It is unknown at this time whether NERC or NAESB will undertake projects to improve electric-gas coordination or develop new or revised standards as a result of the 2021 event, but SPP will engage in projects as appropriate to improve the reliability of the bulk power system during extreme events.

APPENDIX E: COMMUNICATIONS SURVEY OF RSC AND CAWG MEMBERS

EXECUTIVE SUMMARY

The SPP communications department launched the RSC - Winter Storm Event Survey March 30, 2021, and closed the survey April 9, 2021. Staff distributed survey invitations to the 10 members of the Regional State Committee (RSC), the 11 members of the Cost Allocation Working Group (CAWG), and extended an invitation to complete the survey to the Texas Office of Public Utility Counsel (OPUC).

Ten RSC commissioners, nine members of the CAWG, and one member of the Texas OPUC completed the survey. The distribution of respondents by state is shown in Table 1.

On a scale of zero to four, with zero being "Highly Ineffective" and four being "Highly Effective," survey respondents gave an average rating of 2.95 when rating SPP's overall effectiveness during the winter storm event.

Table 1: Respondents by State

State	Respondents
Arkansas	2
Iowa	2
Kansas	2
Louisiana	2
Missouri	1
Nebraska	2
New Mexico	2
North Dakota	2
Oklahoma	2
South Dakota	2
Texas	1

Table 2: Overall Effectiveness

Q1. How would you rate the overall effectiveness of SPP's communication during the winter storm event?		
Respondent Type	**Average Rating**	**Equivalent Score**
Commissioners (10)	3.00	Effective
CAWG representatives (9)	2.88	Effective
Other (Texas OPUC, 1)	3.00	Effective
All Respondents	**2.95**	**Effective**

For individual categories of communication performance, the lowest ratings were given to the performance of SPP's members, and to assessments of how SPP and its members shared responsibility of communication with government and regulatory officials.

Some of the themes staff identified in open-ended responses were: a desire to improve advance notification, a need for more consistent communication from SPP and members, a need for clear sources of information and points of contact, a desire to improve the frequency of communication during an event, a need for more collaboration to reach overlapping audiences, and an opportunity to educate regulators, members and the public about these types of emergency events and how to respond.

SURVEY RESULTS BY QUESTION

The survey asked respondents to their agreement with the following statements below.

Q4: SPP's communication during the winter storm event was timely.

	Response percent	Response total
Strongly Agree	15%	3
Agree	65%	13
I don't know	5%	1
Disagree	15%	3
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q5: SPP communicated with appropriate frequency during the winter storm event.

	Response percent	Response total
Strongly Agree	10%	2
Agree	60%	12
I don't know	15%	3
Disagree	15%	3
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q6: Communication from SPP during the winter storm event was clear and understandable.

	Response percent	Response total
Strongly Agree	15%	3
Agree	70%	14
I don't know	5%	1
Disagree	10%	2
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q7: SPP effectively used a variety of communication methods (email, press releases, webinars, phone calls, website updates and social media) during the event.

	Response percent	Response total
Strongly Agree	20%	4
Agree	40%	8
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q8: SPP's leadership demonstrated necessary knowledge and expertise during the event, and were consistent in the delivery of their message.

	Response percent	Response total
Strongly Agree	25%	5
Agree	65%	13
I don't know	5%	1
Disagree	5%	1
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q9: SPP's communications clearly explained the actions stakeholders should take during the winter storm event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	50%	10
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	5%	1

Statistics based on **20** respondents;

Q10: SPP's communications during the event increased my trust in the credibility of SPP.

	Response percent	Response total
Strongly Agree	10%	2
Agree	45%	9
I don't know	35%	7
Disagree	5%	1
Strongly Disagree	5%	1

Statistics based on **20** respondents;

Q11: SPP staff were available and willing to answer my questions during the event.

	Response percent	Response total
Strongly Agree	25%	5
Agree	45%	9
I don't know	30%	6
Disagree	0%	0
Strongly Disagree	0%	0

Statistics based on **20** respondents;

Q12: SPP's member organizations effectively communicated actions they were taking during the winter storm event.

	Response percent	Response total
Strongly Agree	15%	3
Agree	25%	5
I don't know	25%	5
Disagree	20%	4
Strongly Disagree	15%	3

Statistics based on **20** respondents;

Q13: SPP and its member organizations effectively shared responsibility for communicating with regulators during the event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	25%	5
I don't know	40%	8
Disagree	20%	4
Strongly Disagree	10%	2

Statistics based on **20** respondents;

Q14: SPP and its member organizations effectively shared responsibility for communicating with other elected officials during the event.

	Response percent	Response total
Strongly Agree	5%	1
Agree	15%	3
I don't know	75%	15
Disagree	0%	0
Strongly Disagree	5%	1

Statistics based on **20** respondents;

APPENDIX F: COMMUNICATIONS SURVEY OF STAKEHOLDERS

SURVEY RESULTS BY QUESTION

Q1. Which of the following applies to you? (check all that apply)		
Respondent Type	**#**	**%**
Communications staff at an SPP member organization	31	20%
Government affairs staff at an SPP member organization	22	14%
Regulatory staff at an SPP member organization	17	11%
Operational staff at an SPP member organization	45	29%
Market staff at an organization participating in SPP's Integrated Marketplace	15	10%
Roster member of an SPP working group or committee	58	37%
Members Committee member of SPP	25	16%
SPP board member	7	5%
SPP staff	0	0%

Communications staff at an organization that is not a member of SPP	2	1%
Other role at an organization that is not a member of SPP	4	3%
Other role at an SPP member organization	16	10%
Other	8	5%
All Respondents (155 respondents)	**250**	**100%**

Q1. In what state(s) does your organization operate?		
State	**#**	**%**
Oklahoma / OK	53	14%
Kansas / KS	46	12%
Nebraska / NE	40	10%
Texas / TX	33	9%
Arkansas / AR (and one response of "AK" probably intended to be "AR")	27	7%
Missouri / MO	27	7%
South Dakota / SD	25	7%
New Mexico / NM	22	6%
Iowa / IA	21	5%
Louisiana / LA	17	4%
Minnesota / MN	17	4%
North Dakota / ND	17	4%
Montana / MT	12	3%
Wyoming / WY	13	3%
Colorado / CO	9	2%
Arizona / AZ	1	0%
California / CA	1	0%
Nevada / NV	1	0%
Utah / UT	1	0%
All Respondents (152 respondents)	**383**	**100%**

Q3: How would you rate the overall effectiveness of SPP's communication during the winter storm event? (154 responses)

The survey asked respondents to their agreement with the following statements.

Q4: SPP's communication during the winter storm event was timely. (155)

	Response percent	Response total
Strongly Agree	23.87%	37
Agree	58.71%	91
I don't know	7.1%	11
Disagree	9.03%	14
Strongly Disagree	1.29%	2

Q5: SPP communicated with appropriate frequency during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	26.45%	41
Agree	54.84%	85
I don't know	9.03%	14
Disagree	8.39%	13
Strongly Disagree	1.29%	2

Q6: Communication from SPP during the winter storm event was clear and understandable. (155)

	Response percent	Response total
Strongly Agree	24.52%	38
Agree	56.77%	88
I don't know	10.32%	16
Disagree	7.74%	12
Strongly Disagree	0.65%	1

Q7: SPP effectively used a variety of communication methods (email, press releases, webinars, phone calls, website updates and social media) during the event. (155)

	Response percent	Response total
Strongly Agree	21.94%	34
Agree	54.84%	85
I don't know	17.42%	27
Disagree	5.16%	8
Strongly Disagree	0.65%	1

Q8: SPP's communications clearly explained the actions stakeholders should take during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	18.07%	28
Agree	50.32%	78
I don't know	18.71%	29
Disagree	10.97%	17
Strongly Disagree	1.94%	3

Q9: SPP communications during the event increased my trust in the credibility of SPP. (155)

	Response percent	Response total
Strongly Agree	20%	31
Agree	50.32%	78
I don't know	24.52%	38
Disagree	3.87%	6
Strongly Disagree	1.29%	2

Q10: SPP's leadership demonstrated necessary knowledge and expertise during the event, and were consistent in the delivery of their message. (155)

	Response percent	Response total
Strongly Agree	29.03%	45
Agree	58.71%	91
I don't know	8.39%	13
Disagree	3.23%	5
Strongly Disagree	0.65%	1

Q11: SPP staff were available and willing to answer my questions during the event. (155)

	Response percent	Response total
Strongly Agree	30.32%	47
Agree	41.94%	65
I don't know	27.1%	42
Disagree	0%	0
Strongly Disagree	0.65%	1

Q12: SPP's member organizations effectively communicated actions they were taking during the winter storm event. (155)

	Response percent	Response total
Strongly Agree	8.39%	13
Agree	46.45%	72
I don't know	32.9%	51
Disagree	10.97%	17
Strongly Disagree	1.29%	2

Q13: SPP and its member organizations effectively shared responsibility for communicating with regulators during the event. (22 Respondents – this question was only available to respondents who indicated they were government affairs or regulatory staff)

	Response percent	Response total
Strongly Agree	9.09%	2
Agree	45.46%	10
I don't know	31.82%	7
Disagree	13.64%	3
Strongly Disagree	0%	0

Q14: SPP and its member organizations effectively shared responsibility for communicating with other elected officials during the event. (22 Respondents – this question was only available to respondents who indicated they were government affairs or regulatory staff)

	Response percent	Response total
Strongly Agree	13.64%	3
Agree	31.82%	7
I don't know	27.27%	6
Disagree	27.27%	6
Strongly Disagree	0%	0

Southwest Power Pool
MARKET MONITORING UNIT

REPORT ON

FEBRUARY 2021

WINTER WEATHER EVENT

Published on July 14, 2021

CONTENTS

FIGURES

1 EXECUTIVE SUMMARY

This report covers the Market Monitoring Unit's lessons learned and recommendations from the February 2021 winter weather event in the SPP region. The Market Monitoring Unit developed this report independently in conjunction with SPP's comprehensive review of the February 2021 winter weather event. In this report, we cover a range of topics and provide a series of recommendations. In some cases, our recommendations provide specific guidance, such as detailed tariff changes; in other cases, we recommend that a study be performed to identify further lessons and recommendations. Moreover, we highlight critical recommendations that we view as necessary for SPP and its stakeholders to implement in order to avoid potential catastrophic and deadly consequences.

Critical recommendations

While most resource types had availability issues during the February 2021 winter weather event, at the very heart of the cold weather event, natural gas plants were unavailable to generate. Our research notes that natural gas pipeline limitations and access to storage were not driving factors. The primary issue was that power plants could not obtain natural gas molecules from suppliers to generate. In some cases, this was because the cost of gas was so high that some companies did not have enough credit to buy fuel. In other cases, there was no natural gas available at any price. In February 2021, natural gas resources were assumed to be available, but many were not available because they could not procure fuel to run. This leads to the following critical recommendations:

- **Critical Recommendation #1:** If SPP is to rely on any resource to be available to provide energy, then that resource should be available. This will require accounting for more granular approaches to measuring capacity including seasonality and forced outage rates. Availability may require resources to have secondary or backup fuel sources, or alternatively storage capabilities.

- **Critical Recommendation #2:** There should be meaningful incentives for availability. To the extent that a resource is more available there should be incentives, to the extent that a resource is less available, there should be disincentives.
- **Critical Recommendation #3:** Different times of the year present different system challenges. SPP resource adequacy requirements focus on meeting peak summer load. A more frequent resource adequacy requirement, such as a seasonal (or perhaps monthly) requirement, should be developed.
- **Critical Recommendation #4:** SPP should plan for shocks to generator availability including extreme weather events, pipeline outages, wind turbine icing and solar eclipses, and implement mitigation measures.

Remaining recommendations and recommendation ranking

We follow the RTO ranking of recommendations into three tiers: Tier 1, Tier 2, and Tier 3. Tier 1 recommendations are necessary and urgent to address root causes of the February winter weather event. Tier 2 recommendations while necessary and urgent address consequences of the event as opposed to root causes. Tier 3 recommendations represent other recommendations not covered by the other tiers. Our critical recommendations fall under Tier 1 recommendations. We group the remaining recommendations into categories that represent chapters in this report. At the end of each recommendation, we note the appropriate tier ranking. In this report, we highlight 7 Tier 1 recommendations, 22 Tier 2 recommendations, and 16 Tier 3 recommendations. We strongly recommend that SPP and stakeholders address all 45 MMU recommendations.

Recommendations – FERC Order No. 831 process

- The MMU should work with SPP staff and stakeholders to improve the process of reviewing and approving expected costs. Software improvements should be considered. (Tier 2)

- The MMU should consider obtaining access to Intercontinental Exchange information, which would allow expected costs for the day-ahead market to be verified more quickly. (Tier 2)

- The MMU should review the process for verifying offers above $1,000/MWh and required substantiating documentation as a standing topic to SPP's annual winter weather preparedness workshop. (Tier 2)

- The MMU should work with SPP and stakeholders to modify SPP's tariff to also clearly state that during periods with energy offers over $1,000/MWh, start-up and no load costs will be based on the mitigated no-load and mitigated start-up offers, which will then be verified by the MMU for actual costs. (Tier 2)

- Modify software to allow easy comparison of a current offer with the last approved offer to expedite the expected cost approval process. (Tier 2)

- SPP and stakeholders should modify the uncertainty adder from a fixed $100/MWh adder to a 10 percent adder. (Tier 2)

- SPP should conduct a study to determine what the value of lost load in SPP is. This will inform many other decisions such as pricing while shedding load, the appropriate offer cap, and upper limit on offers being approved. (Tier 2)

- SPP and stakeholders should consider permanently changing the timeline in the tariff for submittal of actual costs from 35 days to 75 days. (Tier 3)

- SPP and stakeholders should consider permanently changing the timeline in the tariff for the MMU review of actual costs from 45 days to 105 days. (Tier 3)

- SPP and stakeholders should consider permanently updating the settlements dispute language to allow disputes on the S120 settlement statement related to the settlement of actual costs under FERC Order No. 831. (Tier 3)

- SPP and the stakeholders should develop tariff language that ensures all participants are reimbursed fairly and consistently, and strengthen the rules for calculating accurate expected costs by (a) limiting reimbursement for actual costs to all offers that require verification prior to use in market clearing, and (b) outlining under what specific circumstances the MMU would have the latitude to consider reimbursement for actual costs that are in excess of expected costs. (Tier 2)

- SPP and stakeholders should update the tariff to allow for make-whole payments for instructed real-time incremental energy costs above the day-ahead cleared position for offers that fall under FERC Order No. 831 regardless of the reason for the commitment. (Tier 2)

- SPP and stakeholders should update the tariff to allow for make-whole payments for self-committed resources for day-ahead clearing and real-time dispatch above a resources minimum operating limit for offers that fall under FERC Order No. 831. (Tier 2)

- SPP and stakeholders should modify the tariff to allow for the combination of day-ahead and real-time revenues and costs when assessing the need for make-whole payments consistent with FERC Order No. 831. (Tier 2)

- SPP should perform an evaluation of the current settlement approach to determine if there are over-or under-compensation of actual fuel costs through make-whole payments. The study should also identify issues with how make-whole payments are distributed. (Tier 3)

Recommendations – Resources

- Stakeholders should approve the MMU State of the Market recommendations related to outages. The Generator Outage Task Force has approved this and is awaiting ORWG action. (Tier 2)

- SPP should clearly indicate how to report icing in the outage coordination methodology. (Tier 3)

- Market participants should follow the Outage Coordination Methodology. SPP should consider not approving outages with missing required information. (Tier 2)

- SPP and its stakeholders, including regulators, should conduct a study on behind the meter resources that are below the 10 megawatt threshold and determine their (a) impacts on reliability and market outcomes, and (b) performance as capacity resources. (Tier 2)

- Establish an incentive mechanism for capacity credited in the planning reserve margin calculation to maintain availability for the duration of the accreditation period. This recommendation connects with critical recommendation #2. (Tier 1)

- Establish a more frequent resource adequacy requirement, such as seasonally (or perhaps monthly), that acknowledges load requirements and generation performance characteristics that are unique to that period. This recommendation connects with critical recommendation #3. (Tier 1)

- Evaluate available capacity on a resource-level, seasonally, taking into account historical availability to determine the amount of deliverable capacity that can be accredited. This recommendation connects with critical recommendation #1. (Tier 1)

- Account for major contingencies, such as a shock to fuel systems or mechanical functionality, and implement mitigation measures. This recommendation connects with critical recommendation #4. (Tier 1)

Recommendations – Price formation

- SPP and stakeholders should devise an approach to ensure that congestion prices reflect underlying physical and economic conditions. (Tier 2)

- SPP, stakeholders, and the MMU should perform a study to determine an appropriate hard cap offer level that balances the need for prices to reflect marginal costs and the need to protect ratepayers from potentially uncompetitive outcomes in fuels markets. (Tier 3)

- SPP and stakeholders should evaluate how to set prices during EEA1, EEA2, and EEA3 events to send price signals for market participants to take actions to help relieve the emergency. (Tier 2)

- SPP and stakeholders should work with MISO to petition FERC to consider the implications of different pricing approaches to the value of lost load and consider whether a single value or approach would be appropriate. (Tier 2)

- SPP and stakeholders should modify the tariff to clarify that the updated cleared quantities will be used in the settlement of repriced day-ahead periods. (Tier 3)

Recommendations – Scheduling and dispatch

- SPP and stakeholders should work to update the tariff with an approach that allows the use of mitigated offers, similar to the process for multi-day minimum run time resources, for resources committed by the multi-day reliability assessment. (Tier 2)

- SPP and MISO should include the benefits of enhanced transmission capabilities in addressing systems emergencies like the February 2021 winter weather event in their joint transmission planning process. (Tier 2)

- SPP should perform a study to identify if there are barriers to participation of imports in the day-ahead market and identify changes to address any issues identified in the analysis. (Tier 3)

- SPP should study the performance of the market-to-market process during the event and provide lessons learned and recommendations. (Tier 3)

- SPP should study the effectiveness of virtual transactions during the winter weather event and identify any potential lessons learned or recommendations going forward. (Tier 3)

Recommendations – Gas-electric coordination

- SPP and its stakeholders should engage with regulators (both federal and state) and the natural gas industry to appreciate the challenges in the connection between the availability of natural gas supply and the ramifications to SPP's system in the event of a natural gas supply shock and to work for a solution to limit the possibility of harm from another event such as occurred in February. (Tier 1)
- SPP and its stakeholders should engage with regulators (both federal and state) and the natural gas industry to recognize the relationship between uncapped natural gas prices and capped electric prices and the harm that can occur to electric ratepayers. We further recommend that a solution be developed to limit the possibility of harm to electric ratepayers as a result of uncapped natural gas markets. (Tier 1)
- SPP and its stakeholders can petition federal regulators and collaborate with the gas industry on a natural gas market trading approach that addresses the needs of natural gas-fired resources to be able to start up quickly and on short notice. (Tier 1)

Recommendations – Other

- SPP should understand the potential for how high prices can get and stress test the credit requirements based on these possibilities. SPP should update credit requirements based on lessons learned from stress tests. (Tier 2)
- SPP should consider developing a memorandum of understanding with ERCOT with regards to confidential credit information sharing. With respect to FERC jurisdictional RTOs, consider coordinating with RTOs to petition FERC to allow confidential credit information sharing. (Tier 3)
- SPP and stakeholders should consider ways to adjust credit calculations to account for structural as well as temporary shifts in market conditions. (Tier 3)

- SPP should evaluate its processes to ensure market participants receive timely and effective responses, particularly with respect to settlements and repricing. (Tier 3)

- SPP should develop and maintain an email list that reaches all market participants to help facilitate market communications. (Tier 3)

- SPP should communicate to market participants when day-ahead capacity shortages occur and update the market protocols as appropriate. (Tier 3)

- SPP and stakeholders should modify the tariff to clearly explain when and how the dispatch target adjustment process is used, and that this dispatch is treated as an OOME for settlement purposes. (Tier 3)

- SPP and stakeholders should evaluate whether a more precise emergency maximum parameter would more reliably represent actual physical limits, such as a graduated emergency maximum with an associated time limit parameter. (Tier 2)

- SPP and stakeholders should consider limiting wind for emergency maximum clearing to a number based on a forecast. (Tier 2)

2 BACKGROUND

In order to understand the MMU's recommendations and takeaways, it is important to understand the background, in particular, with regards to FERC Order No. 831. The MMU has a specific role as outlined in FERC Order No. 831. In this section, we provide the context of this order and the specific actions the MMU undertook during this event.

2.1 POLAR VORTEX AND FERC ORDER NO. 831

In January 2014, the eastern United States was affected by a significant cold snap. This cold snap, known as a polar vortex, brought bitterly cold artic air into the continental United States.[1] The cold weather set record low temperatures through the region, and set new winter demand records throughout multiple RTOs. In addition to stressing RTO and ISO operations, the cold weather event also stressed RTO markets. Of note, natural gas prices increased to levels that potentially did not allow generators to offer in at marginal costs; PJM, NYISO, and MISO, requested that FERC either temporarily or permanently approve increases to the $1,000/MWh offer cap.[2] For instance in the PJM region, natural gas prices reached over $100/MMBtu, which had the potential to cause offers of natural gas fired generation to exceed the offer cap of $1,000/MWh.[3]

FERC recognized that should similar conditions occur to cause natural gas prices to rise to levels experienced during the polar vortex, the offer cap of $1,000/MWh in the electric markets could potentially create issues given that electric generators would potentially not recover costs. FERC initiated a proceeding in Docket No. AD14-14-000 to review price formation in RTO markets. In January 2016 FERC issued a NOPR (Docket No. RM16-5-000) to require RTOs to allow verified

[1] For more information on the January 2014 polar vortex see: https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[2] FERC Order No. 831 paragraph 14, https://www.ferc.gov/sites/default/files/2020-06/RM16-5-000.pdf.

[3] See https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014q1-som-pjm.pdf, p. 128.

offers over the $1,000/MWh cap in price formation and in settlement. This ultimately became FERC Order No. 831, which was issued in November 2016.

FERC Order No. 831 allows the market monitor to verify offers over $1,000/MWh for price formation and settlements purposes. Specifically, if the MMU verifies an offer above $1,000/MWh and below $2,000/MWh before the clearing of the market, the offer will be used in price formation. Offers above $2,000/MWh that are verified before the market clearing, will be included in the market clearing processes at an offer of $2,000/MWh. Offers that cannot be verified before market clearing will enter the market clearing process at $1,000/MWh. This verification process requires participants to submit justification for their offer. This justification can include a screen shot. If no justification is provided, the MMU cannot verify the offer. For settlements purposes, the MMU will verify actual costs above $1,000/MWh. The RTO settlements system will then use these MMU verified actual costs to determine if make-whole payments are necessary.

Ultimately, FERC intended the order to improve price formation, allow compensation for costs incurred, to allow for efficient dispatch, and to encourage resources to offer in when most needed.[4] The FERC order also intended the MMU to play a critical role in verifying expected costs prior to market clearing and in reviewing actual costs for settlements purposes.

2.2 MMU ACTIONS

Leading into the cold weather event, the MMU was aware of the general system conditions. For instance, the MMU through its surveillance activities was aware of the icing conditions that affected wind turbines beginning on February 7 and was tracking market outcomes and performance. The MMU observed a doubling of natural gas prices above their normal levels on February 8. On February 10, market participants informed the MMU that they were switching resources from natural gas to fuel oil. By mid-day on February 11, SPP operations staff informed the MMU that they were likely to commit resources through the holiday weekend to ensure

[4] FERC Order No. 831 pages 1-2

resources were available for the beginning of the week when loads were forecast to be the highest. The MMU received a handful of requests from market participants for offers above $1,000/MWh on February 11 and answered questions related to the process for submitting offers over the $1,000/MWh cap. The MMU anticipated receiving multiple offers above $1,000/MWh on February 12 for the day-ahead market for February 13 and prepared MMU staff to be able to manually review offers.

MMU staff were initially overwhelmed by the volume of offers over $1,000/MWh on Friday, February 12, relative to the close of the day-ahead market. Moreover, many of the initial offers over $1,000/MWh were not supported by documentation justifying the offer levels. As such, only a handful of offers over $1,000/MWh were approved prior to the close of the day-ahead market on February 12 for February 13. The MMU did approve several offers over $1,000/MWh in the real-time market for February 12. Over the course of the next week, the MMU received over 50,000 offers above the offer cap of $1,000/MWh. As the days went on, MMU staff became more efficient in approving offers above the cap. One notable challenge was offers that changed de minimus from prior levels. In these instances, the MMU would review and approve an offer, only to have the offer resubmitted with minimal changes a few minutes before the close of the market.[5] In these instances, the MMU may not have had an opportunity to review the offer before the close. This represents an area of improvement going forward.

The MMU was in constant contact with SPP staff, board members, regulators, and market participants throughout the event. For instance, the MMU alerted federal regulators of the exorbitant natural gas price levels on February 12. In the evening of February 12, the MMU was alerted to issues with the processing of offers over $1,000/MWh and advised SPP of the MMU opinion on the issues by midday on February 13. In the morning of February 14, MMU staff alerted the chairman of the Oversight Committee and the MMU Oversight Committee liaison of the potential size of make-whole payments, indicating that make-whole payments were likely to be in excess of $1 billion, and that the MMU had heard from market participants regarding

[5] Market close is 9:30 am central time for the day-ahead market and 30 minutes prior to the operating hour for the real-time market.

potential credit issues. The MMU presented to a full session of the board of directors on market conditions and potential settlement and credit ramifications on the afternoon of February 14. On February 15, the MMU advised SPP staff to consider correcting day-ahead prices for operating days February 13 and 14. The MMU responded to multiple calls from market participants regarding market anomalies including transaction curtailment, dispatch concerns, and low market prices given the cost of fuel, and addressed multiple calls regarding the gas cost recovery process.

After the event had ended, the MMU outlined the actual cost verification process. MMU staff understood that additional procedural information was necessary to be developed and communicated to market participants in order to successfully validate costs within the tariff required timeline of 45 days. On March 1, the MMU published a memo describing the information and process necessary to validate costs over $1,000/MWh. The MMU presented this information to market participants on March 3. Interest in this discussion was so overwhelming that the MMU had a follow-up presentation on March 4.

Shortly after these presentations, the MMU began hearing from several market participants that they were unlikely to get invoices from natural gas pipelines in time to meet the 35 day tariff requirement to submit cost information to the MMU. The MMU began to consider a waiver as an option to delay the tariff required timelines. The MMU began drafting a waiver and then reached out to SPP staff on March 8, and discussed the waiver with FERC staff during a pre-filing discussion on March 10. The MMU and SPP jointly filed the waiver request on March 11. FERC approved the waiver request on March 17, extending the timeline for participants to submit actual gas cost information from 35 days to 75 days, extending the MMU timeline from 45 days to 105 days, and modifying the process for disputing the 120 day settlement statement for the winter weather event period.

The MMU received a handful of actual cost information under the original timeline and acted in good faith to review the costs in advance of the 53 day settlement statement. Given the challenges of reviewing and processing this information, this information was processed on the 120 day settlement statement. The MMU worked closely with RTO staff to ensure a smooth handoff of actual cost information from the MMU processes to the RTO settlement systems, providing information that would allow SPP staff to validate processing of information in addition to the actual cost data.

The MMU was active in presenting on the winter weather market events to stakeholders. The MMU presented to FERC staff on multiple occasions including February 25, March 9, and April 13. The MMU presented to the MWG on March 16, the MOPC on April 13, the Oversight Committee on April 14, and the Regional State Committee on April 26.

2.3 COMPREHENSIVE REVIEW PROCESS

At the March 2 board meeting, SPP launched its effort to comprehensively review the outcomes of the winter weather event, identify lessons learned, and make recommendations for improvement. There were five paths of review including operations, financial, communication, the Regional State Committee, and market monitoring.

The MMU developed a work plan that covered three main areas. These areas include actual cost review and process analysis, behavioral issues and related rules issues, and a review of market performance and rules. The MMU identified that it would present its findings and recommendations with various working groups including the MWG, ORWG, SAWG, CAWG, and CPWG. These discussions were useful in providing information to the working groups and soliciting feedback on issues, concerns, and ideas for improvement.

Over the past several months, the MMU was active in engaging these working groups on lessons learned from the winter weather event. The MMU participated in multiple sessions with multiple working groups. In addition to attending the weekly MWG sessions, the MMU spoke with the CPWG leadership about credit concerns on April 7; discussed resource adequacy, outages, and behind the meter generation with SAWG on April 9; discussed key takeaways and lessons learned with the CAWG on April 19; and presented on pricing, dispatch, resource availability and outages with the ORWG on April 20. The topics covered by the MMU included the FERC Order No. 831 process, make-whole payments, price formation, scarcity pricing, supply adequacy, repricing, gas-electric coordination, interties/seams, virtual transactions, dispatch, and communication.

2.4 REPORT LAYOUT

This report is the culmination of efforts by the MMU in communication with working groups, SPP staff, market participants, and regulators. This report represents the MMU's independent assessment of the February 2021 winter weather event. This report overlaps in places with reports developed through the working group process and also includes some areas of divergence. MMU staff looks forward to working with SPP and stakeholders to develop solutions to the issues identified in this report.

The report is laid out in the following sections. The report begins with the Executive Summary, which highlights MMU findings and recommendations. Chapter 2 provides background on FERC Order No. 831 as well as the MMU's involvement in the winter weather event and engagement in the comprehensive review process. This is followed by chapter 3 on FERC Order No. 831 offer verification and the make whole payment process. Chapter 4 covers resources including resource performance, the outage process, and behind the meter generation. Price formation is covered in chapter 5. Scheduling and dispatch items are outlined in chapter 6. Chapter 7 covers gas-electric coordination issues, and chapter 8 covers other categories, which include credit and communication related issues. Chapter 9 highlights the MMU's conclusions.

3 FERC ORDER NO. 831

The FERC Order No. 831 process requires the MMU to review expected costs over $1,000/MWh before use in the market clearing process and to review actual costs before use in the settlement process. Prior to the winter weather event, the MMU had never received an offer over $1,000/MWh and, thus, the processes in place had not been exercised in a production environment. Moreover, the processes in place going into the winter weather event, were not designed to manage the volume of offers above $1,000/MWh that occurred during the event. There were many lessons learned as part of this event on how to improve the processes associated with FERC Order No. 831. We provide recommendations related to expected costs, actual costs, and make-whole payments below.

3.1 EXPECTED COSTS

Expected costs issue #1

The MMU's review process is a highly manual process that takes time to approve a high volume of offers. Although the MMU already has some information, such as heat rate for generators, the fuel cost must be provided by the market participant. One challenge is obtaining documentation from the market participants prior to the start of the day-ahead market clearing process. While information on the natural gas market was limited prior to the day-ahead market close, market participants were sometimes slow to submit required documentation. The day-ahead market solve time still needs to meet the 1 pm posting time, particularly on days in which a timely natural gas nomination is even more important. This meant that the MMU only had a very small window to approve offers in the day-ahead market after the close and before the market-clearing process begins.

In contrast, once natural gas prices are published, the MMU can use these values to approve a number of offers, making approval of expected real-time offers generally much quicker.

Finally, after a decision to approve an offer is made, both the day-ahead market and mitigated offers for each hour must be manually approved by an MMU staff member prior to the start of the clearing process.

Recommendations

- The MMU should work with SPP staff and stakeholders to improve the process of reviewing and approving expected costs. Software improvements should be considered.
- The MMU should consider obtaining access to Intercontinental Exchange information, which would allow expected costs for the day-ahead market to verified more quickly.
- SPP conducts a winter preparedness workshop annually. The MMU should review the process for verifying offers above $1,000/MWh and required substantiating documentation as a standing topic to the winter weather preparedness workshop. (Tier 2)

Expected costs issue #2

No load and start-up costs are not a part of the expected cost verification process. While these costs are not part of price formation, they are considered as part of commitment decisions. Such commitment decisions may result in substantial make-whole payments. No-load costs in excess of $300,000 an hour occurred several times during the event. While during the event, particularly during energy emergency alerts, all resources with access to fuel were online, at certain times throughout the event commitment decisions were made.

Recommendation

The MMU should work with SPP and stakeholders to modify SPP's tariff to also clearly state that during periods with energy offers over $1,000/MWh, start-up and no load costs will be based on the mitigated no-load and mitigated start-up offers, which will then be verified by the MMU for actual costs. (Tier 2)

Expected costs issue #3

The resubmission of offers that were already approved created challenges in getting offers above $1,000/MWh into the price formation process. In other words, a market participant with an approved offer above $1,000/MWh would resubmit an offer with an identical or nearly identical price curve. Often this was the result of a market participant business practice of re-submitting the whole offer package at about 27 minutes past the hour. Programmatic resubmitting of offers near market close with de minimus changes presents a problem because it cancels the approved offers. SPP starts the market clearing process by determining which resources are on regulation 25 minutes prior to the operating hour. When the resubmissions occurred, the MMU would often have to begin the review process all over again, which made the approval process more cumbersome and could result in prices below the marginal cost of production.

Recommendation

Modify software to allow easy comparison of a current offer with the last approved offer to expedite the expected cost approval process. (Tier 2)

Expected costs issue #4

While FERC Order No. 831 allows an adder of $100/MWh to cover fuel uncertainty, this amount is only permitted when the offer is between $1,000/MWh and $2,000/MWh. While resources above $2,000/MWh are made whole to actual costs, they are not able to recover any premium to cover the financial risk they are taking to procure gas, such as interest or gas price changes between the offer time and clearing time. For example when gas prices are in the $300/MMBtu range, the MMU observed that the prices seemed to change in $25/MMBtu increments. This equates to a $200/MWh price change for times in which the price is $2,400/MWh. This may cause generators not to offer if they are concerned about these risks, which is counter to one of the goals of FERC Order No. 831.[6]

Recommendation

SPP and stakeholders should modify the uncertainty adder from a fixed $100/MWh adder to a 10 percent adder. A 10 percent adder would be in line with existing mitigation percentages in the SPP tariff and would serve as consistent and equitable mitigation against uncertain fuel prices. (Tier 2)

Expected costs issue #5

SPP has not determined what the value of lost load is. As the winter weather event progressed, higher and higher offers were submitted. On February 18, the MMU reviewed offers as high as $24,000/MWh for certain very inefficient gas units on outage, and $16,000/MWh for units that could procure fuel. Although the MMU was required to approve offers that were arithmetically correct, it became clear that these offers were well in excess of many published value of lost load numbers in other RTOs and that SPP did not have its own published value. Some load and ratepayers might have preferred to get off the grid at a lower cost than these values. Determining what the value of lost load in SPP is will help to inform how SPP can meet its mission of "Working together to responsibly and economically keep the lights on today and in the future." For example, ERCOT has determined that the value of lost load is $9,000/MWh and prevents recovery above this level and sets the price to this amount while shedding load.

Recommendation

SPP should conduct a study to determine what the value of lost load in SPP is. This will inform many other decisions such as pricing while shedding load, the appropriate offer cap, and upper limit on offers being approved. (Tier 2)

[6] Order 831, paragraph 15.

3.2 ACTUAL COSTS

FERC Order Nos. 831 and 831-A specify that offers over $1,000/MWh that are eligible for make whole payments need to reflect actual costs, rather than expected costs. SPP tariff attachment AF 3.2(J) is consistent with this requirement. During the February winter weather event, the MMU, along with SPP legal staff, filed a joint waiver to address issues related to the short timeline and review period associated with the review of actual costs. The MMU proposes to permanently update some of this language, and to change other language associated with exceptions within FERC Order No. 831-A.

Actual costs issue #1

Market participants needed more than 35 days after the market day to submit actual cost information to the MMU. This requirement is outlined in tariff attachment AF section 3.2 (J). The primary issue during the February winter weather event was that market participants would not have supporting documentation available to justify their actual costs, including information such as natural gas pipeline invoices.[7] While some participants were able to provide the actual cost information on the original timeline, most participants were not able to get this information to the MMU in 35 days. Given this issue, MMU counsel crafted a tariff waiver, along with SPP legal staff, to increase the timeline to provide actual cost information from 35 to 75 days. The extended timeline was sufficient for market participants to acquire the necessary background information to justify their actual costs.

Recommendation

SPP and stakeholders should consider permanently changing the timeline in the tariff for submittal of actual costs from 35 days to 75 days. Market participant can always have the option to submit sooner than the requirement and the MMU can act in good faith to review the

[7] Many natural gas pipelines filed waiver requests with FERC which delayed them from issuing invoices.

information to be included on an earlier settlement statement if submitted in a timely manner. (Tier 3)

Actual costs issue #2

The MMU is required to review actual cost information no later than 45 days after the market date. This requirement is outlined in tariff attachment AF section 3.2 (J). In most cases, this would only give the MMU 10 calendar days to complete its review. The primary issue during the February winter weather event was the significant volume of resources affected by the event, at over 240 resources for 10 operating days. Given this issue, MMU counsel crafted a tariff waiver, along with SPP legal staff, to increase the timeline for the MMU to provide SPP actual cost information from 45 to 105 days. Given that the waiver also increased the timeline for market participants to submit actual costs from 35 to 75 days, this effectively gave the MMU 30 days to complete its review. While some participants provided their submittals in advance of the 75 day requirement, many submitted their actual costs around the requirement period. The review of actual costs was the primary focus of the MMU during this period, and required the majority of the MMU staff to complete on time.

Recommendation

SPP and stakeholders should consider permanently changing the timeline in the tariff for the MMU review of actual costs from 45 days to 105 days. Market participants will always have the option to submit sooner and the MMU can act in good faith to process it on an earlier settlement statement if submitted in a timely manner. (Tier 3)

Actual costs issue #3

If verified actual costs are to be included on the S120 settlement statement, participants should be allowed to dispute these costs. Disputes on the S120 settlement statement are typically limited to incremental changes from the previous settlement statement. This requirement is outlined in tariff attachment AE section 10.3. The primary issue during the February winter weather event was that actual cost verification would occur after the S53 settlement statement.

Given this issue, MMU counsel crafted a tariff waiver, along with SPP legal staff, to allow for 30 days to dispute the S120 settlement statements associated with the actual cost review of offers in excess of $1,000/MWh.

Recommendation

SPP and stakeholders should consider permanently updating the settlements dispute language to allow disputes on the S120 settlement statement related to the settlement of actual costs under FERC Order No. 831. This language would be consistent with the waiver and allow for an additional 30 days to dispute the settlements associated with actual costs without demonstration of a material incremental change. (Tier 3)

Actual costs issue #4

Not allowing resources to recover higher costs can lead to perverse incentives and potential gaming issues. In FERC Order No. 831-A, FERC noted that "…allowing a resource to receive uplift in excess of its verified cost-based incremental energy offer could give that resource the incentive to submit offers that do not reflect its actual short-run marginal costs and could thus result in inefficient resource selection."[8] However, given the experience during the February winter weather event, we believe that the greater issue, on balance, is that market participants would be incented to wait to the last possible second to submit an offer in an attempt to not allow the MMU sufficient time to verify expected costs prior to market close. In this case, the offer would be capped at $1,000/MWh for price formation in market clearing, deflating the marginal price and resulting in inefficient resource selection. However, the resource would also be eligible for recovery of actual costs that were higher than the estimated values, increasing uplift charges to the market. Another issue is that a market participant could inflate their offer by inflating the price they pay for natural gas for a small quantity to increase the marginal cost. While this would be an act of market manipulation, the MMU does not monitor natural gas market trading activity for manipulation. Or worse, a market participate may take an outage for

[8] FERC Order No 831-A paragraph 39.

lack of fuel, because they are concerned that they cannot recover their actual costs. We do not view this as an appropriate outcome. Ultimately, market participants should have the correct incentives to offer in their legitimate expected costs in a timely manner to allow for verification by the MMU prior to market clearing, and that perverse incentives associated with actual cost recovery should be addressed.

The MMU recognizes the perverse incentives and market inefficiencies associated with price formation based on capped offers, dispatch instructions based on estimated costs, and make-whole payments based on actual costs. Because reimbursement for actual costs incurred is capped at the verified expected cost at the time of market clearing, participants are incentivized to artificially inflate their expected cost, and submit offers at the last minute to prevent verification prior to market clearing. These issues need to be addressed as part of any solution.

Recommendation

SPP and the stakeholders should develop tariff language that ensures all participants are reimbursed fairly and consistently, and strengthen the rules for calculating accurate expected costs as follows:

- Limit reimbursement for actual costs to all offers that require verification prior to use in market clearing, and
- Outline under what specific circumstances the MMU would have the latitude to consider reimbursement for actual costs that are in excess of expected costs. (Tier 2)

3.3 MAKE-WHOLE PAYMENTS

Make-whole payment issue #1

Current SPP tariff rules do not allow make-whole payments for instructed real-time incremental energy (i.e., above day-ahead), with the exception of out-of-merit energy (OOME). Outside the FERC Order No. 831 process, resources would only be instructed to increase energy if the incremental energy offer was consistent with the prevailing price at their location, or if SPP operators gave the resources an OOME. However, because FERC Order No. 831 caps offers at either $1,000/MWh or $2,000/MWh, the circumstance can arise that the price at a resource's location is in fact less than offered marginal cost of the resource. This is true whether the resources is committed by the market or is self-committed. FERC Order No. 831 recognized this issue and indicated that these resources should be made-whole after the market monitor verifies actual costs. However, SPP's current tariff rules and market settlements design do not account for the circumstances associated with capped energy offers under FERC Order No. 831. For example, consider a scenario where a resource had a day-ahead schedule of 100 MW and was increased to 150 MW in real-time. In both instances the incremental cost was $3,000/MWh and day-ahead and real-time prices were the same at $2,000/MWh. While the resource will be made whole to their $3,000/MWh cost in the day-ahead market for the 100 MW, the additional 50 MW dispatch in real-time will not receive a make-whole payment based on current SPP rules and settlement processes. The resource will only receive the real-time price for the additional 50 MW, leaving the resource $50,000 short to cover costs.[9]

Recommendation

SPP and stakeholders should update the tariff to allow for make-whole payments for instructed real-time incremental energy costs above the day-ahead cleared position for offers that fall under FERC Order No. 831 regardless of the reason for the commitment. The settlements system should then be updated in accordance with the change. (Tier 2)

Make-whole payment issue #2

Current SPP tariff rules do not allow make-whole payments for self-committed resources. When a resource self-commits, it gives the market energy at minimum operating limit in exchange for the locational marginal price. Effectively, the resource is a price taker at its minimum operating limit with costs that include start-up, no-load, and energy. Aside from being ramp constrained, any dispatch above minimum operating limit should be economic relative to the resources

[9] Resource incremental cost minus real-time price times the incremental real-time generation above day-ahead, ($3,000/MWh - $2,000/MWh) * 50 MW = $50,000.

competitive energy offer, leaving any supplier surplus to defray start-up and no-load costs. When the market clears with capped energy offers, even though dispatch instructions may be in economic order, the prevailing price at a location does not reflect the cost of incremental energy. Under these circumstances, the market may dispatch a self-committed resource uneconomically. FERC Order No. 831 states one of the goals in price formation is to ensure that all suppliers have an opportunity to recover their costs. While a resource may have accepted the risk associated with starting and operating at its economic minimum output for the potential of supplier surplus from energy dispatches above minimum, when those dispatches result in negative revenue, the resource does not have an opportunity to recover their cost. This issue is present in both the day-ahead and real-time markets.

Recommendation

SPP and stakeholders should update the tariff to allow for make-whole payments for self-committed resources for day-ahead clearing and real-time dispatch above a resources minimum operating limit for offers that fall under FERC Order No. 831. The settlements system should be updated in accordance with the modified language. (Tier 2)

Make-whole payment issue #3

Resources can be made-whole in the day-ahead market to verified costs that exceed prices, but will buy back their position in real-time based to prices formed by capped offers. This situation can lead to inappropriate make-whole payments. For example, a 100 MW resource may be dispatched at full output at a price of $2,000/MWh, but the verified costs were $3,000/MWh. This resource would receive $100,000 in day-ahead make-whole payments for total day-ahead revenues of $300,000.[10] However, load drops and imports increase in the real-time market, which results in prices falling to $1,000/MWh and the resource being dispatched to a minimum of 20 MW. The resource will buy back 80 MW at $1,000/MWh for a cost of $80,000/MWh. Thus, the resource received $220,000, which includes the day-ahead make-whole payment even

[10] Market revenues = (100 MW * $2,000/MWh) = $200,000; Make-whole payments = (100 MW * $3,000/MWh) - $200,000 = $100,000; Total payments = $200,000 + $100,000 = $300,000.

though the actual cost of real-time production was $60,000 (20 MW * $3,000/MWh). In this instance, the make-whole payment was not necessary. If day-ahead and real-time positions were combined, there were sufficient revenues to cover actual costs without any make-whole payment.[11] While we agree that keeping day-ahead and real-time revenues separate is appropriate in most circumstances, the MMU believes that day-ahead and real-time revenues should be combined when evaluating make-whole payments associated with FERC Order No. 831.

Recommendation

SPP and stakeholders should modify the tariff to allow for the combination of day-ahead and real-time revenues and costs when assessing the need for make-whole payments consistent with FERC Order No. 831. The settlements system should then be updated in accordance with the change. (Tier 2)

Make-whole payment issue #4

There is a range of other potential make-whole payment and distribution issues that should be reviewed and considered to determine their appropriateness and consistency with FERC Order No. 831. The MMU is concerned that resources may be overcompensated or undercompensated through make-whole payments in various ways, and that the tariff and settlements system should be modified to minimize these issues.

Recommendation

SPP should perform an evaluation of the current settlement approach to determine if there are over-or under-compensation of actual fuel costs through make-whole payments. The study should also identify issues with how make-whole payments are distributed. The study should highlight recommendations for addressing any identified issues. (Tier 3)

[11] Day-ahead quantity times day-ahead price minus real-time buyback quantity times real-time price is greater than real-time quantity times actual cost. (100 MW * $2,000/MWh) – (80 MW * $1,000/MWh) = $200,000 - $80,000 = $120,000 > (20 MW * $3,000/MWh) = $60,000.

4 RESOURCES

4.1 OUTAGES

Outages contributed significantly to the event. While the amount of generation on routine maintenance outages reduced throughout the event, a significant amount of resources were on outage for fuel supply issues.

Outages issue #1

Several resources were in an economic outage at the start of the event on February 8. Some of these resources report economic outage while generating in ERCOT, while others reflect economic outages because they are only committed by MISO in cases where an SPP market participant is a minority owner. Some of these outages reflected resources that are not typically needed outside the summer season.

When the event began, resources in which the SPP market participant has a minority stake, but are committed by MISO started, ran throughout the event, and went back into outage afterwards. This was appropriate and expected behavior. Furthermore, ERCOT consistently had higher prices than SPP, so some resources generated in ERCOT instead of SPP as expected.

However, there were multiple units that had marginal costs well below prevailing prices that did not start early on in the event. The current outage rules do not explicitly require an economic outage to include a recall time, even though by definition, this unit is in good working order. This problem was identified in the MMU's review of SPP Conservative Operations in 2019 and was included as an Annual State of the Market Report recommendation.

Recommendation

Approve the MMU State of the Market recommendations related to outages. As of the date of publication of this report, this change had been approved by the Generator Outage Task Force and is awaiting ORWG action. (Tier 2)

Outages issue #2

Icing was not reported under a single outage type. Some plants reported these as fuel outage, while others classified these as environmental. This made situational awareness of wind generator status difficult.

Recommendation

SPP should clearly indicate how to report icing in the outage coordination methodology. (Tier 3)

Outages issue #3

A large number of outages that the MMU reviewed did not have all of the information that is required by the Outage Coordination Methodology. The MMU observed a large amount of generation on fuel outage for gas supply; however, market participants for some of these facilities later indicated in public forums that they had no difficulty procuring gas during the event. Such material misstatements of outage information could be considered providing false information to the RTO and may result in referral to FERC.

Recommendation

Market participants should follow the Outage Coordination Methodology. SPP should consider not approving outages with missing required information. (Tier 2)

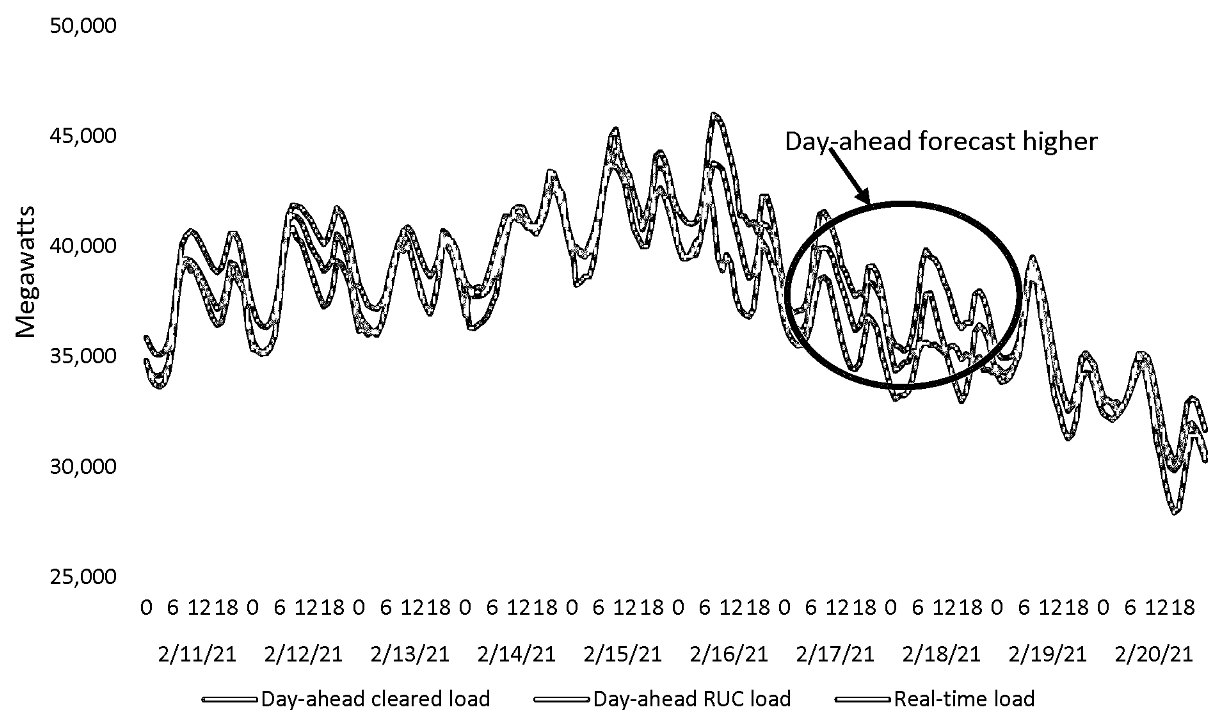
4.2 BEHIND THE METER CAPACITY

Tariff attachment AE section 2.2(6) exempts resources that are behind the meter and less than 10 megawatts from registering in the market. This can include both small generation as well as demand response resources. Given the tight supply and demand conditions during this event, every resource becomes critically important. The MMU understands that some market participants accounted for these resources in load assessments. However, what is not clear is how all of the resources were accounted for in the day-ahead and real-time markets, to what extent there were unused behind the meter resources, and to what extent there were limitations to accessing these resources in SPP's markets. In this section, we outline two issues and provide recommendations.

Behind the meter capacity issue #1

Behind the meter resources 10 megawatts or less are not required to be explicitly accounted for in the market and may or may not have been accounted for in load estimates during the winter weather event. Collectively these resources can have significant effects on system reliability as well as on market prices. For instance, day-ahead load forecasts were high relative to real-time load (see Figure 4-1), particularly on February 16, 17, and 18. There are multiple factors that can contribute to this difference including temperature differences between forecasts, unaccounted for conservation, public appeals, and unforecasted use of exempted behind the meter resources. Including or not including these resources in either the day-ahead or real-time load forecasts can have significant effects on market outcomes as well as reliability. Understanding their impact can improve both reliability and price signals.

Figure 4-1 Load comparison during winter weather event



Recommendation

SPP and its stakeholders, including regulators, should conduct a study on behind the meter resources that are below the 10 megawatt threshold and determine their impacts on reliability and market outcomes. The study would identify lessons learned and provide recommendations for any potential future operational or market enhancements. (Tier 2)

Behind the meter capacity issue #2

It is unclear how unregistered behind the meter capacity performed relative to capacity requirements during the winter weather event. If these resources were counted on as capacity, it would be important to understand their performance during this event, and what changes, if any, would be required going forward.

Recommendation

SPP and its stakeholders, including regulators, should conduct a study on behind the meter resources that are below the 10 megawatt registration threshold and determine their performance as capacity resources. The study would identify lessons learned and provide recommendations for any potential future enhancements. (Tier 2)

4.3 RESOURCE ADEQUACY

While most resources types had availability issues during the February 2021 winter weather event, at the very heart of the cold weather event, natural gas plants were unavailable to generate. Our research notes that natural gas pipeline limitations and access to storage were not driving factors. The primary issue was that power plants could not obtain natural gas molecules from suppliers to generate. In some cases, this was because the cost of natural gas was so high, some companies did not have enough credit to buy fuel. In other cases, there was no natural gas available at any price.

In February 2021, natural gas resources were assumed to be available, but many were not available because they could not procure fuel to run. While there may have been sufficient capacity, this capacity was not available to run. In order to address this, the MMU believes that better planning and incentives are required. The MMU considers these changes as critical and necessary to avoid another potential repeat of the conditions that occurred during the February winter weather event.

In this section, we highlight issues and recommendations for critical changes to improve outcomes.

Resource adequacy issue #1

SPP's tariff lacks effective incentives for accredited capacity to be available in the day-ahead and real-time markets. SPP tariff Attachment AA recognizes that if SPP is to rely on resources that have been accredited in the resource adequacy process, then those resources should actually be available to serve load in the markets. Attachment AA accurately states that "Maintaining appropriate planning reserves ensures that the Transmission Provider will have sufficient capacity to serve the SPP Balancing Authority Area's peak demand."[12] Furthermore, Attachment AA says that it "*requires* a Load Responsible Entity to *maintain capacity* required to meet its load and planning reserve obligations."[13] However, the tariff does not provide any meaningful incentives to maintain available, useful capacity in any deliverable sense, other than a FERC referral for a tariff violation. Without meaningful and effective incentives, the best resource adequacy process will not result in an effective plan to serve load.

Incentives can help ensure that accredited capacity will be available in day-ahead and real-time. One such incentive could be a defined measureable availability requirement with a penalty payment for *un*availability. Consequently, capacity accredited in the resource adequacy process could be required to offer in the day-ahead and real-time markets. The unavailability payments collected could be distributed to entities whose availability exceeded the requirement. Another such incentive could be an availability auction where capacity is paid to be available on a mid-term basis, e.g., quarterly, monthly. Similar to the requirement-penalty incentive, this would

[12] SPP Open Access Transmission Tariff, Sixth Revised, Volume No. 1, Attachment AA, Section 1.0.
[13] Ibid.

begin with a defined measureable requirement and would carry a must-offer requirement for all accredited capacity. In the availability auction, payment should be performance based and could include an additional penalty for unavailability.

Both systems could incentivize actual availability, but each has benefits over the other. Both of the above approaches leave the methods of reliable generation up to the market participants, whether it be on-site fuel storage, dual-fuel capability, specialized heating, etc... The biggest advantage for the requirement-penalty incentive is that it is simpler to implement. The availability auction is much more complex. However, the requirement-penalty incentive may increase costs to resource owners that would have to be recovered through marginal prices in the energy market. The availability auction would directly pay for these costs. Additionally, the availability auction should minimize the cost of ensuring availability. In contrast, the requirement-penalty incentive would apply the requirement for all capacity across all resources, which would not minimize the cost to ensure availability and may over-procure availability.

Any incentives, including those described above, would require increased implementation costs and would increase the cost to market participants. There is a definite cost to ensure that the supply will be adequate. While the current supply adequacy requirement has served SPP well for many years, it was inadequate during the February 2021 winter event. If SPP is expected to reliably serve load without interruption, then SPP must be able to rely on generation to be available, even in some extreme circumstances. If SPP is to rely on generation to be available, then it must provide effective incentives.

Recommendation

Establish an incentive mechanism for capacity credited in the planning reserve margin calculation to maintain availability for the duration of the accreditation period. These payments would be applicable to actual resource performance, separate from the current deficiency payments for Load Responsible Entities crediting insufficient capacity towards meeting their required planning reserve margin. This recommendation connects with critical recommendation #2. (Tier 1)

Resource adequacy issue #2

SPP's resource adequacy process anticipates the capacity need only for the summer period. While meeting and planning for summer peaks is important, other times of the year may demand unique capacity requirements. Some periods of the year may have a lower capacity need. Furthermore, resources have different performance capabilities at different times of the year. A single capacity requirement for the entire year is too narrow to determine the year round capacity need.

Furthermore, as SPP anticipates the capacity need more granularly, it should also evaluate the fulfillment of the capacity requirement throughout the year. Currently, resource adequacy is evaluated once per year on February 15. If the resource adequacy process is expected to translate into useful available capacity, then it must be evaluated throughout the year.

Recommendation

Establish a more frequent resource adequacy requirement, such as seasonally (or perhaps monthly), that acknowledges load requirements and generation performance characteristics that are unique to that period. SPP should evaluate to what extent the requirement is fulfilled throughout the year. This recommendation connects with critical recommendation #3. (Tier 1)

Resource adequacy issue #3

The amount of capacity accredited is inaccurately measured and therefore may be over-accrediting capacity. Standard formulas for resource adequacy may often overlook generation portfolio characteristics and seasonal impacts. Some resources have higher outage rates and larger derates than others, yet the current resource adequacy process does not account for expected performance on all resources. If the resource adequacy process intends to connect useable generation to load, then it should estimate future availability based on historical performance and expected future outages and derates.

Variations in resource availability can be compounded by seasonal changes. Some resources have a higher maximum rating in the winter while some have lower winter ratings. The same is true for summer. If the resource adequacy process plans around seasonal needs, then seasonal accreditation should recognize the differences in available capacity across seasons. The current evaluations of resource capacity do not consider historical performance and expected future unavailability as well as seasonal variations in availability and therefore may be under- or over-accrediting capacity. This inaccurate measurement of capacity may result in an ineffective plan to meet load.

Recommendation

Evaluate available capacity on a resource-level, seasonally, taking into account historical availability to determine the amount of deliverable capacity that can be accredited. For instance, a resource's credit toward the planning reserve margin would be discounted by its historical outages and derates during like periods of the year. This allows market participants to decide the appropriate solutions that increase the certainty that their resource will be available while providing an incentive to increase that availability. This recommendation connects with critical recommendation #1. (Tier 1)

Resource adequacy issue #4

In the resource adequacy process, SPP must plan for major shocks to fuel systems and mechanical functionality. Any reliable plan must account for major contingencies. The February 2021 winter event is an example. The reserve margin should consider the effects of a major fuel disruption, such as losing a major pipeline or fuel source. SPP has experienced unavailability of coal and hydro resources during flooding and a loss of generation due to drought. Wind generator production has dropped off sharply due to icing and excessive wind speed. Some resources are difficult to start in extreme temperatures. Likewise, major transmission contingencies can render capacity undeliverable. The reserve margin may need to be increased, or constraints may need to be applied, such as resource type, fuel type, or zonal location. While it would be difficult to plan for every possible contingency, there are opportunities to increase certainty that load will be served.

Recommendation

Account for major contingencies, such as a shock to fuel systems or mechanical functionality, and implement mitigation measures. These measures could include enhancing the planning reserve margin calculation and adjusting the overall margin to increase certainty that peak load will be served during a major contingency. This recommendation connects with critical recommendation #4. (Tier 1)

5 PRICE FORMATION

Prices convey information to the marketplace. The information carried by prices is an essential function in the fundamental coordination of an economic system.[14] This information provides a signal as to the relative surplus or scarcity of the underlying conditions. Market participants consume this information and adjust their production or consumption of the underlying good or service. However, when the price does not accurately signal surplus or scarcity, market participants are less likely to adjust their level of production or consumption or might adjust them in a manner contrary to market needs. In this section we highlight situations where price signals did not accurately reflect underlying conditions, and provide recommendations to improve pricing outcomes.

5.1 PRICES

Price issue #1

When constraint limits are relaxed to the point where unsolvable congestion is alleviated, market prices do not reflect underlying physical or economic conditions. The practice of constraint relaxation can result in an outcome where transmission elements most in demand, whose transfer capability is most scarce, are priced at zero. This outcome is cause for concern, because the zero price is the same price that conveys surplus, not scarcity. For this reason, the information conveyed to market participants under these conditions is inaccurate. That is to say, constraint relaxation causes locational congestion price(s) to be different, and in some cases very different, relative to what they would otherwise be. On February 18, where, under exceptionally congested conditions, the day-ahead market produced locational congestion prices of zero for every location for every hour of an entire operating day. However, in fact, there was significant underlying, unpriced congestion that occurred.

[14] Wikipedia, via Boudreaux, Donald J. "Information and Prices". The Concise Encyclopedia of Economics. Library of Economics and Liberty (econlib.org). Retrieved 18 June 2017.

The MMU does not view the market software's use of violation relaxation limits or their associative price blocks as the root of the problem. The problem rests with the complete relaxation of a constraint such that the scarcity condition, and ultimately the pricing signal is lost. The MMU sees several potential acceptable solutions to this issue.

Recommendation

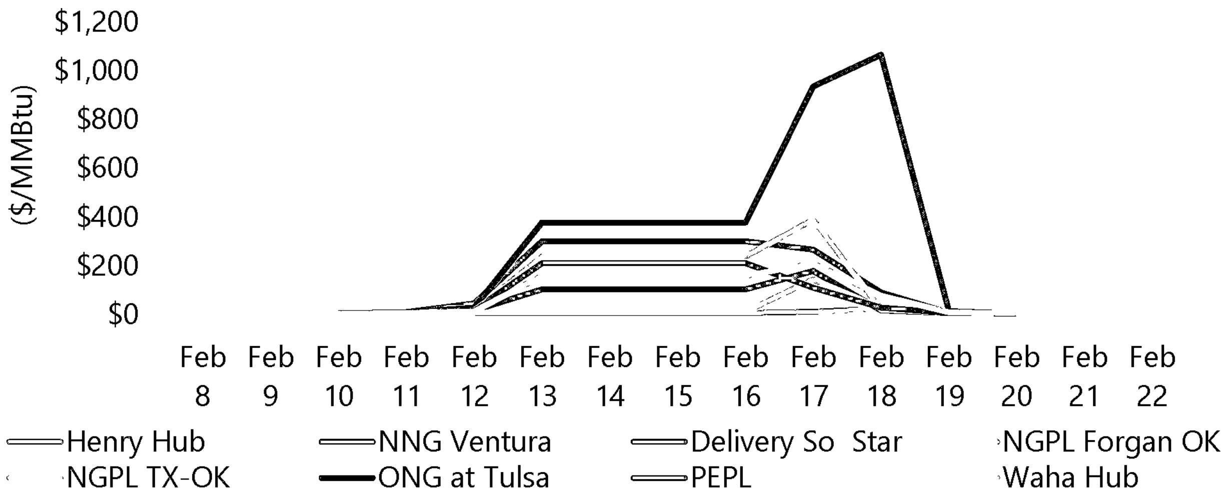
SPP and stakeholders should devise an approach to ensure that congestion prices reflect underlying physical and economic conditions. Ultimately, when transmission is scarce, the congestion should be valued and priced rather than eliminated. (Tier 2)

Price issue #2

The hard offer cap of $2,000/MWh was likely too low. In its summary of Order No. 831, FERC noted that the order "...will improve price formation by reducing the likelihood that offer caps will suppress LMPs below the marginal cost of production..."[15] Given the level of natural gas prices experienced during this event, the hard cap of $2,000/MWh was significantly below the marginal cost of production for many resources. Figure 5-1 shows that natural gas prices were in the $100/MMBtu to $400/MMBtu range for much of this event. Gas prices peaked at one trading hub at over $1,000/MMBtu.

[15] Order 831, Summary, paragraph 90.

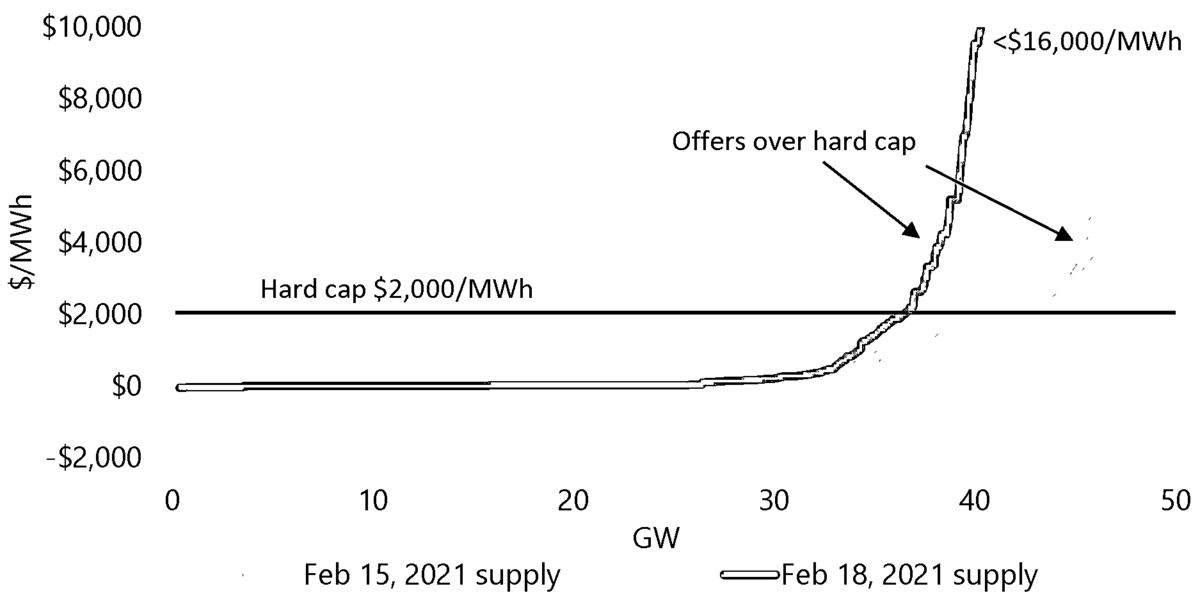
Figure 5-1 Next day natural gas hub prices



Data source: SNL data

Figure 5-2 shows the uncapped offers on two of the days during the winter weather event. Note that on one day, the uncapped offers exceeded $10,000/MWh.

Figure 5-2 Average daily uncapped supply curves



Caps on electric market prices help protect electric ratepayers from the exercise of market power, gaming, and uncompetitive outcomes not only in the electric markets themselves, but also in fuels markets, such as the natural gas market. As such, caps on electric prices should remain in place. However, given the volume of offers above the $2,000/MWh offer cap during the February winter weather event, the SPP energy markets may not have reflected the marginal cost of production of natural gas resources.

Recommendation

SPP, stakeholders, and the MMU should perform a study to determine an appropriate hard cap offer level that balances the need for prices to reflect marginal costs and the need to protect ratepayers from potentially uncompetitive outcomes in fuels markets. (Tier 3)

5.2 PRICING IN EMERGENCIES

Pricing in emergencies issue #1

Prices in the real-time market do not always reflect the level of system tightness during an emergency. This was of particular note during Energy Emergency Alert (EEA) events. The MMU highlighted this issue after the August 2019 EEA1 event.[16] Figure 5-3 shows real-time pricing during the energy emergency alerts, and Table 5-1 summarizes the pricing results. As shown in the table, prices on the low end were $15/MWh during the EEA1, $20/MWh in the EEA2, and $53/MWh during the EEA3. These prices are more consistent with prices on a typical day, rather than during a period of scarcity and extreme system stress.

[16] SPP MMU 2019 Annual State of the Market report, page 274.

Figure 5-3 Real-time pricing during emergencies

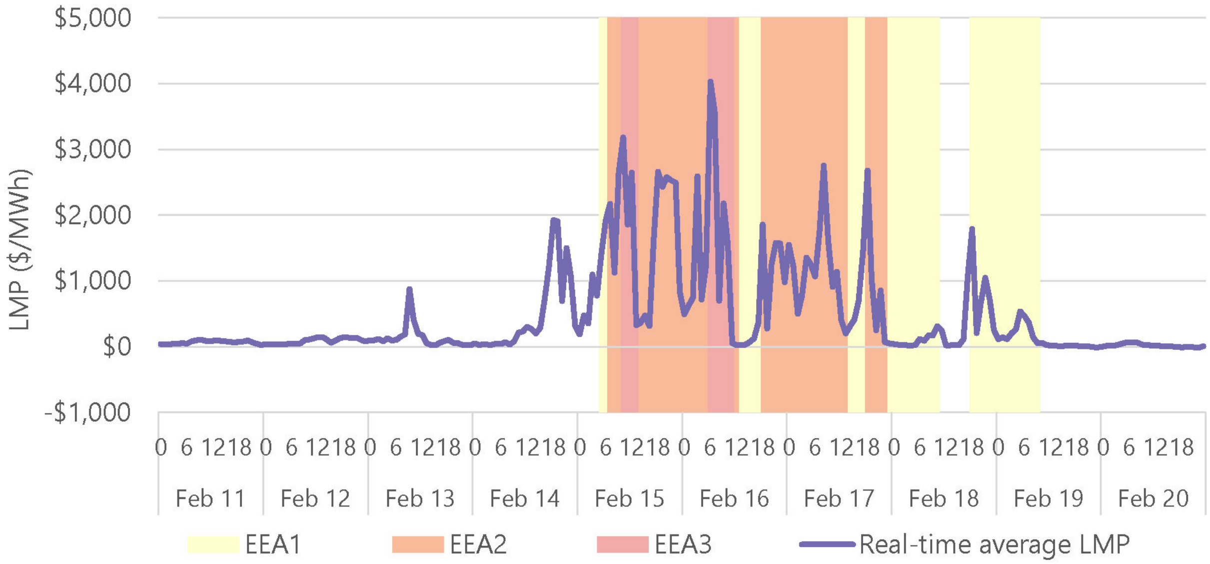


Table 5-1 Real-time price summary during emergencies

Emergency	Hours	Average price ($/MWh)	Low price ($/MWh)	High price ($/MWh)
EEA1	39	$ 383	$ 15	$ 1,912
EEA2	45	$ 1,277	$ 20	$ 2,753
EEA3	10	$ 2,010	$ 53	$ 4,029

Emergency prices can signal a need for imports, demand response, and distributed resources to assist in resolving the concern. In particular, imports played a very significant role in assisting SPP in reducing the depth and length of the emergency conditions as well as the load disruptions. However, when prices dropped to around $300/MWh on February 15 when SPP left the EEA3, there were also lower levels of imports, even though SPP remained in emergency conditions.

Recommendation

SPP and stakeholders should evaluate how to set prices during EEA1, EEA2, and EEA3 events to send price signals for market participants to take actions to help relieve the emergency. Consider reviewing approaches in other markets as a guide to potential approaches. (Tier 2)

Pricing in emergencies issue #2

Different regions value the loss of load differently. Currently, SPP does not explicitly price the value of lost load during an EEA3 event. However, both MISO and ERCOT set prices based on a value of lost load approach when load is curtailed. For instance, prices at the Arkansas hub in MISO during the MISO EEA3 for the southern region were set to value of lost load of $3,500/MWh, and prices in ERCOT were set to $9,000/MWh for the duration of their EEA3. When regions value and price the value of lost load differently, this can create competition for imports among the markets from non-affected regions. FERC jurisdictional markets have consistent offer caps, a soft cap of $1,000/MWh and a hard offer cap of $2,000/MWh. For some of the same reasons why offer caps are the same between regions, there are reasons why value of lost load pricing could also be the same.

Recommendation

SPP and stakeholders should work with MISO to petition FERC to consider the implications of different pricing approaches to the value of lost load and consider whether a single value or approach would be appropriate. (Tier 2)

5.3 REPRICING

Repricing issue #1

The initial repricing of the day-ahead market results for February 13 and 14 did not include updates to day-ahead market cleared amounts. SPP tariff attachment AE section 8.4.2(c) governs day-ahead market price corrections. This section notes that "The Transmission Provider shall perform any necessary Resettlement using the recalculated Day-Ahead Market results." However, the tariff is not entirely clear that the results should include cleared amounts. Not including the recalculated day-ahead amounts produced a less efficient solution and had significant ramifications for transactions such as virtual demand on the S7 settlement statement.

The MMU received multiple calls on the MMU hotline from market participants with virtual transactions that were negatively impacted by the initial repricing of February 13 and 14 prior to the S7 settlement statement. They indicated that they had put in offers to buy virtual load that were accepted at lower price levels in the original market outcome. When the price corrections were made, this resulted in prices above the offer and the new cleared quantities were lowered to zero. However, the S7 settlement included the new prices and the original quantities. While the tariff is clear that the rerun should recalculate cleared amounts, the tariff was not as clear that these new cleared quantities should also be used in the settlement. Ultimately, this was corrected during a second repricing done for the S53 settlement statement. Even so, the tariff should be updated to make clear that cleared amounts will be used in the settlement of repriced days for the day-ahead market.

Recommendation

Change tariff attachment AE section 8.4.2(c) to make clear that updated cleared amounts shall be used in the settlement of repriced day-ahead periods. For instance, tariff attachment AE section 8.4.2(c) could be updated to state "The Transmission Provider shall perform any necessary Resettlement using the recalculated Day-Ahead Market results, including LMPs, MCPs, and Day-Ahead Market cleared amounts." (Tier 3)

6 SCHEDULING AND DISPATCH

6.1 MULTI-DAY RELIABILITY ASSESSMENT

Multi-day reliability assessment issue #1

Tariff language associated with multi-day reliability assessment was in conflict with the intent of FERC Order No. 831. Tariff attachment AE section 4.5.3 reads that "The Transmission Provider will communicate the Commitment Instructions resulting from the Multi-Day Reliability Assessment to the affected Market Participants. At the time of this notification, the submitted Offers become binding and the selected Resource(s) Offers are committed in the Day-Ahead Market." Specifically, this section notes that "submitted Offers become binding." We recognize that this protects the market from participants trying to take advantage of a known commitment and raising their offers to game the market. Ultimately, another process addresses this problem using a different approach. When multi-day minimum run time resources are committed, a very similar issue exists. Specifically, a market participant can take advantage of a known commitment and increase their offers to game the market. The market working group in conjunction with SPP and the MMU devised a solution to this issue that was accepted by FERC.[17] This solution ultimately limits make-whole payments to the mitigated offer for extensions to original commitments to honor minimum runtime.[18] If a similar process were used for the multi-day reliability assessment encompassing the entire minimum runtime, it would not only solve the issue by clarifying the use of FERC Order No. 831 offers for resources committed through the multi-day reliability assessment process, but would also account for changes in costs for offers that are less than $1,000/MWh.

Recommendation

[17] Tariff Revisions Regarding Make Whole Payments and Minimum Run Time

[18] 8.5.9 Day-Ahead Make Whole Payment Amount (3)(a)(i – ii)

Update tariff attachment AE section 4.5.3 with an approach that allows the use of mitigated offers, similar to the process for multi-day minimum run time resources, for resources committed by the multi-day reliability assessment. (Tier 2)

6.2 INTERTIES/SEAMS

Imported generation played a significant role in helping SPP meet demand in the real-time market. That SPP could take advantage of intertie capabilities was a significant benefit to the SPP system. SPP received thousands of megawatts from PJM and MISO during several critical periods during the event. While this was a very positive outcome and a key factor in maintaining reliability, we did identify a few issues and recommendations for moving forward, which we outline below.

Intertie/seams issue #1

Imports into SPP from other parts of the Eastern Interconnection were critical in helping SPP minimize rotating blackouts during the February cold weather event. However, there have been very few interregional transmission additions with SPP and other regions, and none with MISO. SPP and MISO perform regular joint studies, but SPP and MISO evaluate benefits and costs differently; however, it is clear that there were substantial benefits to interregional transfer capability during the winter weather event. It is clear that there are significant potential benefits to addressing emergency conditions that should be factored into any benefit-cost analysis performed with regards to interregional transmission additions.

Recommendation

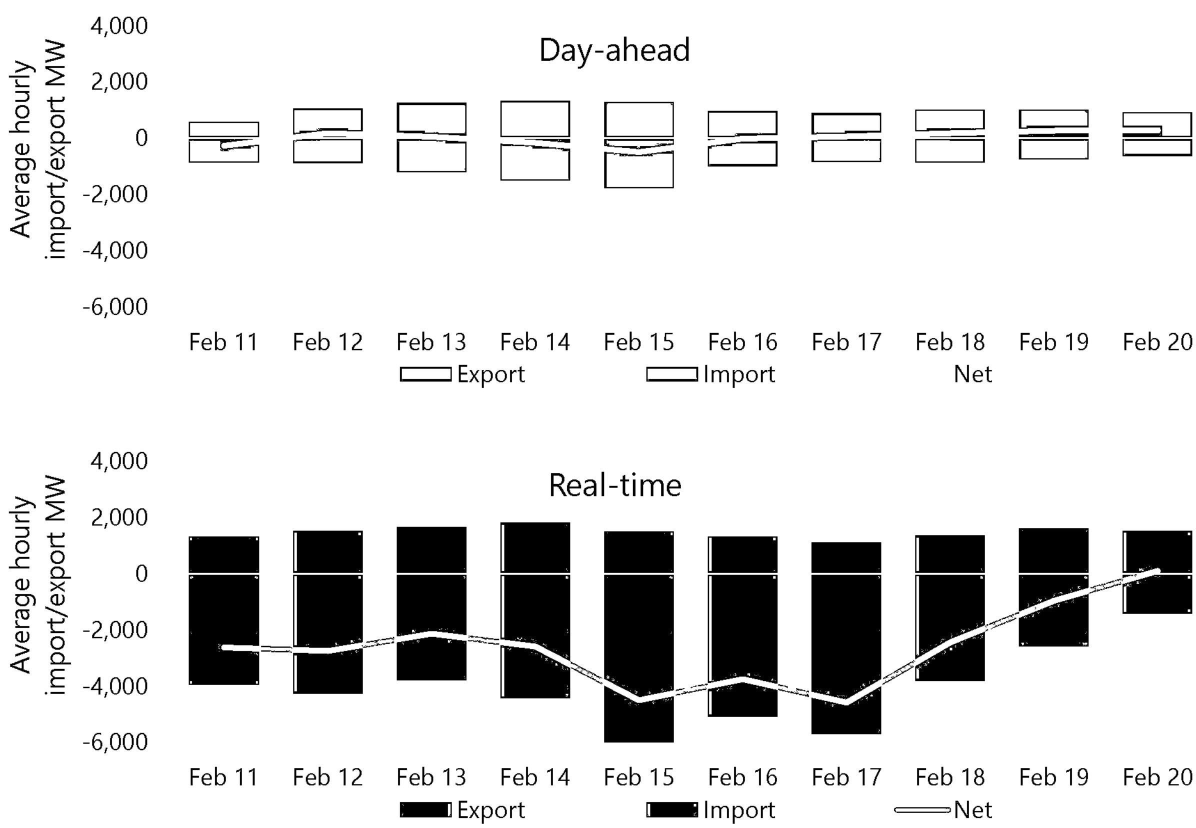
SPP and MISO should include the benefits of enhanced transmission capabilities in addressing systems emergencies like the February 2021 winter weather event in their joint transmission planning process. (Tier 2)

Intertie/seams issue #2

The volume of real-time imports was significantly higher than day-ahead imports. Routine MMU surveillance of the SPP market has observed that the net megawatts from imports and exports are often not correlated between the real-time and day-ahead markets, with day-ahead usually expecting more exports than real-time. The winter weather event magnified this difference. Specifically, from February 11 through February 21 there was an average of 2,621 MW imported in the real-time market and 7 MW in the day-ahead market.

Figure 6-1 below demonstrates the average net megawatts for each day:

Figure 6-1 Day-ahead and real-time exports and imports



Real-time had net imports of more than 4,000 MW on two days while the day-ahead never reached more than 1,000 MW of net imports. This significant difference in imports could have a significant impact in both price and congestion levels in the day-ahead market. However, it is possible that additional imports in the day-ahead market could have better reflected the pricing and congestion in the real-time market, and could have helped SPP operators to better assess reliability day-ahead.

Recommendation

Perform a study to identify if there are barriers to participation of imports in the day-ahead market and identify changes to address any issues identified in the analysis. (Tier 3)

Intertie/seams issue #3

It is not clear how the market-to-market process performed during the winter weather event. There was significant congestion in real-time that affected both the SPP and MISO systems. The market-to-market process is designed to help address congestion between the two markets that can be resolved by resources in the other system. Given the supply and demand conditions in both regions as well as the large volume of imports into the SPP region, it would be useful to study the performance of the market-to-market process during this event and to identify areas of effectiveness and of concern.

Recommendation

Study the performance of the market-to-market process during the event and provide lessons learned and recommendations. (Tier 3)

6.3 VIRTUAL TRANSACTIONS

Virtual transaction issue #1

It is not clear the extent that virtual transactions provided benefits during the winter event. The MMU estimates that virtual transactions made just under $400 million during this period, much of this was associated with virtual offers, the equivalent of supply. Given that this event included periods of physical scarcity and capped offers, it is not clear precisely how virtual transactions benefited the market during these periods, specifically in regards to market efficiency and price convergence. Given the large magnitude of the cost of virtual transactions, estimating the benefits they provided during this period is warranted.

Recommendation

Perform a study to assess the effectiveness of virtual transactions during the winter weather event and identify any potential lessons learned or recommendations going forward. (Tier 3)

7 GAS-ELECTRIC COORDINATION

The winter weather event highlighted significant gas-electric coordination issues. Ultimately, many of these issues will require coordination beyond SPP and its stakeholders. It will require the gas industry, state regulators, FERC, and NERC along with SPP and other RTOs to resolve. This dialogue and resolutions will be increasingly important as electric markets decarbonize and rely more on natural gas-fired generation to provide dependable capacity and generation when needed.

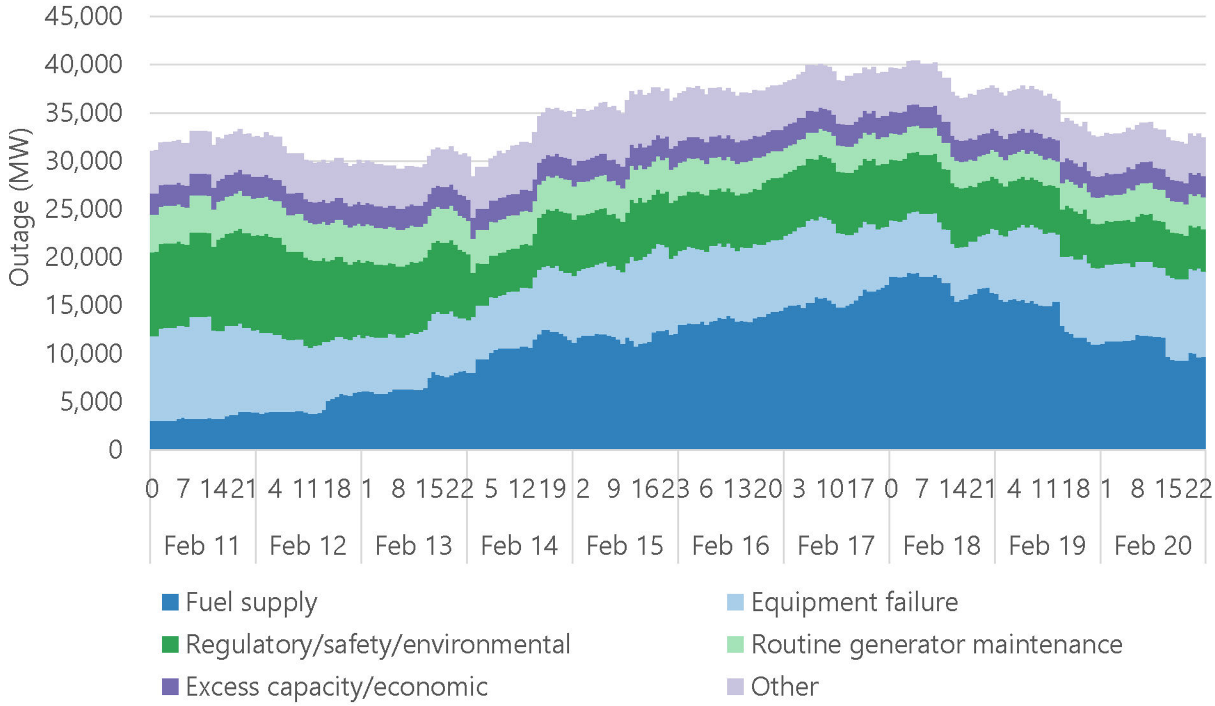
In this section, we highlight gas-electric coordination issues and pose recommendations to inform that dialogue. We highlight three key issues and provide recommendations. Furthermore, we note the extent to which SPP or others can address the recommendations.

Gas-electric coordination issue #1

There were instances where SPP market participants informed the MMU that they were not able to acquire spot natural gas at any price. The MMU was in constant contact with market participants about natural gas market conditions during the winter weather event. In some instances, market participants informed the MMU that they had submitted a bid to buy natural gas in the hundreds of dollars that was either at or above the last market traded price at a particular hub and that there were no takers for their bid. This would result in the participant attempting to find natural gas later, or to take an outage of the resource. As can be seen in Figure 7-1, fuel supply outages were the number one reason for outages during the winter weather event. Moreover, natural gas was the number one fuel source of resource outages.

SPP's system depends on natural gas-fired generation to reliably and economically meet the needs of electric consumers. If the supply of natural gas is disrupted, limited, or unavailable, as occurred during this event, then the reliability of the electric grid would be comprised and electric consumers would be exposed to exorbitant costs. Both of these situations occurred during the winter weather event.

Figure 7-1 Outages by reason



Recommendation

SPP and its stakeholders should engage with regulators (both federal and state) and the natural gas industry to appreciate the challenges in the connection between the availability of natural gas supply and the ramifications to SPP's system in the event of a natural gas supply shock and to work for a solution to limit the possibility of harm from another event. Significant coordination by SPP with FERC and state commissions that regulate natural gas production may be required to resolve these problems. This recommendation is increasingly important as SPP's system has and will likely become increasingly dependent on natural gas-fired generation as a source of capacity. (Tier 1)

Gas-electric coordination issue #2

Natural gas prices are uncapped. Natural gas prices at the ONG hub reached record highs with a recorded trade for natural gas at over $1,200/MMBtu. There is no limit to stop natural gas prices from getting higher. The Intercontinental Exchange had a cap of $999/MMBtu that was raised during the event. This is unlike FERC jurisdictional wholesale electricity markets that impose offer caps with the potential for cost recovery. Faced with significant reliability concerns and potentially hazardous and deadly outcomes, the demand for natural gas to supply electricity was essentially vertical.

This situation creates a very significant disconnect between the gas and electric markets and can expose electric ratepayers and consumers to astronomical and uncompetitive natural gas market costs.

Additionally, the NERC EOP-011 Reliability Standard requires that Balancing Authorities which include the wholesale markets to purchase generation to meet load regardless of cost. This may be in contrast to economically maintaining reliability.

Recommendation

SPP and its stakeholders should engage with regulators (both federal and state) and the natural gas industry to recognize the relationship between uncapped natural gas prices and capped electric prices and the harm that can occur to electric ratepayers. We further recommend that a solution be developed to limit the possibility of harm to electric ratepayers as a result of uncapped natural gas markets. A potential solution could include imposing limits on natural gas prices. (Tier 1)

Gas-electric coordination issue #3

Natural gas markets traded next day spot gas for a weekend package that was four days long. Unlike electricity trading which is a 24 hour, 7 day a week trading operation, natural gas markets generally trade in a much narrower window with generally much less liquidity outside this window. For instance, the majority of spot natural gas trading occurs for what is known as the Timely nomination cycle on non-holiday weekdays. Much of the trading occurs around and after the close of offers for the day-ahead market at 9:30 am CT. In most circumstances, this does not pose a significant issue. However, during periods of limited supply of natural gas and higher demand for electricity, this can be an issue. During the winter weather event, spot natural gas traded on Friday, February 12 for Saturday, Sunday, Monday, and Tuesday. The peak load for SPP was on Monday morning, February 15. Peak load likely would have been higher on Tuesday had load not been shed during the morning ramp. In anticipation of the Monday morning peak, and with appreciation of the natural gas market dynamics, SPP operators committed over 200 resources in advance of the Friday gas market. SPP experienced over $500 million in make whole payments for natural gas resources on Saturday and Sunday alone.

The electricity market has become increasingly dependent on natural gas-fired resources to provide flexibility to meet demand. There are times when wind has exceeded 80 percent of generation on the SPP system, and there are days where wind has exceeded 50 percent of the generation for the day. There are other times that wind may represent less than 10 percent of generation. Wind is at times very variable and requires resources that back this up and provide capacity to be able to start up quickly and on short notice. The winter weather event has highlighted that the ability to acquire spot natural gas does not provide a high level of flexibility under certain circumstances, such as a four-day holiday weekend.

Recommendation

SPP and its stakeholders can petition federal regulators and collaborate with the gas industry on a natural gas market trading approach that addresses the needs of natural gas-fired resources to be able to start up quickly and on short notice. (Tier 1)

8 OTHER

In the other sections of this report, we have covered a range of different topics, each with multiple subsections. This section highlights the issues that are not covered or grouped in other sections of the report, credit, communications, and maximum generation limits. In this section, we highlight issues and concerns that we observed during the winter event and, as with other sections, offer recommendations for SPP and stakeholders to consider going forward.

8.1 CREDIT

SPP and stakeholders have focused on improving credit calculations over the past couple years following the GreenHat default in PJM. These discussions have focused primarily on credit concerns related to transmission congestion rights (TCRs). The winter weather event in SPP highlights a different set of credit challenges that SPP and stakeholders should consider. We outline three issues and recommendations in this section.

Credit issue #1

Prices elevated to levels and for a duration that had never been seen before in the market. Both day-ahead and real-time prices exceeded $3,000/MWh for several hours, with some prices exceeding over $4,000/MWh. These prices have changed the view of risk potential, particularly with respect to virtual transactions, but also with respect to other transactions as well. While we did not observe any significant issues with respect to financial losses during this event, the potential for a significant issue exists. For example, consider a situation where a virtual participant bought 100 MW of virtual load at $2,000/MWh with expectations that real-time prices would be $3,000/MWh. However, because of greater imports, prices in real-time fell to $1,000/MWh, this virtual participant would lose $100,000 rather than gaining $100,000.[19] If this occurred in all 24 hours, the virtual participant would have lost $2.4 million. This highlights the

[19] The realized loss is calculated as ($1,000/MWh - $2,000/ MWh) * 100 MW = -$100,000. The expected gain is calculated as ($3,000/MWh - $2,000/ MWh) * 100 MW = $100,000.

concern that credit requirements may not be sufficient given the extreme pricing levels that were observed during the event. Furthermore, it would be a useful exercise for SPP and stakeholders to consider how high prices can get, and to understand if credit is sufficient under extreme pricing outcomes.

Recommendation

Understand the potential for how high prices can get and stress test the credit requirements based on these pricing possibilities. Update credit requirements based on lessons learned from stress tests. (Tier 2)

Credit issue #2

The winter event was not just limited to the SPP region, but also significantly affected ERCOT. Several SPP market participants also participate in ERCOT. While the onus is on the market participant to inform SPP of any adverse financial impacts, the speed at which this event occurred and the large potential uncertainties with respect to settlements and pricing that existed, may have made this process difficult and inefficient. However, we believe it would have been useful for SPP to understand the implications to its markets more directly rather than through indirect channels such as the trade press. With regards to ERCOT, SPP could consider developing a memorandum of understanding with respect to confidential credit information sharing. With respect to FERC jurisdictional RTOs, SPP could coordinate with other RTOs to petition FERC to consider allowing for confidential credit information sharing. For example, FERC allows and encourages market monitors to share information with regard to referrals.[20] Much like the sharing of referrals, sharing credit information sharing confidentially among RTOs during these types of events can better prepare SPP, and its markets, should an issue arise.

Recommendation

[20] See 137 FERC ¶ 61,046 / Docket Nos. ER09-1050-006, ER09-1192-005, and ER11-121-000 (not consolidated), issued October 20, 2011, paragraph 19.

Consider developing a memorandum of understanding with ERCOT with regards to confidential credit information sharing. With respect to FERC jurisdictional RTOs, consider coordinating with RTOs to petition FERC to allow confidential credit information sharing. (Tier 3)

Credit issue #3

The sole use of historical prices can result in an inappropriate and unreasonable credit requirement. During the event, prices reached new highs and remained elevated for much longer than previously observed. While historical prices may, at times, be useful in assessing risk, historical prices may not accurately reflect underlying conditions. For instance, it may miss underlying structural shifts in congestion patterns, and, as observed in the February winter weather event, it may overstate the impacts of extreme temporary changes and volatility in underlying fuels markets. The clearing prices observed during the winter weather event support the need for considering additional factors. This was not the result of a shift in market conditions or trading activity, but a temporary and transient circumstance. The credit calculations resulted in the overestimation of credit requirements and a subsequent tariff filing to waive credit requirements because of the event.[21] This highlights the difficulties in properly accounting for historical prices in credit calculations and the need to adjust calculations based on underlying conditions.

Recommendation

SPP and stakeholders should consider ways to adjust credit calculations to account for structural as well as temporary shifts in market conditions. (Tier 3)

[21] For more information see ER21-1193-000.

8.2 COMMUNICATIONS

The winter weather event presented a unique challenge for both SPP and the MMU in communicating with stakeholders and market participants. In this section the MMU identifies four issues and makes recommendations to help improve communications going forward.

Communication issue #1

The MMU received calls and emails to the MMU hotline regarding lack of SPP responsiveness. Specifically, the MMU received calls to the MMU hotline with complaints regarding lack of responsiveness to RMS tickets related to settlement and repricing concerns. This particular issue is not that the MMU hotline received notification of a settlement or repricing concern, but rather that the MMU was receiving multiple complaints that SPP staff was not responsive to their queries.

Recommendation

SPP should evaluate its processes to ensure market participants receive timely and effective responses, particularly with respect to settlements and repricing. (Tier 3)

Communication issue #2

There is no set list as to who should receive market communications. During the winter event, the MMU worked with communications staff to send out two market wide communications. The MMU appreciated the responsiveness and assistance from communications staff in helping to facilitate these communications. In most cases, the MMU sends its communications to the MMU email list exploder. This list includes stakeholders that have signed on to receive communications from the MMU and includes a range of stakeholders including market participants, regulators, and reporters. However, during the winter weather event, the MMU communications needed to reach all market participants.

The first communication was to inform market participants about best practices in submitting offers above $1,000/MWh. The second communication was with regards to informing participants about the review of actual costs for offers above $1,000/MWh. These communications needed to reach all participants in the market, but it was not clear what email list was most appropriate to reach all market participants. In both cases, multiple lists were used and more people than necessary received the communication. We believe we were able to reach most, if not all, of the market participants who needed to see the communication. However, it would have been more optimal and efficient to have an email list that reaches all market participants.

Recommendation

SPP should develop and maintain an email list that reaches all market participants to help facilitate market communications. (Tier 3)

Communication issue #3

SPP did not communicate that a capacity shortage occurred in the day-ahead market. In evaluating the winter weather event, the MMU noticed that the day-ahead supply and demand curves did not intersect. Given this situation, the day-ahead market would not solve. The MMU followed up with SPP operations staff and identified that day-ahead capacity shortage procedures were implemented on multiple days during the winter event in order to facilitate a day-ahead market solution.[22] These procedures have a significant impact on the market and can highlight a potential reliability issue. However, that these procedures were implemented was never communicated to the market. In contrast, market participants regularly receive notice when the day-ahead market completion is delayed.

Recommendation

[22] SPP Tariff, Attachment AE, sections 5.1.2(1)(a)(i) and 5.1.2.1(2). In the event of a capacity shortage, the fixed demand bids and fixed firm export interchange transactions will be reduced on a pro-rata basis to match the available capacity and scarcity pricing shall be implemented.

SPP should communicate to market participants when day-ahead capacity shortages occur and update the market protocols as appropriate. SPP could consider sending the notice to the same list that receives communications when the day-ahead market completion is delayed. (Tier 3)

Communication issue #4

Due to some challenges with dispatch during EEA levels 2 and 3, SPP operated in dispatch target adjustment mode for over 20 hours. While this process meets the Out of Merit Energy definition in the tariff, this was not clear to market participants. Numerous market participants were concerned about being made-whole to their positions. More explicit tariff or protocol language would make this clear to participants.

Recommendation

SPP and stakeholders should modify the tariff to clearly explain when and how the dispatch target adjustment process is used, and that this dispatch is treated as an OOME for settlement purposes. This will clarify the make-whole payment process under such circumstances. (Tier 3)

8.3 EMERGENCY MAXIMUM GENERATION LIMITS

During capacity shortages, the market may solve using unsustainable or inappropriate maximum *emergency* operating limits, resulting in infeasible market solutions. The first issue highlights the unsustainability of using emergency maximum generation limits for prolonged periods. The second issue questions the validity of emergency maximum limits for forecasted resources. These issues are outlined below.

Emergency maximum issue #1

During capacity shortages, the market may solve using unsustainable maximum *emergency* operating limits, resulting in infeasible market solutions.[23] Market solutions during the winter event included such emergency maximum limits. When total supply, as defined by economic

[23] SPP Tariff, Attachment AE, sections 5.1.2(1)(a)(i)(2), 5.2.2(2)(a)(2), 6.1.2(2)(a)(2), 6.2.2.1(1).

maximums, is insufficient to meet demand, the sustainable economic maximum limits are replaced by emergency maximum limits. However, these emergency maximum limits are not sustainable for long periods of time. Some resources are able to operate significantly above their sustainable economic maximum for short periods of time. However, although market participants submit a run time with the emergency maximum limit, the market clearing engine does not evaluate this run time. Furthermore, the maximum emergency capacity operating limit and its associated time limit are each single values, respectively. These single point parameters do not accurately represent the various combinations of output and its associated run time limitation. Yet, this imprecise maximum limit is depended upon to determine the reliable market solution.

If the market clearing engine generates solutions based on an imprecise maximum, the result may not be reliable. For instance, if the capacity shortage lasts a full day, a generator may not be able to sustain its emergency maximum for the entire day. In this case, less capacity is available than expected. Furthermore, the longer a resource runs above its sustainable maximum, the more likely it is to need maintenance.

Recommendation

SPP and stakeholders should evaluate whether a more precise emergency maximum parameter would more reliably represent actual physical limits, such as a graduated emergency maximum with an associated time limit parameter. Tariff and protocol changes should be made as needed. (Tier 2)

Emergency maximum issue #2

Wind in SPP was also cleared to its submitted emergency limits during several operating days. In several cases, these emergency limits were well in excess of the wind forecast. While there are no rules in the tariff to prohibit wind from taking on an unsustainable position, generation was cleared that was clearly not in a position to actually perform. In contrast, the economic maximum of the wind resources is generally reflective of and influenced by the forecast. The day-ahead RUC limits the clearing to the forecast.

Recommendation

SPP and stakeholders should consider limiting wind for emergency maximum clearing to a number based on a forecast. This will reduce the risk of infeasible solutions. (Tier 2)

9 CONCLUSION

SPP staff along with market participants worked hard to keep the lights on during the significant cold snap in mid-February 2021. This cold snap stressed SPP systems, markets, and processes and highlighted multiple areas for improvement. Of particular note, the unavailability of natural gas generation during the event, because of lack of fuel, highlighted critical weaknesses in current rules and processes. In this report, we highlighted several recommendations on how to improve SPP processes going forward. However, the most critical and necessary recommendations we make in this report revolve around resource adequacy and availability. Specifically, we highlighted the following recommendations as necessary to protect consumers and citizens from extreme consequences should another event occur. These recommendations include:

- If SPP is to rely on any resource to be available to provide energy, then that resource should be available. This will require accounting for more granular approaches to measuring capacity including seasonality and forced outage rates. This may require resources to have secondary or backup fuel sources, or alternatively storage capabilities.
- There should be meaningful incentives for availability. To the extent that a resource is more available there should be incentives, to the extent that a resource is less available, there should be disincentives.
- Different times of the year present different system challenges. SPP resource adequacy requirements focus on meeting peak summer load. A more frequent resource adequacy requirement, such as a seasonal (or perhaps monthly) requirement, should be developed.
- SPP should plan for shocks to generator availability including extreme weather events, pipeline outages, wind turbine icing and solar eclipses, and implement mitigation measures and procedures.

Addressing these recommendations is an essential and necessary step to improve and prepare SPP systems for potential future events. Moreover, addressing all MMU recommendations will help address not only the root causes of the event, but also items in response to the event should another event occur.