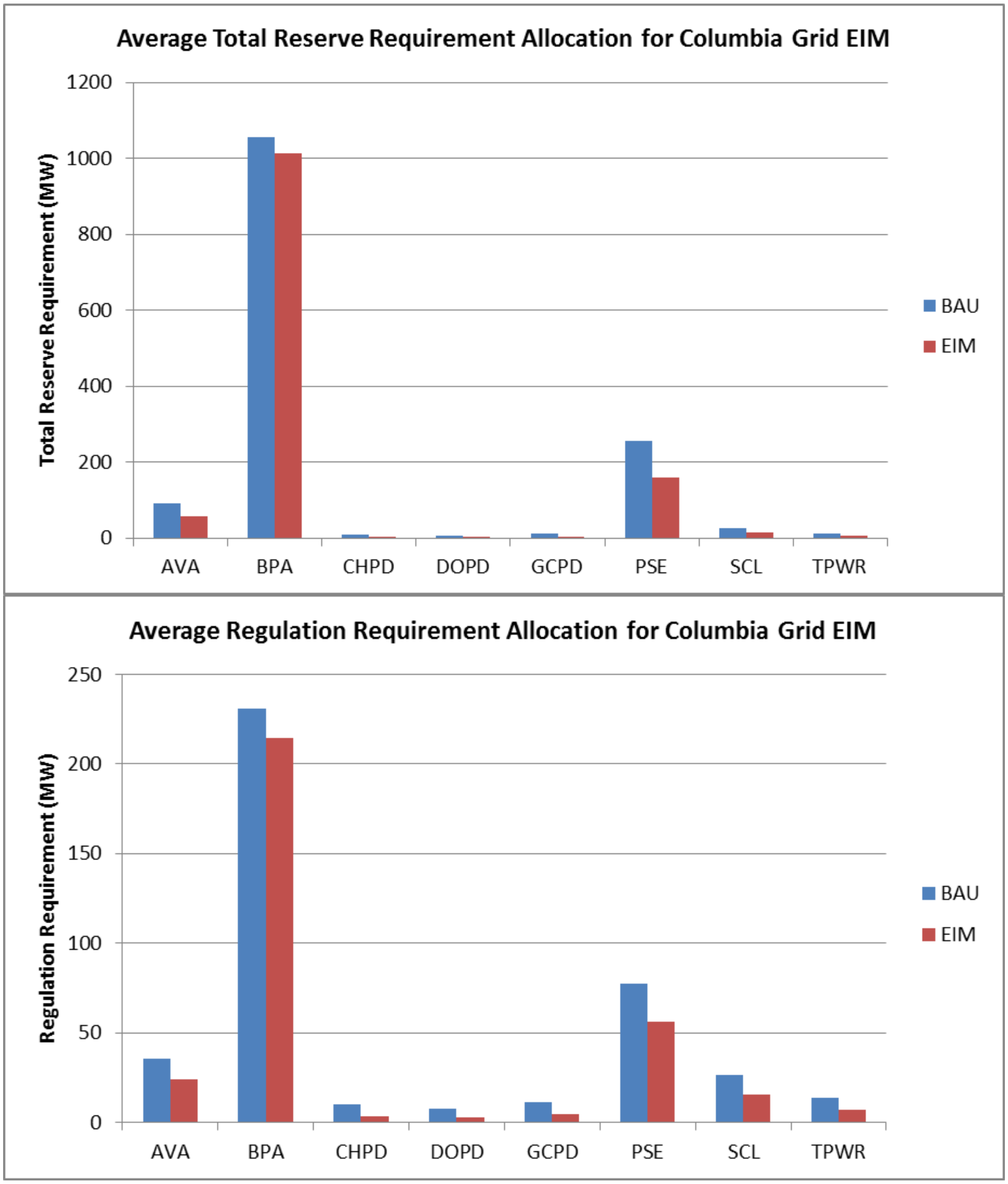


Figure 24. Allocation of reserves in the Columbia Grid EIM

The value of the reserve savings was calculated using the prices shown in Table 11. These reserve savings are shown in Table 13 for each BA participating in the EIM. The total savings for the Columbia Grid EIM is approximately $12 million. Note that the values are in millions of dollars.

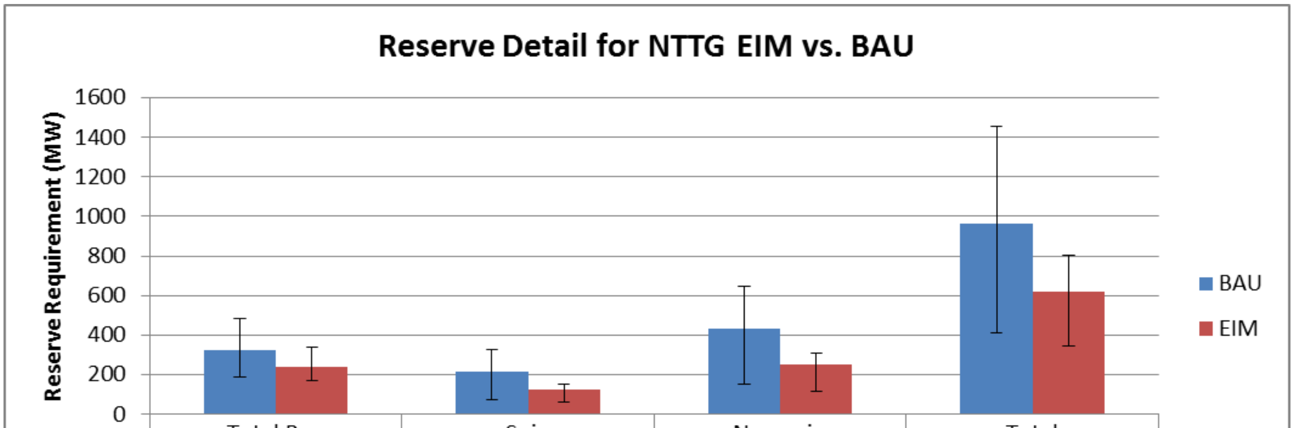
Table 13. Value of Annual Reserve Savings for Columbia Grid EIM ($M)

BAA	Regulation	Spin	Non-Spin	Total
AVA	$1.22	$0.42	$0.14	$1.78
BPA	$1.75	$0.44	$0.15	$2.34
CHPD	$0.69	$0.00	$0.00	$0.69
DOPD	$0.50	$0.00	$0.00	$0.50
GCPD	$0.72	$0.00	$0.00	$0.72
PSE	$2.24	$1.32	$0.44	$4.00
SCL	$1.16	$0.00	$0.00	$1.16
TPWR	$0.69	$0.00	$0.00	$0.69
Total	$8.97	$2.18	$0.73	$11.88

5.4.2 NTTG EIM

NTTG was evaluated as a separate subregional EIM. Figure 25 shows the net reserve requirement reduction results for NTTG with all the members participating in the EIM.

For NTTG, the savings are more substantial because of additional diversity in the wind resources in the subregion. The wind is spread across a large area without large concentrations. The net regulation requirement is reduced from 497 MW, on average, to 338 MW—a 32% reduction. Average total net reserves are reduced from 1744 MW to 1191 MW—also a 32% reduction.



	Total Reg	Spin	Non-spin	Total
BAU	322	215	429	966
EIM	240	126	251	617

Figure 25. Net reserve reductions for NTTG EIM

Figure 26 shows the load and net load ramp savings from implementing the subregional EIM. The savings are relative to ramping that would be seen in the same set of BAAs without the EIM.

For net ramps, the maximum up-ramp reduction is about 20% and down-ramp is about 17%. Ramping energy or average ramp savings is about 9%. The average ramp is reduced by 26 MW. For load ramps, the maximum up-ramp reduction is 15% and down is 13%. The average ramp savings is about 5%, or 11 MW.

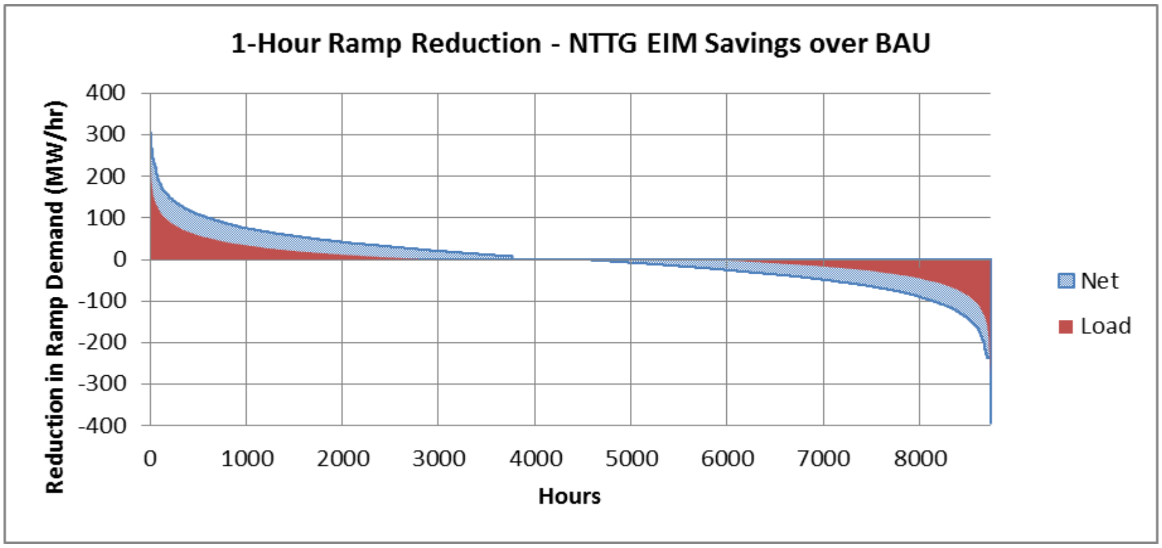


Figure 26. NTTG EIM 1-hour ramp savings

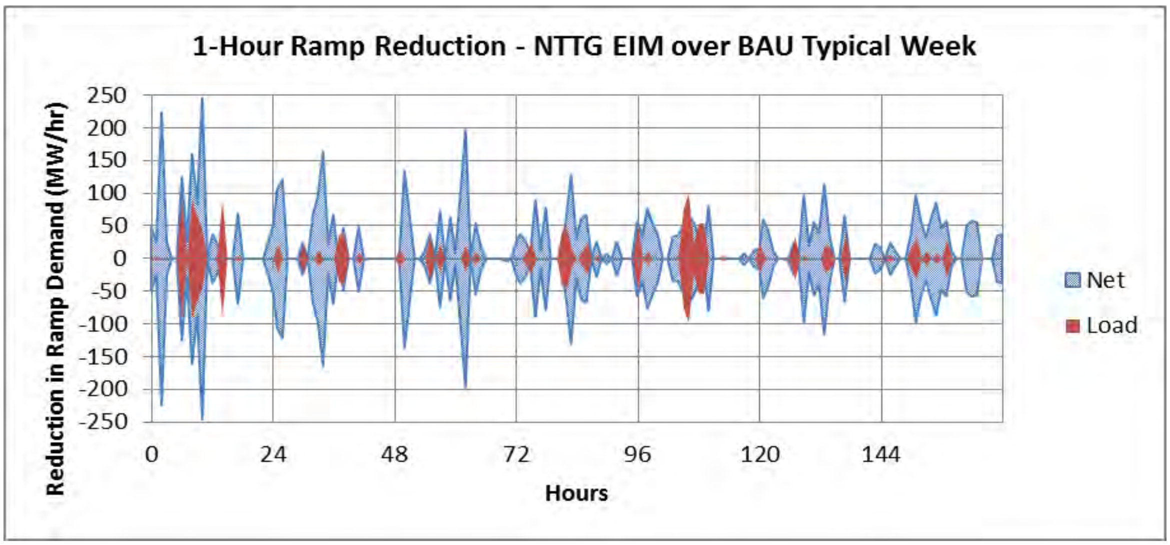


Figure 27. NTTG EIM ramp savings over a typical week

The allocation of average total reserves and average total regulation is shown in Figure 28. This figure compares the allocation for the BAU case with the NTTG subregional EIM case.

The relationship among BAA characteristics, size of the EIM, and resulting EIM reserve savings is complex. Small BAAs can have a disproportionately large effect on the aggregate if they add geographic diversity. Large BAAs with low diversity in their VG can see a disproportionately small effect on aggregate diversity because they dominate the aggregate diversity. One example is PACE, which experiences an 81-MW reduction (17%), while NWE—with a small load and high penetration—experiences a reduction of 94 MW (55%) in average total reserves. PACW and PGE show a similar, substantial reduction in both total reserves (~38%) and total regulation (~20%), as their size and VG penetration are similar. IPC sees a large percentage decrease in both total reserves and regulation because it contributes to the diversity of the EIM even with a low penetration of wind.

Tabular data for these graphs can be found in Appendix A in Table 26.

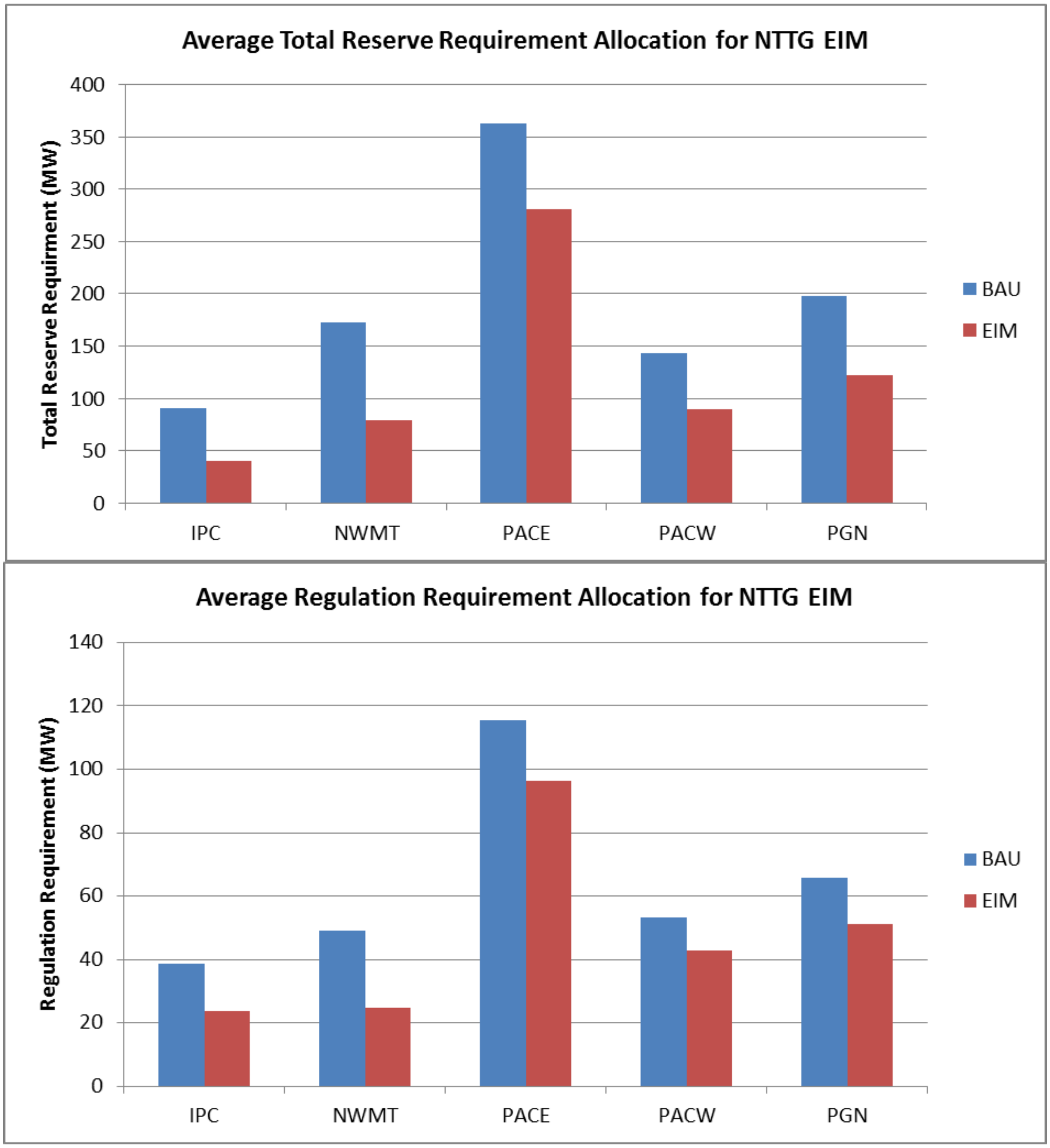


Figure 28. Allocation of reserves for NTTG EIM

The value of the reserve savings was calculated using the prices shown in Table 11. These reserve savings are shown in Table 14 for each BA participating in the EIM. The total savings for the NTTG EIM is approximately $15 million. Note that the values are in millions of dollars.

Table 14. Value of Annual Reserve Savings in NTTG EIM ($M)

BAA	Regulation	Spin	Non-Spin	Total
IPC	$1.57	$0.62	$0.21	$2.39
NWE	$2.54	$1.21	$0.40	$4.15
PACE	$2.03	$1.04	$0.35	$3.42
PACW	$1.09	$0.74	$0.25	$2.08
PGE	$1.53	$1.06	$0.35	$2.95
Total	$8.77	$4.66	$1.55	$14.99

5.4.3 WestConnect EIM

WestConnect was evaluated as a separate EIM with all the members participating and also with three subregions of WAPA not participating (Section 5.6.3). Figure 29 shows the net reserve requirement reduction results for WestConnect with all the members participating in the EIM.

Of the three subregional EIM implementations modeled, WestConnect realizes the greatest benefits both in absolute and relative terms. This is due to the large load and footprint of the subregion and high geographic diversity of the wind resources. Total regulation is reduced from 749 MW for the BAs operating independently to 496 MW for the EIM—a 34% reduction. Total reserve requirements are reduced from 2572 MW to 1823 MW for the EIM—a 29% reduction.

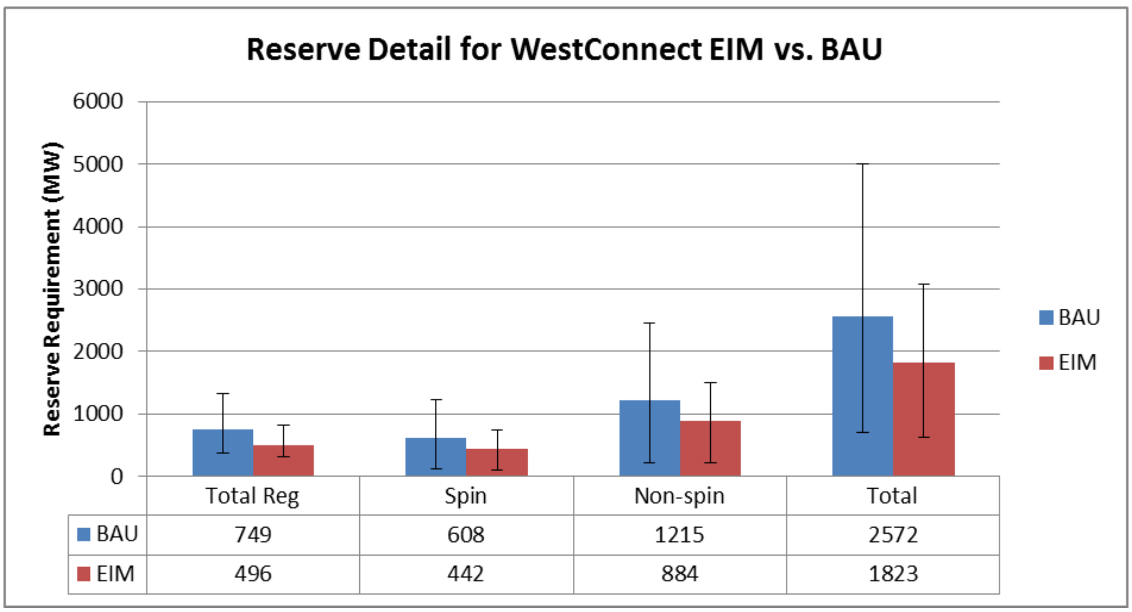


Figure 29. WestConnect EIM net reserve reductions

Figure 30 shows the load and net load ramp savings from implementing the subregional EIM. The savings are relative to ramping that would be seen in the same set of BAAs without the EIM.

For net ramps, the maximum up-amp reduction is about 21% and down-ramp is about 19%. Ramping energy or average ramp saving is about 18%. The average ramp is reduced by 117 MW. For load ramps, the maximum up-ramp reduction is 17% and down is 19%. The average ramp savings is about 9% or 56 MW.

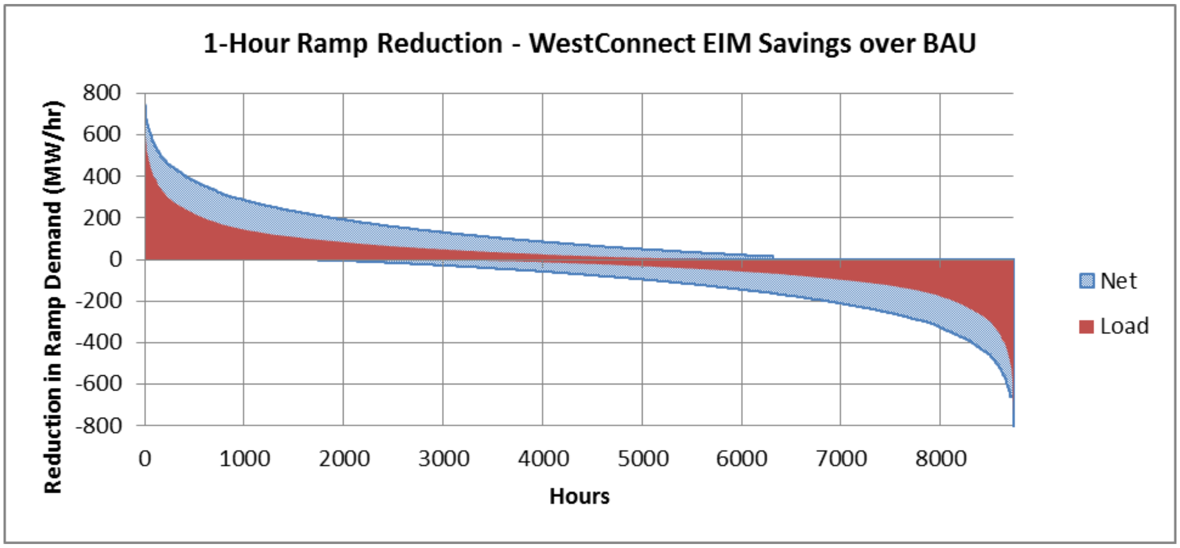


Figure 30. WestConnect EIM 1-hour ramp savings

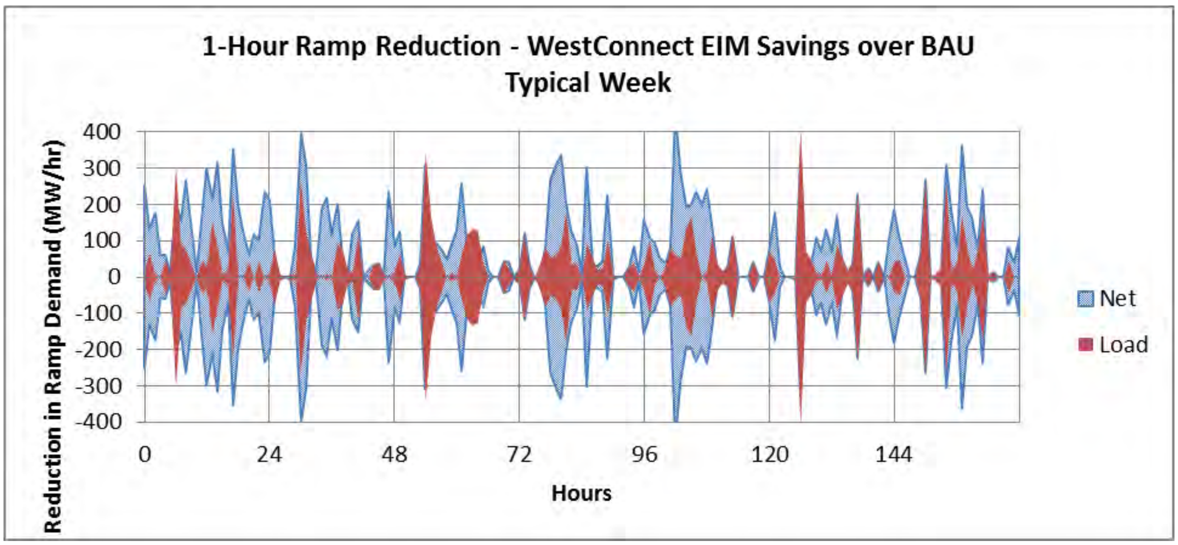


Figure 31. WestConnect EIM ramp savings over a typical week

The BAA allocation of average total reserves and average total regulation for the WestConnect subregional EIM is shown in Figure 32. The WestConnect subregional EIM has enough participants so that no one participant exceeds 20% of the total load, so no one BAA dominates the others.

In VG penetration however, PSCO has about 40% of the total in both wind and solar. With this penetration of VG, we might expect PSCO to see relatively small savings. However, the VG in PSCO is made up of both wind and significant solar, giving those combined resources comparatively low variability.

AZPS, on the other hand, sees relatively smaller reductions because its VG is highly correlated and low penetration compared with PSCO.

Tabular data for these graphs can be found in Appendix A in Table 27.

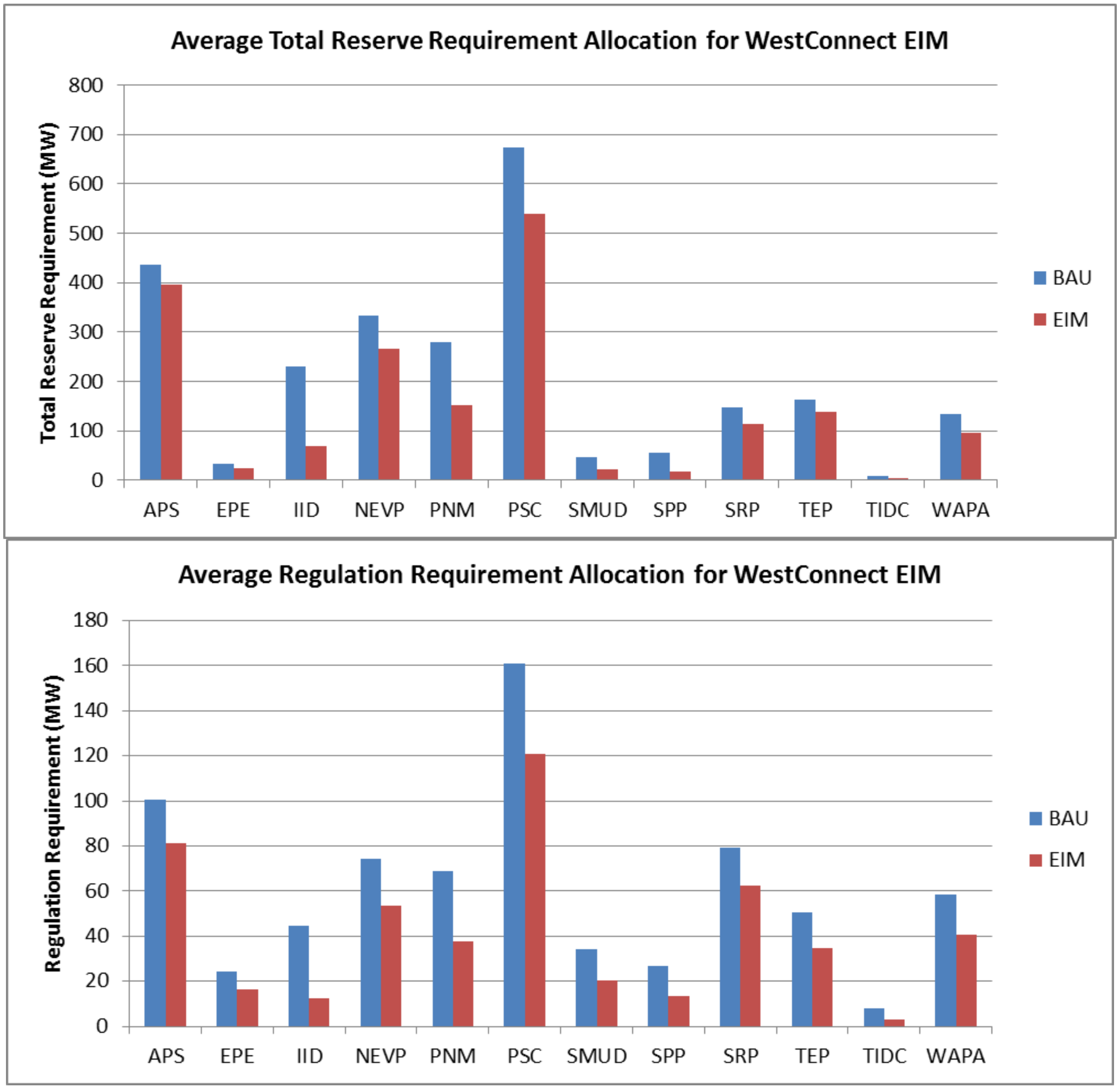


Figure 32. Allocation of reserves for WestConnect EIM

The value of the reserve savings was calculated using the prices shown in Table 11. These reserve savings are shown in Table 15 for each BAA participating in the EIM. The total savings for the WestConnect EIM is approximately $36 million. Note that the values are in millions of dollars.

Table 15. Value of Annual Reserve Savings for WestConnect EIM ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$2.03	$0.37	$0.12	$2.52
EPE	$0.88	$0.01	$0.00	$0.90
IID	$3.39	$2.21	$0.74	$6.34
NEVP	$2.20	$0.84	$0.28	$3.32
PNM	$3.30	$1.66	$0.55	$5.51
PSCO	$4.22	$1.60	$0.53	$6.36
SMUD	$1.46	$0.20	$0.07	$1.73
SPP	$1.44	$0.45	$0.15	$2.04
SRP	$1.77	$0.30	$0.10	$2.17
TEP	$1.65	$0.17	$0.05	$1.87
TID	$0.51	$0.00	$0.00	$0.51
WAPA	$1.90	$0.34	$0.11	$2.35
Total	$24.76	$8.17	$2.72	$35.64

5.5 WECC TEPPC EIM Study Phase 2 EIM and Reduced Footprint With Flex-Only Regulation

WECC performed an independent study to understand the benefits of EIM implementation using chronological production cost modeling techniques. NREL was asked to provide the reserve requirement calculation to this effort. The GridView reserve model, as developed for the WECC study carried out by E3, was developed using a separate calculation for the load regulation, so a new class of reserve was defined to cover just the VG portion of what we have defined as regulation for this study. This component is called the flex-only regulation and is defined in Equation 3 in Section 4.1. The spin and non-spin components of reserves are as defined in Equation 5.

The flex reserve requirements were calculated for the full-Western Interconnection footprint as defined in Section 2.4. The flex requirements differ from the regulation requirement used elsewhere in this analysis because there is no load component included in this flex reserve calculation. Figure 33 shows the flex regulation-based reserve requirements for the footprint EIM. The data in this chart can be compared to Figure 14, which shows the reserve requirements for the same EIM definition with load regulation included.

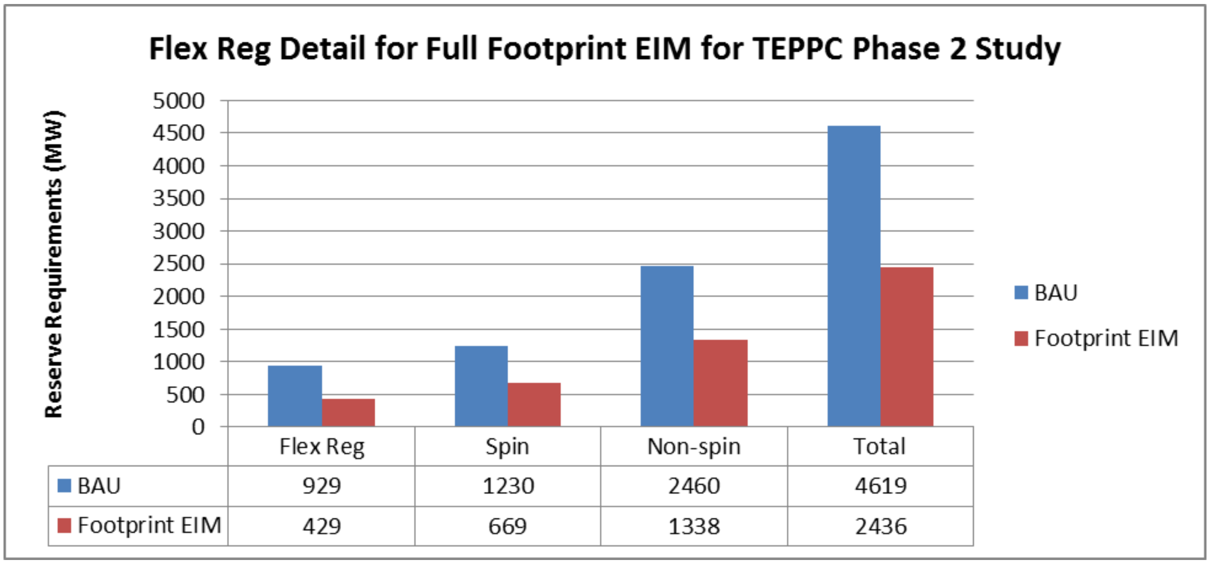


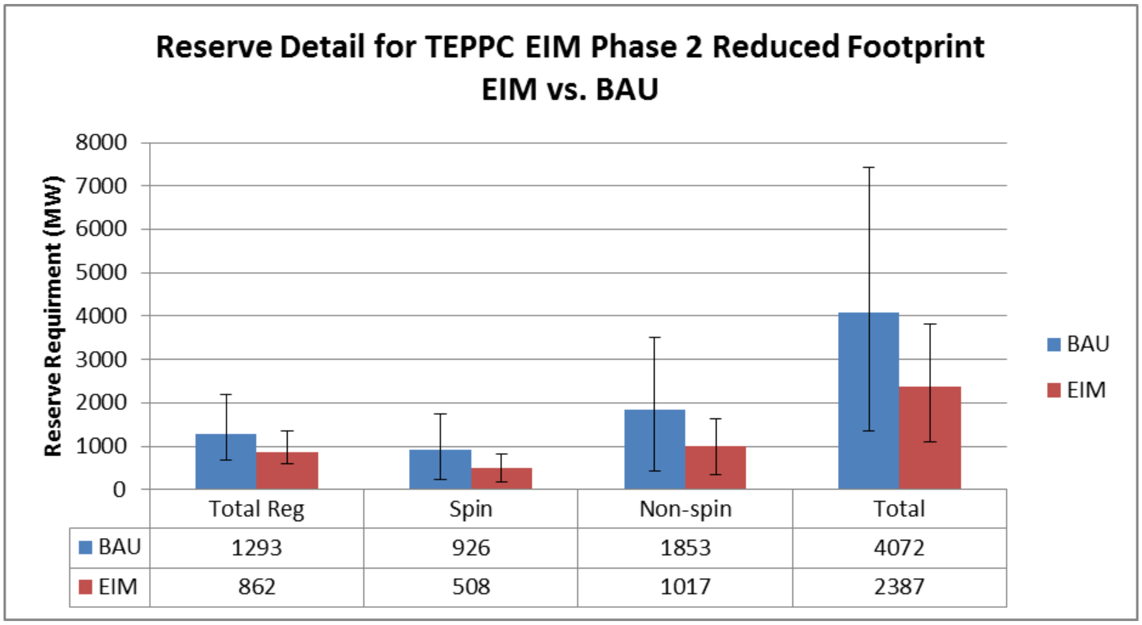
Figure 33. Flex-only regulation and total requirements for footprint EIM

When the model was developed, a new reduced-footprint EIM was defined that is close to, but not quite the same as, the scenario that excluded BPA and WAPA. The difference is that the municipal and public utility district entities that are embedded in BPA were also excluded from the EIM.

Table 16. BAAs Included in the TEPPC Phase 2 Reduced Footprint Scenario

BAAs in Reduced Footprint	
Avista	Pacificorp West
Arizona Public Service	Portland General Electric
British Columbia	Public Service of New Mexico
El Paso Electric	Public Service of Colorado
Imperial Irrigation District	Puget Sound Energy
Idaho Power Corp.	Sacramento Municipal Utility District
LA Department of Water and Power	Sierra Pacific Power
Nevada Power	Salt River Project
Northwest Energy	Tucson Electric Power
Pacificorp East	Turlock Irrigation District

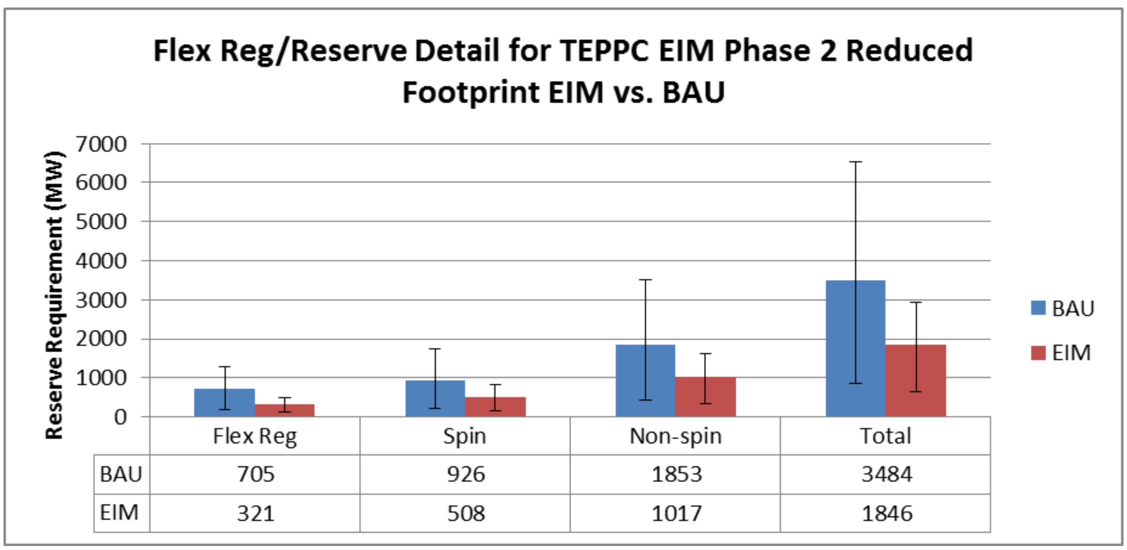
The reserve data were calculated using both the method used in this study and the flex reserves from the TEPPC EIM Phase 2 study. Figure 34 shows the results using load regulation as part of the total regulation calculation, as was done in all earlier analyses in this report.



	Total Reg	Spin	Non-spin	Total
BAU	1293	926	1853	4072
EIM	862	508	1017	2387

Figure 34. Average reserves for reduced footprint with load regulation component included

The flex reserves are the regulation requirement to cover the in-the-hour movements of VG only and do not include load regulation. The total regulation values used throughout this report include a load component, as defined in Section 4.1.



	Flex Reg	Spin	Non-spin	Total
BAU	705	926	1853	3484
EIM	321	508	1017	1846

Figure 35. Average reserves for reduced footprint using flex-only regulation with no load component

5.6 Results With BPA and WAPA Not Participating in EIM

One of the important elements of this work was to understand the effect of nonparticipation of BAs with large VG production on the EIM implementations. To do this, cases were run with BPA and WAPA managing their net load variability independently of the EIMs. When a BA does not participate, it obviously cannot reduce its own reserve requirements, but it also impacts the savings for the remaining participants.

5.6.1 BPA Not Participating in Footprint EIM

The footprint EIM case was evaluated with BPA not participating. Without BPA, there is still a significant reduction in reserves, as shown in Figure 36. This chart compares the BAU case with the full EIM and the EIM with BPA not participating. The bar labeled “NP BPA” includes the standalone requirements for BPA added to the footprint EIM requirements (without BPA participating) so the total requirements across the study area can be compared. The bars show the average requirements, and the whiskers show the minimum and maximum values. The effect on reserve requirements for the EIM's remaining participants is investigated below.

There is a reduction in benefit to the total footprint reserve requirements when a large BA such as BPA does not participate. The average total reserve requirement rises from 3083 MW for the full EIM with BPA to 3570 MW without BPA. However, there are still savings compared with the BAU, and most of the full EIM benefit is captured.

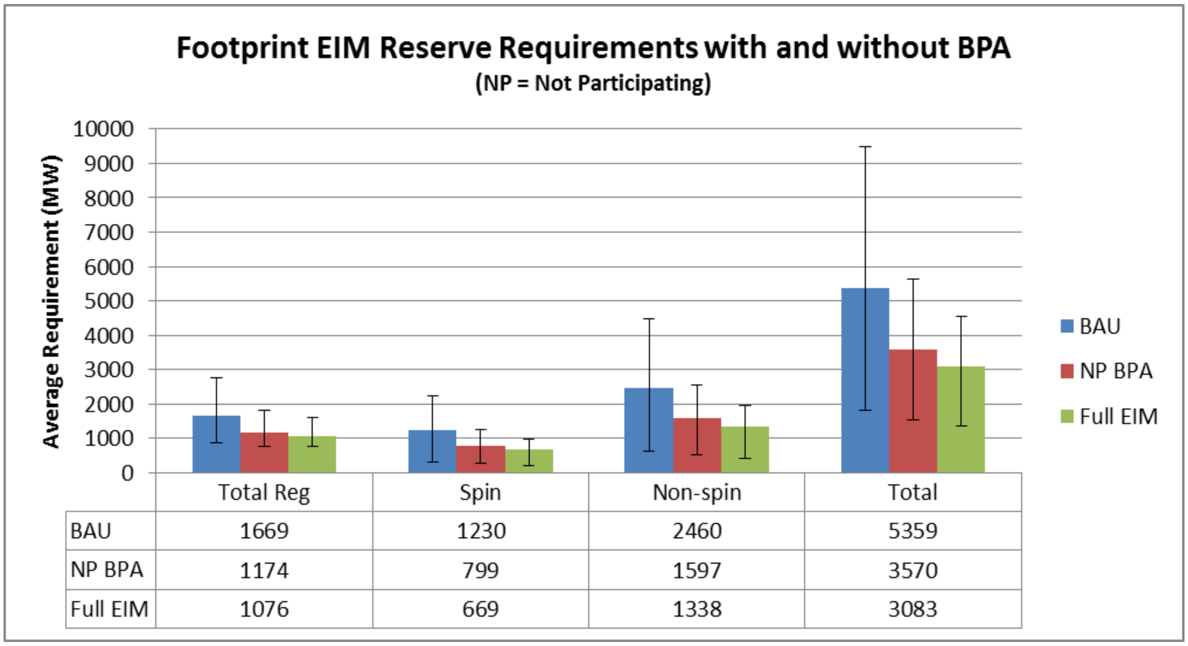
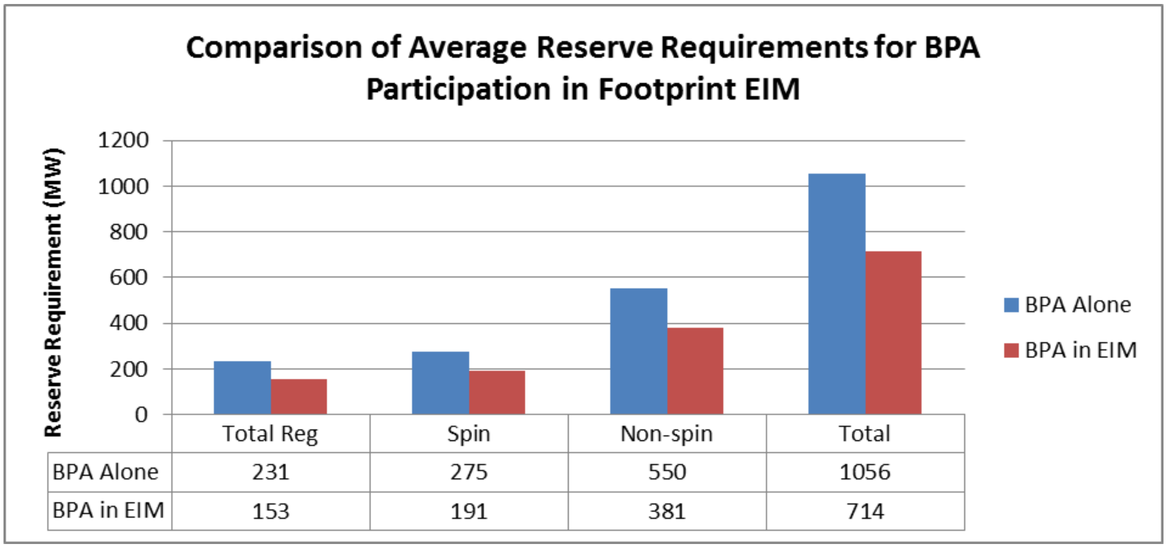


Figure 36. Reserve requirement for footprint EIM with and without BPA participation

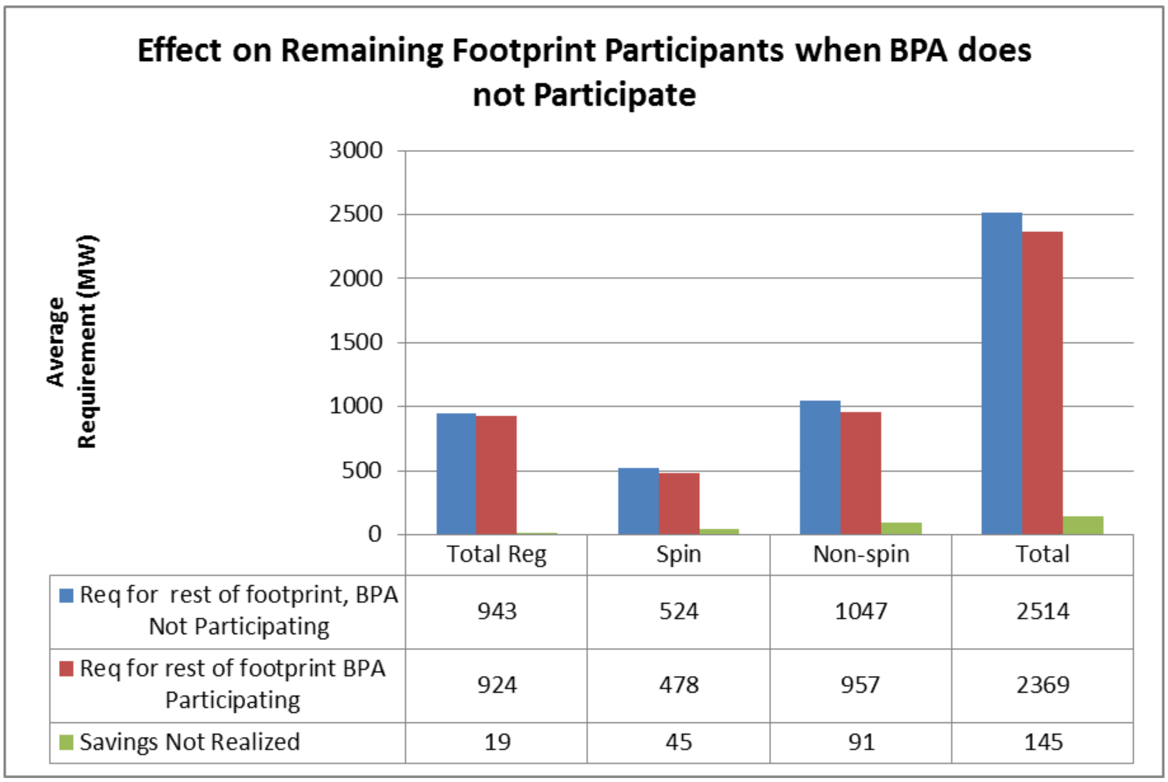
When a region does not participate, it will not receive the benefits of the EIM. For BPA, the difference between participating and not participating is shown in Figure 37. The reserve requirements for the case with BPA participating are calculated using the allocation method detailed in Section 4.3 and shown in Figure 20. The differences between the bars are the potential savings BPA receives from the footprint EIM. The potential savings are approximately 33% for each class of reserves.



	Total Reg	Spin	Non-spin	Total
BPA Alone	231	275	550	1056
BPA in EIM	153	191	381	714

Figure 37. BPA's reserve requirements are reduced if it participates in the EIM

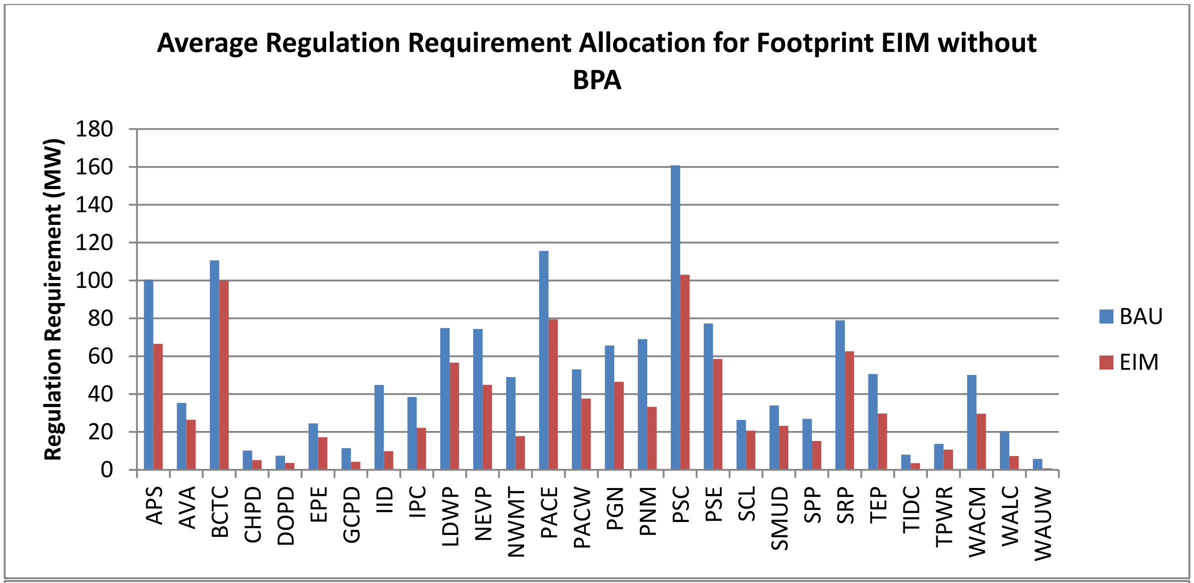
The savings for the rest of the EIM participants are affected by the participation of other BAs also. The effect for the remaining participants is much smaller than for BPA. Figure 38 shows that the lost savings when BPA does not participate are modest relative to the overall requirement, although they do add up to 145 MW of savings in total reserves.



	Total Reg	Spin	Non-spin	Total
Req for rest of footprint, BPA Not Participating	943	524	1047	2514
Req for rest of footprint BPA Participating	924	478	957	2369
Savings Not Realized	19	45	91	145

Figure 38. Summary of reserves for footprint EIM with and without BPA

The BA allocation of average total reserves and average total regulation for the footprint EIM without BPA is shown in Figure 39. Tabular data for this figure can be found in Appendix A in Table 28.



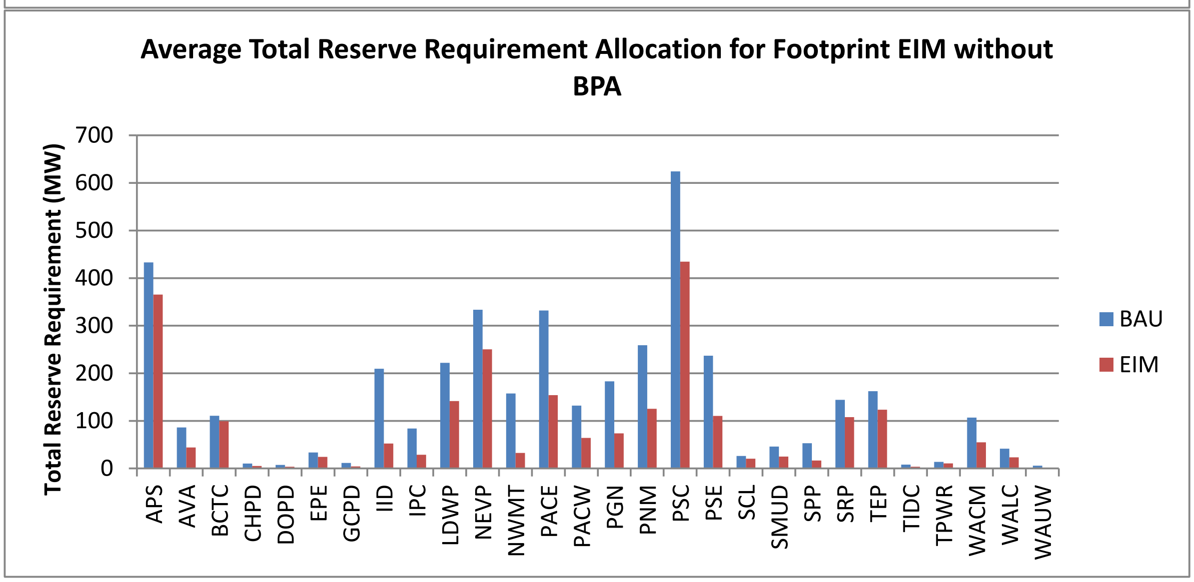


Figure 39. Allocation of reserve savings for footprint EIM without BPA participation

The value of these savings can be calculated using the price assumptions shown in Table 11. The resulting values are shown in Table 17. Note that the values are in millions of dollars and do not include costs to operate or participate in the EIM.

Table 17. Value of Annual Reserve Savings for Footprint EIM Without BPA ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$3.57	$0.60	$0.20	$4.37
AVA	$0.94	$0.58	$0.19	$1.71
BCTC	$1.12	$0.00	$0.00	$1.12
CHPD	$0.53	$0.00	$0.00	$0.53
DOPD	$0.40	$0.00	$0.00	$0.40
EPE	$0.76	$0.04	$0.01	$0.81
GCPD	$0.76	$0.00	$0.00	$0.76
IID	$3.67	$2.09	$0.70	$6.45
IPC	$1.71	$0.68	$0.23	$2.62
LDWP	$1.92	$1.09	$0.36	$3.37
NEVP	$3.11	$0.93	$0.31	$4.35
NWE	$3.28	$1.63	$0.54	$5.45
PACE	$3.80	$2.47	$0.82	$7.10
PACW	$1.63	$0.91	$0.30	$2.84
PGE	$2.01	$1.57	$0.52	$4.11
PNM	$3.76	$1.69	$0.56	$6.01
PSCO	$6.08	$2.18	$0.73	$8.99
PSE	$1.97	$1.87	$0.62	$4.46
SCL	$0.60	$0.00	$0.00	$0.60
SMUD	$1.14	$0.18	$0.06	$1.37
SPP	$1.23	$0.43	$0.14	$1.81
SRP	$1.73	$0.35	$0.12	$2.19
TEP	$2.19	$0.31	$0.10	$2.61
TID	$0.48	$0.00	$0.00	$0.48
TPWR	$0.32	$0.00	$0.00	$0.32
WACM	$2.15	$0.55	$0.18	$2.88
WALC	$1.38	$0.09	$0.03	$1.49
WAUW	$0.53	$0.00	$0.00	$0.53
Total	$53	$20	$7	$80

5.6.2 BPA Not Participating in Columbia Grid Subregional EIM

As we saw with the full Columbia Grid EIM in Section 5.4.1, the savings are somewhat less than those for the other EIMs relative to the total size. BPA dominates with around 45% of the average load and around 81% of the total average wind in Columbia Grid. Removing BPA from the EIM further reduces the savings, as shown in Figure 40. Note that the bar labeled “NP BPA*” includes the standalone requirement for BPA added to the Columbia Grid EIM without BPA requirement to allow comparison of values across the complete Columbia Grid.

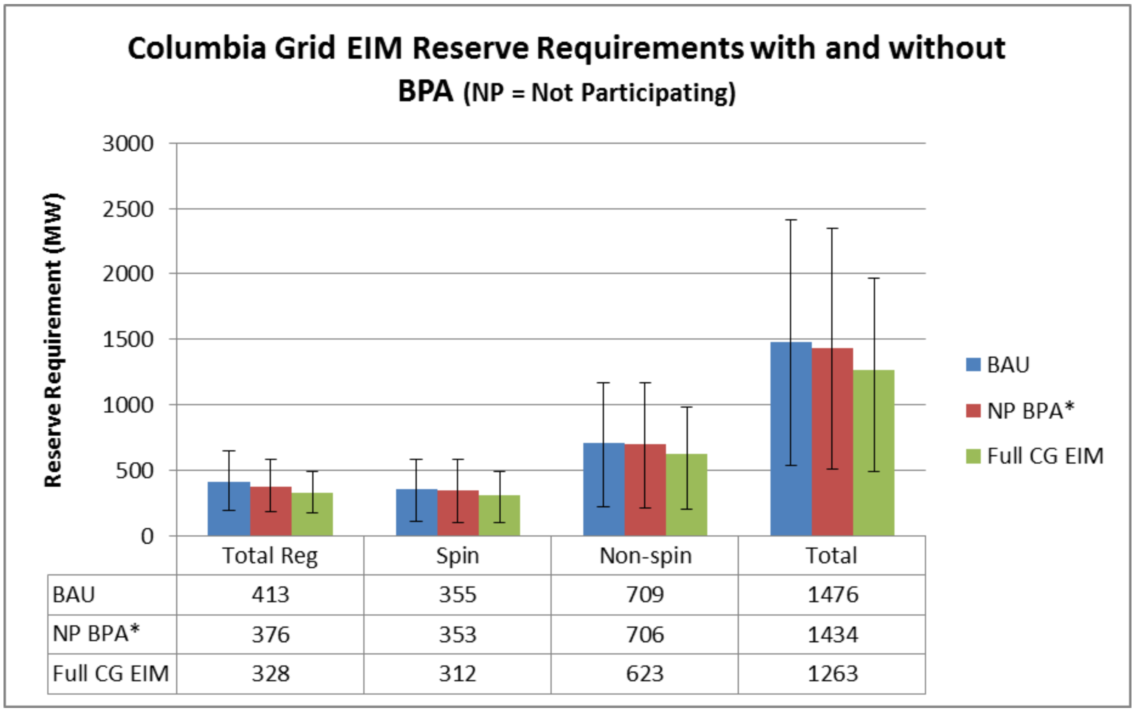


Figure 40. Net average reserve requirements for Columbia Grid EIM with and without BPA

Figure 41 shows the effect on BPA for participation in the Columbia Grid subregional EIM. These savings are small because BPA dominates the VG in the EIM. Note that the allocation for BPA is calculated using the method described in section 4.3 .

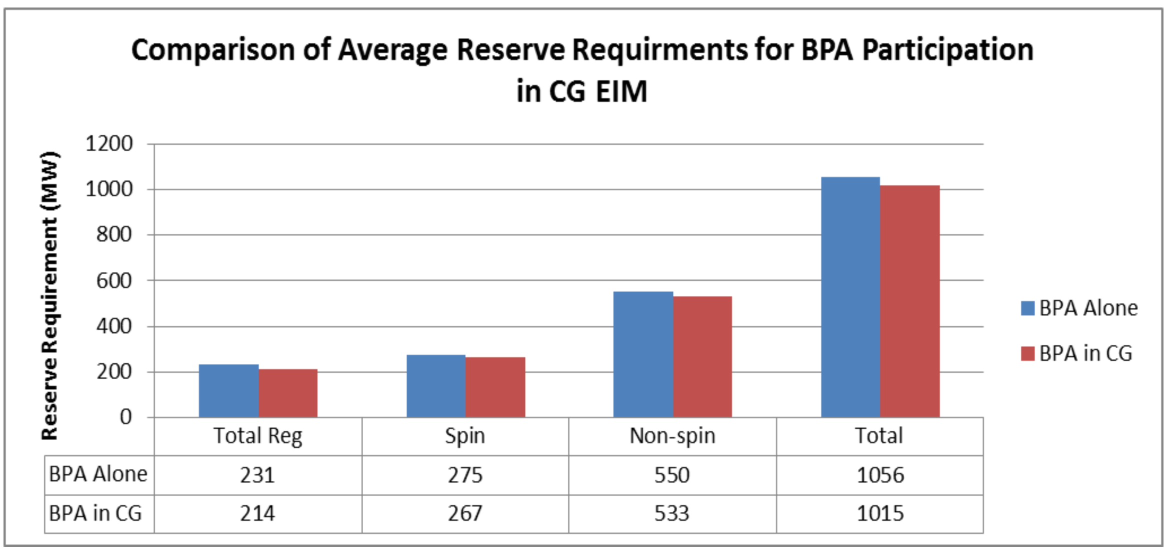


Figure 41. Effects of BPA not participating in EIM on BPA requirements

Without BPA, the remaining participants in the EIM still enjoy savings but significantly less than with BPA. Figure 42 compares the requirements for the BAAs included in the EIM with and without BPA's participation. BPA requirements are not included in the bars. The unrealized savings are shown in the right-most bar.

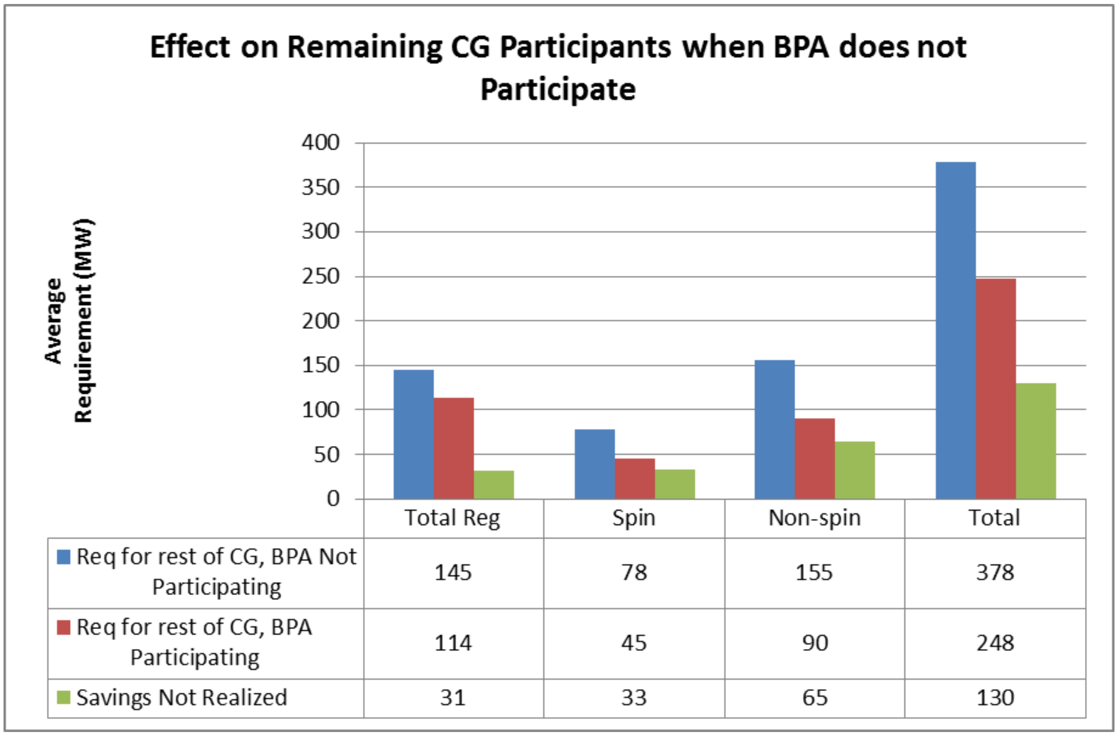
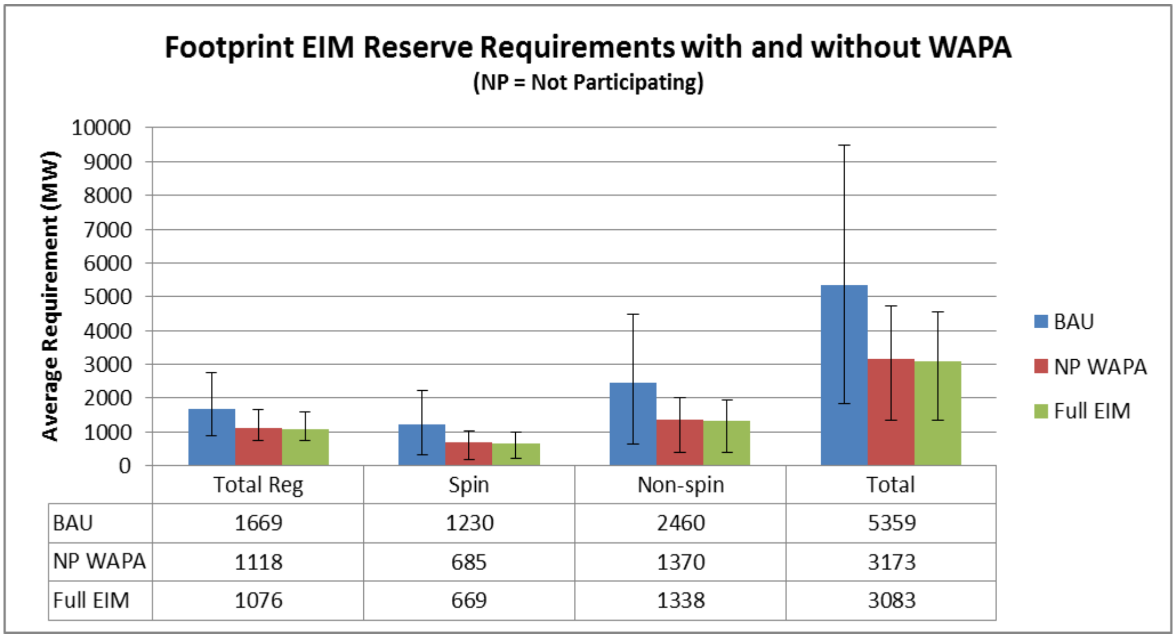


Figure 42. Effect on CG EIM participants when BPA does not participate

5.6.3 WAPA Not Participating in Footprint EIM

The full-footprint EIM was also evaluated with WAPA regions not participating. The three WAPA regions in the model represent approximately, on average, 5% of the load, 2% of the wind, and 0.5% of the solar modeled in the footprint EIM. With these proportions, the impact of the WAPA regions on the EIM is not very significant.

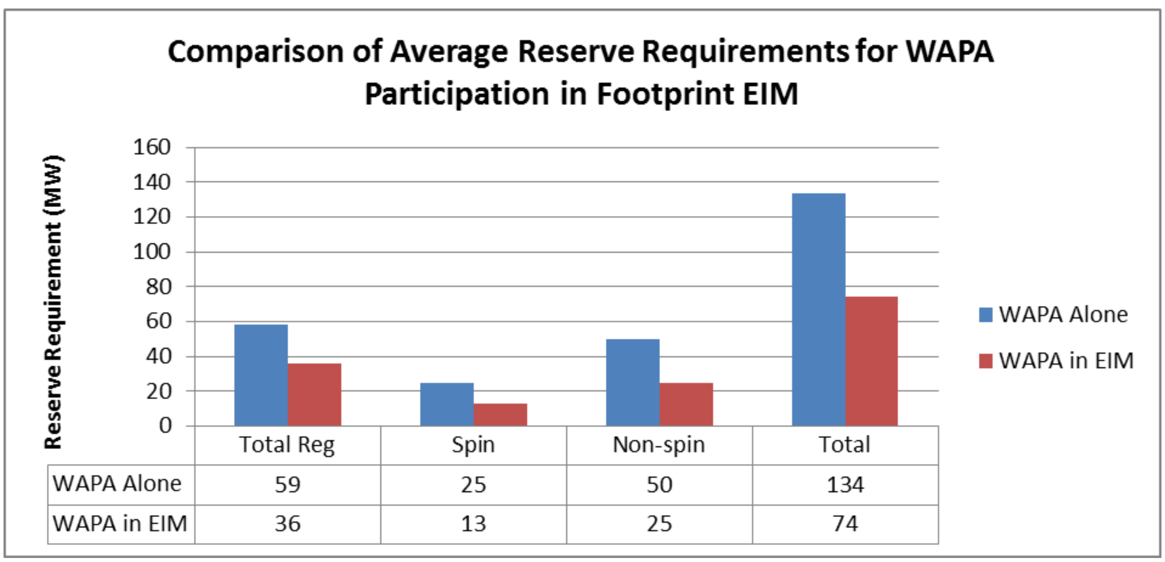
Figure 43 compares the BAU case requirements with those for the EIM both with and without WAPA participating. The bar labeled "NP WAPA" contains the standalone requirements for WAPA added to the footprint EIM requirements so that the total requirements across the study area can be compared. The bars are the average value, and the whiskers are minimum and maximum values. As shown, the impact on total reserve requirements for the entire footprint including WAPA is relatively small, with only a 90-MW (3%) difference between WAPA participating in the EIM or not. The majority of the savings for the EIM are intact without WAPA.



	Total Reg	Spin	Non-spin	Total
BAU	1669	1230	2460	5359
NP WAPA	1118	685	1370	3173
Full EIM	1076	669	1338	3083

Figure 43. Reserve requirements for footprint EIM with and without WAPA participation

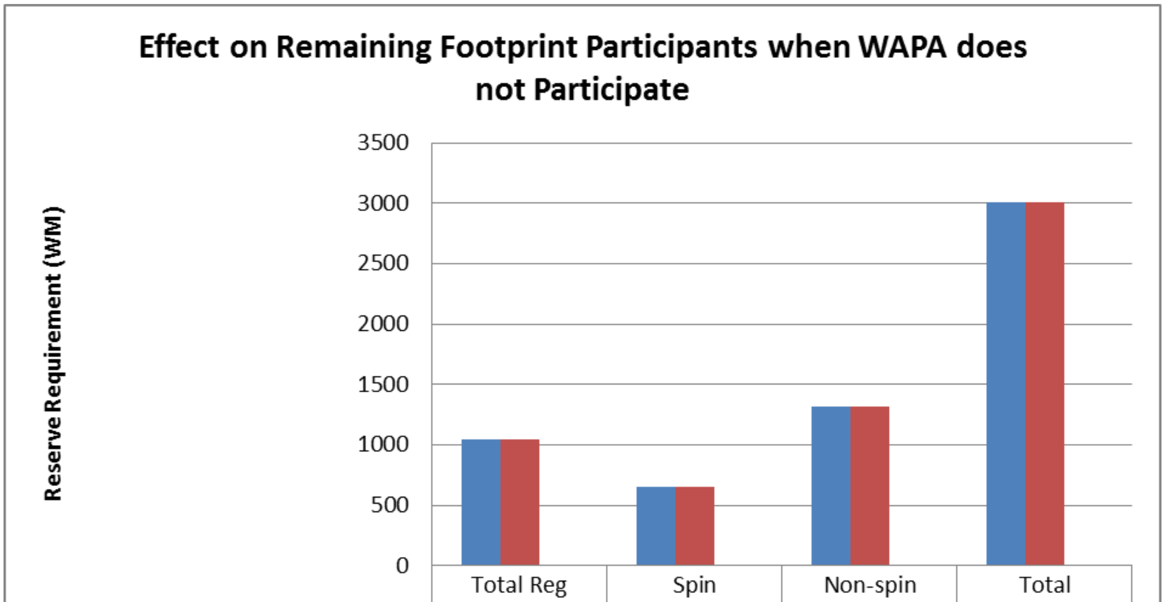
Next, we examined the effect on WAPA's reserve requirements of not participating in the footprint EIM. Figure 44 compares WAPA's reserve requirements in and out of the EIM. In relative terms, the unrealized savings are quite significant. For total reserves, the savings could be 60 MW, or 45%. The allocation of reserves for WAPA in the EIM is calculated using the method described in Section 4.3.



	Total Reg	Spin	Non-spin	Total
WAPA Alone	59	25	50	134
WAPA in EIM	36	13	25	74

Figure 44. Effects of WAPA not participating in footprint EIM on WAPA requirements

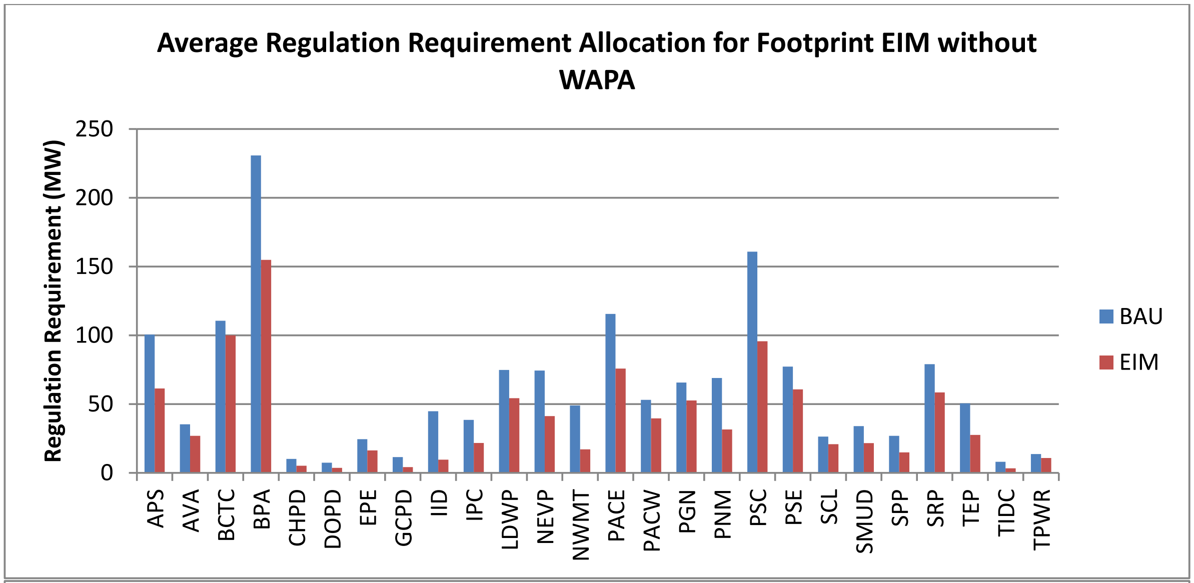
WAPA's participation in the Footprint EIM has little effect on the other participants in the EIM. This is because of the low percentages of load, wind, and solar in WAPA. These savings are in the low single digits for all classes of reserves. Figure 45 shows the effect of WAPA nonparticipation.



	Total Reg	Spin	Non-spin	Total
Req for rest of footprint, BPA Not Participating	1042	657	1313	3011
Req for rest of footprint BPA Participating	1040	656	1313	3009
Savings Not Realized	1	1	0	2

Figure 45. Effect of WAPA not participating in footprint EIM

The BAA allocation of average total reserves and average total regulation for the footprint EIM without WAPA can be seen in Figure 46. Tabular data for this figure can be found in Appendix A in Table 29.



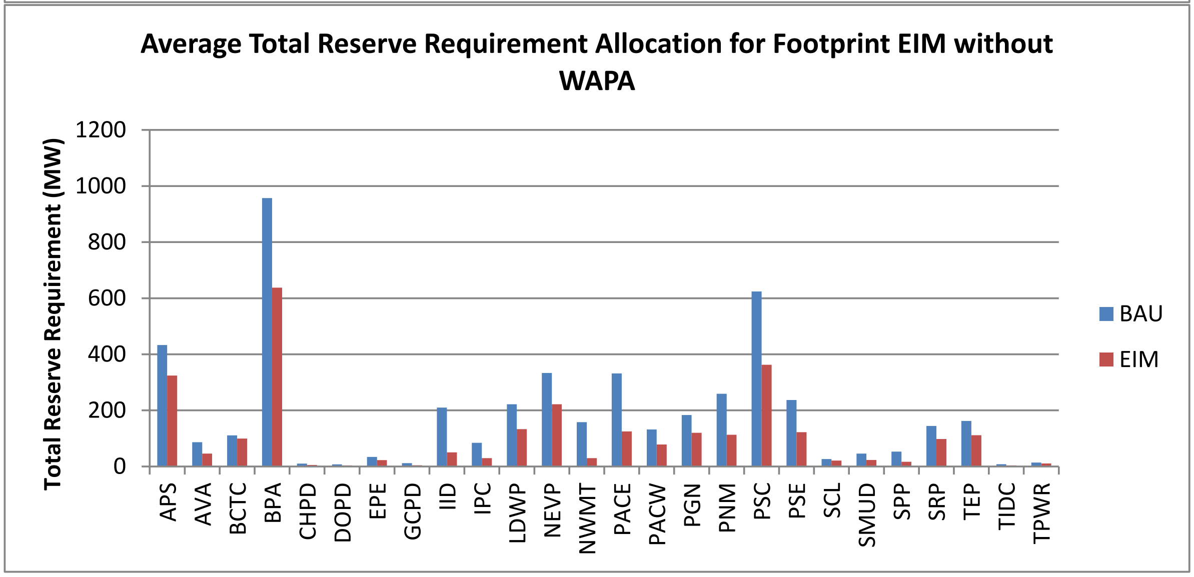


Figure 46. Allocation of reserve savings for footprint EIM without WAPA participation

The value of these savings can be calculated using the price assumptions shown in Table 11. The resulting values are shown in Table 18. Note that the values are in millions of dollars.

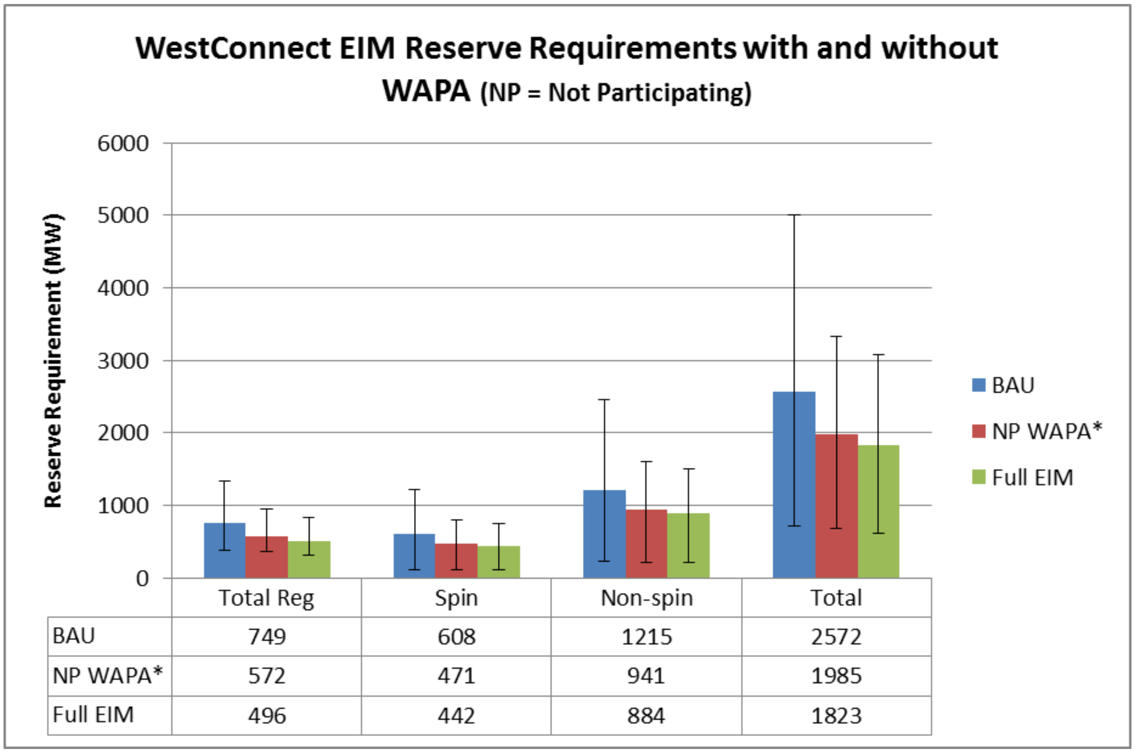
Table 18. Value of Annual Reserve Savings for Footprint EIM Without WAPA ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$4.11	$1.20	$0.40	$5.71
AVA	$0.89	$0.56	$0.19	$1.64
BCTC	$1.12	$0.00	$0.00	$1.12
BPA	$7.99	$4.27	$1.38	$13.64
CHPD	$0.53	$0.00	$0.00	$0.53
DOPD	$0.40	$0.00	$0.00	$0.40
EPE	$0.85	$0.06	$0.02	$0.93
GCPD	$0.76	$0.00	$0.00	$0.76
IID	$3.70	$2.13	$0.72	$6.55
IPC	$1.76	$0.66	$0.22	$2.64
LDWP	$2.16	$1.18	$0.40	$3.74
NEVP	$3.48	$1.34	$0.45	$5.27
NWE	$3.35	$1.70	$0.56	$5.61
PACE	$4.18	$2.89	$0.98	$8.05
PACW	$1.41	$0.71	$0.24	$2.36
PGE	$1.37	$0.87	$0.29	$2.54
PNM	$3.93	$1.89	$0.63	$6.45
PSCO	$6.85	$3.27	$1.13	$11.25
PSE	$1.75	$1.71	$0.57	$4.03
SCL	$0.57	$0.00	$0.00	$0.57
SMUD	$1.30	$0.19	$0.06	$1.55
SPP	$1.27	$0.43	$0.14	$1.84
SRP	$2.16	$0.45	$0.15	$2.75
TEP	$2.41	$0.49	$0.16	$3.07
TID	$0.49	$0.00	$0.00	$0.49
TPWR	$0.31	$0.00	$0.00	$0.31
Total	$59	$26	$9	$94

5.6.4 WAPA Not Participating in WestConnect Subregional EIM

We also evaluated the effect WAPA nonparticipation would have on a WestConnect subregional EIM. The three WAPA regions modeled constitute 11% of the load, 8% of the wind, and 1% of the solar modeled in WestConnect.

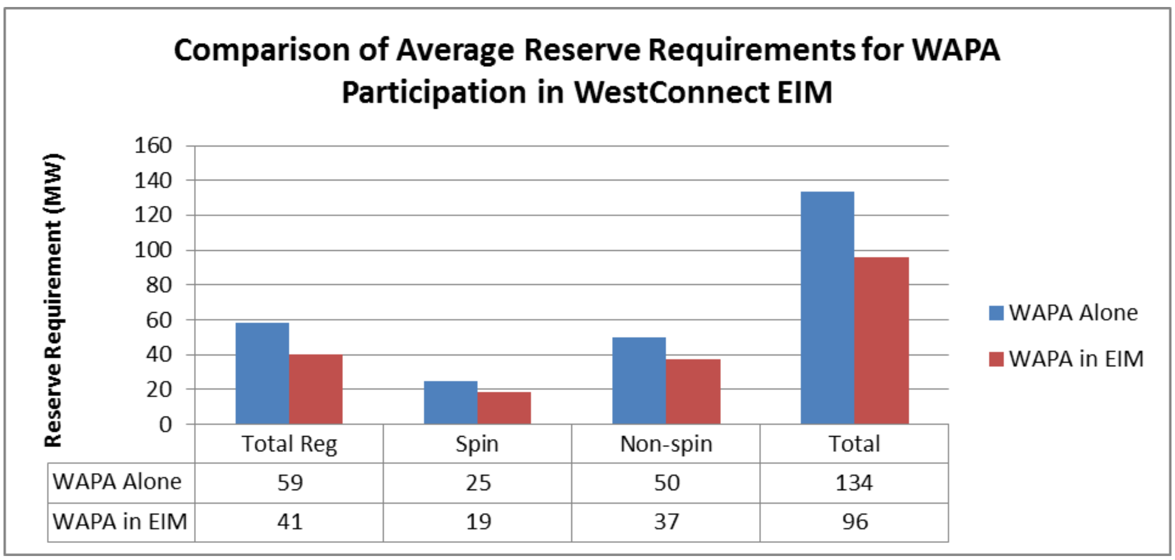
Figure 47 shows the reserve requirements for the WestConnect subregional EIM with and without WAPA compared with the BAU case. Note that the bar labeled “NP WAPA*” includes the standalone requirements for WAPA added to the WestConnect EIM without WAPA so that total requirements for the complete WestConnect can be compared. The bars show the average requirements, and the whiskers show the minimum and maximum values.



	Total Reg	Spin	Non-spin	Total
BAU	749	608	1215	2572
NP WAPA*	572	471	941	1985
Full EIM	496	442	884	1823

Figure 47. Reserve requirements for WestConnect EIM with and without WAPA participation

Although WAPA sees no benefit when it does not participate, it is interesting to compare the standalone requirements with WAPA's allocation of requirements in the full EIM to see how much savings WAPA would forgo by not participating. Figure 48 compares these values and shows that WAPA potential savings, although modest in absolute numbers, are appreciable as a percentage of its total requirement at about 28%.



	Total Reg	Spin	Non-spin	Total
WAPA Alone	59	25	50	134
WAPA in EIM	41	19	37	96

Figure 48. Effect of WAPA participation in WestConnect EIM on WAPA reserve requirements

Although there are impacts on the BAs in the WestConnect subregional EIM when WAPA does not participate, those impacts are quite small—in the single digits. Figure 49 shows the impact.

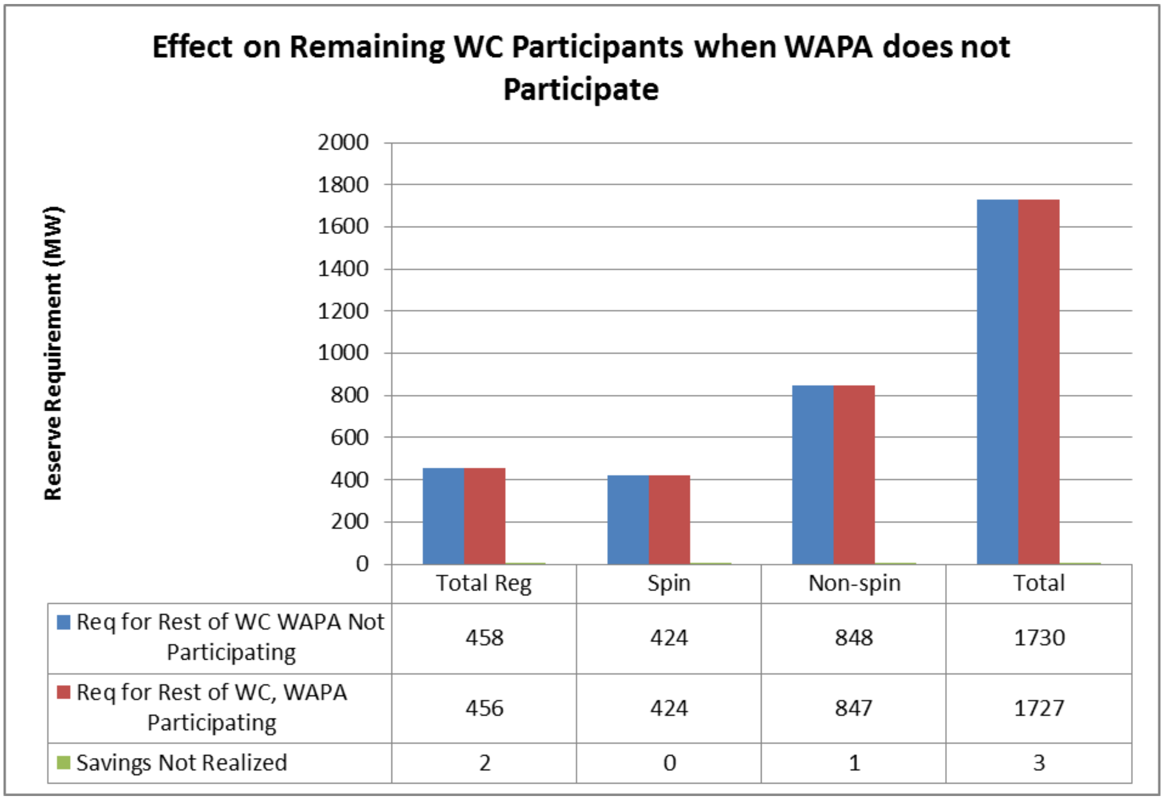
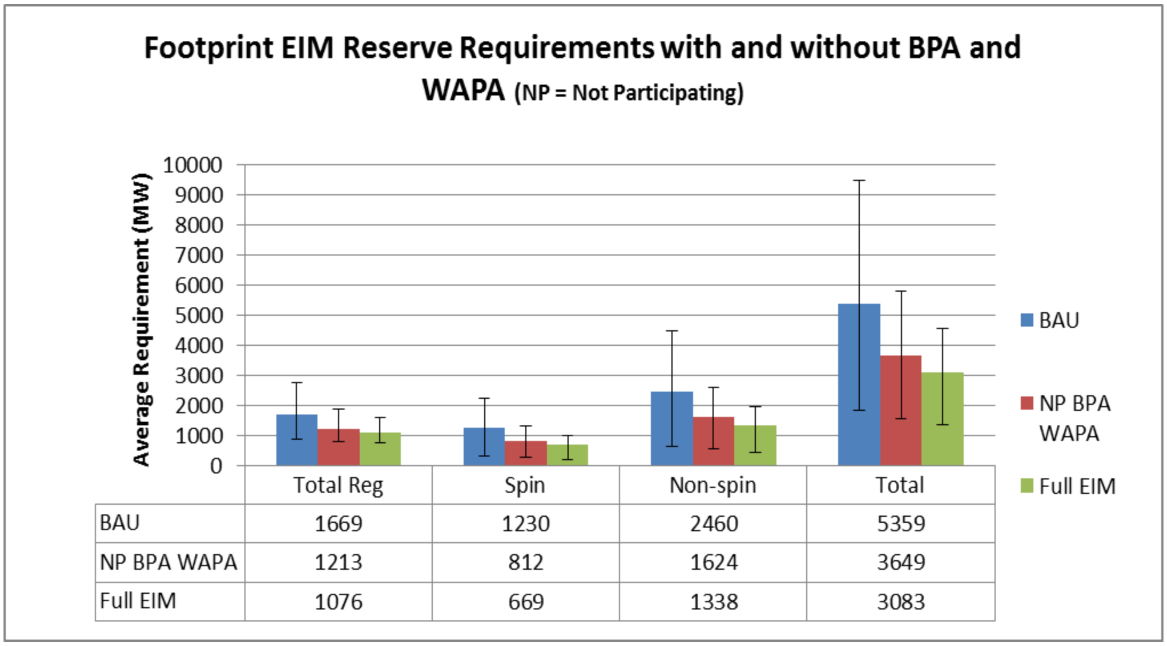


Figure 49. Effect of WAPA not participating in WestConnect subregional EIM

5.6.5 BPA and WAPA Not Participating

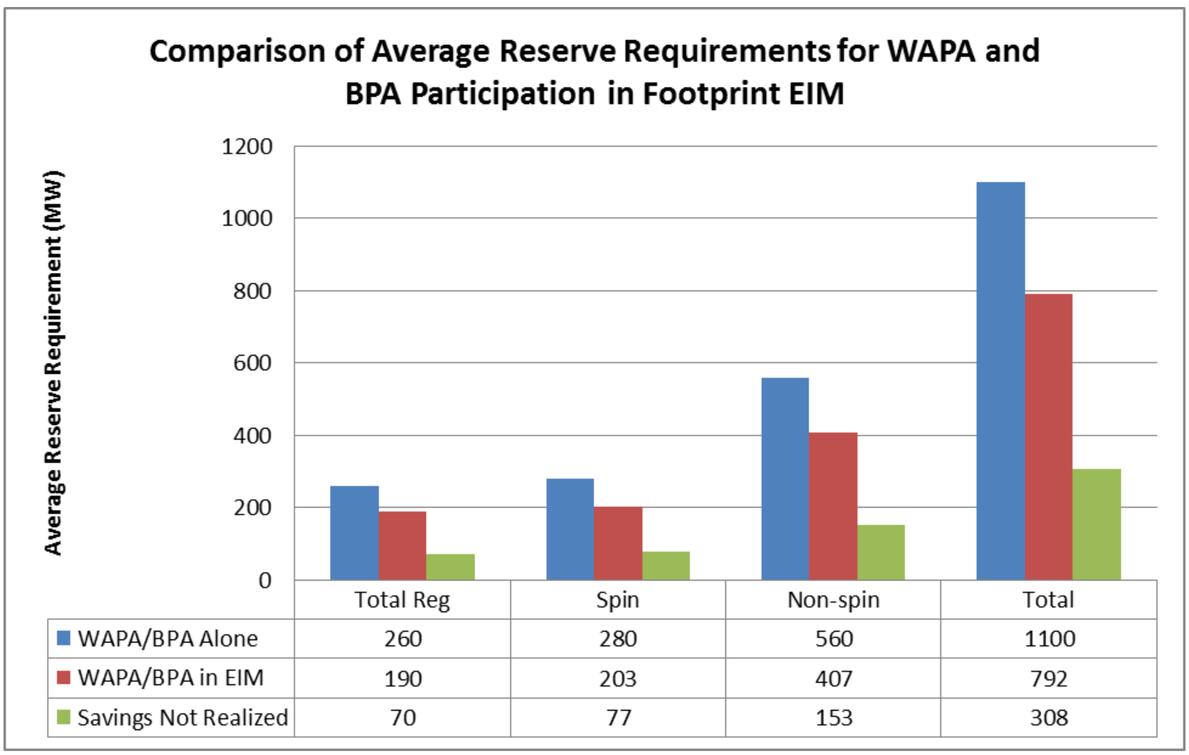
The case in which neither BPA nor WAPA participate in a footprint-wide EIM was also evaluated. These BAAs represent a significant portion of the wind in the entire footprint, with approximately 35% of the total wind resource modeled. Figure 50 shows reserve requirements for the footprint with these two BAAs not participating in the EIM. The bar labeled “NP BPA WAPA” contains the standalone requirements for WAPA and BPA added to the footprint EIM requirements so that the total requirements across the study area can be compared. The bars are the average value, and the whiskers are minimum and maximum values. Although we can see a definite reduction in requirements of the EIM, there still are significant savings for the remaining participants in the EIM.



	Total Reg	Spin	Non-spin	Total
BAU	1669	1230	2460	5359
NP BPA WAPA	1213	812	1624	3649
Full EIM	1076	669	1338	3083

Figure 50. Reserve savings for footprint EIM without BPA or WAPA participation

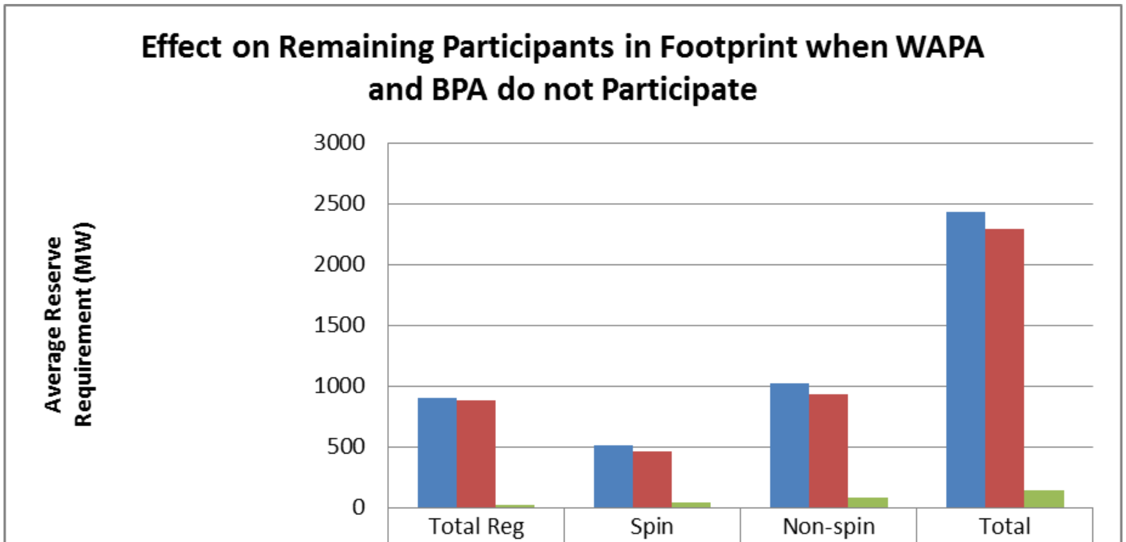
The savings with BPA and WAPA participating in the footprint EIM are roughly the sum of the savings for the individual BAAs seen in the previous two sections. Figure 51 shows a summary of the average reserves for BPA and WAPA both in and out of the footprint EIM.



	Total Reg	Spin	Non-spin	Total
WAPA/BPA Alone	260	280	560	1100
WAPA/BPA in EIM	190	203	407	792
Savings Not Realized	70	77	153	308

Figure 51. Summary of reserves for WAPA and BPA alone and in footprint EIM

Figure 52 shows a summary of the reserve requirements for the footprint EIM with and without BPA and WAPA. This shows a relatively small impact on the participants of the EIM when BPA and WAPA do not participate.



	Total Reg	Spin	Non-spin	Total
Req for Rest of FP WAPA/BPA Not Participating	906	508	1017	2432
Req for Rest of FP WAPA,BPA Participating	886	466	931	2291
Savings Not Realized	20	42	86	141

Figure 52. Effect on remaining footprint EIM participants with and without BPA and WAPA

Figure 53 shows the allocation of average total reserves and average regulation for the footprint EIM without participation of BPA and WAPA. The method for calculating these allocations is discussed in Section 4.3. Tabular data for this figure can be found in Appendix A in Table 30.

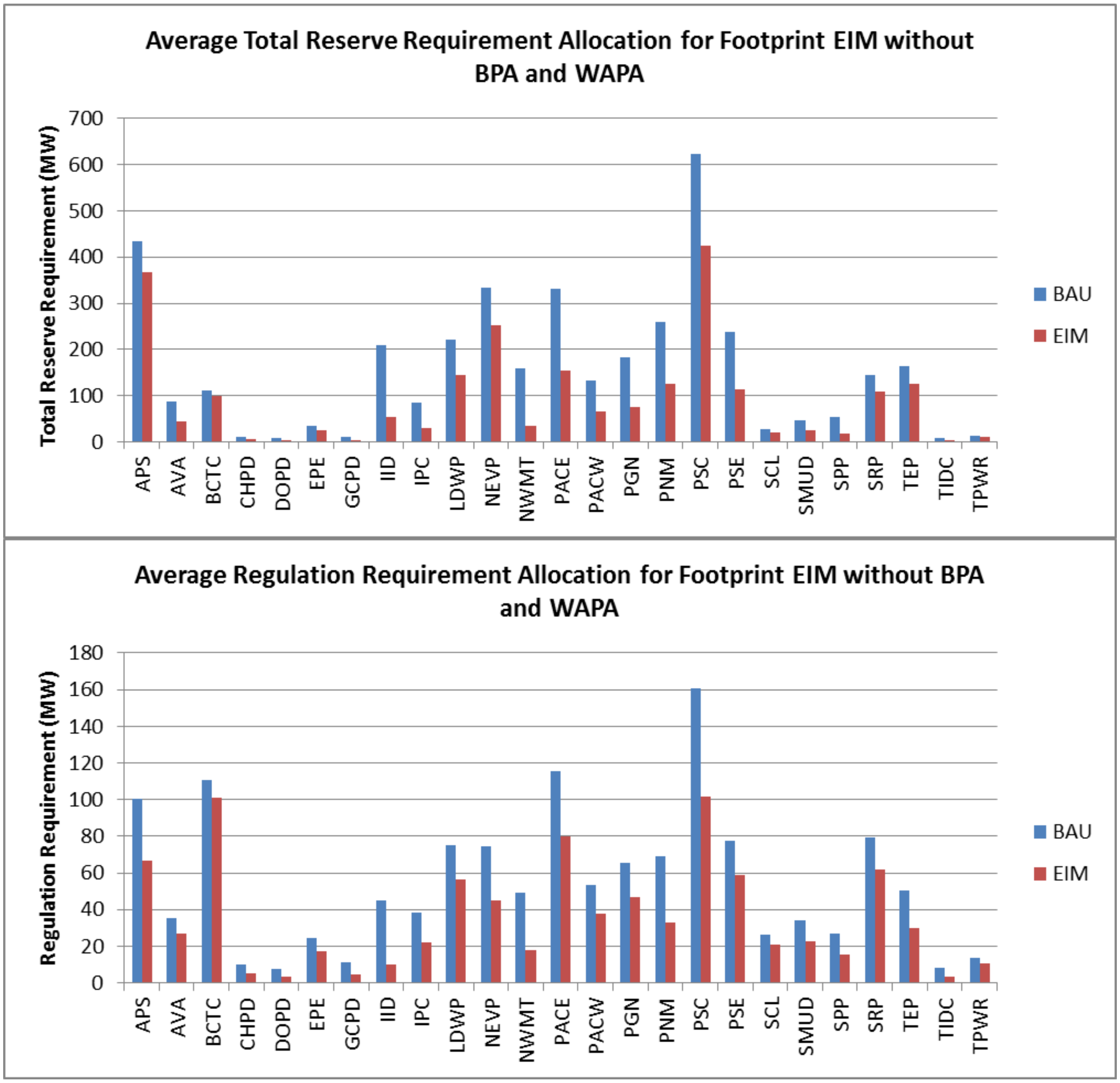


Figure 53. Allocation of reserves in footprint EIM without BPA and WAPA participation

The value of the reserve savings was calculated using the prices shown in Table 11. These reserve savings are shown in Table 19 for each BA participating in the EIM. The savings for this footprint are approximately $77 M. By comparison, the full-footprint savings for the BAs included in this reduced footprint are approximately $83 M. This indicates that the nonparticipation of BPA and WAPA costs the remaining participants about $6 M in potential savings.

Table 19. Value of Annual Reserve Savings for Footprint EIM Without BPA and WAPA ($M)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	$3.59	$0.62	$0.21	$4.42
AVA	$0.92	$0.61	$0.21	$1.74
BCTC	$1.03	$0.00	$0.00	$1.03
CHPD	$0.53	$0.00	$0.00	$0.53
DOPD	$0.40	$0.00	$0.00	$0.40
EPE	$0.78	$0.04	$0.01	$0.84
GCPD	$0.75	$0.00	$0.00	$0.75
IID	$3.66	$2.23	$0.74	$6.64
IPC	$1.72	$0.75	$0.25	$2.73
LDWP	$1.92	$1.17	$0.39	$3.48
NEVP	$3.10	$0.92	$0.31	$4.33
NWE	$3.27	$1.82	$0.61	$5.70
PACE	$3.77	$2.77	$0.92	$7.47
PACW	$1.61	$0.97	$0.32	$2.90
PGE	$1.99	$1.71	$0.57	$4.26
PNM	$3.77	$1.89	$0.63	$6.28
PSCO	$6.25	$2.67	$0.89	$9.81
PSE	$1.93	$1.97	$0.66	$4.55
SCL	$0.58	$0.00	$0.00	$0.58
SMUD	$1.18	$0.20	$0.07	$1.45
SPP	$1.22	$0.46	$0.15	$1.83
SRP	$1.79	$0.39	$0.13	$2.30
TEP	$2.20	$0.31	$0.10	$2.62
TID	$0.48	$0.00	$0.00	$0.48
TPWR	$0.31	$0.00	$0.00	$0.31
Total	$48.74	$21.49	$7.17	$77.40

6 Comparison With a 30% Wind Energy Penetration

Comparing these results with the earlier Western Wind and Solar Integration Study 30% wind energy scenario [10], savings are significantly less for the 8% wind/3% solar case, as we would expect. Said another way, the EIM benefits would grow significantly with increasing penetrations of wind and solar energy. The Western Wind and Solar Integration Study scenario has nearly three times the VG (all wind) than the TEPPC 2020 PC0 case. The footprint EIM reserve reductions (in average megawatts) ranged from 51% to 54% for the Western Wind and Solar Integration Study scenario and from 35% to 42% for the TEPPC 2020 PC0 scenario. Table 20 shows a summary of the results from the earlier Western Wind and Solar Integration Study analysis. It is clear from these two studies that the reserve savings are very sensitive to the level of wind and/or solar build-out represented by the study.

Table 20. Summary of Results From Western Wind and Solar Integration Study Data Analysis: Average Megawatts

		Footprint EIM		Subregional EIM	
	BAU	EIM	Reduction	EIM	Reduction
Regulation	2440	1198	51%	1547	37%
Spin	2096	969	54%	1420	32%
Non-Spin	4192	1938	54%	2840	32%
Total	8729	4105	53%	5807	33%

We also calculated the value of the reserve reductions by using the vector allocations described in Section 4.3 to each class of reserve and applying the prices in Table 11 to the savings. The values in Table 21 are the results of these calculations. This shows that, for the 30% wind penetration case, a total of $221 million/year could be saved with the implementation of the EIM. This table can be compared with Table 12 for TEPPC 11% penetration data, where the potential EIM reserve savings were found to be $103 million/year.

Table 21. Estimated Value of Annual Reserve Savings for Western Wind and Solar Integration Study Data Analysis Full EIM Case ($M)

BAA	Regulation	Spin	Non-Spin	Total
AVA	$2.87	$1.59	$0.53	$4.99
AZPS	$16.99	$8.50	$2.83	$28.32
BCTC	$2.59	$0.00	$0.00	$2.59
BPA	$17.39	$10.25	$3.42	$31.05
CHPD	$1.19	$0.54	$0.18	$1.91
COPD	$0.97	$0.00	$0.00	$0.97
DOPD	$0.49	$0.00	$0.00	$0.49
EPE	$1.32	$0.48	$0.16	$1.96
GCPD	$2.57	$1.23	$0.41	$4.21
IID	$0.72	$0.09	$0.03	$0.83
IPC	$5.68	$3.76	$1.25	$10.69
NEVP	$3.81	$1.81	$0.60	$6.23
NWEA	$3.00	$1.55	$0.52	$5.07
PACE	$11.29	$7.73	$2.58	$21.60
PACW	$4.34	$2.41	$0.80	$7.56
PGE	$2.31	$0.70	$0.23	$3.24
PNM	$9.48	$6.11	$2.04	$17.62
PSCO	$7.72	$4.90	$1.63	$14.25
PSE	$1.35	$0.10	$0.03	$1.48
SCL	$0.86	$0.00	$0.00	$0.86
SMUD	$4.84	$2.77	$0.92	$8.54
SPP	$6.39	$3.75	$1.25	$11.39
SRP	$2.96	$0.55	$0.18	$3.69
TEP	$1.53	$0.00	$0.00	$1.53
TID	$0.88	$0.18	$0.06	$1.12
TPWR	$0.62	$0.00	$0.00	$0.62
WACM	$11.68	$7.09	$2.36	$21.13
WALC	$1.56	$0.74	$0.25	$2.54
WAUW	$3.17	$1.27	$0.42	$4.87
Total	$130.57	$68.09	$22.70	$221.36

These calculations were also carried out for the Western Wind and Solar Integration Study 30% scenario with BPA and WAPA not participating in the EIM. Table 22 shows the allocated savings for each participating BA. These data can be compared with the TEPPC 11% case shown in Table 19, where the potential savings were $77 million/year. Regardless of wind power and solar power penetration, the results show a significant reduction in benefits without the participation of the power marketing administrations, including WAPA and BPA; and of course, the administrations receive no additional benefit from the EIM if they do not participate.

Table 22. Estimated Value of Annual Reserve Savings for Western Wind and Solar Integration Study Data Analysis EIM Case Without BPA and WAPA

BAA	Regulation	Spin	Non-Spin	Total
AVA	$2.82	$1.61	$0.54	$4.96
AZPS	$14.22	$4.41	$1.47	$20.10
BCTC	$2.19	$0.00	$0.00	$2.19
CHPD	$1.20	$0.46	$0.15	$1.81
COPD	$0.96	$0.00	$0.00	$0.96
DOPD	$0.49	$0.00	$0.00	$0.49
EPE	$1.25	$0.37	$0.12	$1.74
GCPD	$2.55	$1.15	$0.38	$4.09
IID	$0.66	$0.09	$0.03	$0.79
IPC	$5.51	$3.40	$1.13	$10.04
NEVP	$3.48	$1.66	$0.55	$5.69
NWEA	$2.99	$1.65	$0.55	$5.19
PACE	$9.96	$5.77	$1.92	$17.66
PACW	$4.22	$2.36	$0.79	$7.37
PGE	$2.16	$0.63	$0.21	$3.00
PNM	$9.05	$5.34	$1.78	$16.17
PSCO	$7.28	$4.64	$1.55	$13.46
PSE	$1.21	$0.12	$0.04	$1.37
SCL	$0.80	$0.00	$0.00	$0.80
SMUD	$4.69	$2.73	$0.91	$8.33
SPP	$6.20	$3.48	$1.16	$10.83
SRP	$2.62	$0.53	$0.18	$3.33
TEP	$1.41	$0.00	$0.00	$1.41
TID	$0.86	$0.17	$0.06	$1.08
TPWR	$0.60	$0.00	$0.00	$0.60
Total	$89.36	$40.57	$13.52	$143.46

7 Conclusions

This report examines several alternative implementations of the proposed EIM in the nonmarket areas of the Western Interconnection. We adapt the reserves method from the Eastern Wind Integration and Transmission Study to analyze the implications of these alternative market structures on the flexibility reserve requirements for the EIM and its participants. This method is extended to include solar generation. Although we use standard deviation as the variability metric, our approach could easily be adapted to non-normal distributions. We also adapt a vector allocation method for allocation of variability to the participants of the EIM. This method possesses characteristics that lead to a fair allocation of reserves.

Our analysis focuses only on the ramping and flexibility reserve impacts of the EIM. We do not consider or evaluate production costs, nor do we consider the costs to establish or operate the EIM. The flexibility reserve calculations in this report do not consider transmission limitations that might affect the delivery of an EIM transaction across congested interfaces. The flexibility reserves that we calculate here were used as inputs to the WECC benefit study and are also input to production simulation modeling, using the Plexos production simulation model, currently under way through a partnership between NREL and Energy

Exemplar. Both the WECC and Plexos analyses incorporate transmission constraints into the production simulations. The flexibility reserve calculations in this report establish the need for these reserves, and the production simulation provides a means of evaluating whether the demand for energy and reserves can be met.

The proposed EIM includes two independent beneficial changes in operating practices: subhourly scheduling and inter-BA coordination. Half of the load in the country is served in regions with 5-min markets. This includes PJM, MISO, ERCOT, New York Independent System Operator (NYISO), Independent System Operator – New England, and California Independent System Operator. It is therefore likely that there are no real technical barriers to implementing 5-min scheduling in the rest of the Western Interconnection, too. Inter-BA cooperation has been practiced for decades with contingency reserve sharing pools and energy transactions. The EIM simply extends this concept through an automated imbalance market.

Based on our analysis, we conclude that full participation of all BAs would result in maximum benefit across the interconnection—as much as a 46% reduction in requirements for some reserve classes. Lesser participation levels (which include subregional implementations of the EIM) and several exclusions (BPA and Western) will still improve on the BAU case but will fail to achieve the maximum benefit of the full-participation scenario, especially for the nonparticipants.

Table 23 shows a summary of the reserve savings, comparing the footprint EIM and the subregional EIM with the BAU case. The subregional EIM implementation results in 10% less savings across the complete study footprint.

Table 23. Summary of EIM Benefits to Footprint and Subregional EIM Implementations

	BAU (MW)	Footprint EIM			Subregional EIM		
		EIM (MW)	Reduction Over BAU (MW)	% Savings	EIMs (MW)	Reduction Over BAU (MW)	% Savings
Total Regulation	1669	1076	592	35%	1250	419	25%
Spin	1230	669	561	46%	933	297	24%
Non-Spin	2460	1338	1122	46%	1865	594	24%
Total	5359	3083	2275	42%	4048	1311	24%

The participating BAs will capture 70% to 90% of the benefits of reduced reserves if BPA or WAPA are unable to participate, but the excluded BA will forgo a 44% (for WAPA) or 32% (for BPA) savings in a footprint EIM. We recognize there may be various institutional impediments to a full EIM implementation, but the results of our analysis suggest that potential participants should undertake a careful cost-benefit analysis to determine whether it may be economically efficient to implement institutional changes that can help move toward a full EIM implementation. Expanding the EIM to the full Western Interconnection may be possible in the future and would result in additional savings.

Realizing that our cost benefits are order-of-magnitude and depend on how the reserve obligations and deployment would be allocated under the EIM, our analysis points out some important insights. The reserve reduction, along with the reserve cost savings, depend on the level of market participation and the size of the footprint, along with the penetration of VG. Because the future build-out of wind power and solar power facilities is unknown, reliance on a single-point estimate of the EIM benefit may not provide a robust view of the potential benefit of the EIM.

Finally, we note that the proposed EIM does not consider coordinated unit commitment. We believe that, over time, participants will conclude that some form of coordinated commitment will achieve additional savings, although additional analysis would be needed to determine these impacts. Partial coordination of unit commitment may occur naturally as participants learn to anticipate what generation is likely to be available from other BAAs tomorrow through the EIM and then incorporate those expectations into their own unit commitment. Participants may engage in bilateral contracts to add certainty to those expectations. Firm transmission may be necessary to fully capture the benefits of coordinated unit commitment.

8 References

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Appendix A: Reserve Savings Data Tables

This appendix provides the source reserve savings data for the reserve values calculations referenced in this report. Table 11 provides the hourly prices used for value calculations in this report. Other price assumptions can be evaluated using these tables by multiplying the average hourly savings given by the assumed price for each service and then by 8760 to annualize. The total savings can be calculated as the sum of savings for regulation, spin, and non-spin categories.

Table 24 shows the average hourly megawatt reserve savings allocated to each BAA in the full EIM footprint. These values were calculated by applying the vector allocation method described in Section 4.3 to the participants of the EIM and subtracting the EIM allocated values from the before-EIM allocated values. These values where used to calculate the value data in Table 12.

Table 24. Average Hourly Reserve Savings for TEPPC Full EIM Case (MW)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	39	24	48	112
AVA	9	12	23	44
BCTC	11	0	0	12
BPA	78	85	169	342
CHPD	5	0	0	5
DOPD	4	0	0	4
EPE	8	1	2	11
GCPD	7	0	0	7
IID	35	45	90	172
IPC	17	14	28	59
LDWP	21	26	52	99
NEVP	33	26	52	113
NWE	32	37	73	142
PACE	40	63	126	229
PACW	14	15	30	58
PGE	13	18	36	68
PNM	37	41	81	160
PSCO	64	71	141	278
PSE	17	36	73	126
SCL	6	0	0	6
SMUD	12	4	8	23
SPP	12	9	18	38
SRP	20	9	19	48
TEP	23	10	20	54
TID	5	0	0	5
TPWR	3	0	0	3
WACM	22	14	27	63
WALC	14	2	5	21
WAUW	5	0	0	5

Table 25 shows the average reserve megawatt hourly savings for the Columbia Grid EIM case with full participation. These values were used to calculate the data in Table 13.

Table 25. Average Hourly Reserve Savings for Columbia Grid EIM Case

BAA	Regulation	Spin	Non-Spin	Total
AVA	12	8	16	36
BPA	17	8	17	41
CHPD	7	0	0	7
DOPD	5	0	0	5
GCPD	7	0	0	7
PSE	21	25	50	97
SCL	11	0	0	12
TPWR	7	0	0	7

Table 26 shows the average reserve megawatt hourly savings for the NTTG subregional EIM case with full participation. These values were used to calculate the data in Table 14.

Table 26. Average Hourly Reserve Savings for NTTG EIM Case

BAA	Regulation	Spin	Non-Spin	Total
IPC	15	12	23	50
NWE	24	23	46	94
PACE	19	20	39	81
PACW	10	14	28	53
PGE	15	20	41	76

Table 27 shows the average reserve megawatt hourly savings for the WestConnect subregional EIM case with full participation. These values were used to calculate the data in Table 15.

Table 27. Average Hourly Reserve Savings for WestConnect EIM Case

BAA	Regulation	Spin	Non-Spin	Total
AZPS	19	7	14	40
EPE	8	0	1	9
IID	32	42	84	161
NEVP	21	16	32	69
PNM	31	32	63	127
PSCO	40	31	61	134
SMUD	14	4	8	26
SPP	14	9	17	40
SRP	17	6	12	35
TEP	16	3	6	25
TID	5	0	0	5
WAPA	18	6	13	38

Table 28 shows the average reserve megawatt hourly savings for the TEPPC footprint EIM case without BPA participation. These values were used to calculate the data in Table 17.

Table 28. Average Hourly Reserve Savings for TEPPC EIM Case Without BPA (MW)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	34	11	23	67
AVA	9	11	22	42
BCTC	11	0	0	11
BPA	5	0	0	5
CHPD	4	0	0	4
DOPD	7	1	1	10
EPE	7	0	0	7
GCPD	35	40	79	157
IID	16	13	26	55
IPC	18	21	41	81
LDWP	30	18	35	83
NEVP	31	31	62	125
NWE	36	47	94	178
PACE	16	17	35	68
PACW	19	30	60	109
PGE	36	32	64	134
PNM	58	42	83	190
PSCO	19	36	71	126
PSE	6	0	0	6
SCL	11	3	7	21
SMUD	12	8	16	36
SPP	16	7	13	36
SRP	21	6	12	39
TEP	5	0	0	5
TID	3	0	0	3
TPWR	20	10	21	52
WACM	13	2	3	18
WALC	5	0	0	5

Table 29 shows average megawatt hourly savings for the TEPPC footprint EIM case without WAPA participation. These values were used to calculate the data in Table 18.

Table 29. Average Hourly Reserve Savings for TEPPC EIM Case Without WAPA (MW)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	39	23	46	109
AVA	8	11	21	41
BCTC	11	0	0	11
BPA	76	81	157	319
CHPD	5	0	0	5
DOPD	4	0	0	4
EPE	8	1	2	11
GCPD	7	0	0	7
IID	35	41	82	159
IPC	17	12	25	54
LDWP	21	22	45	89
NEVP	33	26	51	111
NWE	32	32	64	128
PACE	40	55	112	207
PACW	13	13	27	54
PGE	13	17	33	63
PNM	37	36	72	146
PSCO	65	62	129	262
PSE	17	33	65	114
SCL	5	0	0	6
SMUD	12	4	7	23
SPP	12	8	16	36
SRP	21	9	17	46
TEP	23	9	19	51
TID	5	0	0	5
TPWR	3	0	0	3

Table 30 shows the megawatt hourly savings for the EIM implementation if BPA and WAPA do not participate. These values were used to calculate the values in Table 19.

Table 30. Average Hourly Reserve Savings for TEPPC Full EIM Case Without BPA and WAPA (MW)

BAA	Regulation	Spin	Non-Spin	Total
AZPS	34	12	24	69
AVA	9	12	24	44
BCTC	10	0	0	11
CHPD	5	0	0	5
DOPD	4	0	0	4
EPE	7	1	2	10
GCPD	7	0	0	7
IID	35	42	85	166
IPC	16	14	29	59
LDWP	18	22	45	85
NEVP	30	18	35	82
NWE	31	35	69	136
PACE	36	53	106	195
PACW	15	19	37	71
PGE	19	32	65	117
PNM	36	36	72	145
PSCO	59	51	102	220
PSE	18	37	75	132
SCL	6	0	0	6
SMUD	11	4	7	23
SPP	12	9	17	38
SRP	17	7	15	39
TEP	21	6	12	39
TID	5	0	0	5
TPWR	3	0	0	3

Appendix B: VG Penetration by BAA

BAA	Load			Wind			Solar			Total VG			VG Penetration	
	Min (MW)	Avg (MW)	Max (MW)	Avg (MW)	Max (MW)	CF (%)	Avg (MW)	Max (MW)	CF (%)	Avg (MW)	Max (MW)	CF (%)	Avg (%)	Max (%)
AZPS	2550	4100	8410	58	173	34%	371	1293	29%	429	1464	29%	10%	46%
AVA	1041	1715	2882	105	323	32%	0	0	0%	105	323	32%	6%	28%
BCTC	5091	7194	11393	0	0	0%	0	0	0%	0	0	0%	0%	0%
BPA	4748	6577	10377	1909	6693	29%	0	0	0%	1909	6693	29%	29%	126%
CHPD	323	464	719	0	0	0%	0	0	0%	0	0	0%	0%	0%
DOPD	100	244	466	0	0	0%	0	0	0%	0	0	0%	0%	0%
EPE	794	1215	2135	0	0	0%	9	44	22%	9	44	22%	1%	4%
GCPD	352	592	877	0	0	0%	0	0	0%	0	0	0%	0%	0%
IID	231	537	1243	219	857	26%	0	0	0%	219	857	26%	47%	300%
IPC	1280	2233	4043	101	330	31%	0	0	0%	101	330	31%	5%	20%
LDWP	2171	3712	6778	210	585	36%	74	321	23%	285	848	34%	8%	25%
NEVP	1893	3224	6603	0	0	0%	281	835	34%	281	835	34%	8%	36%
NWE	864	1307	1875	298	833	36%	0	0	0%	298	833	36%	23%	82%
PACE	4685	6387	10548	814	1973	41%	0	0	0%	814	1973	41%	13%	38%
PACW	1311	2361	3904	174	630	28%	2	9	18%	176	635	28%	8%	42%
PGE	1488	2681	4294	230	805	29%	2	11	18%	232	813	29%	9%	47%
PNM	1346	1846	2886	269	749	36%	76	257	30%	345	1001	35%	19%	62%
PSCO	3859	5651	9339	886	2880	31%	242	1000	24%	1128	3782	30%	20%	74%
PSE	1829	3010	5365	345	1067	32%	0	0	0%	345	1067	32%	12%	54%
SCL	766	1243	1924	0	0	0%	0	0	0%	0	0	0%	0%	0%
SMUD	1305	2111	4802	19	104	18%	0	0	0%	19	104	18%	1%	6%
SPP	1060	1453	2155	40	150	26%	0	0	0%	40	150	26%	3%	13%
SRP	2610	4599	8800	38	127	30%	62	165	38%	100	290	35%	2%	8%
TEP	1123	1877	3677	12	50	25%	106	494	22%	119	543	22%	6%	38%
TID	215	358	793	0	0	0%	0	0	0%	0	0	0%	0%	0%
TPWR	352	618	1035	0	0	0%	0	0	0%	0	0	0%	0%	0%
WACM	2586	3388	4678	131	420	31%	6	30	20%	137	444	31%	4%	15%
WALC	409	860	1591	0	0	0%	17	87	20%	17	87	20%	2%	14%
WAUW	22	72	128	0	0	0%	0	0	0%	0	0	0%	0%	0%

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Sources of grid reliability services☆

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ABSTRACT

The bulk power system is undergoing a digital revolution. With the recent and continuing growth of inverter-based generation, primarily wind and solar energy, the industry has begun exploring the implication of these new resources on power system reliability and resilience. This paper provides an overview and description of grid services that key resource types are able to provide, showing that new resources can provide many of the required grid reliability services.

1. Introduction

The bulk power system (BPS) is undergoing a digital revolution. With the recent and continuing growth of inverter-based generation, largely from wind and solar energy, the power system industry has begun exploring the implication of high levels of wind and solar energy on power system reliability and resilience. In 2014, the North American Reliability Corporation (NERC), the recognized reliability authority on the BPS, formed the Essential Reliability Services Task Force (ERSTF).[1] The objective of the ERSTF was to examine the implication of the changing resource mix, including the trends toward use of less coal, more natural gas, more demand response, and higher levels of variable energy resources (VER) with regard to the provision of essential reliability services (ERS). This task force changed to a working group, but its focus has remained the same.

Recently, the Federal Energy Regulatory Commission opened a proceeding on grid resilience, terminating the United States Department of Energy Notice of Proposed Rulemaking that proposed new market rules for resources capable of stockpiling fuel supplies. At the heart of the U.S. DOE concern was the changing nature of the BPS power supply.

As these and other efforts have moved forward, it has become apparent that there is no widespread understanding of the grid services that can be provided by alternative resource types. In some cases, there were unfounded claims that traditional resources could provide all of the required ERS and that new resources cannot. However, it is difficult to make such generalizations, and so the objective of this paper is to provide an overview and description of grid services that key resource types are able to provide. We begin with a brief summary of these services, and base this discussion on the emerging expert work of the NERC ERSWG (and ERSTF before that).

2. What services are important, and how can they be provided?[2]

There are several prerequisites for a resource to provide a grid service: (1) physical capability of providing the service, (2) be in an appropriate operating state to provide services when needed, (3) have an economic incentive, and/or no economic disincentive, to provide the service.[3]

Reliable grid operation depends on ensuring that the aggregate demand and supply are matched at all times. To accomplish this balance, grid operations have various processes that operate on multiple time scales so that the needed equipment can be in place and available when needed. Some of these grid services, such as primary frequency response, operate in very fast time scales and help to ensure that system frequency is held at nominal values (within small allowable

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[1] https://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.

[2] NERC Essential Reliability Services Concept Paper. Available at https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf#search=erstf.

[3] The ownership of a resource can significantly affect its deployment. Resources owned by the grid operator can be deployed whenever they are needed to support reliability. Other resources may be available via a tariff or other operational agreement, with some form of payment for service. It is important that institutional constraints don't drive physical capability/response constraints that can compromise reliability (or economics, when a more expensive solution is needed).

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differences). Other grid services such as frequency regulation and ramping, operate more slowly, but are also used to maintain system balance. These services are not provided uniformly; a resource may respond quickly or slowly, be capable of providing the given service for long or short time periods, be able to provide a limited quantity of a given service, or be able to provide the service only if the resource is in certain state(s).

During normal grid operations, supply and demand must be kept in balance.

The discussion below focuses on selected key resources, including coal-fired, gas-fired, nuclear, hydro, wind, and solar generation. Additionally, we provide information about generic battery storage, and some discussion of emerging demand-response. The objective of this paper is to provide a short, yet comprehensive, summary of the grid services that can be provided from key resource types, helping to inform the wide range of decision-makers regarding the potential source of these important grid services.

2.1. *Grid reliability services*

The ability of different resources to provide grid services is being driven by a "digital revolution" that is occurring in the electric power sector.[4] Wind, solar, and battery storage are electronically coupled to the power system. Because the power electronics devices that couple DC to AC power offer very fast response, it is now possible to use software to control how the resource interacts with the power system, subject to physical constraints. This has profound implications on how current and future wind, solar, and battery resources will provide grid services, and may also have a significant impact on the way that some grid services are defined, offered, and procured (Fig. 1).

2.2. *Grid services during normal operation*

Demand and supply must be balanced at all times. Grid operators carry out an economic dispatch function, normally every 5 min in most of the U.S., that instructs resources to generate a given level of output based on an economic optimization function. Demand fluctuates between these dispatch intervals, and therefore the frequency regulation service is used to ensure balance between successive dispatches. Computers monitor the grid frequency/balance and send signals to regulating resources to increase or decrease their output, nominally every 4 s; the process is often called automatic generation control (AGC). This frequency regulation service compensates for the constant, small variations in demand and supply. This is illustrated in Fig. 2.[5] The upper part of the figure contains a table that briefly describes the differences between the need for frequency regulation services and the need for flexibility/dispatch. The graph shows demand fluctuations over a one-month period in blue, and the daily demand cycles are apparent. This represents the load-following changes in demand, which are met by units on economic dispatch. Although it is not discernible in the blue trace on the graph, there are many very small changes in the load. These are calculated separately and shown on the graph by the red trace, which has a separate scale on the right. This red trace represents the frequency regulation needs of the system, provided by AGC.

Demand response

Demand response is not a single technology; rather, it is a combination of technologies that allow the customer to alter consumption patterns, with the possibility of selling services to the grid operator via established electricity markets. In principle, DR can deliver several services to the grid: (1) energy efficiency, which reduces electricity consumption and often reduces peak demand, (2) price-responsive load, which can shift usage from high-value time periods to low-value time periods, (3) peak shaving, which does not reduce total energy consumed but shifts some demand to off-peak periods, (4) reliability response that includes a fast frequency response that can respond quickly to system contingency, (5) frequency regulation service. Although there is a very large technical and economic potential for DR, it has generally been slow to develop in the U.S. With recent improvements in electricity market design, communication, instrumentation, and control technology, DR appears to be emerging and may in the future capture a significant market presence.

Currently there is interest in developing new DR products that illustrate its forward potential. PJM has undertaken a pilot program to help develop and adopt a regulation signal that could be used to help integrate grid-scale batteries, flywheels, and water heaters.[a] Mosaic Power utilizes a fleet of hot water heaters to supply frequency regulation into the PJM market. [a] There are recent grid interconnected water heating (GIWG) pilots at Portland General Electric (PGE), Arizona Public Service (APS), and Green Mountain Power (GMP).[a] Programs like this depend on the diversity of demand coupled with the thermal storage capability residing in the hot water heater so that a response fast enough to provide frequency regulation can be obtained. Because DR encompasses a wide variety of resources, pooling these alternative responses can result in the provision of grid services that is not necessarily apparent. Multiple individual resources, such as compressors, aerators, grinders, HVAC, and others can be combined to provide accurate frequency regulation signals, as shown in Fig. 1.[a] In ERCOT, DR provides up to 50% of the required contingency reserve.

Demand response market development and technology are poised to change rapidly, and it is not clear how much of this capability will be developed. DR can provide frequency regulation, may be able to shift loads from peak to off-peak, and may be able to function in a short-term dispatch market. For the discussion that follows, we include DR capabilities as they appear to be effective today; however, this is a rapidly changing technology/market.

[a] Ela, E; Milligan, M.; Kirby, B. (2011) Operating Reserves and Variable Generation. Available at https://www.nrel.gov/docs/fy11osti/51978.pdf page 46.

Economic dispatch has two components of grid services that will be discussed below: (1) flexibility and (2) ramping. Together, dispatch and regulation services are key to preserving system balance. They are used in routine operations, and as will be seen later, are key components of grid recovery after a large disturbance.

2.2.1. *Reactive power and voltage control*

2.2.1.1. Description. The supply of reactive power provides the ability to regulate voltage, which in turn prevents equipment damage from voltage that is outside of nominal design limits. As with real power, maintaining an active reserve for reactive power helps promote system reliability and resilience.

[4] Ahlstrom (2018) "Digital Transformation of Power Systems: Implications on Reliability, Operations, and Markets." IEEE Transmission and Distribution Conference and Exposition. April 17-19. Denver, CO.

[5] Adapted from Shiu, Milligan, Kirby, Jackson (2005) California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis: Multi-year Analysis Results and Recommendations. Available at http://www.energy.ca.gov/2006publications/CEC-500-2006-024/CEC-500-2006-024.PDF.

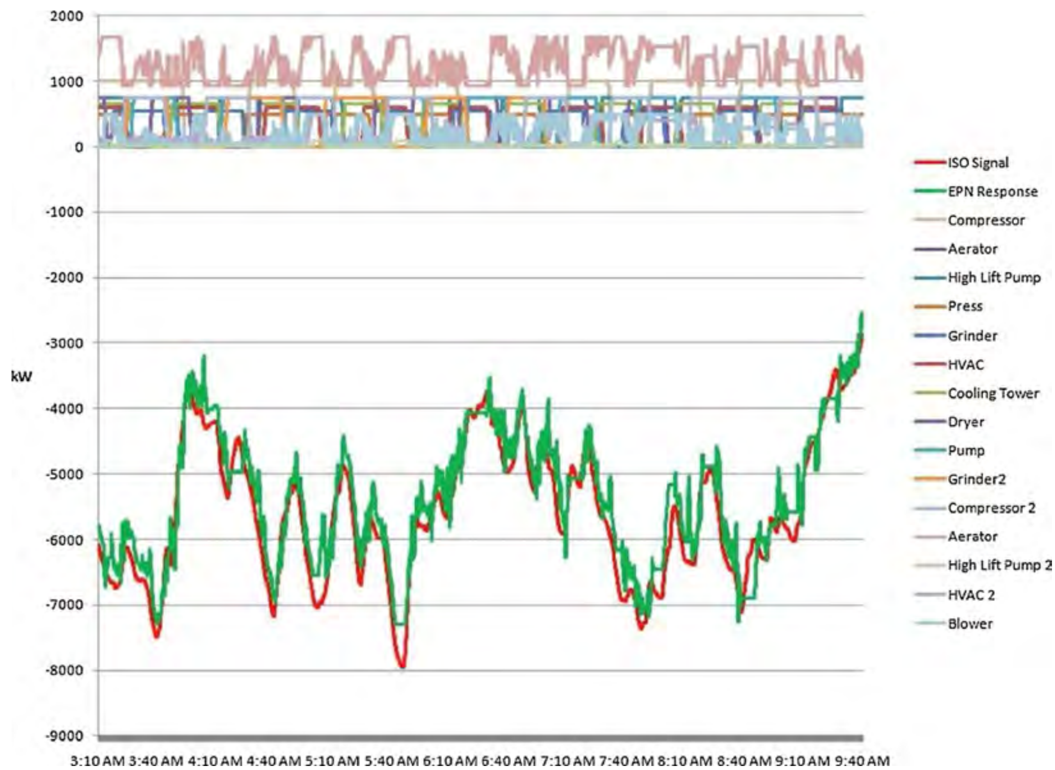

Fig. 1. Example of DR aggregation to provide frequency regulation.

2.2.1.2. Resources that can provide reactive and voltage control. Large thermal plants—coal, nuclear, and natural gas—can provide this service if they are generating real power, as can hydro power. Wind and solar plants can provide reactive and voltage control though power electronics-based controls, and they can therefore supply the service even if they are not generating.[6] Battery with power electronics can provide this service similarly to wind/solar because the connection characteristic is the same.[7]

2.2.2. Voltage/voltage ride-through

2.2.2.1. Description. Devices that are interconnected into the BPS are designed to operate at nominal voltages within a range of design limits. A grid disturbance, which may be caused by a transmission line or generator tripping offline or other faults, may cause the voltage to vary so that other resources may go offline. In many cases, the original fault does not in itself threaten grid stability; however, if other resources or loads trip offline, the cascading disconnections may, in extreme cases and if not arrested, cause a blackout. To prevent this type of cascading outage, generators can be designed to ride through voltage fluctuations within a given limit.

2.2.2.2. Resources that can provide voltage ride-through. Wind generators are required to ride through voltage faults[8] and can ride through these events better than most other generators. Solar plants are physically capable of riding through voltage disturbances, but until the recent FERC Order 828, were not always required do so. Order 828 requires that newly connected solar facilities subject to the Small Generator Interconnection Agreement (SGIA) must ride thru abnormal frequency and voltage events without disconnecting.

For many years distributed solar resources were required to disconnect and remain offline after a voltage event. Recent changes in the IEEE 1547 requirement will now require new DER resources to ride through the event. Because batteries are connected to the grid via a converter like wind and solar, they can, with proper controls, ride through a voltage excursion.[9] Presumably, they would also be subject to the same ride-through requirements as solar plants.

Not all resources can provide this service.[10] Gas-fired generation is often taken offline by grid disturbances, and therefore has not always provided substantial voltage ride-through.[11] Similarly, coal plants often go offline during voltage faults because some combination of the generator or critical plant equipment such as pumps and conveyor belts cannot ride through the disturbance.[12]

Nuclear plants can go offline for similar reasons.[13] The inability of

[6] NERC (2009) Special Report: Accommodating High Levels of Variable Generation. Available at https://www.nerc.com/files/ivgtf_report_041609.pdf.

[7] Tan, J., Zhang, Y. "Coordinated Control Strategy of a Battery Energy Storage System to Support a Wind Power Plant Providing Multi-Timescale Frequency Ancillary Services." IEEE Transactions on Sustainable Energy, Vol 8, No. 3, July 2017.

[8] FERC Order 661 https://www.ferc.gov/CalendarFiles/20051212171744-RM05-4-001.pdf.

[9] P1547/D7.3, Dec 2017 - IEEE Approved Draft Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. Available at https://ieeexplore.ieee.org/document/8233447/.

[10] I describe voltage ride-through as a service, but I note that this is not a NERC requirement. Instead, NERC's PRC-024 refers to the setting of voltage protection relays.

[11] TRC Solutions (2015) Revisions to NERC PRC Standards Have Significant Implications for Utility Compliance Programs. Available at https://www.trcsolutions.com/writable/images/Regulatory-Update-NERC-PRC-Standards-Changes-Nov-2015-FINAL.pdf.

[12] NERC (2015) Standard PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings. Available at https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-024-2.pdf.

[13] Electric Light and Power (2015) Both Calvert Cliffs nuclear units go offline due to D.C. area disruption. Available at https://www.elp.com/articles/2015/

some large generators to ride through a disturbance contributed to recent blackouts in Washington, D.C. and Florida.[14]

2.3. Grid services responding to contingency events

To describe several of the grid services it is helpful to refer to a graphic representation of the various types of response (Fig. 3). Our discussion centers around the key time periods and their relevant responses starting with the contingency event and ending with frequency recovery:

1 Contingency event occurs. This is often a large generating unit or transmission line[15] that disconnects unexpectedly as a result of mechanical or electrical failure
2 Frequency begins to drop from its nominal rate of 60 Hz. The rate of decline is a function of system inertia—the rotating mass of large generators. This inertial response can slow the rate of change in frequency (RoCof) but cannot by itself arrest the decline. Combined with resources that provide fast frequency response (FFR), the frequency decline is slowed, and then arrested by FFR resources. In the diagram this point of arresting is identified as the "nadir" of the frequency drop. It is important that the nadir occurs before frequency falls far enough to trigger under-frequency load shedding events (UFLS), which has the potential to exacerbate the situation. FFR can be provided by several resource types, including wind/solar and storage. Fig. 3 shows this as the "arresting period."
3 Primary frequency response (PFR) helps improve frequency, and occurs when governors respond to the frequency decline by speeding up, thereby helping to increase frequency towards its nominal value. Power electronics on wind/solar and storage can often contribute to PFR. This is shown in Fig. 3 as the "rebound period."
4 A combination of frequency regulation (automatic regulation control, AGC) and economic dispatch increase power output (or reduce demand, or both) so that the frequency reaches its pre-disturbance level. This is shown in the graph as the "recovery period."

Grid reliability services contribute to (a) helping to arrest the initial frequency drop, (b) contribute to the rebound period, increasing frequency after the nadir occurs, (c) inject energy during the recovery period, helping to restore frequency to pre-disturbance levels. These are discussed further below.[16]

2.3.1. Arresting frequency drop: inertial and fast frequency response

2.3.1.1. Description. Inertial response comes from large rotating machines, and it is an attribute of the entire interconnection.[17] Immediately after a disturbance, system inertial response sets the rate of decline of frequency; by itself, it is not capable of arresting frequency. FFR injects power into the grid, which contributes to slowing the frequency decline, and then arresting the decline. Thus the frequency drop is arrested by a combination of inertial response and FFR. The action of FFR occurs prior to the frequency nadir.

2.3.1.2. Resources that can provide this service. Inertial response is provided by large rotating generators, such as coal, nuclear, or gas. FFR can be supplied by coal and gas plants, and it is not provided by nuclear plants because governor response has been disabled in the U.S. FFR can be supplied by VER and batteries that have sufficient controls and incentives to do so, and if they are operating in a partially curtailed state.[18],[19] In many cases this FFR is much faster than that provided by thermal generation and can have a beneficial impact on the initial rate of frequency decline immediately after a disturbance.[20] In ERCOT, DR provides up to one half of the contingency response obligation for the market, and thus DR can contribute to arresting the frequency.

2.3.2. Primary frequency response

2.3.2.1. Description. Primary frequency response (PFR) is an automatic response to frequency decline, and it begins within seconds following a disturbance. Governors respond to the frequency drop by increasing power output.

2.3.2.2. Resources that can provide this service. PFR can be provided by natural gas, coal, and nuclear plants although in practice approximately 10% of these plants actually provide this response.[21] Not all resources respond at the same rate: some resources can respond more quickly than others. In some cases, a higher response is required before the frequency drop is arrested. The level and speed required for PFR to arrest the frequency drop can also be influenced by some of the attributes of AGC. "Improvements in the full AGC control loop of the generating resource, which accounts for the expected Primary Frequency Response, have improved the delivery of quality Primary Frequency Response while minimizing secondary control actions of generators. Some of these actions can provide quick improvement in delivery of Primary Frequency Response."[22] PFR is generally slower than FFR.

2.3.3. Frequency regulation

2.3.3.1. Description. Generation that responds to computer signals

(*footnote continued*)
04/both-calvert-cliffs-nuclear-units-go-offline-due-to-d-c-area-disruption.html.

[14] Reuters (2008) FPL cites human error as cause of Florida blackout. Available at https://www.reuters.com/article/us-florida-blackout/fpl-cites-human-error-as-cause-of-florida-blackout-idUSWNAS318320080229.

[15] As noted early, most transmission line outages are not contingency events, and therefore have different impacts on the grid than the loss of a large resource. Key reliability services will likely still be required, although at a lower level than the loss of a large resource.

[16] Special protection systems (SPS), also known as remedial action schemes (RAS) can also be considered as reliability services. RASs detect abnormal system conditions, and respond via pre-determined actions so that operational reliability is maintained.

[17] Traditionally, the fastest form of frequency response is the inertial response of large, rotating machines. In the past few years, power electronics have made it possible for wind and solar power to provide an extremely fast frequency response that operates in a similar time scale as inertial response. We distinguish these as inertial response and fast frequency response, FFR, respectively.

[18] Gevorgian and Zhang (2016) "Wind Generation Participation in Power System Frequency Response," 15th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, Vienna, Austria. Available at https://www.nrel.gov/docs/fy17osti/67287.pdf.

[19] Milligan et al. (2015) Alternatives No More. IEEE Power and Energy Magazine, October. Available at http://iiesi.org/assets/pdfs/ieee-power-energy-mag-2015.pdf.

[20] Over-frequency events, such as loss of load, can be provided by VER anytime they are generating power. In future power systems with limited inertial response, it is likely that FFR, along with suitable controls, will be able to replace much of the potentially retiring inertial response. See for example https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/2017-03-10-GE-FFR-Advisory-Report-Final—2017-3-9.pdf.

[21] Comments of the North American Electric Reliability Corporation Following September 23 Frequency Response Technical Conference. Docket Nos. RM06-16-010 and RM06-16-011 available at https://www.nerc.com/files/FinalFile_Comments_Resp_to_Sept_Freq_Resp_Tech_Conf.pdf. Also see Miller et al (2013) "Eastern Frequency Response Study" shows the impact of alternative levels of participation in frequency response by large thermal plants. Available at https://www.nrel.gov/docs/fy13osti/58077.pdf.

[22] See NERC: Frequency Response Standard Background Document, Nov. 2012. Available at https://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/Bal-003-1_Background_Document_Clean_20121130.pdf

	Regulation	Load Following
Patterns	Random, uncorrelated	Largely correlated
Generator control	Requires AGC	Economic dispatch
Maximum swing (MW)	Relatively small	10-20 times more
Ramp rate (MW/minute)	5-10 times more	Relatively slow
Sign changes	20-50 times more	Relatively few

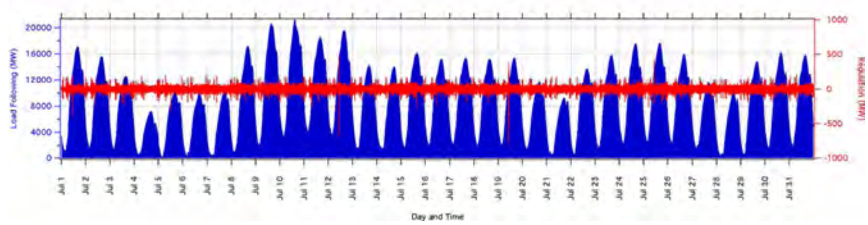

Fig. 2. Relationship between frequency regulation ("regulation") and economic dispatch (load following).

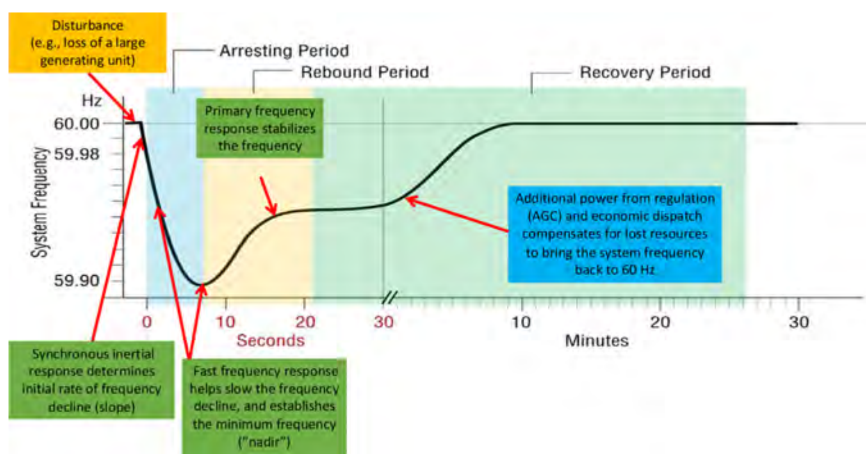

Fig. 3. Grid services immediately following a contingency event.

Table 1
Grid Services Summary.

	Inverter-Based			Synchronous				Demand Response
	Wind	Solar PV	Storage/ Battery	Hydro	Natural Gas	Coal	Nuclear	Demand Response
Disturbance ride-through	Excellent	Very Good	Very Good	Excellent	Good	Good	Good	Good
Reactive and Voltage Support	Excellent	Excellent	Excellent	Excellent	Excellent	Excellent	Excellent	Limited
Slow and arrest frequency decline (arresting period)	Very Good	Very Good	Very Good	Very Good	Good	Good	Limited	Good
Stabilize frequency (rebound period)	Very Good	Very Good	Very Good	Very Good	Excellent	Limited	Limited	Good
Restore frequency (recovery period)	Good	Good	Good	Excellent	Excellent	Limited	Incapable	Good
Frequency Regulation (AGC)	Very Good	Very Good	Excellent	Excellent	Excellent	Limited	Incapable	Excellent
Dispatchability/Flexibility	Good	Good	Excellent	Excellent	Very Good	Limited	Incapable	Good

These services also contribute to frequency restoration, but are also considered essential reliability services on their own.

Excellent Very Good Good Limited Incapable

(automatic generation control, AGC), commonly at intervals of one to four seconds, to ensure frequency is in nominal range. AGC service is utilized at all times, but it is also useful during the recovery period after a contingency event (see above). It is a slower response than FFR and PFR.

2.3.3.2. Resources that can provide frequency regulation. Although the system needs to have access to up-regulation and down-regulation, individual resources can provide either, or both of these responses. A resource can provide down-regulation when it is operating above minimum output, and it can provide up-regulation and down regulation when it is operating between min-gen and max-gen with sufficient foot room and/or head room to provide service. Wind and solar resources are no different: they can provide upward frequency regulation only if (a) they are "pre-curtailed," running at less than maximum output for the given wind/solar fuel input, and (b) only if there is sufficient wind/sun for the resource to respond.[23] They can provide downward regulation whenever they are producing power. Obtaining this service from variable energy resources (VER), such as wind and solar power, may be costly because a more expensive resource from the dispatch stack must be called upon to make up for the energy lost by the VER providing frequency regulation. Batteries can supply frequency regulation if the state of charge is sufficient, or if charging is in process during the time the services is called upon.[24] Gas generators can generally provide this service efficiently and accurately. Nuclear plants in the U.S. do not provide this service, whereas coal plants can do so, but often do not have the capability for accurate response.[25] [26]Hydro generation and DR can also provide this service.

2.3.4. *Flexibility/Dispatch*

2.3.4.1. Description. Although several definitions of flexibility have emerged, they generally describe the ability of the resource—or portfolio of resources—to have the ability to react to changes in the power system, both anticipated and unanticipated.[27] Flexibility that is inherent in a particular resource depends on its design objectives and operational modes, along with the type of fuel it uses.

2.3.4.2. Resources that can provide this service. Controllable hydro plants, some combined-cycle gas, aero-derivative gas turbines, and reciprocating engines are very flexible. Some plants that are somewhat inflexible can be made more flexible by "strategic modifications, proactive inspections and training programs, among other operational changes to accommodate cycling, can minimize the extent of damage and optimize the cost of maintenance."[28] Wind and solar plants can easily provide this service in a downward direction if they are generating, and can perform very quickly and accurately. They can also provide upward ramping if they are operated in a pre-curtailed mode. Although wind and solar have very flexible technological attributes, it may be more economic to obtain this flexibility from other resources.

2.3.5. *Ramping/ramping reserve*

2.3.5.1. Description. Ramping—changing the output of a generator or other resource in a given time period—has been identified as an essential reliability service by NERC[29] and is receiving renewed attention following CAISO's adoption of it as a market-based product, and MISO's ramp capability product development.[30] Ramping is an inherent part of power system operation because resources must change their output to match fluctuating demand. As the BPS evolves to higher levels of VER, additional ramping will be needed to maintain system balance. Although some RTOs/ISOs have developed ramping products, others are able to utilize the fast, 5-minute economic dispatch to find sufficient flexibility in the operational time frame. Without ramping products, inflexible resources may be rewarded for their inflexibility if they are paid the market-clearing energy price during ramp-constrained periods when combustion turbines (or other costly resources) are on the margin.[31] Ramp products, which may be in fact ramping reserve products (holding back some capacity so that it can be ramped up/down if needed) can separate the ramping service from the energy product, providing incentive to flexible resources that can ramp. There is some evidence that a look-ahead dispatch that locks in advisory prices may result in the same dispatch and revenue as an energy market with ramp product.[32]

2.3.5.2. Resources that can provide ramping/ramping reserve. Wind and solar plants can both provide very fast and accurate dispatch/ramping response. However, this may be costly to the system because these plants typically have the lowest marginal cost for producing energy and therefore incur the largest lost opportunity cost if they are backed down to retain headroom for ramping, so may not be utilized often. Most, but not all, natural gas generators have the potential to ramp and are often the resource of choice to do this because they have reasonably good flexibility and are often marginal units in the dispatch stack. Many coal plants have limited ramping capability because of a combination of thermal inertia, operating practice, and design, and therefore may have difficulty ramping as quickly as needed in some situations. Nuclear plants do not provide ramping service in the U.S. because of a combination of regulations, economics, and technical challenges, but can be more flexible in other countries.[33] Batteries can ramp up or down very quickly, depending on the state of charge. Controllable hydro power can normally ramp quickly, but it may be subject to water flow constraints or other regulations that may inhibit this response[34]. DR can potentially provide this service, but it may be limited in the energy component that it can provide.

2.3.6. *Other facets of flexibility*

2.3.6.1. Description. Although resource flexibility is often thought of as fast-ramping, there are additional flexibility components:

(a) Fast startup time: ability to move from non-operational state to operational state.

[23] ERCOT: Demonstration of PFR Improvement September 2017. ERCOT Operations Planning. https://www.pjm.com/-/media/committees-groups/task-forces/pfrstf/20171009/20171009-item-04-ercot-frequency-response-improvements.ashx.

[24] Battery-supplied regulation does not require up-down charging, but can also be provided by variable/intermittent charging or discharging, separately.

[25] Chen, Leonard, Keyser, Gardner, "Development of Performance-Based Two-Part Regulating Reserve Compensation on MISO Energy and Ancillary Service Market. IEEE Transactions on Power Systems, Vol 30, 1, Jan. 2015.

[26] Examples can be found in Milligan M, et al., Integration of Variable Generation, Cost-Causation, and Integration Costs Electr. J. (2011), doi:https://doi.org/10.1016/j.tej.2011.10.011, and in Milligan et al. (2011) Cost-Causation and Integration Cost Analysis for Variable Generation, NREL. Available at https://www.nrel.gov/docs/fy11osti/51860.pdf.

[27] Examples include Cochran et al. (2014) Flexibility in 21st Century Power Systems. Clean Energy Ministerial and National Renewable Energy Laboratory. Available at https://www.nrel.gov/docs/fy14osti/61721.pdf, and Milligan et al. (2015) Advancing System Flexibility for High Penetration Renewable Integration. NREL. Available at https://www.nrel.gov/docs/fy16osti/64864.pdf.

[28] Cochran et al. (2014) Flexible Coal: Evolution from Baseload to Peaking Plant. NREL. Available at https://www.nrel.gov/docs/fy14osti/60575.pdf.

[29] NERC ERSTF ibid.

[30] MISO (2016) Ramp Capability Modeling in MISO Dispatch and Pricing. Presented at FERC Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency through Improved Software, June 27-29. Available at https://www.ferc.gov/CalendarFiles/20160629114652-1%20-%2020160621%20FERC%20Technical%20Conference_MISO%20Ramp%20Product.pdf.

[31] Milligan, M., Kirby, B. (2010) Market Characteristics for Efficient Integration of Variable Generation in the Western Interconnection. NREL Technical Report. P 17. https://www.nrel.gov/docs/fy10osti/48192.pdf.

[32] Ela, E.; O'Malley, M. (2016) Scheduling and Pricing for Expected Ramp Capability in Real-Time Power Markets. IEEE Transactions on Power Systems, Volume: 31, Issue: 3, May.

[33] Utility Dive (2016), "How market forces are pushing utilities to operate nuclear plants more flexibly." Oct. Available at https://www.utilitydive.com/news/how-market-forces-are-pushing-utilities-to-operate-nuclear-plants-more-flex/427496/.

[34] U.S. Department of Energy Hydropower Vision: A New Vision for United States Hydropower. https://www.energy.gov/eere/water/articles/hydropower-vision-new-chapter-america-s-1st-renewable-electricity-source.

(b) Fast shutdown time: ability to go off-line; may be to a cold state or warm state
(c) short min up/down times: Minimum length of time that the plant must stay in an operational state before being taken offline, or minimum length of time that a plant must be in a non-operational state before it can be started again.
(d) Minimum stable generation level: The minimum output level that the plant can sustain, often expressed as a percentage of rated power. This is also an indicator of the plant's operating range: the difference between rated capacity and minimum stable generation. The ramp rate measures how quickly a resource can move across its range of output.

2.3.6.2. Resources that can provide other facets of flexibility. Coal, nuclear, and some gas plants generally have slow startup and shutdown times, and relatively long minimum uptimes and downtimes. Nuclear plants in the U.S. do not cycle or ramp, and therefore have undemonstrated minimum generation levels that are significantly below rated power.

Coal plants' minimum generation levels are dependent in part on plant design, but they are often in the 65–75% of rated capacity range. The high minimum generation constraints limit flexibility and limit the ability to efficiently utilize wind and solar energy.[35] This inflexibility causes more wind and solar energy to be curtailed. Thermal plant startup and shutdown times are generally long, as are minimum uptime and downtime.

Some gas plants have similar flexibility attributes as some coal plants. However, newer combined-cycle gas plants can be quite flexible, and some can be operated either in combined-cycle mode or single-cycle mode, providing additional flexibility compared to only combined-cycle mode operation. Peaking plants that use aero-derivative gas turbines or reciprocating engines can be very flexible, with minimum generation levels that may approach as little as 1% of rated capacity, short up/down minimums, fast starting and shutdown, and fast ramp rates.[36]

Hydro plants can be very flexible from a technical point of view. Their main constraints, if any, relate to a combination of water supply and water regulations, including water delivery schedules and minimum/maximum flow constraints to mitigate environmental damage. Thus, there is no one-size-fits-all characterization; however, this resource has the potential to be very flexible.[37]

Wind and solar plants can ramp very quickly in both directions, depending on the generators' current state, and can both achieve a very low minimum generation level even when the wind is blowing or the sun is shining.

Batteries have similar characteristics as wind and solar, but subject to the battery's state of charge.

DR does not have specific minimum up/down times in the same sense as conventional generators. However, there are limits as to how much/how often a DR resource may be called upon, and this may provide a similar constraint. However, the quick potential response of DR makes it a valuable contributor to ramping capability over short time frames.

3. Grid services summary

All resources discussed herein can provide at least some reliability services. The speed of provision, depth of provision, and machine type and state will all play a role in determining the physical capability of each resource type. Market and reliability rules may limit response in some cases; however, rules should be revised if that is the case. Table 1 summarizes the discussion of the reliability service capabilities from different resources.

3.1. Recommended policy directions

As this summary shows there are many sources of grid services. As technology changes, it becomes important to avoid placing unintentional limits that constrain the types of resources that can provide it. Any resource that is capable of providing a grid service should not be prevented by reliability rules or market rules from doing so. Instead of binding technology type with grid service, the latter should be carefully defined so that individual resources can demonstrate their ability to provide the relevant service(s). Not all resources will perform equally, and therefore grid service definitions should be constructed in such a way that resources can be distinguished; this also makes it possible for grid experts to assess whether there is a sufficient level of reliability services to avoid problems. Specific attributes may include (a) speed of response and (b) depth of response; other characteristics should be investigated as appropriate.

After rigorous definitions of these various services is put in place, a certifying process could then be used so that new resource types (or configurations) could then be recognized as valid contributors to BPS reliability.

Michael Milligan recently retired as Principal Researcher at the National Renewable Energy Laboratory, with more than 30 years' experience in power systems and wind/solar power integration. He has authored/coauthored more than 220 articles and reports, and has led/participated in numerous North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and IEEE Power and Energy Society working groups and committees. His work influenced the formation of the Energy Imbalance Market in the Western Interconnection, and the Pilot Project on 05-Minute Scheduling in India. Formerly a key contributor to International Energy Agency Task 25, he is now an independent power system consultant.

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Alternatives No More

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Wind and Solar Power Are Mainstays of a Clean, Reliable, Affordable Grid

By Michael Milligan, Bethany Frew, Brendan Kirby, Matt Schuerger, Kara Clark, Debbie Lew, Paul Denholm, Bob Zavadil, Mark O'Malley, and Bruce Tsuchida

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WIND AND SOLAR PHOTOVOLTAIC (PV) GENERATION, no longer alternative energy sources, have grown rapidly in the United States and worldwide during the last decade. This rapid growth is due to significantly improved technology (power electronics, controls, and physical attributes such as tower heights and blades), plummeting costs, and vast advancements in understanding how to plan and operate reliable regional power systems that have high penetrations of variable renewable resources. Wind and PVs have become mainstays of a clean, reliable, affordable electric grid.

The capital costs for installed wind and PV power plants have dropped dramatically in recent years; independent sources report wind energy as a least-cost energy resource **<AU: resource for what?>,** and at least one state has selected PVs as a least-cost capacity resource **<AU: resource for what?>**. At the same time, this fuel input is cost free, and energy from these generation sources has nearly zero marginal cost.

Wind and PV generation, known as variable generation (VG), are primarily energy sources because the "fuel" input to these systems cannot be controlled. VG resources, however, can contribute a fraction of their nameplate capacity toward planning reserves, and their connection to the power system through inverter-based power electronics allows for a fast, accurate control of their output.

The capabilities of wind and PV generation have evolved significantly during the past decade, and these resources can contribute to the economics and reliability of the power system. As the penetration of VG increases relative to the amount of conventional generation and peak demand, there is potential for these operational capabilities to grow in value and provide the types of services traditionally delivered by conventional synchronous machines.

The range of services is divided into two main categories. The first, system balance, concerns the operation of the power system under normal conditions, when constantly changing electric demand, potentially augmented by VG output variability, must be compensated by adjustments in net resource output. Relevant topics include balancing net load (load minus VG generation), regulation, and economic dispatch. Although maintaining this balance often involves reliability-related aspects, such as maintaining the interconnection frequency within prescribed limits, the primary concern is the economic operation of the power system.

The second category includes services that are critical to maintaining the operational security of the bulk power system during and after major disturbances. In this category, the economics of power system operation take a backseat to reliability. Relevant issues include frequency response, system inertia, and frequency and voltage ride-through capabilities.

VG was initially considered **<AU: considered for what?>** to increase the power system operator's challenges in both of these categories. Technological advancements are now providing some power system operators with additional tools to maximize the delivery of renewable energy while reducing system operations cost and enhancing system reliability and stability, in some ways even better than conventional generators. Numerous studies, new advanced analysis tools, and the growing level of experience with VG on the power system are all showing that wind and PVs are no longer constrained by many physical limitations. This article addresses frequently cited misperceptions of wind and solar power by focusing on the capabilities that modern wind turbines and PV systems can provide to both the balance and security of the bulk power system. As such, this article provides an update to 2009 article in this magazine, "Wind Power Myths Debunked," by describing the recent development of advanced features of wind and PV power generation that can provide many ancillary services that were not envisioned several years ago. When properly incentivized, VG can contribute to system balance and control.

VG Can Contribute to System Balancing Needs

Two of the primary balancing functions are automatic generation control (AGC) or AGC (regulation) and economic dispatch.

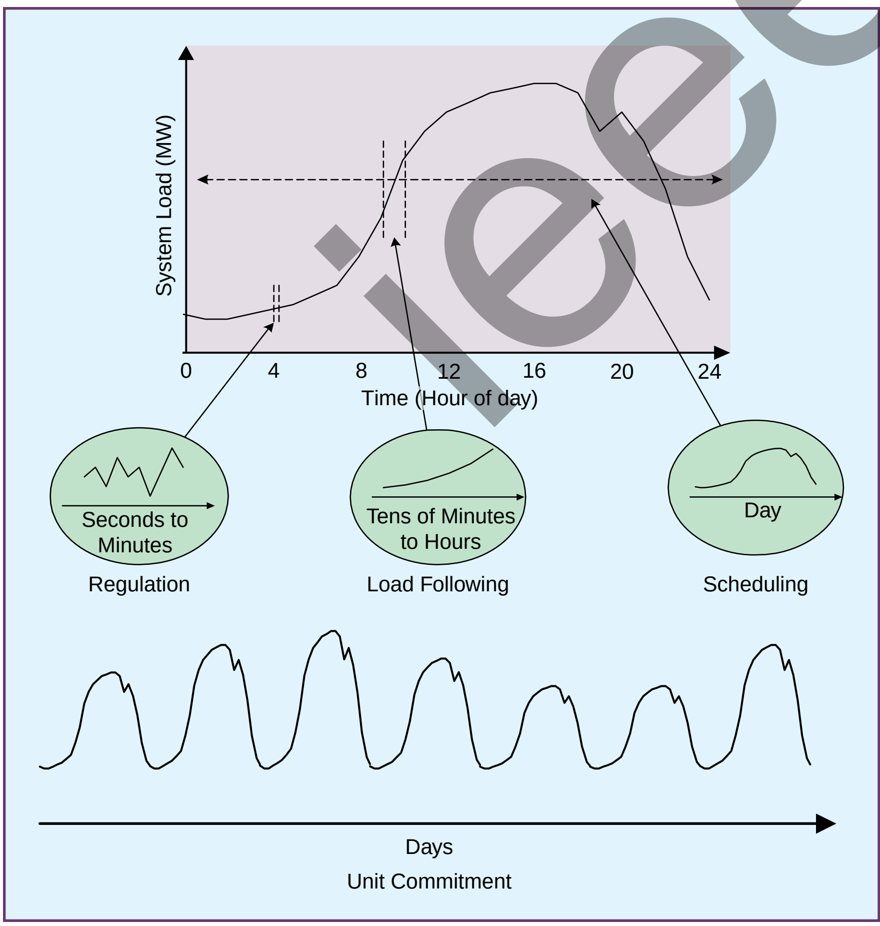

figure 1. The demand for electricity is constantly changing so operators have processes that allow generation output to change while maintaining the required balance between generation and load.

System Balance

The operational planning cycles in bulk system operations, whether under wholesale energy market structures or in vertically integrated utility settings, have the objective to position the system to meet the net load and to provide the range of services needed to guarantee operational security on multiple timescales. As shown in Figure 1, this involves scheduling generators the day before via a process called unit commitment based on the forecasted net load. In real time, available generating capacity is dispatched to meet the continually changing net load. Load following capacity is adjusted manually, on a frequent economic dispatch cycle, or through the operation of subhourly energy markets to track changes in net load on a timescale between 5 min and 1 h. Computer-controlled "regulation" from AGC redispatches capacity on a second-to-minute basis to support interconnection frequency control (60 Hz in North America).

Traditionally, demand for electricity tends to peak in the afternoon or evening and is low in the middle of the night. System operators use intermediate units, such as combined-cycle gas units, to follow the load, whereas less-expensive base-load units run at high output 24 h per day.

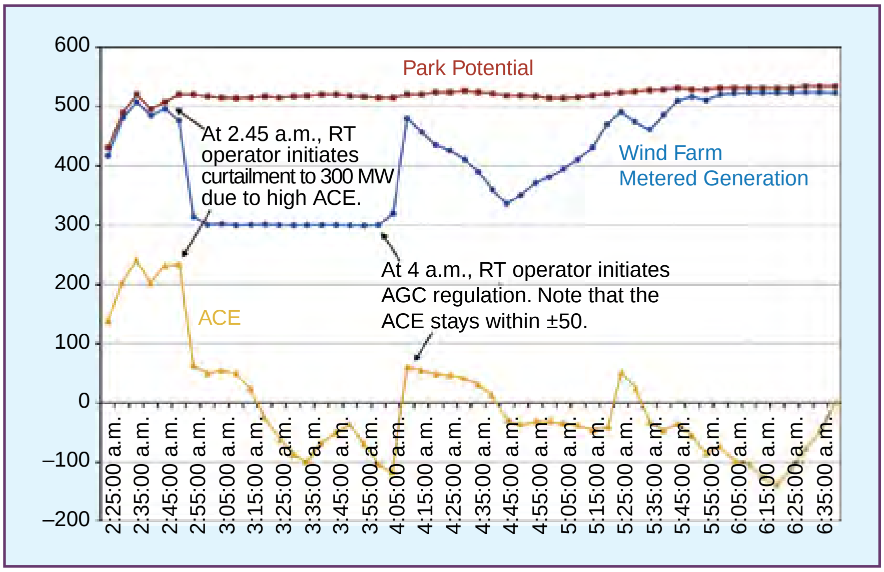

figure 2. A wind power plant in the Xcel/PSCO area is the first to manually block curtailed wind and then put it on AGC regulation. The y axis is in megawatts. The resulting ACE is shown in yellow.

Large amounts of VG change the way the system is operated. The variations in net load and short-term uncertainty are increased, thereby increasing the amounts of required regulating capability and increasing load following or ramping to meet the increased variability of the net load. In some regions, wind power output can be higher at night when demand is low, which can make the traditional operating paradigm more difficult **<AU: more difficult for what? to use?>**. When the base-load units are generating at their minimum output level and additional wind energy is available, wind energy must be curtailed or a base-load unit must be decommited. The economically rational solution is usually to decommit the base-load unit because it burns fuel and wind energy does not. However, if the base-load unit has a long shutdown/start-up period, it may be impossible to decommit the unit and have it available, if needed, the next day, .

Wind down-ramps can also be challenging because the operator needs adequate up-reserves to compensate for the reduced generation. Wind forecasting can often predict down-ramps but there may be a timing error (the down-ramp may occur sometime before or after its prediction). The geographic diversity of wind is very helpful for smoothing out these issues. On the other hand, solar output is easier to predict—we know when the sun will rise and fall every day, although partly cloudy days can make forecasting difficult. The geographic diversity of solar helps with variability caused by cloud movement, but the sunrise and sunset ramps require power system operation throughout much wider geographic regions for mitigation by diversity. Managing large amounts of PV generation requires being able to manage the sunrise and sunset ramps while reducing other generation midday to accept the PV generation.

VG Can Provide Regulation/AGC Services

More sophisticated approaches have emerged and been implemented in recent years to reduce the incremental burden that VG may bring to system balancing. For example, wind power plants currently provide regulating reserves in the Xcel/Public Service of Colorado (PSCO) balancing authority area. In 2014, PSCO had 19% wind and 1% solar energy penetration on its system. With a 33% renewable portfolio standard by 2020, these levels are expected to increase. This system is fairly small; it has a peak load of 7 GW, and more than half of the energy comes from coal. It can be challenging to balance a small system with large amounts of coal generation and high VG penetrations. For example, PSCO reported that wind served more than 50% of the load during 6% of the hours in October 2014, and it reached a peak of 60% on 24 May 2013, between 1 and 2 a.m. When loads are low at night and wind is high, PSCO has to decide between deeply cycling their coal-powered plants or curtailing wind power output. In 2011, PSCO quantified the trade-offs between these options and found that total costs were remarkably similar. The company chose the wind curtailment protocol, which provides two benefits:

- ✔ Coal cycling costs have high uncertainty, and reduced cycling can avoid potential high-impact, low-probability events.
- ✔ Curtailed wind can provide an upward regulating reserve.

Wind can be curtailed manually through a block curtailment, which is a reduction in wind power plant output by a fixed amount for a period of time with little if any changes in wind output. Figure 2 shows wind power plant potential (pink), actual wind power plant output (blue), and area control error (ACE, in yellow) during a windy night. The ACE was high (the PSCO balancing authority area was generating more than its load), so at 2:45 a.m., the system operator block-curtailed the wind from its output of more than 500 MW down to 300 MW. The ACE immediately dropped toward zero but then dropped too low (PSCO was consuming more than it was generating). At 4 a.m., the operator put the wind power plant on AGC regulation. The curtailed wind power plant was able to adjust output up and down as appropriate to help keep the ACE within specified limits. At 6 a.m., the wind power plant was released from AGC. After 6 a.m., the ACE dropped low again, but at that point the wind power plant was producing at its potential, and it could not help the system further; this is similar to a thermal unit running at full power output and therefore unable to provide up-regulation. This demonstrates that putting wind on AGC can provide a significant improvement compared to manually curtailing wind. It simultaneously minimizes wind curtailment (note that from 3:20 a.m.–4:10 a.m., the ACE was negative and the block curtailment could have ended if the operator had finer control over block curtailment) and allows wind to provide effective ancillary services to help balance the system.

As wind can provide fast up and down responses without the wear and tear that thermal generators incur, it may be in PSCO's interest to use wind to provide as much regulation as possible (when it is curtailed) and use the thermal generators for any remaining requirements. Wind has been so effective at providing regulation that 2,172 MW of Xcel's wind generation are now capable of providing AGC when needed.

The industry has much less experience with PVs on AGC, but in principle the mechanics would be the same. Several markets (**<AU: please spell out SPP, CAISO, PJM, NYISO, BPA>** such as SPP, the Electric Reliability Council of Texas (ERCOT), CAISO, PJM, NYISO, and BPA) allow VG to provide downward (and upward, in some cases) regulating reserves, provided they meet eligibility requirements. Many markets (**<AU: please spell out ISO-NE, MISO, IESO>** ISO-NE, Midcontinent Independent System Operator (MISO), and IESO) still do not allow VG to provide regulation, and some (**<AU: please spell out AESO>** AESO) have rules (regulation is procured day ahead, and suppliers must provide it for 60 min) that preclude VG from providing it. For regions anticipating high penetrations of VG, it would be wise to consider making adjustments to market rules to allow VG (or any other resource, such as load, as long as it meets eligibility requirements) to provide regulation.

There is a cost and limit, however, to using this curtailed energy to provide system support. Wind curtailment is achieved by either automated market-based mechanisms, such as the MISO dispatchable intermittent resource (DIR) economic dispatch or through manual directives by the system operator. Usually the most expensive plant is curtailed first to alleviate system congestion or maintain system balance. The economic compensation provided to the wind power plant varies and depends on the specifics of the power contract. Output from individual turbines can be reduced in seconds to provide downward reserves and ramping support. Output from curtailed wind turbines can be increased quickly, on the order of seconds to tens of seconds, to provide frequency, upward reserve, and ramping services. Curtailment from PVs is achieved by controlling inverter output, and therefore it acts on very short timescales of fractions of seconds. This turns wind and PVs into dispatchable resources, but it is at the economic cost of reduced energy output. Therefore, the economic choice to curtail VG at any given moment reflects the trade-off between the instantaneous value of the energy produced and the value of upward reserves provided. This economic trade-off is further complicated for wind (in the United States) for projects utilizing production-based subsidies. However, some positive feedback may exist. For example, thermal generators that stay online to provide upward reserves and subsequently force wind to curtail could instead be decommitted if the curtailed wind provides the upward reserves.

VG Can Be Economically Dispatched

There can be times when the system is constrained with too much generation and not enough demand and/or transmission to move the energy. Managing this type of overgeneration condition is most effective if the solution is incorporated directly into the economic dispatch process, which (under normal conditions) requires no direct operator intervention and can be done very quickly and cost effectively. MISO manages more than 14 GW of wind generation in its market footprint. The continued growth of wind generation, especially in the western areas of its territory, has created local transmission congestion issues during certain periods that were traditionally managed by manual curtailments of specific wind generation facilities. In 2011, MISO implemented the DIR protocol, which effectively places wind power plants on AGC under control of the MISO real-time market systems. This resulted is an overall reduction of curtailed renewable energy delivery along with a much higher level of operational efficiency and transparency. Figure 3 shows the monthly downward dispatch of energy as a percent of the economic maximum. According to MISO, approximately 95% of wind energy's potential can be captured through economic dispatch. All new wind generation facilities in MISO must register as DIRs, and more than 80% of wind generation in MISO is dispatchable.

VG Can Contribute to Operational Security

As the instantaneous penetration of VG resources increases, there is greater interest in wind's potential impacts on maintaining the operational stability and security of the bulk power system during and after major disturbances. Although this has not been studied as extensively as balancing issues or widely incorporated into system operation, there is increased understanding that VG can provide frequency, inertia, and voltage control capabilities that have been traditionally provided by synchronous generators.

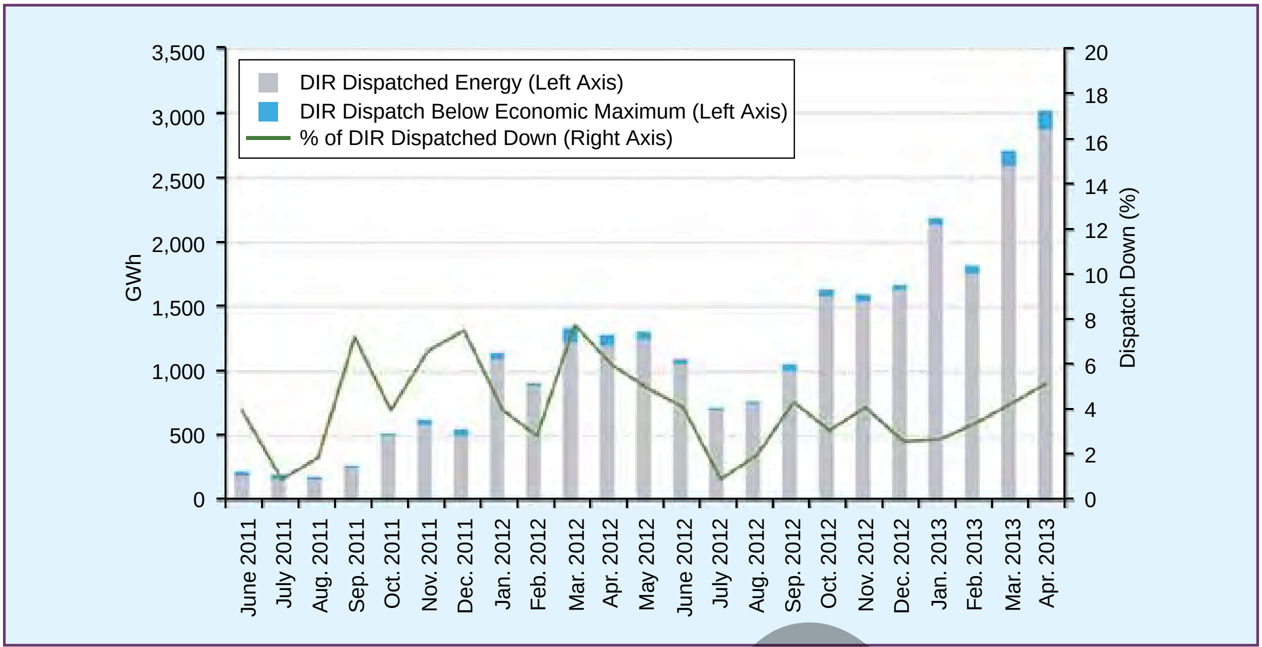

figure 3. Wind power plant dispatch in MISO with DIR protocol.

Frequency Response and Synthetic Inertial Control

Frequency response is the overall response of a power system to small, routine fluctuations in frequency and also large, sudden mismatches between generation and load that may result from generation or transmission tripping offline. The loss of a large central station generating plant is of most concern. When total demand exceeds total generation, system frequency drops. Traditionally, the inertia of synchronous machines helps retard the frequency decline, providing an opportunity for generating units with governors to increase power output to stabilize the system before a frequency-based disturbance could otherwise occur.

Among power system operators and utilities, there is a concern regarding the degradation of frequency response in North America during the past two decades. The decline has resulted from various factors, including the withdrawal of primary or governor response shortly after an event, the lack of in-service governors on conventional generation, and the unknown and changing nature of load frequency characteristics. Large penetrations of inverter-based (or nonsynchronous) generation technologies further complicate this issue. Synchronous machines always contribute to system inertia, and some fraction of the synchronous generation in operation at any time has governor controls enabled. By contrast, wind and PV plants, in different ways, can provide "synthetic system inertia" through a fast frequency response (FFR) with a power electronic converter to simulate inertial response, and a slower frequency response can be provided through electronic governor action. When wind and PV generation displace conventional synchronous generation, the mix of the remaining synchronous generators changes, and there is the potential to adversely impact overall frequency response if good engineering practice is not followed.

The impact of nonsynchronous generation on frequency stability may appear more quickly in relatively small grids with high penetrations of wind because a relatively low wind capacity level can comprise a larger percentage of demand than in a larger grid. For example, the combined Ireland and Northern Ireland power system has developed a system of nonsynchronous penetration (SNSP) ratio to help identify operating limits. Eirgrid currently limits SNSP to less than 50%. In the future, EirGrid expects to raise that limit to 75%. This is an issue that much larger systems will face in future scenarios of high penetrations of wind and solar.

Recent research by the National Renewable Energy Laboratory and GE showed that systemwide frequency response can be maintained with high levels of wind and solar generation when local stability, voltage, and thermal problems are addressed using traditional transmission system reinforcements (e.g., transformers, shunt capacitors, and local lines). The analysis also showed that the limited application of nontraditional but commercially available frequency-responsive controls on wind, PVs, concentrating solar power plants, and energy storage are equally effective at improving minimum frequency and settling frequency and therefore overall frequency response. For example, Figure 4 shows the benefits of dynamic response from VG by comparing the Western Interconnection's frequency for several scenarios studied in "Western Wind and Solar Integration Study Phase 3." All traces are for the sudden trip of two of the Palo Verde generators (2,756 MW) under stressful <AU: is Light Spring a town? > Light Spring load conditions when there is less additional generation available to respond. In Figure 4(a),

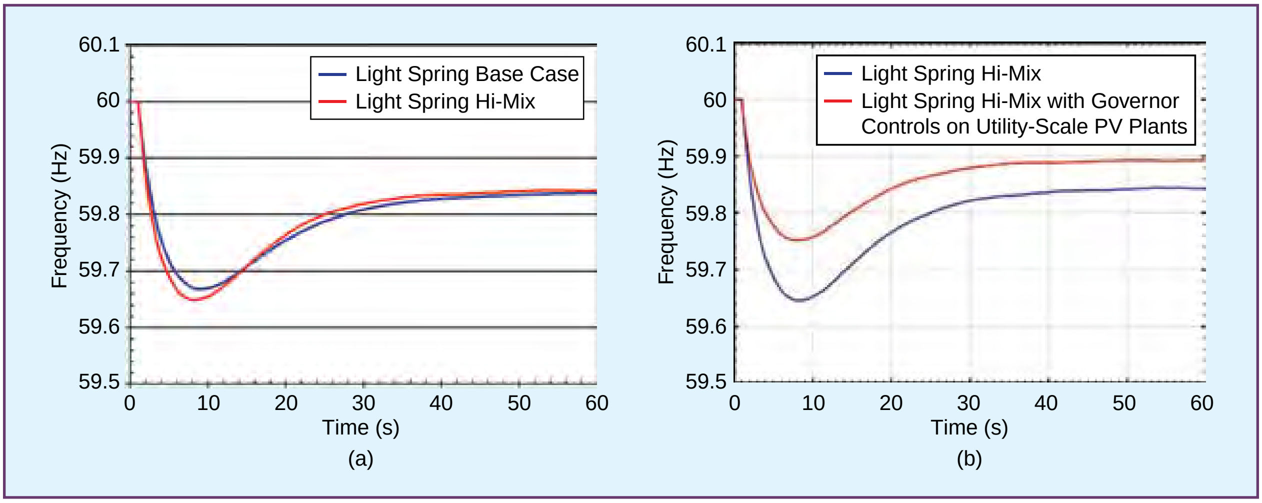

figure 4. Western Electricity Coordinating Council frequency response to the loss of two Palo Verde units for Light Spring conditions. (a) The base case compared to a high mix of wind and solar. (b) Hi-mix with and without frequency controls.

the blue base case has 26 GW of renewables. Doubling the wind and solar production to more than 50 GW (red high-mix case) leaves the characteristic of the system response to this large generation trip event essentially unchanged. When governor controls are added to utility-scale solar PV plants, the systemwide frequency response is substantially improved [Figure 4(b)].

Frequency and Voltage Ride-Through

To date, wind turbines are the only generators required to ride through disturbances. Early wind machines used simple induction generators that provided no dynamic grid support in the event of a power system disturbance. These turbines focused on energy capture rather than grid support. In fact, because they had response characteristics different from conventional synchronous generators, they were required to disconnect if frequency or voltage deviated from nominal to prevent them from making the situation worse. As wind penetration increased, the loss of significant amounts of wind generation during a disturbance became a reliability concern, and utilities wanted to impose ride-through requirements on wind turbines. Wind-turbine technology had advanced, and the wind industry supported ride-through requirements, but they wanted them to be standardized to facilitate product design. With considerable input from both the wind industry and the power system industry, the Federal Energy Regulatory Commission addressed these concerns in 2005 with Order 661A, which requires all new wind turbines to ride through low-voltage events rather than disconnecting. This order also set power factor design criteria and supervisory control and data acquisition requirements for wind generators.

The North American Electric Reliability Corporation considered applying the same requirement to all new generators when it drafted the new standard PRC-024-1, *Generator Frequency and Voltage Protective Relay Settings*. During several balloting processes conducted by the North American Electric Reliability Corporation, the industry repeatedly defeated the inclusion of an actual ride-through performance requirement. Instead, the standard requires only that the primary protective relays not be set to trip the generator within the "no trip zone" of voltage and frequency curves. Conventional generators do not need to ride through an event, but wind turbines must still meet the requirement imposed by the Federal Energy Regulatory Commission to ride through disturbances. Wind turbines are also required to provide voltage support if needed by the power system.

Ride-through requirements for distributed PV systems are also evolving. Utilities require distributed PV systems to disconnect when voltage or frequency is out of bounds. This is based on safety concerns to prevent the PV system from energizing a portion of the grid that is supposed to be de-energized (anti-islanding). As with wind, the requirement was reasonable when there was not much PV generation on the power system, but it is not viable with thousands of megawatts of generation that might disconnect during a disturbance. Fortunately, anti-islanding technologies have improved, and safety concerns can be addressed while having distributed PV ride through disturbances. IEEE 1547, *Standard for Interconnecting Distributed Resources with Electric Power Systems,* is being modified to allow PV ride-through. California and Hawaii are requiring ride-through capabilities from new distributed PV installations.

Wind Generation's Evolving Dynamic Response Capability

The evolving dynamic response capability of wind offers an example of technical, regulatory, and reliability progress for both wind turbines and the electric power industry. Lack of dynamic grid support from any generation technology in the event of a power system disturbance is problematic both because the generator is not helping to stabilize the power system and because it may be displacing generation that could. Both the power industry's understanding and wind turbine capabilities have evolved so that reliability is now increased with the addition of wind.

These reliability improvements include frequency, voltage ride-through requirements, and voltage support, as previously discussed. More recently, the ability of wind turbines to actively control the energy injected into the power system has been exploited. With electronics coupling the generator to the power system, modern wind turbines are able to control their output much faster and more accurately than conventional synchronous generators. Wind turbine control is possible in cycles (milliseconds, which is the inertial time frame) rather than in seconds (the response time of conventional generator governors). The rotating mass of the wind turbine blades themselves coupled to the short-term overload capability of the power electronics provides an additional source of completely controllable stabilizing energy. Unlike conventional synchronous generators, which provide uncontrolled inertia response, the response from wind turbines is completely controllable. Power system transient stability response to a major disturbance involves power oscillations as generators swing against each other. Studies show that wind turbine "synthetic inertia" provides benefits similar to those of synchronous inertia to help the power system ride through a disturbance while also dampening undesirable oscillations. Figure 5 shows the superior stability response of doubly fed asynchronous wind turbines compared to conventional synchronous generators following a grid disturbance.

Additional Sources of Flexibility

Although wind and solar generators can provide fast and accurate control, integrating additional wind and solar generation is often aided by broadening the power system operator's suite of flexible resources. These sources can allow decommitting conventional generation and increasing the amount of renewable energy that the power system is able to reliably and economically integrate. Existing resources often can be operated in a flexible manner if there are incentives and if the institutional structure does not prevent it. Two groups of relatively new emerging sources are demand response and other sources of flexibility.

Demand Response

Demand response can allow conventional generation that would otherwise be kept online to be decommitted to provide fast reserves. Historically, a utility would ensure that adequate unloaded conventional generation was online and had active governors to ensure that power system frequency could recover from the worst credible contingency without triggering any underfrequency load shedding. For example, it could be challenging for ERCOT to keep the frequency nadir above 59.4 Hz immediately after a major contingency if light load and abundant wind generation had displaced much of the conventional generation. Rather than relying exclusively on generator response, ERCOT has found that FFR from load (FFR that responds in fewer than 30 cycles once system frequency reaches 59.7 Hz) provides at least the same reliability benefit as conventional generation providing primary frequency response (PFR). For example, at low load, high wind conditions, as shown in Figure 6, it was found that 1,400 MW of FFR provides the same reliability benefit as 3,300 MW of conventional generation providing PFR. This shows that FFR from load can be 2.35 times as effective as the frequency response from conventional generation. In addition, decommitting conventional generation operating at low load simply to provide PFR also reduces wind and solar curtailment, which reduces emissions and saves money. Carrying the same reserves with wind or solar would require spilling zero marginal cost energy to create the response headroom. Although renewables could provide the reliability response, obtaining the response from the load allows the renewables to supply more energy, and ERCOT has found this to be more cost-effective.

Other Sources of Flexibility

Improvements in conventional generation flexibility also help with effective renewable integration. Fast-start reciprocating engines and combustion turbines that have lower minimum loads and higher efficiencies and can be started within minutes without incurring start-up costs can help provide ramping and nonspinning reserves. Shortening the start-up time (and lowering the start-up cost) lets the system operator delay response until wind and solar conditions are more certain, which improves forecast accuracy and reduces the requirement for online reserves. Retrofitting existing conventional generators to reduce start-up times, minimum loads, and cycling costs provides similar benefits. Storage

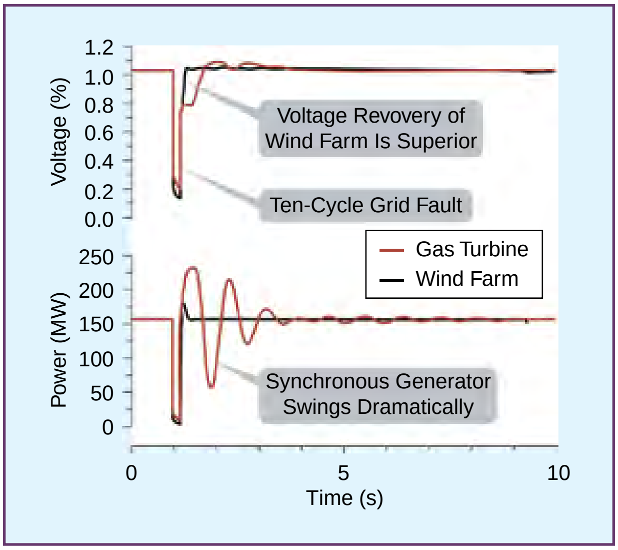

figure 5. Wind power plants with doubly fed asynchronous generators are more stable than those that have conventional synchronous generators.

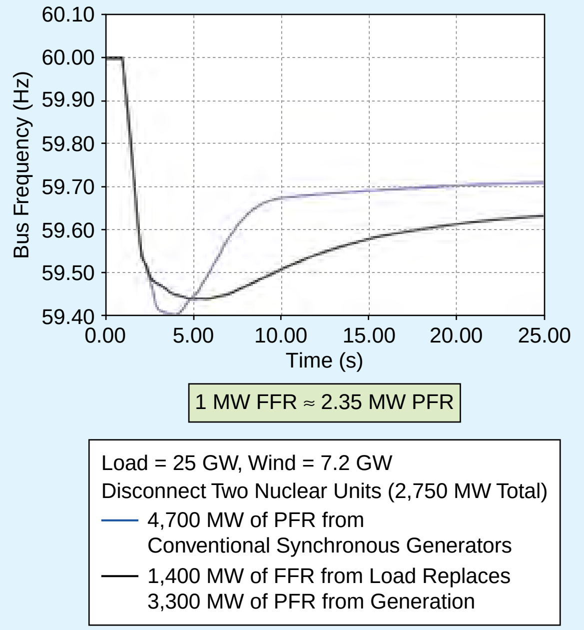

figure 6. An example of FFR to the loss of two nuclear units (2,750 MW total) from load (black) compared to PFR from conventional generators (blue) in ERCOT. Fast frequency response responds in fewer than 30 cycles. Primary frequency response is the governor response, typically within 10 s.

provides similar technical benefits and should be used whenever it is the least-cost resource.

Power System of the Future

Increasing amounts of wind and PVs, which are largely connected to the electricity grid by nonsynchronous power electronic converters, is part of a bigger trend in the evolution of power systems. This trend also includes increased levels of power electronics embedded in loads (e.g., modern electronic loads) and transmission (e.g., high-voltage dc transmission). The more distributed nature of wind, PVs, and other forms of generation (e.g., combined heat and power) along with more active consumer participation are all contributing to a dramatic shift in the nature and characteristics of the future electricity grid. These changes create the need for more physical flexibility that can be sourced from many different assets on the electricity grid.

The island of Ireland is an interesting example in which the increase in nonsynchronous generation is necessitating the development of both innovative wind power plant controls and holistic solutions. These solutions include advanced wind turbine controls (i.e., synthetic inertia), fast demand response, and synchronous generators capable of riding through larger frequency swings all within the regulatory and market framework. ERCOT also found that fast demand response is more effective than the response from conventional generator governors in stabilizing the power system after a major disturbance.

As the system continues to evolve toward higher levels of VG, this market framework must provide the appropriate signals to incentivize sufficient flexibility in both the operational and investment time horizons. Not only is a sufficient level of capacity required to meet future demand, but the nature of this capacity is fundamentally different than it was in the past because of the need for flexibility. This issue is explored in more detail in the accompanying article in this issue by Ahlstrom et al.

It is also important to note the rapid spread of distributed generation. This will have a larger impact on transmission and distribution systems in which the current planning is still largely centralized. The challenge of the electricity industry is twofold: first, there must be a vision of a market structure that accommodates these changes, and second, a transition is needed that can be done with minimal disruption, both physically and financially.

Summary and Conclusions

Wind and PV generation have emerged as mainstream energy resources that have increasing economic competitiveness in many power systems around the world. With increased deployment, there is also a more fundamental understanding of VG's characteristics, impacts, and benefits.

table 1. Evolving Characteristics of VG Technologies.

Characteristic	Old	New
Dispatchability	Uncontrollable, "must take"	Dispatchable through participation in economic dispatch
Forecast/uncertainty	Unpredictable	Increasingly forecastable
Variability	Highly variable over multiple timescales	Very short-term variability largely mitigated via spatial diversity
Reserve requirements	Requires dramatic increase in operating reserves from thermal units	Relatively small increase in regulation required. Can self-provide multiple reserves across multiple timescales with selective/economic curtailment
Grid support	Provides no grid support/decreases grid stability	Can provide multiple grid support services

The traditional "old" model of VG, shown in Table 1, has been replaced by a "new" model based on detailed operational simulation as well as years of real-world experience in systems throughout North America and Europe.

This more mature approach to assessing the impacts and benefits of VG recognizes the ongoing challenges to integration at increased penetration levels. VG increases the net variability and uncertainty on the system, and therefore more creativity and flexibility is required to maintain reliable operation. In response, system operators and planners have discovered and developed a larger set of flexibility options both in methods to operate existing grid assets and to deploy new technology options. On the generation side, these options range from reexamining historical operating practices for operating traditional thermal generation to exploiting advanced capabilities of VG itself. On the demand side, new markets may tap significant flexibility from dispatchable loads. Developing these flexibility resources in the most cost-effective manner requires ongoing assessments of the various options. With proper incentives and market designs, all flexibility options, including provisions of multiple flexibility services from wind and solar, can be deployed to minimize the overall costs of a clean, reliable power system.

For Further Reading

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Callouts:

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Among power system operators and utilities, there is a concern regarding the degradation of frequency response in North America during the past two decades.

Compilation of Storage Proposed in Integrated Resource Plans

State	Utility	IRP Year	Storage Proposed (MW)	Timeline
OR	PGE	2016	39.8	2020
HI	HECO	2016	535	2020
KY	Kentucky Power	2016	10	over 10 years
IN	IPL	2016	833	over 20 years
AZ	TEP	2017	30	2020
NM	PNM	N/A	160	2022
WA	Puget Sound	2017	75	2029
NC	Duke Carolinas	2017	75	2019-2021
OR	PacifiCorp	2017	4	2020
WA	Avista	2017	5	2029
AZ	UNS Energy Corp	2017	20	2028
CO	Xcel	2018	275	2030
VA	Dominion	2018	30	2025
VA	Appalacian Power	2018	10	2025
FL	FPL Energy	2018	50	2020
MI	Consumers	2018	400	2040
NV	NVE	2018	100	2021
NC	Duke Carolinas & Duke	2018	290	2026
NM	El Paso Electric	2018	115	2035
AZ	APS	2019	850	2025
GA	Georgia Power	2019	80	N/A
MI	Indiana Michigan Powe	2019	50	2028
NV	NVE	2019	590	2023
FL	FP&L	N/A	409	2021
TN	TVA	2019	5,300	2028
Total Not Including TVA			**5,036**	
Total With TVA			10,336	

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Electric Company** for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.	Case No. U-20471 ALJ Sally L. Wallace

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony of Michael Milligan on behalf of Michigan Environmental Council, Natural Resources Defense Council and Sierra Club along with Exhibits MEC-64 through MEC-74** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

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Counsel for MEC-NRDC-SC

Date: August 21, 2019

By: Digitally signed by Breanna Thomas
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