UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tenaska Clear Creek Wind, LLC	)	
	)	
Complainant	)	
	)	Docket No. EL21-____-000
v.	)	
	)	
Southwest Power Pool, Inc.	)	
	)	
Respondent.	)	

NOTICE OF COMPLAINT

( )

Take notice that on May 21, 2021, Tenaska Clear Creek Wind, LLC filed a formal complaint against Southwest Power Pool, Inc. pursuant to Sections 206, 306, and 309 of the Federal Power Act ("FPA") and Rule 206 of the Commission's Rules of Practice and Procedure, alleging that SPP's affected system studies for the Tenaska Clear Creek Wind Project are unjust, unreasonable, and contrary to Commission precedent.

Tenaska Clear Creek Wind, LLC certifies that copies of the complaint were served on the contacts for Southwest Power Pool, Inc. as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose,

Secretary.

COMPLAINT REQUESTING FAST TRACK PROCESSING

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tenaska Clear Creek Wind, LLC	)	
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COMPLAINT AND REQUEST FOR FAST TRACK PROCESSING OF TENASKA CLEAR CREEK WIND, LLC

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COMPLAINT REQUESTING FAST TRACK PROCESSING

UNITED STATES OF AMERICA
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Southwest Power Pool, Inc.	)	
	)	
Respondent.	)	

COMPLAINT AND REQUEST FOR EXPEDITED CONSIDERATION OF TENASKA CLEAR CREEK WIND, LLC

Pursuant to Sections 206, 306, and 309 of the Federal Power Act ("FPA") and Rule 206 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure,[1] Tenaska Clear Creek Wind, LLC ("Tenaska Clear Creek") submits this complaint concerning the Southwest Power Pool, Inc.'s ("SPP") affected system studies for the Clear Creek Wind Project, a 242 MW wind generation facility interconnected to the system of Associated Electric Cooperative, Inc. ("AECI") in Maryville, Missouri ("Clear Creek Project" or "Project").

Tenaska Clear Creek is filing this complaint to ask the Commission to issue an order bringing an end to a multi-year affected system study process that has been characterized by systematic errors, irregularities, and delays and has culminated in SPP issuing a restudy report assigning the Project cost responsibility for approximately $99 million in upgrades, including $66 million in upgrades necessary to address reliability issues that pre-date the Project's interconnection.

[1] 16 U.S.C. §§ 824e, 825e, and 825h; 18 C.F.R. § 385.206.

Tenaska Clear Creek has spent the past three years working with SPP to complete the affected system study process for the Project. From the beginning, the affected system studies of the Clear Creek Project contained errors and oversights. After the initial affected system impact studies and facilities studies identified approximately $16 million in network upgrades associated with the Clear Creek Project, SPP informed Tenaska Clear Creek that it would be increasing the costs assigned to the Clear Creek Project to approximately $34 million, more than doubling the costs imposed on the Project.[2]

A year and a half later, following the withdrawal of a higher-queued project—whose withdrawal had *no impact* on Tenaska Clear Creek's cost responsibility for network upgrades—SPP presented preliminary restudy results that assigned approximately $763 million in network upgrade costs to Tenaska Clear Creek.[3] Over the course of the six months following the receipt of the preliminary results, SPP revised the restudy multiple times, ultimately issuing a study proposing to allocate approximately $99 million in costs to the Project—representing an approximately 300% increase from the costs assigned to the Project in the initial studies. Following the receipt of these study results, Tenaska Clear Creek learned that the dramatic increase in the costs assigned to the Clear Creek Project was the product of SPP's decision to effectively restart the study process after using a new set of study models and assumptions, including adding in approximately 4,500 megawatts ("MW") of generation resources that SPP claims was omitted from the initial studies of the Project. As a result of these adjustments, SPP has taken the position that Tenaska Clear Creek should be required to fund upgrades of facilities that SPP's own studies

[2] Attachment 1, Testimony of Boone Staples on behalf of Tenaska Clear Creek Wind, LLC, ("Staples Testimony") at 15-16:236-243.
[3] *Id.* at 25:401-408.

show are overloaded in the base case model even when the Clear Creek Project is not interconnected.

Tenaska Clear Creek respectfully requests that the Commission issue an order granting the Complaint and directing SPP to respect the results of the initial studies of the Clear Creek Project. As discussed further herein, the manner in which SPP has conducted the evaluation of the Clear Creek Project is inconsistent with the SPP Tariff and Commission precedent defining the permissible boundaries of the restudy process. SPP's proposal to assign Tenaska Clear Creek costs associated with the construction of network upgrades that appear necessary to address overloads that existed prior to the introduction of the Project is prohibited by Commission policy and inconsistent with basic cost causation principles. For the foregoing reasons, Tenaska Clear Creek requests that the Commission find that the cost responsibility of the Clear Creek Project for upgrades on the SPP system should be limited to the approximately $34 million identified in the initial studies of the Clear Creek Project with the remaining upgrade costs rolled into regional transmission rates.

To the extent that the Commission believes that it does not have sufficient evidence to summarily make such a finding, then the Commission should issue an order finding that SPP's proposal to assign $66 million in additional costs to the Project is unjust and unreasonable and set for hearing the issue of how these costs can be allocated equitably to all parties that will benefit from the construction of the upgrades. While SPP has claimed that the base case overloads that exist in the model are attributable to the cumulative impact of higher-queued generation resources that individually did not qualify for an allocation of costs, as detailed further in the attached testimony of Judah Rose and Himali Parmar of ICF International Inc. ("ICF Testimony"), ICF's analysis indicates that these overloads are attributable to specific, identifiable interconnection customers that would have triggered the need for these upgrades if the generation resources that SPP has claimed were omitted from the initial studies of the Project had been taken into account. Rather than forcing Tenaska Clear Creek—and the Project alone—to bear all of the costs, the costs of these facilities should be allocated in a manner that aligns with cost causation principles and basic principles of equity.

Tenaska Clear Creek respectfully requests that the Commission act under fast track procedures and issue an order within 60 days of the submission of this Complaint. Tenaska Clear Creek is requesting fast track processing in order to ensure that the significant uncertainty that has been created as a result of SPP actions is promptly resolved and to avoid any further harm to the Project. Tenaska Clear Creek recently learned that the Project is being curtailed when facilities that SPP has charged the Project with upgrading are constrained, which is causing ongoing harm to the Project. Promptly issuing an order that finds that Tenaska Clear Creek cannot be allocated the additional costs that SPP has identified through the restudy process will help ensure that this dispute is promptly resolved and mitigate any further harm to the Project.

I. EXECUTIVE SUMMARY

Commission policy and the SPP Tariff make clear that the purpose of the generator interconnection process is to ensure that interconnection customers receive a timely, good faith upfront estimate of costs in order to provide customers with the ability to make informed business decisions. The Commission also has established that repeated restudies of interconnection projects based on events that were not foreseeable are fundamentally inconsistent with the need to provide upfront certainty to customers. These same requirements are reflected in the SPP Tariff, which requires SPP to conduct timely studies consistent with Good Utility Practice, with a level of care that SPP would exercise to protect its own interest.

The manner in which SPP studied the Clear Creek Project falls far short of these standards. Only after questioning the results of the restudy of the Project has Tenaska Clear Creek learned that the dramatic increase in the costs assigned to the Project are the result of SPP's decision to adjust the models used as the basis of the restudies of the Project to take into account an additional 4,500 MW of generation resources that SPP claims were inadvertently omitted from the initial studies of the Project. Whether this is—as SPP claims—an oversight that was simply overlooked despite the fact that SPP made multiple corrections to the earlier studies of the Project or a decision by SPP to second guess study assumptions after the fact, SPP has used the withdrawal of a higher-queued interconnection as an opportunity to belatedly "fix" its omission by restarting the study process for the Clear Creek Project using a new study model and study assumptions. As a result of these actions, SPP is now claiming that Tenaska Clear Creek should be required to fund an additional $66 million in network upgrades, years after the Project was financed, constructed, and entered commercial operation and the initial studies of the Project were complete. At the same time, while SPP has acknowledged that it omitted this 4,500 MW of generation from the studies performed for other interconnection customers—and Tenaska Clear Creek's analysis indicates that the universe of interconnection customers affected by the omission is broader than SPP has acknowledged—SPP has indicated that it has no plans to comprehensively restudy or re-evaluate these projects.

The impact of SPP's actions has been exacerbated by the significant delays in conducting the restudy. SPP notified Tenaska Clear Creek of its intent to restudy the Clear Creek Project in November 2019. But it was not until one year later—after the Project had commenced commercial operation—that SPP provided the restudy results to Tenaska Clear Creek. Even then, SPP did not tell Tenaska Clear Creek what SPP had apparently concluded at that point: that the initial studies of the Project omitted thousands of megawatts of generation. Moreover, given the delay, SPP decided to restudy the project using a completely new study model and study assumptions. Notably, SPP made these changes after *both SPP and the Commission* acknowledged in a proceeding concerning the restudy of the DISIS-2016-002 study group that changing the underlying model when conducting a restudy is inappropriate.

SPP has also taken the position that Tenaska Clear Creek should be held responsible for the costs of funding network upgrades necessary to address reliability issues that exist in the study model *prior* to the introduction of the Clear Creek Project. Commission policy requires that interconnection customers only be held responsible for network upgrades that would not be necessary but for the interconnection of the project. Despite that policy, SPP continues to take the position that Tenaska Clear Creek should be held responsible for the costs of upgrades that its own studies demonstrate are necessary to address overloads that pre-date the Clear Creek Project.

SPP has attempted to minimize these concerns by claiming that these overloads reflect the cumulative impact of higher-queued customers that did not individually trigger the need for network upgrades. Tenaska Clear Creek's review of the models, however, has identified higher-queued projects that appear to have triggered the need for the upgrades that SPP is now proposing to allocate to the Clear Creek Project. Yet, Tenaska Clear Creek is still being asked to fund the entirety of these costs, with no plans to restudy or otherwise properly allocate these costs to the higher-queued customers that are driving the need for these upgrades.

At the same time, SPP has declined to make adjustments to the study, such as employing more realistic study assumptions and cost allocation thresholds that could help mitigate these issues. Tenaska Clear Creek has pointed out that slight modifications to the dispatch assumptions used in the study would prevent the need to upgrade certain facilities. Nevertheless, SPP refused to evaluate this solution before finalizing Tenaska Clear Creek's network upgrade cost responsibilities.

Tenaska Clear Creek recognizes that SPP has indicated that it was the withdrawal of a higher-queued generation customer that led SPP to restudy the Project. The purpose of a restudy, however, is not to provide the transmission provider with an opportunity to restart the study process by employing a range of new assumptions regarding higher-queued generation resources, line ratings, and other factors. Instead, the purpose is to evaluate whether the withdrawal of the higher-queued generation resource had an impact on the customer that is the subject of the restudy. In this case, SPP has acknowledged that the withdrawal of the higher-queued customer ***had no effect*** on the cost responsibility of the Clear Creek Project.

This is not a matter of Tenaska Clear Creek attempting to avoid responsibility for funding network upgrades necessary to address the interconnection of its Project. To the contrary, this complaint is about preventing SPP from shifting costs onto Tenaska Clear Creek that are not necessary but for the interconnection of the Project, but rather to address pre-existing reliability issues associated with higher-queued generation resources.

Finally, this dispute carries far more import than the interconnection of the Clear Creek Project. Significant amounts of renewable generation are attempting to interconnect to transmission systems throughout the country. The facts here, if unremedied by the Commission, will certainly impact decision-making by developers of renewable projects on the SPP system and elsewhere. Allowing SPP to effectively restart the study process using a new study model and new study assumptions after systematic errors and delays would create havoc for even an interconnection customer that was still in the earlier stages of the development and construction process. But to allow SPP to hold Tenaska Clear Creek responsible for costs of upgrades that, at best, were not promptly identified due to SPP's mishandling of the process and appear necessary to address pre-existing reliability issues would send a signal that renewables developers nationwide cannot count on transmission providers complying with minimal standards of care when conducting studies and that customers simply cannot count on the results of the interconnection process.

II. CORRESPONDENCE AND COMMUNICATIONS

All correspondence and communications with Tenaska Clear Creek in this docket should be addressed to the following individuals, whose names should be entered on the official service list maintained by the Secretary in connection with these proceedings:

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III. THE PARTIES

A. Tenaska Clear Creek (Complainant)

Tenaska Clear Creek Wind, LLC is an affiliate of Tenaska, Inc., a privately held company organized under the laws of the State of Delaware, with its principal place of business located in Omaha, Nebraska. Tenaska Clear Creek Wind, LLC developed and now owns and operates the Clear Creek Project, a 242 MW wind-powered generator located north of Maryville in Nodaway County, Missouri. Tenaska Clear Creek executed a generator interconnection agreement ("GIA") with AECI in December 2018, and the Clear Creek Project entered commercial operation on May 4, 2020.

B. SPP (Respondent)

SPP is a non-profit corporation incorporated under the laws of the State of Arkansas. SPP is a Commission-approved Regional Transmission Organization ("RTO") that administers open access transmission service over more than 48,000 miles of transmission lines in eight states, including Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. SPP borders the Midcontinent Independent System Operator ("MISO").

IV. FACTUAL BACKGROUND

Tenaska Clear Creek initiated the interconnection process on May 2, 2017, when Tenaska Clear Creek submitted an interconnection request to AECI. Thereafter, AECI commenced its own study process and directed Tenaska Clear Creek to coordinate affected system studies with SPP and the Midcontinent Independent System Operator, Inc. ("MISO").

On August 20, 2018, Tenaska Clear Creek formally requested that SPP conduct an affected system study of the Clear Creek Project.[4] At the time Tenaska Clear Creek submitted this request to SPP, SPP informed Tenaska Clear Creek that the Clear Creek Project would be "queued" between the SPP DISIS-2016-002 and DISIS-2017-001 study groups and that SPP would be utilizing the DISIS-2016-002 transfer case as the "base case" starting point for the study of the Clear Creek Project.[5] The DISIS-2016-002 transfer case, in turn, was based on the 2017 Integrated Transmission Planning ("ITP") study model. At this time, SPP informed Tenaska Clear Creek that affected system studies involving AECI take approximately *four to five weeks* to complete.[6]

[4] Staples Testimony at 8:83-90; Exhibit 3 at 5.
[5] *Id.* at 8-9:91-104; Exhibit 3 at 4-5.
[6] *Id.*

A. Initial Studies and Revisions

SPP issued its first Affected System Impact Study, ASGI-2018-001, Rev. 0, on October 5, 2018.[7] The study identified $31.2 million in upgrades required on SPP's system: upgrades to the Maryville – Maryville 161 kV Circuit ($1.2 million) and a re-conductoring of the Creston – Maryville 161 kV Circuit ($30 million).[8]

On November 5, 2018, SPP issued a revised study to correct an omission in the initial version of the study.[9] Specifically, SPP had omitted a higher-queued MISO project from Table 1 of the study, which listed pending higher-queued interconnection requests that SPP had not taken into account in the affected system impact study.[10] Other than the addition of a higher-queued interconnection request, SPP did not make any substantive changes to the results of the study or Tenaska Clear Creek's responsibility for network upgrades.[11]

On October 31, 2018, Tenaska Clear Creek executed a facilities study agreement authorizing SPP to proceed with an Affected System Facilities Study.[12] The purpose of the Facilities Study is to "specify and estimate the cost of the equipment, engineering, procurement, and construction work needed to implement the conclusions of the System Impact Study" to interconnect the project.[13] Under the facilities study, SPP was obligated to use "Reasonable Efforts" to complete the study within 90 days of receipt of an executed version of the agreement and to provide Tenaska Clear Creek with an estimate of costs that was within 20% of the actual costs.[14]

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[7] *Id.* at 9-10:119-123; *see* Exhibit 4.
[8] *Id.* at 11:143-149; *see* Exhibit 4.
[9] *Id.* at 12:163-169; Exhibit 5.
[10] *Id.*
[11] *Id.* at 12:170-172.
[12] *Id.* at 12-13:173-185; Exhibit 6.
[13] *Id.*; Exhibit 6 at 1.
[14] Staples Testimony at 12-13:173-185; Exhibit 6 at 12.

On February 12, 2019, SPP issued an Affected System Interconnection Facilities Study Report that revealed a significant decrease in the Project's network upgrade costs.[15] The facilities study identified approximately $16.3 million in network upgrades associated with the interconnection of the Project—approximately $15 million less than the estimate provided in the system impact study.[16] The decrease in costs reflected the fact that one of the transmission owners responsible for constructing network upgrades associated with the Clear Creek Project, the Western Area Power Administration ("WAPA"), had determined that the costs associated with re-conductoring the Creston – Maryville 161 kV line had decreased from $30 million to approximately $14.9 million.[17]

Approximately one month after SPP had provided the results of the Facilities Study, Tenaska Clear Creek learned that SPP would be issuing a revised System Impact Study to correct an omission in the earlier versions of the study. On March 21, 2019, SPP issued a revised system impact study assigning Tenaska Clear Creek responsibility for mitigating the Braddyville (J611) – Maryville 161 kV Circuit 1 constraint.[18] SPP informed Tenaska Clear Creek that SPP "incorrectly categorized" the J611 – Maryville 161 kV Circuit 1 constraint in earlier studies and, as a result, had failed to assign it to the Clear Creek Project.[19] The result of the addition of the J611 – Maryville 161 kV Circuit 1 constraint was to more than *double* the total network upgrade costs to $33.017 from the $16.3 million estimate that had been provided in the Facilities Study.[20]

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[15] *Id*. at 13:186-192; Exhibit 7.
[16] *Id.*
[17] *Id.* at 13:194-197
[18] *Id.* at 15:230-235; Exhibit 9.
[19] *Id.* at 13-14:198-220; *see* Exhibit 8 at 2-3.
[20] *Id.* at 15:224-229.

On April 8, 2019, SPP issued a revision to the Affected System Interconnection Facilities Study for the project.[21] The revised facilities study identified $33.535 million in network upgrades necessary to accommodate the entirety of the Clear Creek Project's 242 MW capacity.

Each of the upgrades that were assigned to the Clear Creek Project as part of the initial studies of the Project were associated with constraints that SPP identified when modeling the Tenaska Clear Creek Project for Energy Resource Interconnection Service ("ERIS"). No additional upgrades were identified as necessary as a result of SPP's modeling of the Project using Network Resource Interconnection Service ("NRIS") standards.

With the AECI, MISO, and SPP study processes drawing to a close, Tenaska Clear Creek commenced construction of the Project in Spring 2019.[22] At the same time, Tenaska commenced negotiations of Facilities Construction Agreements ("FCA") with the transmission owners responsible for constructing the upgrades, Kansas City Power & Light ("KCPL") and WAPA. On August 30, 2019, Tenaska Clear Creek executed a FCA with KCPL for $1.9 million in upgrades to the Maryville – Maryville 161 kV line and to the Maryville substation. KCPL tendered a separate FCA to upgrade the Maryville – Braddyville 161 kV line, and separately, WAPA tendered an FCA to upgrade the Maryville – Creston 161 kV line.[23]

B. Restudy

On November 1, 2019, SPP notified Tenaska Clear Creek that it intended to restudy the Clear Creek Project.[24] At the time Tenaska Clear Creek received notification of SPP's intention to restudy the Project, construction and project financing were well underway, with approximately

[21] *Id.* at 15-16:236-243; Exhibit 10.
[22] *Id.* at 17-18:274-276.
[23] The latter FCAs providing for the upgrades to the Maryville – Braddyville and Maryville – Creston 161 kV lines were not executed due to SPP's indication that it intended to restudy the project.
[24] Staples Testimony at 18-19:291-299; *see* Exhibit 11.

50 turbines installed and $266 million committed to the Project.[25] The reason cited for the basis of the restudy was the withdrawal of a higher-queued customer interconnecting to the MISO system—J570—from the queue on August 5, 2019.[26]

In the months that followed, Tenaska Clear Creek repeatedly communicated with SPP to obtain an update on the status of the restudy process. Initially, SPP indicated that it intended to complete the restudy process by the first quarter of 2020 and that the restudy would be completed using the same study model that was used as the basis for the initial studies of the Clear Creek Project (*i.e.*, the 2017 ITP model).[27] In reality, however, it would not be until May 2020—six months after SPP informed Tenaska Clear Creek of J570's withdrawal and after the Project had commenced commercial operation—that SPP provided something that resembled a concrete update on the scope and timing of the study. It was at that time that SPP informed Tenaska Clear Creek that since the models used for the original impact study were over a year old, SPP intended to conduct the restudy using a new study premised on the 2019 ITP model, the study model that had been adopted for the lower-queued DISIS-2017-1 study cluster.[28]

On November 2, 2020, approximately one year after SPP first provided notice that it was recommending restudy of the project, SPP provided the initial results of the restudy in the Generator Interconnection Affected System Impact Restudy Report, ASGI-2018-001, Rev. 0 ("Restudy").[29] The Restudy stated that Tenaska Clear Creek's cost responsibility for network upgrades on SPP's system had ballooned from the previous estimate of $33.535 million to approximately $763 million. The dramatic increase in upgrade costs reflected the assignment of

[25] *Id.* at 19-20:307-315.
[26] *Id.* at 18-19:291-302; see Exhibit 11.
[27] *Id.* at 20:316-322; *see* Exhibit 11.
[28] *Id.* at 21:340-350; Exhibit 12.
[29] *Id.* at 24:395-400; Exhibits 14-15.

cost responsibility to Tenaska Clear Creek for approximately 20 *additional* network upgrades.[30] For the first time, SPP's studies indicated that network upgrades were necessary to address constraints identified when using NRIS modeling standards. This news came to Tenaska Clear Creek just as the Clear Creek Project was nearing its sixth month of commercial operation.

Reeling from this Restudy, Tenaska Clear Creek contacted SPP to gain clarity on what went wrong. In doing so, Tenaska Clear Creek learned about serious irregularities in the study process. Most notably, SPP for the first time informed Tenaska Clear Creek that in October 2020, SPP had concluded that it had omitted thousands of MW of higher-queued generation on the MISO system in the initial studies of the Clear Creek Project as well as in the studies of the DISIS-2016-002 study cluster that were used as the basis for the evaluation of the Clear Creek Project.[31] And while SPP had cited the withdrawal of J570 as the reason for the restudy of the Clear Creek Project, SPP subsequently acknowledged that the cost responsibility of the Clear Creek Project in the initial studies of the Project did not depend on the construction of network upgrades that had been identified as necessary to accommodate the interconnection of J570.[32]

While Tenaska Clear Creek was attempting to retrace the steps taken by SPP throughout its affected system study process, SPP provided Tenaska Clear Creek with updated study results for the Clear Creek Project on December 18, 2020.[33] These updated results lowered the Project's cost responsibility to $106.8 million—a welcome development, but still more than three times the amount that had been allocated to the Project as part of the initial studies.[34] SPP subsequently

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[30] *Id.* at 25:400-408; *see* Exhibit 15.
[31] SPP has provided varying estimates of the amount of capacity that had been omitted. Based on information that SPP has provided, ICF estimates that approximately 4,500 MW of the approximately 7,000 MW of "omitted" generation that SPP has identified was not included in the initial studies of the Clear Creek Project.
[32] Staples Testimony at 30:454-460.
[33] *Id.* at 27:413-417; Exhibit 17.
[34] *Id.*

lowered the Project's cost responsibility once more on January 8, 2021 to remove a line identified in the December 18, 2020 results, bringing Tenaska Clear Creek's cost responsibility down to $93 million.[35]

Over the course of January and February 2021, SPP made additional adjustments to the study after it revisited the service designations that had been assigned to MISO projects included in the restudy.[36] Specifically, on February 26, 2021, SPP delivered updated study results indicating that Tenaska Clear Creek's network upgrade costs had been reduced to approximately $91 million.[37]

Finally, on March 25, 2021, SPP posted an affected system study report proposing to assign a total of $99 million dollars in network upgrades. Collectively, the March 25, 2021 study continues to assign the $34 million in ERIS upgrades initially assigned to the Clear Creek Project as part of the initial studies. In addition, the study assigns approximately $66 million in NRIS upgrade costs ("NRIS Upgrades") to the Clear Creek Project. Table 1 below provides an overview of the upgrades assigned to the Project in the March 2021 study.

Table 1: ERIS and NRIS Upgrades Assigned to the Clear Creek Project

Upgrade Type	Upgrade	Cost (Million $)
ERIS	Reconduct Maryville to Crestone 161 kV	14.9
ERIS	Rebuild Maryville to Braddyville 161 kV	18.6
NRIS	Rebuild Maryville to Midway 161 kV	21.5
NRIS	Rebuild Midway to Avenue City 161 kV	21.5
NRIS	Rebuild Avenue City to St. Joseph 161 kV	4.9
NRIS	Add 2nd Nashua 345/161 kV Transformer	8.5

[35] *Id.* at 28:427-431.
[36] *Id.* at 28-29:437-449; Exhibits 17-18.
[37] *Id.* at 29:437-443.

NRIS	Rebuild Nashua to Roanridge 161 kV	9.15

C. Attempts to Resolve

Over the last six months, Tenaska Clear Creek has worked with SPP to attempt to reach a mutually acceptable resolution. As of the date of this complaint, however, SPP continues to take the position that the only just and reasonable outcome is to require Tenaska Clear Creek to pay the costs of the NRIS Upgrades. SPP appears to believe that the fact that a higher-queued project withdrew gives it unbounded discretion to completely redo the study of the Clear Creek Project using a brand new study model, new study assumptions, and with the addition of approximately 4,500 MW of generation resources. SPP claims that the withdrawal of a higher-queued customer gives SPP the opportunity for a "fresh start" without regard to the impact on the Clear Creek Project or the hundreds of millions of dollars that it invested based on the outcomes of the prior study process. SPP's position appears to be that the risk that a transmission provider may use the withdrawal of a higher-queued customer to conduct a new study using new study assumptions with additional generation is simply a "business risk" that interconnection customers are required to bear as part of the study process.

V. COMPLAINT

A. SPP's Restudy Of The Clear Creek Project Is Inconsistent With The SPP Tariff, Contrary To Commission Policy, And Unduly Discriminatory

1. SPP Cannot Use The Withdrawal Of A Higher-Queued Customer As An Opportunity To Introduce A New Study Model And New Study Assumptions

SPP's claim that the withdrawal of a higher-queued customer gives it the authority to completely restart the study process with a new study model and new study assumptions is fundamentally inconsistent with Commission precedent requiring that customers receive a timely upfront determination of costs and limiting the bounds of the restudy process.[38] The Commission has consistently recognized that the ability of customers to receive timely, upfront determinations of their cost responsibility through a predictable and non-discriminatory interconnection process is critical to the ability of customers to make informed business decisions.[39] The Commission has repeatedly recognized the importance of ensuring that interconnection customers receive a timely, upfront determination of their cost responsibility. Without timely and reliable information regarding their interconnection costs, interconnection customers cannot make reasoned business decisions and secure funding for their projects. With this in mind, the Commission has designed the interconnection process to ensure that customers receive a final determination of their cost responsibility for network upgrades by the time they enter into an interconnection agreement and has acknowledged that the process cannot work efficiently if the determinations made in these studies are subject to continual review and revisions.[40]

Importantly, the Commission has never suggested that transmission providers have unfettered discretion when conducting a restudy. To the contrary, the Commission has recognized

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[38] *See, e.g., Old Dominion Electric Coop. v. Virginia Electric and Power Co.,* 133 FERC ¶ 61,009 at P 28 (2010); *FPL Energy Marcus Hook, L.P., v. PJM Interconnection, L.L.C.,* 118 FERC ¶ 61,169 at P 14 (2007); *Neptune Regional Transmission System, LLC,* 110 FERC ¶ 61,098 ("*Neptune*"), *order on reh'g*, 111 FERC ¶ 61,455 (2005) ("*Neptune Order on Rehearing*"), *aff'd sub. nom. Pub. Serv. Elec. & Gas Co. v. Fed. Energy Reg. Comm'n,* 485 F.3d 1164 (D.C. Cir. 2007).

[39] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g,* Order No. 2003-A, 106 FERC ¶ 61,220 at P 2, *order on reh'g*, 109 FERC ¶ 61,287 (2004), *order on reh'g,* Order No. 2003-C, 111 FERC ¶ 61,301 (2005) (recognizing that an interconnection process that is "fraught with delays and lack of standardization . . . discourage merchant generators from entering into the energy marketplace, in turn stifling the growth of competitive energy markets"); *Reform of Generator Interconnection Procedures and Agreements*, 157 FERC ¶ 61,212 at P 147 (2016) (recognizing in the notice of proposed rulemaking leading to Order 845 that while "transmission providers should continue to have flexibility in completing interconnection studies, [the Commission] is nonetheless concerned that delays in the interconnection process continue. At times, it is not clear to interconnection customers why and where queue delays are occurring, and the underlying causes of queue delays are not always agreed upon by interconnection customers and transmission providers.").

[40] *See, e.g., Neptune Regional Transmission System, LLC,* 110 FERC ¶ 61,098.

that allowing transmission providers to repeatedly restudy interconnection customers using new assumptions, including the generation capacity that is online and pending in the queue, is inconsistent with the requirement that interconnection customers receive a timely estimate of the costs of interconnection and deprives interconnection customers of the certainty necessary to make investment decisions.[41] The Commission has recognized that allowing transmission providers to repeatedly restudy interconnection customers to reflect changes that occur after a customer's initial system impact study is completed would make it "impossible for the customer to make reasoned business decisions" by subjecting "the customer . . . to constant changes within the provider's system."[42]

Consistent with this principle, the Commission has sought to limit the extent to which transmission providers depart from the assumptions employed in the initial system impact studies when conducting a restudy. As the Commission has explained, the boundaries of the "re-study process *must* correlate to circumstances known to [the transmission provider] and the interconnection customer at the time of the initial System Impact Study, or through exercising due diligence, was reasonably ascertainable at that time[.]"[43] Consistent with this principle, in previous cases, the Commission has rejected arguments that a transmission provider should be permitted to revisit key modeling assumptions when conducting a restudy.[44]

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[41] *Neptune Order on Rehearing* at P 22 (explaining that holding interconnection customers for changes in system topology that occur after they enter the queue "could lead the interconnection provider . . . to fail to not determine the final level of interconnection costs within a reasonable period of time."); *PJM Interconnection, L.L.C.*, 112 FERC ¶ 61,276 (2005) (noting the Commission's concerns regarding transmission provider's ability to "continuously restudy proposed generation and merchant transmission projects providing no termination to the restudy process and no certainty for the interconnecting customers."); *Old Dominion Elec. Coop. v. Virginia Elec. Power Co*., 33 FERC ¶ 61,009 at PP 28-31 (finding that when an interconnection customer executed a GIA, the transmission provider could not allocate to the interconnection customer costs for a second line required by the state commission for reliability purposes).

[42] *Neptune* at P 23.

[43] *Southwest Power Pool, Inc.*, 132 FERC ¶ 61,020 (2010) (citing and relying on *Neptune*).

[44] *See, e.g., Neptune* (denying request to restudy customer to take into account impact of higher-queued generator retirements).

SPP's treatment of the Clear Creek Project did and does not comport with these requirements. It is important to recognize that what SPP has characterized as a "restudy" amounts to nothing short of completely restarting the study process for the Clear Creek Project. By transitioning to the use of a new study model and new study assumptions as part of the restudy, SPP has effectively "reset" the baseline used to evaluate the cost responsibility of the Clear Creek Project. As described in detail in ICF's testimony, ICF's analysis identified considerable changes between the 2017 ITP used as the basis for the initial studies of the Project and the 2019 ITP used as the basis for the restudy. Notable changes include:

- ***The addition of thousands of MW of additional generation:*** As noted above, after providing Tenaska Clear Creek with preliminary study results, SPP informed Tenaska Clear Creek that it had excluded 7,000 MW of MISO generation from the initial restudies of the Project. Out of this 7,000 MW, ICF's analysis indicates that approximately 4,500 MW was omitted from the evaluation of the Clear Creek Project. The remaining 2,600 MW appears to have been included in the initial studies of the Clear Creek Project.[45]
- ***Difference in the years studied:*** As ICF explains, the "run" years evaluated in each of the studies differed significantly. The 2017 ITP model evaluated 2017, 2018, 2021, and 2026. In contrast, the 2019 ITP model evaluated 2019, 2020, 2024, and 2029.[46]
- ***Differences in SPP generator dispatch***: ICF observed changes in the dispatch of multiple generation units interconnected to the SPP system that contribute significantly to the loading on the facilities that SPP is now claiming Tenaska Clear Creek should be responsible for upgrading.[47]
- ***Differences in MISO generator dispatch***: Similarly, ICF's analysis identified differences in the way that SPP has dispatched generators within MISO's footprint impacting the constraints that SPP is claiming Tenaska Clear Creek is responsible for resolving through the construction of network upgrades.[48]

In short, SPP has effectively used the withdrawal of a higher-queued customer as an opportunity to restart the study process from scratch. SPP has not made any attempt to ensure that the restudy is conducted in a manner that correlates to the circumstances at the time of the

[45] Attachment 2, Testimony of ICF on behalf of Tenaska Clear Creek Wind, LLC at 20-21:282-297 ("ICF Testimony").
[46] *Id.* at 37:513-517.
[47] *See id.* at 37-38:518-529.
[48] *See id.* at 42-43:601-611.

initial System Impact Study or respects the settled expectations of Tenaska Clear Creek. Instead, SPP has unilaterally declared that the prior studies of the Clear Creek Project are invalid and commenced a new study process with a new model and new study assumptions, including an additional 4,500 MW of generation resources.

SPP undoubtedly will argue that it had the right to restudy the Clear Creek Project given the withdrawal of J570. But the purpose of a restudy when a higher-queued customer withdraws is not to give a transmission provider an opportunity to allocate new, previously unidentified costs to the customer by completely changing the study model and assumptions used as the basis for the assessment of the interconnection customer. Instead, the purpose of a restudy in the case of a higher-queued withdrawal is to evaluate whether the network upgrades that were originally the responsibility of the withdrawing customer should be assigned to the interconnection customer that is being restudied.[49] In particular, the Commission has recognized that the business risks borne by an interconnection customer in connection with the withdrawal of a higher-queued customer is the risk that they will be required to fund "network upgrades that were the responsibility of a higher-queued interconnection customer that drops out of the queue."[50] The Commission has never suggested that a transmission provider is permitted to use the withdrawal

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[49] Order No. 2003-A at P 320 (clarifying that interconnection customers are responsible for funding network upgrades that "were the responsibility of a higher-queued Interconnection Customer that then dropped out of the queue if . . .[the upgrades] are necessary to support the interconnection of the Interconnecting Customer's Generating Facility."); *Neptune* at P 23 (explaining that the interconnection queue is intended to insulate an "interconnection customer from costs arising from events occurring after its System Impact Study is completed, other than costs arising from changes from higher-queued generators").

[50] *Jeffers South, LLC v. Midwest Indep. Transmission Sys. Operator Corp.,* 144 FERC ¶ 61,033 at PP 61-62 (2013) (recognizing that the risk borne by customers in connection with withdrawal of higher-queued customer is that customer will be required to fund network upgrades that were funded by the withdrawing customer that remain necessary for the interconnection of the restudied project); Order No. 2003-A at P 320 (clarifying that interconnection customers are responsible for funding network upgrades that "were the responsibility of a higher-queued Interconnection Customer that then dropped out of the queue if . . .[the upgrades] are necessary to support the interconnection of the Interconnecting Customer's Generating Facility.); *Neptune* at P 23 (explaining that the interconnection queue is intended to insulate an "interconnection customer from costs arising from events occurring after its System Impact Study is completed, other than costs arising from changes from higher-queued generators").

of a higher-queued interconnection customer as an opportunity for a "free for all" completely untethered from the earlier studies of the project. In fact, SPP has recognized as much in its filings with the Commission:

> [W]hen a higher-queued project drops out of the queue, as is the case here, the purpose of the required restudy will be to determine the impact that the withdrawal has on the lower-queued projects, not to assess the impact of subsequent events that occurred after the interconnection request was studied . . . The mere fortuitousness of a higher-queued project having withdrawn should not enable an interconnection customer to have its cost allocation take account of all manner of other subsequent events that have occurred.[51]

Moreover, while the Commission has recognized that restudying a customer when a higher-queued customer withdraws may be appropriate, the Commission has made a concerted effort to ensure that customers are timely informed of their financial exposure associated with higher-queued withdrawals. For instance, in Order No. 2003, the Commission explained that transmission providers *must* provide a customer with an estimate of its maximum possible funding exposure associated with higher-queued generation prior to the execution of the customer's GIA.[52] Granting the transmission providers unfettered discretion when conducting a restudy following the withdrawal of a higher queued customer would eviscerate the value of such protections

In reality, the costs and risks that SPP is attempting to impose on Tenaska Clear Creek have no relationship to the withdrawal of the higher-queued customer that SPP has cited as the reason for the "restudy." In this case, there is ample evidence demonstrating that the withdrawal of J570 did not have a material impact on the cost responsibility of the Clear Creek Project. As detailed further in the attached testimony of ICF, power flow analyses conducted by ICF confirm that the withdrawal of J570 does not materially change the results of the analysis of the Clear Creek

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[51] *Sw. Power Pool, Inc.*, Answer of Southwest Power Pool, Docket No. ER10-1233-000, at 9 (filed June 17, 2010); *see also Sw. Power Pool, Inc.,* 132 FERC ¶ 61,020 at 25 (2010).
[52] Order No. 2003-A at P 320.

Project.[53] This is consistent with SPP's acknowledgement that the cost responsibility of the Clear Creek Project in the initial studies did not depend on the construction of network upgrades that had been identified as necessary for the interconnection of J570.

Once SPP determined that Tenaska Clear Creek was not depending on any network upgrades that were being funded by J570—a fact that would have been easily discernable from a cursory review of the previous studies of the project—the "restudy" process should have ended. There simply is no basis in the SPP Tariff or Commission precedent for SPP to use the withdrawal of a higher-queued project as a pretext for restarting the study process, using new study models and assumptions, and tripling the project's cost responsibility for network upgrades years after Tenaska Clear Creek commenced the affected system study process and after the Project had commenced commercial operation.

2. SPP's Claim That It Is Merely Correcting An Error Does Not Justify SPP's Actions

a. It Is Not Clear That The Omission Is An Error

SPP likely will argue that it should be permitted to correct "errors" in the earlier studies of the Clear Creek Project as part of the restudy process. But it is not clear that the failure of SPP to include these generation resources in the study used as the basis for the evaluation of the Clear Creek Project constitutes an error. Instead, it appears that the changes made to the model and assumptions used as part of the restudy process may reflect a decision by SPP to revisit key study assumptions that it employed in connection with the initial studies of the Clear Creek Project, including which MISO generation resources should be taken into account in the studies, after the initial studies of the Project were completed.

[53] ICF Testimony at 24:338-349.

As an initial matter, ICF's evaluation of the list of "omitted" generation provided by SPP confirms that approximately 2,600 MW of the allegedly omitted 7,000 MW that SPP identified as being omitted from the initial studies was actually *included* in the studies of the Clear Creek Project. The fact that SPP now believes that it should have included a larger group of MISO generators in the earlier studies of the Clear Creek Project does not render earlier study models incorrect or justify making such a significant shift in assumptions when restudying the Clear Creek Project. When conducting an interconnection study, SPP is only required to include generation facilities on affected systems that, on the date the study is commenced, "are interconnected to Affected Systems and may have an impact on the Interconnection Request" under study.[54] This section does not require SPP to include *all* generation resources that are interconnected to affected systems in the study; instead, it calls for SPP to make a determination at the time of the initial studies of the Clear Creek Project about what generation resources on the affected system should be included in the study because they may have an impact on the interconnection request.

In practice, SPP and other transmission providers are continuously refining their understanding of the grid and the way in which their systems interact with resources on adjacent systems. The fact that SPP's view of the grid may have changed does not mean that it is appropriate for SPP to employ a fundamentally different set of study models and assumptions when restudying the Clear Creek Project. To the contrary, the requirement that a restudy be conducted in a manner that correlates to the circumstances that were known by the transmission provider at the time of the initial system impact study imposes a duty on SPP to carry through the assumptions used in the system impact study through to the subsequent studies and restudies of

[54] SPP OATT, Attachment V, Section 8.4.1 (stating that a system impact study should include any generating facilities that "on the date the Definitive Interconnection System Impact Study is commenced" were "interconnected to Affected Systems and may have an impact on the Interconnection Request); *see* Staples Affidavit, Exhibit 4 at 5; Exhibit 5 at 5; Exhibit 9 at 5 (listing higher-queued generation resources and generators included in study).

the Clear Creek Project. To allow SPP to revisit and materially alter these assumptions years after the fact—after the Project has already entered commercial operation—would establish a precedent that transmission providers can subject customers to a "never-ending series of changes, creating havoc for interconnection customers."[55]

If SPP believes that its interconnection studies should take into account a broader array of generation resources on affected systems than were reflected in the studies of the Clear Creek Project, then Commission policy requires that SPP make any necessary adjustments to its study models and assumptions prospectively and not as part of a restudy. In order to ensure that interconnection customers are only held responsible for costs based on the circumstances that exist at the time of the customer's system impact study, it is critical that the restudy process be based on the same study model and study assumptions that were employed in the initial studies. Conducting a study using a new study model and study assumptions as SPP has done here does not amount to a restudy, it effectively amounts to an effort by SPP to restart the study process.

b. Even If The Omission Is An Error, Tenaska Clear Creek Should Not Be Prejudiced By SPP's Failure To Meet Its Obligations

The objective of ensuring that interconnection customers receive a timely upfront estimate of costs can only be achieved if the interconnection process produces timely and accurate study results.[56] For that reason, both Commission policy and the SPP Tariff impose an obligation on SPP to conduct studies in accordance with Good Utility Practice. For instance, Section 2.3 of SPP's Generator Interconnection Procedures ("GIP") require SPP to make "Reasonable Efforts" when processing and analyzing Interconnection Requests.[57] "Reasonable Efforts" is defined as

[55] *Neptune Order on Rehearing* at P 19.
[56] *Midwest Indep. Transmission Sys. Operator, Inc.,* 135 FERC ¶ 61,222 (2011), *order on reh'g*, 143 FERC ¶ 61,050 at P 33 (2013) ("*Settlers Trail Order on Rehearing*").
[57] SPP OATT, Attachment V, Section 2.3.

"efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a party would use to protect its own interests."[58] "Good Utility Practice," in turn, is defined in the SPP Tariff as:

> any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition.[59]

Both the SPP-AECI Joint Operating Agreement ("JOA") and SPP Tariff also impose obligations on SPP to promptly conduct affected system studies. In particular, the SPP-AECI JOA requires SPP to "conduct, in a timely manner, any studies required in determining the impact of, and necessary upgrades required to provide . . . generation interconnection service."[60] Similarly, Section 2.3 of the SPP GIP requires SPP to "receive, process, and analyze all Interconnection requests in a timely manner." With respect to restudies more specifically, the SPP Tariff requires that *all* restudies be completed within 60 calendar days from the date that SPP provides notice of its intent to restudy the project.[61]

SPP has not complied with any of these standards or requirements. From the time that SPP provided the initial System Impact Study of the Clear Creek Project in October 2018 to the Final Facilities Study that SPP provided in April 2019, SPP issued numerous separate System Impact Studies and Facilities Study Agreements to correct multiple errors and miscalculations that were made in the course of conducting these studies, including: (1) modifying the study to assign approximately $16.7 million in costs to the project to address a constraint that SPP had overlooked

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[58] SPP OATT, Attachment V (defining Reasonable Efforts).
[59] SPP OATT, Attachment V (defining Good Utility Practice).
[60] Joint Operating Agreement Among and Between Southwest Power Pool, Inc. and Associated Electric Cooperative Inc., Section 7.3.3 (Aug. 12, 2008).
[61] *See, e.g.,* SPP OATT, Attachment V, Section 8.8.

during the initial four iterations of the study; and (2) modifying the study reports to include previously omitted, higher-queued generation resources.

But, Tenaska Clear Creek learned—over a year and a half after the last version of the original study—that the corrections that SPP made as part of these iterations were only the tip of the iceberg and that SPP now believes that all of the earlier studies of the project should be considered invalid due to the omission of approximately 4,500 MW of generation resources on the MISO system from the study model. Despite the numerous corrections made to the initial studies of the Clear Creek Project—including updates to the list of higher-queued interconnection customers included in the study—and the multiple studies and restudies of customers within the DISIS-2016-002 conducted during the same period, SPP claims it failed to identify this omission until October 2020.[62]

The negative impact on the Clear Creek Project was magnified by systematic delays in SPP's processing of the restudy of the Clear Creek Project. While the SPP-AECI JOA and the SPP Tariff impose an obligation on SPP to promptly conduct affected system studies and to complete any restudies within 60 days, it took SPP almost a full year to conduct the restudy after providing notice to Tenaska Clear Creek. Even then, SPP made no effort to promptly inform Tenaska Clear Creek about the significant omission that it believed had been made in the initial studies, but simply provided preliminary study results indicating that the network upgrade costs assigned to the Clear Creek Project had increased by more than 2000% from the last study of the Project. It was only after Tenaska Clear Creek requested an explanation for the dramatic change in the cost responsibility of the Project that SPP disclosed the purported omission. Even then SPP has been inconsistent in the amount of generation that it claims was omitted from the study. For

[62] Staples Testimony at 31:470-478.

instance, while SPP provided Tenaska Clear Creek with a list of approximately 7,000 MW of generation that it claims had been omitted, ICF's analysis indicates that approximately 2,500 MW of this generation was included in the model. ICF also had identified at least two other generation facilities that SPP did not identify, but that appear to have been omitted from the list that SPP provided.

The frequency, scope, and magnitude of SPP's omissions and improper modeling subjected Tenaska Clear Creek to a multi-year restudy process, with erroneous studies and restudies estimating Tenaska Clear Creek's cost responsibility to be between $16 and $763 million. SPP's mishandling of the process and its chronic delays show that SPP failed to meet the Good Utility Practice and Reasonable Efforts standards set forth in SPP's tariff. In addition, these errors and delays deprived Tenaska Clear Creek of the upfront and timely interconnection cost information that the Commission requires. As a result, Tenaska Clear Creek was denied the use of key milestones in the interconnection process and the availability of off-ramps in the iterative interconnection process.

To find that the appropriate remedy in this case is to allow SPP to unilaterally decide to restart the study process and triple the network upgrade costs assigned to the Project would amount to "blaming the victim." SPP's actions have deprived Tenaska Clear Creek of the ability to obtain a timely estimate of costs and subjected it to a study process characterized by a level of uncertainty that goes far beyond what Tenaska Clear Creek or any interconnection customer should be required to bear. Allowing SPP to now hold Tenaska Clear Creek responsible for an additional $66 million in NRIS Upgrade costs in spite of the systematic errors, irregularities, and delays that have characterized the study process would send a message to SPP and other transmission providers that they will not be held accountable for failing to meet even the most basic standards imposed on them in connection with the interconnection process.

Tenaska Clear Creek acknowledges that in *Settlers Trail*, the Commission rejected arguments that the requirement that the restudy process correlate to the circumstances that were known at the time of a customer's system impact study did not prevent MISO from correcting a 30 MW modeling error.[63] Even if the actions that SPP has taken when restudying the Clear Creek Project represent a good faith attempt to correct an error, *Settlers Trail* highlights why it is important that the Commission reach a different conclusion here.

As an initial matter, the magnitude, severity, and impact of SPP's errors and delays are far greater than the limited modeling error at issue in *Settlers Trail*. Specifically, in *Settlers Trail*:

- ***The error was limited in scope***: In contrast to SPP's self-proclaimed 4,500 MW "miss," the oversight at issue in *Settlers Trail* consisted of under-representing the capacity of two higher-queued interconnection requests in the model by *a total of 30 MW*.

- ***The error was promptly identified***: In *Settlers Trail*, the error was promptly identified two months after the affected interconnection customers had GIAs and approximately four months after the studies of the affected interconnection customers was complete. In this case, SPP claims to have identified the error approximately a year and a half after the facilities study of the Clear Creek Project was complete and six months after the Project had reached commercial operation. Even after discovering the omission, SPP did not promptly disclose the error to Tenaska Clear Creek, but only acknowledged the scale and scope of the error after multiple rounds of questions by Tenaska Clear Creek.

- ***There was no dispute that the upgrades were required for the interconnection of the customers***: In *Settlers Trail*, the interconnection customers did not dispute that the upgrades were necessary for their interconnection.[64] In this case, however, there is ample evidence demonstrating that the upgrades are necessary to address overloads that exist prior to the construction of the Clear Creek Project, as discussed further below.

[63] *See Settlers Trail Order on Rehearing*.

[64] *Id.* at P 33 ("Notably, the parties agree that the additional network upgrades are needed in order to reliably provide for the requested level of interconnection service").

In addition, while the Commission found that MISO was permitted to correct the error at issue in *Settlers Trail*, the Commission was careful to make clear that its ruling was not intended to be a "broad policy statement" that transmission providers can simply redo the study process to correct errors, and merely represented a determination by the Commission that the correction of the single error in that case was just and reasonable "based on the specific facts presented" in the case.[65] Rather than endorsing the idea that transmission providers should be permitted to correct their errors regardless of the impact on the interconnection customer at issue, the Commission emphasized the importance of accountability:

> All entities that are responsible for preparing all or parts of an [system impact study] have an obligation to perform their studies carefully and in accordance with industry standards for such analyses, and will be held accountable for failure to do so when circumstances warrant.[66]

Ruling in SPP's favor in this case would set the broad policy that the Commission intentionally – and correctly – refrained from making in *Settlers Trail*. To hold that Tenaska Clear Creek should be solely responsible for SPP's failure to take into account 4,500 MW of generation and that SPP can use the withdrawal of a higher-queued customer to restart the study process would send a message to SPP and other transmission providers that they can completely disclaim responsibility for any omissions or improper modeling in the study process and pass along any financial consequences of their errors to the interconnection customer. Such a ruling would also render meaningless the protections that the Commission has built into the interconnection process by limiting the scope of the restudy process and requiring transmission providers to inform interconnection customers of the additional funding risks associated with the withdrawal of a higher-queued interconnection customer. For interconnection customers, ruling in favor of SPP

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[65] *Id.*
[66] *Id.* at P 34.

in this case would send a message that customers simply cannot count on the interconnection studies received from SPP or other transmission providers, as these studies are always subject to change if the transmission provider later determines the studies are invalid and decides to restart the study process.

To be clear, Tenaska Clear Creek is not asking the Commission to insulate it or any other interconnection customer from *all* business risk. As noted above, SPP made numerous missteps during the initial studies of the Clear Creek Project, including overlooking a constraint that appeared when modeling the Project using ERIS standards. While the result of correcting these errors was to double the network upgrade costs imposed on the Project, Tenaska Clear Creek elected not to challenge that correction because it was corrected promptly on a timeline that allowed Tenaska Clear Creek to take into account the change in costs in its decision-making. SPP also did not use that omission as the opportunity to conduct a brand new study using a new study model and modeling assumptions and SPP did not attempt to assign to Tenaska Clear Creek the cost of resolving reliability issues that existed in the base case prior to the construction of the project.

In short, even if the omission of 4,500 MW of MISO generation was an error, SPP's decision to use the withdrawal of a higher-queued customer as a basis to restart the study process goes far beyond the business risks that interconnection customers should be required to bear. In order for the interconnection process to achieve the Commission's objectives of providing customers with the predictability necessary to make business decisions, there must be some limitation on the ability of a transmission provider to deviate from the assumptions that were employed as the initial studies of a customer when conducting a restudy. While correcting an error as part of a restudy that was identified promptly following the initial studies of an interconnection customer may be appropriate, allowing the transmission provider to make fundamental modifications to the study used as the baseline for assessing the customer's responsibility for network upgrades years after the initial studies were complete and after the customer has invested hundreds of millions of dollars in reliance on these studies is incompatible with the predictability and certainty that the interconnection process is intended to provide.

3. SPP's Treatment Of The Clear Creek Project Is Unduly Discriminatory

SPP's treatment of the Clear Creek Project is problematic when viewed in isolation. What makes SPP's actions particularly troubling, however, is that SPP's treatment of the Clear Creek Project represents a marked departure from the manner in which SPP is treating other interconnection customers.

a. SPP's Decision To Restudy The Clear Creek Project Using The 2019 ITP Model Is Unduly Discriminatory

SPP has attempted to defend its decision to conduct its restudy using the 2019 ITP model by claiming that the previous study model and assumptions had become stale.[67] Among other things, SPP has made vague references to alleged difficulties dispatching the 2017 model due to "non-convergence." In effect, SPP has attempted to portray its transition to the use of a new study model and study assumptions as unavoidable given the passage of time and deficiencies in the earlier versions of the model.

SPP's assertions regarding the purported staleness and difficulties associated with the previous model are undercut by the fact that SPP has continued to restudy other interconnection customers using the *same study model* that was used as the basis for the initial studies of the Clear Creek Project – the 2017 ITP study model. Notably, on April 23, 2021—several weeks after

[67] Staples Testimony at 21:340-350; Exhibit 12.

posting the most recent restudy of the Clear Creek Project—SPP posted a restudy of Groups 5, 9, and 16 within the DISIS-2016-002 *that continues to rely on the 2017 ITP study model*. Specifically, the executive summary of the April 23, 2021 study report, excerpted below, clearly and unambiguously acknowledges that it was completed using the 2017 ITP study model.[68]

Models Used in Study
2017 ITP Series
Winter: 2017, 2021
Summer: 2018, 2021, 2026
Light: 2021 & Spring: 2018
By: SPP Generator Interconnection Department
Published: April 2021

There simply is no justification for SPP to require the Clear Creek Project to be studied using a new model when it is continuing to study the DISIS-2016-002 study cluster using the same 2017 ITP model that formed the basis for the studies of the Clear Creek Project. From the beginning of the affected system study process, SPP has repeatedly affirmed that the Clear Creek Project should be evaluated using the same model as the DISIS-2016-002 study cluster. In fact, SPP initially confirmed that it planned to use the DISIS-2016-002 study model as the basis for the restudy of the Clear Creek Project.[69] It was only in May 2020—after delaying the commencement of the restudy for approximately six months—that SPP informed Tenaska Clear Creek that it had made the decision to restudy the Clear Creek Project using the 2019 ITP model because the prior model was no longer up-to-date.[70] Given the recent revelation that SPP is continuing to rely on

[68] A copy of the results of the restudy are available at: https://opsportal.spp.org/documents/studies/files/2016_Generation_Studies/DISIS_%20Results%20_Workbook_1602-2.xlsx (last checked May 21, 2021).
[69] Staples Testimony at 8-9:91-104; Exhibit 3.
[70] *Id.* at 21:340-350; Exhibit 12.

the 2017 ITP model to evaluate the DISIS-2016-002 study cluster, SPP's statements regarding the purported staleness and difficulties encountered with the 2017 ITP model are puzzling at best.

Indeed, SPP's actions also are in direct conflict with representations that SPP recently made to the Commission regarding its practice respecting restudies.[71] Notably, in a recent case involving a restudy of the DISIS-2016-002 study cluster—the same study cluster that SPP has acknowledged was affected by the "omission" of generation and that it continues to study using the 2017 ITP—SPP expressly acknowledged that its practice is *not* to update the study model and study assumptions when conducting a restudy due to the withdrawal of a higher-queued customer. In that case, a protester argued that SPP's restudy of interconnection requests in Group 8 was improper because SPP had restudied the interconnection requests using updated study models—the 2019 ITP Models—rather than the 2017 ITP Models used in the original study of the interconnection customers. SPP explained that it had used the same models and assumptions used in the original study—except for including projects that had been approved through the regional planning process—"consistent with how SPP conducts all other DISIS restudies for interconnection requests."[72]

Tenaska Clear Creek is not arguing that customers within the DISIS-2016-002 study cluster should be required to be restudied using the 2019 ITP model. To the contrary, using a restudy of an interconnection customer as an opportunity to transition to a new study model and study assumptions is fundamentally inconsistent with the Commission's requirement that interconnection customers be studied based on the circumstances that existed at the time of their initial system impact study.[73] Allowing transmission providers to change study models and

[71] *Sw. Power Pool, Inc.,* 171 FERC ¶ 61,068 (2020).
[72] *Sw. Power Pool, Inc.,* Answer of Southwest Power Pool, Inc., Docket No. ER19-2747-002 (filed Apr. 14, 2020).
[73] *Neptune* at P 23.

assumptions as part of the restudy process will necessarily have the effect—as it has here—of exposing customers to changes in costs associated with system and model changes that occurred after the interconnection customer entered the queue.

But it is simply not credible for SPP to assert that Tenaska Clear Creek must be restudied using a new study model when SPP continues to study SPP interconnection customers using the very same model that formed the basis for the initial studies of the Clear Creek Project and when SPP itself has acknowledged that changing study models as part of a restudy is inappropriate. The Commission has recognized that transmission providers should be permitted to evaluate affected system impacts "in accordance with their existing processes . . . assuming they apply such criteria and procedures consistently and not on a unduly discriminatory basis among all interconnection requests."[74] SPP's consistent deviation from its standard practices and procedures to afford less favorable treatment to the Clear Creek Project than other interconnect customers is unjust, unreasonable, and unduly discriminatory.[75]

SPP may argue that the Commission should look past its uneven treatment of the Clear Creek Project because the decision to restudy the Project using the 2019 ITP rather than the 2017 ITP did not prejudice Tenaska Clear Creek's interest. As noted in the attached testimony of ICF, however, ICF's analysis indicates that maintaining the 2017 ITP when adding in the additional 4,500 MW of MISO generation resources that SPP claims was omitted from the initial studies actually has the effect of reducing overloads on one of the ERIS upgrades that were identified in the initial studies of the Clear Creek Project—thereby reducing the costs assigned to the Clear

[74] *EDF Renewable Energy, Inc. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, 168 FERC ¶ 61,173 at P 86 (2019).
[75] *See, e.g., Midcontinent Indep. Sys. Operator, Inc.,* 173 FERC ¶ 61,035 at PP 19-23 (2020) (citing *Dynegy Midwest Generation, Inc. v. Fed. Energy Reg. Comm'n,* 633 F.3d 1122 (D.C. Cir. 2011) (finding that affording disparate treatment to customers due to their location is unjust, unreasonable, and unduly discriminatory)).

Creek Project by $18.6 million.[76] While allowing SPP to dramatically increase the costs assigned to the Clear Creek Project by effectively resetting the study process would still be improper if the total costs assigned to the Project were reduced by $18.6 million, there simply is no basis to assert that SPP's actions have had no effect on the cost responsibility of the Project.

Finally, even if SPP were not continuing to rely on the 2017 ITP model, it would be inappropriate to require Tenaska Clear Creek to bear additional costs when any need to update the model is the result of SPP's own failure to timely restudy the Project. Initially, after delivering notice of its intent to restudy the project in November 2019, SPP informed Tenaska Clear Creek that it planned to complete the restudy in the first quarter of 2020.[77] In reality, however, it would take SPP more than a year to deliver even preliminary restudy results to Tenaska Clear Creek. In fact, it was not until July 2020—approximately 8 months after providing notice of its intent to restudy the Project—that SPP delivered a study scope to Tenaska Clear Creek.[78]

b. SPP's Selective Correction Of Its "Error" Is Unduly Discriminatory

SPP's insistence on conducting a restudy based on the 2019 ITP model is not the only example of how SPP is treating Tenaska Clear Creek less favorably than other customers. Notably, SPP has acknowledged that the 7,000 MW of generation that it believes was "omitted" from the initial studies of the Clear Creek Project were also omitted from the studies of the DISIS-2016-002 study cluster. The fact that SPP omitted or improperly dispatched higher-queued generation resources when studying the DISIS-2016-002 is unsurprising, as it was the DISIS-2016-002 study model that formed the basis for the initial studies of the Clear Creek Project. In other words, SPP

[76] ICF Testimony at 22:313-318; 41:576-579.
[77] Staples Testimony at 20:316-322; Exhibit 12.
[78] *Id.* at 22:358-365; Exhibit 13.

initially omitted the generation at issue when constructing the base case for the DISIS-2016-002 studies. This omission was then carried through to the studies of the Clear Creek Project.

Despite SPP's acknowledgement of these errors on the DISIS-2016-002 study cluster, SPP has not restarted the study process for all of the impacted projects as it has done in the case of Tenaska Clear Creek. As noted above, while SPP recently announced the completion of a restudy of select groups within the DISIS-2016-002 study cluster, it has not commenced restudies of the remaining study groups. In fact, SPP expressly declined to restudy customers within Group 13 (the group closest to the Clear Creek Project) since none of the remaining generators were relying on upgrades that were being funded by the withdrawing customer—in stark contrast to the treatment afforded to Clear Creek following the withdrawal of J570.[79] And while SPP has restudied certain study groups since learning of its error in October 2020, it remains unclear whether SPP has corrected the studies of these groups to take into account the erroneously excluded generation resources.[80]

ICF's analysis also suggests that similar errors likely were made when studying other higher-queued interconnection customers. Notably, as discussed further below, ICF's analysis suggests that two higher-queued generation customers would have been assigned cost responsibility for the network upgrades that SPP is now proposing to assign to the Clear Creek Project if the "omitted" MISO generation resources had been included in the studies for these projects.[81] Tenaska Clear Creek has asked SPP to confirm whether the same omission was made

[79] Sw. Power Pool, Inc., Presentation to GIUF, DISIS-2016-002 and DISIS-2017-001 Update at 5 (Apr. 28, 2021); *see* Staples Testimony at 34:508-514; Exhibit 20.
[80] The restudies that SPP recently posted for Groups 4, 9, 15, and 16 appear to reference at least some of the higher-queued interconnection customers that SPP has identified as being excluded from the studies of the Clear Creek Project. It is important to note, however, that some of the interconnection customers that SPP inadvertently excluded from the studies of the Clear Creek Project were listed in the study reports for the project. As a result, it is not clear that the fact that some of the higher-queued interconnection customers are referenced in the restudy report means that they were included in the study model.
[81] ICF Testimony at 32:448-452.

when studying these higher-queued customers. Thus far, however, SPP has declined to respond or to provide Tenaska Clear Creek or ICF with the modeling information that was used as the basis for the evaluation of these customers.

If SPP believes that it is appropriate to restart the study process for the Clear Creek Project due to the omission of MISO generation resources from the studies of these projects, then it should restart the study process for all of the interconnection customers that have been affected by this error. As noted above, SPP has taken the position that the earlier studies of the Clear Creek Project were invalid due to its inadvertent exclusion of higher-queued interconnection customers. There is no reason why this same logic would not necessarily apply to the studies of other customers that were impacted by the same error. Yet, SPP has not unilaterally declared the previous studies of these customers invalid and forced them to restart the study process as it has with the Clear Creek Project. Instead, SPP has continued to allow these customers to rely on the results of studies that SPP now claims were fatally flawed. SPP's inconsistent treatment of the Clear Creek Project is unduly discriminatory and contrary to basic principles of comparability.[82]

B. SPP's Proposal To Allocate The Costs Of The NRIS Upgrades To Clear Creek Is Inconsistent With The But For Test And Cost Causation Principles

1. The NRIS Upgrades Are Necessary To Address Pre-Existing Issues That Pre-Date The Clear Creek Project

The Commission has consistently recognized that an interconnection customer should only be required to fund the cost of network upgrades that would not be needed "but for" the

[82] *EDF Renewable Energy, Inc. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, 168 FERC ¶ 61,173 at P 86; *Midcontinent Indep. Sys. Operator, Inc.,* 173 FERC ¶ 61,035 at PP 19-23; *Sierra Pac. Power Co.*, 111 FERC ¶ 61,415 at P 8 (2005) (noting that principles of comparability require that all interconnection customers are treated equally); *Internal Miso Generation*, 154 FERC ¶ 61,248 (2016) ("Tariff provisions should ensure that all interconnection customers, internal and external, and new and existing, are treated comparably . . .").

interconnection of the customer's generating facility.[83] More specifically, the Commission has explained that the "but for" principle requires that interconnection customers only be assigned the "costs of upgrades that would not be necessary but for the interconnection of the developer, minus the cost of facilities that are necessary for load growth and reliability purposes."[84] At the same time, the "but for" principle prohibits transmission providers from assigning interconnection customers cost responsibility for facilities that are necessary to address existing reliability issues or other system needs.[85]

In this case, there is ample evidence demonstrating that the NRIS Upgrades are necessary to address reliability issues that *pre-date* the Clear Creek Project. As described in detail in ICF's testimony, once the MISO generation that SPP claims was omitted from the studies is included in the 2017 ITP study model used as the basis for the initial evaluation of the Clear Creek Project, *four out of five* of the NRIS Upgrades are overloaded before the capacity associated with the Clear Creek Project is included in the study model.[86]

Similarly, the restudy results that SPP initially provided to Tenaska Clear Creek included extensive base case overloads, including of the NRIS Upgrades.[87] Indeed, ICF's analysis using the November 2020 restudy model confirmed that 4 out of 5 of the NRIS Upgrades were

[83] *S.C. Pub. Serv. Auth. v. F.E.R.C.*, 762 F.3d 41, 87 (D.C. Cir. 2014) (quoting *Nat'l Ass'n of Regulatory Util. Commis. v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007); *Illinois Com. Comm'n v. F.E.R.C.*, 576 F.3d 470, 476 (7th Cir. 2009) (*citing Midwest ISO Transmission Owners v. F.E.R.C.*, 373 F.3d 1361, 1368 (D.C. Cir. 2004); *Alcoa Inc. v. F.E.R.C.,* 564 F.3d 1342, 1346–47 (D.C. Cir. 2009).

[84] Order No. 2003, 104 FERC ¶ 61,103 at P 694; *see also Midwest Indep. Transmission Sys. Operator, Inc.,* 129 FERC ¶ 61,019 at P 23 (2009); *Jeffers South,* 144 FERC ¶ 61,033 at P 55 ("'the cost responsibility of interconnection customers 'remains limited to the cost of the facilities that would not be needed but for' the interconnection") (citing *Midwest Indep. Sys. Operator Inc.*, 131 FERC ¶ 61,165 at P 22 (rejecting MISO's allocation of network upgrade costs after MISO failed to show that a particular upgrade would not be needed but for a project's interconnection)).

[85] *Midwest Indep. Transmission Sys. Operator, Inc.,* 129 FERC ¶ 61,019 at P 23 (explaining that developers should only be assigned the "costs of upgrades that would not be necessary but for the interconnection of the developer, minus the cost of facilities that have been determined to be necessary for load growth and reliability purposes").

[86] *See, e.g.,* ICF Testimony at 22:309-24:338.

[87] Staples Testimony at 24:409-412.

overloaded in the base case prior to the introduction of the Clear Creek Project.[88] In fact, in some cases, Tenaska Clear Creek's contribution to the overload on the facility was less than or roughly equal to the existing overload. For instance, the Nashua Transformer was loaded at approximately 125% to 126.7% of its rated capacity in the base case; the addition of the Clear Creek Project increased the overload by 0.1% in a *single season*. Other lines that SPP is attempting to assign to the Clear Creek Project, such as the Maryville – Midway Line, Midway – Avenue City Line, and the Avenue City – St. Joe Line, showed overloads in the range of approximately 130% to 140% in the base case.[89]

Even the most recent study results that SPP provided in March 2021—which include adjustments to dispatch assumptions that reduce the loading on the NRIS Upgrades—show that the Maryville – Midway Line is overloaded in the base case prior to the addition of the Clear Creek Project.[90] Notably, even with SPP's adjustments, the loading on the remaining upgrades in the base case remain near or at the capacity of the line or equipment in one or more of the study years.[91] In addition, one of the NRIS Upgrades—the rebuild of the Nashua Roanridge Line—does not become overloaded with the introduction of the Clear Creek Project.[92] Instead, it is only when the Nashua Transformer upgrade that SPP has proposed to require Tenaska Clear Creek to fund is introduced into the study model that the Nashua Roanridge Line is overloaded.[93] In other words, it is SPP's choice of solution, rather than the Clear Creek Project, that causes the need for the Nashua transformer. Table 2 below compares the loading on the NRIS Upgrades in each of the study scenarios described above.

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[88] *Id.* at 22:310-312.
[89] ICF Testimony at 23, Figure 9.
[90] *Id* at 23:329-337; Figure 9.
[91] *Id.* at Figure 9.
[92] *Id.* at 39:554-557.
[93] *Id.*

Table 2: Loading on ERIS and NRIS Upgrades

Apr 2019 /March 2021Vintage	Type of Constraint	ICF Assessment [1]		2020 Restudy		2021 Restudy	
		Base Case	Transfer Case	Base Case	Transfer Case	Base Case	Transfer Case
Creston-Maryville 161 kV for the loss of Maryville- Maryville Tap 161 kV							
21 SP/24 SP	ER	69.1%	103.0%	77.8%	110.0%	77.6%	110.0%
26 SP/29 SP	ER	74.8%	109.0%	77.1%	109.2%	76.8%	109.2%
J611(Braddyville)- Maryville 161 kV for the loss of Creston-Maryville 161 kV							
21 SP/24 SP	ER	<50%	90 .8%	79.5%	115.8%	76.0%	113.9%
26 SP/29 SP	ER	57.2%	98.1%	78.1%	114.5%	74.7%	112.7%
Maryville- Midway 161 kV for the loss of Gentry-Fairport 161 kV							
21 SP/24 SP	NR	117.4%	154.1%	140.8%	183.7%	104.6%	146.1%
21 WP/24 WP	NR	66.3%	100.1%	107.9%	NConv	78.4%	110.8%
26 SP/29 SP	NR	117.5%	167.6%	140.7%	184.6%	105.9%	147.5%
Midway-Avenue City 161 kV for the loss of Gentry-Fairport 161 kV							
21 SP/24 SP	NR	106.9%	143.4%	133.3%	175.7%	97.5%	138.9%
21 WP/24 WP	NR	54.7%	88.2%	101.6%	NConv	72.4%	104.6%
26 SP/29 SP	NR	107.6%	157.2%	133.2%	176.7%	99.0%	140.3%
Avenue City 161- St Joe 161 kV for the loss of Gentry-Fairport 161 kV							
21 SP/24 SP	NR	105.2%	141.6%	131.8%	174.1%	96.0%	137.3%
21 WP/24 WP	NR	53.4%	86.8%	100.0%	NConv	71.0%	103.1%
26 SP/29 SP	NR	105.9%	155.4%	131.6%	175.0%	97.4%	138.7%
Nashua transformer 345/161 kV for the loss of Hawthorn – Nashua 345 kV							
21 SP/24 SP	NR	107.3%	107.3%	126.7%	126.7%	96.1%	<100%
21 WP/24 WP	NR	94.6%	96.9%	127.0%	NConv	99.7%	102.2%
26 SP/29 SP	NR	104.4%	108.7%	125.0%	125.1%	<100%	<100%
Nashua - Roanridge 161 kV line for the loss of Hawthorn – Nashua 345 kV							
21 SP/24 SP	NR	99.0%	98.3%	116.0%	117.5%	<100%	<100%
21 WP/24 WP	NR	75.4%	77.3%	112.7%	NConv	<90%	101.8%
26 SP/29 SP	NR	95.8%	100.5%	115.3%	116.3%	<100%	<100%

[1] After adjusting for omitted MISO capacity, withdrawal of J 570 and inclusion of MISO customers J718 and J748.

The fact that each of these analyses includes one or more overloads of the NRIS Upgrades in the base case analysis is unsurprising, because the SPP-MISO-AECI seam has been identified as one of the most constrained regions within SPP. In fact, SPP and MISO recently commenced a joint interconnection study in recognition of the overwhelming constraints in the region:

> As observed in the DPP-2017-FEB-West, DPP-2017-AUG-West and DISIS-2017-001 cluster studies, the transmission system is at its capacity and the next iteration

> of network upgrades are too costly for interconnection projects to proceed. While the additional of renewable resources and transmission along the seam benefit the market, current mechanisms do not provide sufficient cost sharing to facilitate new generator interconnection. Process, criteria, and schedule differences between the RTO's contribute to study delays and introduce questions on study results.[94]

A review of historical data regarding congestion on the NRIS Upgrades further confirms that there are constraints on these facilities that pre-date the interconnection of the Clear Creek Project. As ICF explains, a review of historical data shows significant congestion on the Maryville corridor and Nashua during 2016 through April 2020—prior to when the Clear Creek Project commenced commercial operation. The existence of congestion on these facilities further supports the conclusion that the grid is "at capacity" prior to the interconnection of the Clear Creek Project.

It is perhaps unsurprising that SPP is regularly assigning interconnection customers studied through the affected system study process responsibility for funding massive upgrades along the SPP-MISO-AECI seam. As ICF notes, a recent review of affected system studies shows customers on affected system studies being assessed network upgrade costs in the range of close to $1 billion associated with making upgrades to major paths along the SPP seam.[95]

In light of the above, SPP's proposal to assign Tenaska Clear Creek $66 million in costs associated with the construction of the NRIS Upgrades is unjust, unreasonable and contrary to Commission policy. The purpose of the "but for" principle is to prevent transmission providers from holding interconnection customers responsible for the costs of transmission facilities that would otherwise be necessary for other reliability purposes or system needs. Collectively, the base case overloads and other information described above provides ample support for the conclusion

[94] SPP-MISO 2021 Joint Targeted Interconnection Queue Study: Scope of Work (Feb. 19, 2021), available at: https://spp.org/documents/64101/spp-miso%20jtiq%20detailed%20scope%2002192021%20final.pdf.
[95] ICF Testimony at 34-35:473-486.

that the NRIS Upgrades are necessary to address reliability issues that pre-date and are separate and distinct from the interconnection of the Clear Creek Project.

It is important to note that the Commission has previously expressed concerns about transmission providers holding customers responsible for the costs of upgrading facilities that are overloaded in the base case. For instance, in *Midwest Independent Transmission System Operator, Inc.,* the Commission set for hearing and settlement procedures an interconnection agreement that assigned the customer cost of resolving overloads that existed in the base case.[96] While MISO attempted to address the Commission's concerns by assuring FERC that it had applied a "screening technique" to ensure that the interconnection customer would not be held responsible for "any of the pre-existing study overloads," the Commission expressed concern that MISO had not appropriately resolved all pre-existing base case overloads "before considering the network upgrades needed to interconnect" the customer and set the interconnection customer's responsibility for network upgrades for hearing and settlement procedures.[97]

Even in those limited cases where the Commission has acknowledged that a transmission provider may have discretion to require the construction of a facility that addresses reliability needs beyond those associated with accommodating a request for service, the Commission has found that a customer requesting service should not be required to fund that portion of the upgrades that are necessary to address other reliability needs.[98] For instance, in a case involving concerns that the procedures for studying requests for transmission service would allow a transmission provider to hold customers responsible for resolving base case overloads, the Commission explained that the transmission provider was required to "separately, identify the portions of the upgrade costs that

[96] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,113 (2008).
[97] *Id.* at P 33.
[98] *Midwest Indep. Transmission Sys. Operator, Inc.,* 138 FERC ¶ 61,149 at P 18.

are attributable to the base case overload versus the portions of the upgrade costs that are attributable to the transmission request, so the customer will not be responsible for costs attributable to relieving the base case overload."[99]

In this case, SPP has not made any attempt to allocate costs in a manner consistent with these principles or precedent. Instead, SPP has attempted to minimize the significance of the base case violations by claiming that they are attributable to higher-queued projects whose impact did not individually exceed the threshold that would have triggered an allocation of costs. Because Tenaska Clear Creek is the first project to impact these already overloaded facilities—at least according to SPP—then it is left to Tenaska Clear Creek—and Tenaska Clear Creek alone—to fund the construction of facilities necessary to resolve base case overloads.

SPP's arguments are flawed in several respects. As a starting point, even if it were true that the base case violations reflect the contribution of higher-queued generation resources that did not individually meet the criteria for assignment of network upgrade costs, it would still be inappropriate for SPP to charge Tenaska Clear Creek with resolving reliability issues that pre-date the interconnection of the Clear Creek Project. If there are base case overloads prior to the introduction of the Clear Creek Project, then these issues should be resolved through the regional or interregional planning processes.

SPP may take the position that since these upgrades have not been identified through the regional or interregional planning process, then it is appropriate to assign these costs to the Clear Creek Project. But the fact that the regional and interregional planning processes that SPP and other transmission providers use to ensure that the system is planned in a manner that maintains reliability, reduces the cost of delivered power by resolving congestion, and addresses public

[99] *See, e.g., Entergy Services, Inc.*, 137 FERC ¶ 61,199 (2011).

policy needs is more an indictment of the planning process than a reasonable basis to conclude that the manner in which SPP has proposed to assign the costs of NRIS thresholds is appropriate. In other words, the fact that there are gaps in the regional and interregional planning process does not mean that it is just and reasonable to assign the costs of resolving base case violations to the Clear Creek Project. At a time when there is a growing consensus that existing regional and interregional planning processes are failing to meet the evolving needs of the grid,[100] it would be inequitable and counterproductive to find that the appropriate remedy to addressing pre-existing base case overloads is to assign these costs to a single project.

In addition, and perhaps more importantly, ICF's analysis has confirmed that the base case overloads observed in the study of the Clear Creek Project are not attributable to the cumulative effect of higher-queued generation that simply did not meet SPP's thresholds for cost allocation.[101] As described in ICF's testimony, ICF's analysis demonstrates that the base case overloads are associated with identifiable, higher-queued generation resources.[102] While the identity of the generator that would have triggered these upgrades varies depending on whether the 2017 ITP or 2019 ITP model was used, ICF's analysis has identified two higher-queued generation resources that should have triggered the need for these upgrades if the study of these resources took into account the omitted MISO generation: (1) AECI Queue No. GI-53, a 236 MW generation resource

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[100] Americans for a Clean Energy Grid, *Disconnected: The Need for a New Generator Interconnection Policy*, (Jan. 5, 2021), *available at* https://cleanenergygrid.org/disconnected-the-need-for-new-interconnection-policy/; EnergyWire, *Glick: FERC to usher in transmission reforms this summer*, (Apr. 28, 2021) *available at* https://www.eenews.net/energywire/2021/04/28/stories/1063731135 (Chairman Glick expressing support for transmission planning reforms necessary to "further [incentivize] investment or [development of] additional transmission capacity . . ."); *see also* S&P Global Platts Megawatt Daily, *Interconnection policies to get fresh look at FERC as Glick questions current practices* (May 19, 2021) ("On the issue of funding network upgrades, Glick said he found it perplexing to force a new generating facility to pay all the costs of network upgrades needed to connect that facility to the grid, but allow all the generators that come after it in the interconnection queue to benefit from those upgrades at no cost.").

[101] ICF Testimony at 27:378-383.

[102] *Id.*

that is interconnected to the AECI system and located near the Clear Creek Project; and (2) MISO Queue No. J611, a 110 MW generation facility located on the Missouri-Iowa border.[103]

The fact that the SPP affected system studies for these projects did not assign them responsibility for funding the costs of the NRIS Upgrades suggests that these studies may have been affected by the same "omission" that SPP claims was made when studying the Clear Creek Project or other errors. As noted above, if SPP believes that it is appropriate to unilaterally declare its prior studies of the Clear Creek Project invalid due to its purported error and restart the study process for the Clear Creek Project, then it should restart the study process for all of the interconnection customers that have been affected by this error. It should not, however, selectively correct this error and force a single project to bear the consequences of SPP's failure to comply with the obligations imposed on it by the SPP Tariff and Commission precedent.

SPP's argument that Tenaska Clear Creek should be responsible for upgrading facilities that are overloaded in the base case is similar to arguments that the Commission rejected in *Jeffers South*. In that case, MISO argued that an interconnection customer was required to fund the costs of network upgrades necessary to address pre-existing overloads because the project would "push these overloads beyond a permissible level."[104] According to MISO, holding the interconnection customer accountable for addressing pre-existing reliability issues was appropriate because the customer had elected to site its project in a highly constrained area of the grid and the customer's project would adversely affect system reliability absent the construction of the upgrades at issue.[105]

The Commission disagreed, however. The Commission acknowledged that the customer's project would "tax the system" unless the upgrades were constructed. Nevertheless, the

[103] ICF Testimony at 27-29:384-424; *see Midcontinent Indep. Sys. Operator, Inc.,* Filing of Agreement for Engineering, Design, Permitting and Procurement, Docket No. ER19-2586-000 (filed Aug. 13, 2019).
[104] *Jeffers South, LLC v. Midwest Indep. Transmission Sys. Operator, Inc.,* 139 FERC ¶ 63,002 at P 71 (2012).
[105] *Id.*

Commission found that allocating the costs of these upgrades to the customer would violate the "but for" principle because there was evidence that the line would address other reliability needs, including improving overall system constraints, improving generator deliverability, and addressing other reliability issues.[106] While the Commission acknowledged that a transmission provider may determine through "its study process that a large upgrade should be built because it will address both interconnection customers and other system-wide needs . . . the cost responsibility of interconnection customers 'remains limited to the cost of the facilities that would not be needed but for' the interconnection." For that reason, the Commission found that requiring the interconnection customer to solely fund the costs of constructing the network upgrades would violate the "but for" principle.

The Commission should similarly reject SPP's proposal to allocate sole responsibility for funding the costs of the NRIS Upgrades to Tenaska Clear Creek. The fact that SPP's own studies show that the facilities that it is proposing to require Tenaska Clear Creek to upgrade are overloaded in the base case coupled with ICF's analysis demonstrates that the NRIS Upgrades are necessary to address needs that are separate and distinct from the interconnection of the Clear Creek Project. To hold Tenaska Clear Creek solely responsible for the costs of constructing facilities necessary to address these pre-existing reliability issues would violate the "but for" principle.

2. SPP's Application Of NRIS Thresholds To The Clear Creek Project Is Unjust, Unreasonable, and Contrary To Cost Causation Principles

Holding the Clear Creek Project responsible for resolving pre-existing overloads would be particularly inappropriate given that the *only* reason that Tenaska Clear Creek is being assigned these costs is due to SPP study practices that are unrealistic and out-of-step with other regions. As

[106] *Jeffers South, LLC,* 144 FERC ¶ 61,033.

described in detail in ICF's testimony, unlike MISO, SPP conducts affected system studies using NRIS modeling standards when the customer is seeking NRIS on its host system.[107] Other RTOs, in contrast, will conduct affected system studies using ERIS modeling standards regardless of the type of service that is being requested on the host system. The result of this difference is that SPP's affected system study process applies far more restrictive modeling practices when conducting affected system studies than MISO and other RTOs, with the result that affected system customers are often assigned costs associated with making significant upgrades to the SPP system.

SPP's decision to study the Clear Creek Project using NRIS modeling thresholds provides an unrealistic assessment of the impact that the Clear Creek Project will have on the SPP system and the benefits that Clear Creek would derive from the upgrades. By definition NRIS is interconnection service that "allows the Interconnection Customer to integrate its Generating Facility with the Transmission System in a manner comparable to that in which the Transmission Owner integrates its generating facilities to serve Native Load Customers as a Network Resource."[108] ERIS, in contrast, refers to interconnection service that allows the interconnection customer to inject energy on an "as available" basis.[109] The reality is that SPP will not operate its system in a manner to ensure that Tenaska Clear Creek receives service comparable to the service that SPP provides to native load customers. In practice, if generation resources located on the AECI system are impacting flows on a constrained interface, the likely result is that AECI would redispatch its system to mitigate these impacts. SPP, in contrast, would not reduce the output of generation resources on its system in order to ensure that the Clear Creek Project is able to operate.

[107] ICF Testimony at 12:156-162.
[108] SPP OATT, Attachment V (defining Network Resource Interconnection Service).
[109] SPP Guidelines for Generator Interconnection Requests, Section 4.2.

This is particularly true in the case of the Clear Creek Project. As noted above, the output of the Clear Creek Project is committed under a long-term agreement with AECI. In practice, the output of the Clear Creek Project will be injected into, and sink in, the AECI system. The Clear Creek Project will not be serving load on, or taking transmission over, the SPP system. Any incidental impacts on the SPP system can be managed through curtailment of the output of the Project as necessary.

SPP is not assigning the costs of the NRIS Upgrades to Tenaska Clear Creek because the operation of the Project will cause reliability issues on the SPP system that must be resolved through the construction of these upgrades. In fact, SPP has recently acknowledged that the use of ERIS practices is an appropriate basis for evaluating the impact of customers on adjacent systems in connection with the SPP-MISO Joint Interconnection Practices. Specifically, SPP has stated that all MISO interconnection requests evaluated as part of the study will only be modeled using ERIS standards.[110] If SPP applied this same approach to the Clear Creek Project, the result would be that Tenaska Clear Creek would not be responsible for funding *any* of the NRIS Upgrades. Instead, however, SPP is taking the position that Tenaska Clear Creek—and Tenaska Clear Creek alone—should be responsible for the costs of upgrades necessary to resolve pre-existing issues on a system that the Project will not take service on and which will not be operated in a manner to ensure that the Project receives the same priority as native load. Such an outcome is inherently unjust, unreasonable, and contrary to basic cost causation principles.[111]

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[110] SPP-MISO 2021 Joint Targeted Interconnection Queue Study Scope of Work at 5 (Feb. 19, 2021) ("As MISO will not be evaluating Network Resource Interconnection Service (NRIS) for SPP, the SPP GI study will not evaluate NRIS for MISO. MISO and SPP interconnection requests will be evaluated for ERIS only."), *available at*: https://spp.org/documents/64101/spp-miso%20jtiq%20detailed%20scope%2002192021%20final.pdf.

[111] *See S.C. Pub. Serv. Auth. v. F.E.R.C.*, 762 F.3d at 87; *Nat'l Ass'n of Regulatory Util. Commis. v. FERC*, 475 F.3d at 1285; *Illinois Com. Comm'n v. F.E.R.C.*, 576 F.3d 470, 476 (7th Cir. 2009).

VI. RELIEF REQUESTED

Tenaska Clear Creek respectfully requests that the Commission issue an order directing SPP to halt the restudy process and limit Tenaska Clear Creek's cost responsibility to the $34 million identified in the initial affected system studies. Promptly issuing an order prohibiting SPP from assigning Tenaska Clear Creek an additional $66 million in costs associated with the NRIS Upgrades is necessary to clear the cloud of uncertainty that has been cast over the Project due to SPP's actions.

The magnitude, severity, and impact of SPP's failure to meet its obligations under the Tariff or Commission precedent make this an exceptional case. Even during the initial phases of the study process, SPP made numerous corrections to the studies of the Clear Creek Project to address major oversights, including doubling the costs assigned to the Project in order to take into account a constraint that was initially overlooked. The culmination of this process has been SPP using the withdrawal of a higher-queued interconnection as an opportunity to restart the affected system study process for the Clear Creek Project—based on a new study model and employing a host of new assumptions—with the result that the Project is being directed to pay an additional $66 million in costs in order to build upgrades that appear to be necessary to address issues that existed prior to the interconnection of the Clear Creek Project.

The most appropriate remedy in this case is to require SPP to respect the results of the initial studies of the Clear Creek Project. To find that the withdrawal of J570 justifies SPP's actions would be to elevate form over substance. While SPP has characterized the process that has unfolded over the past year and a half as a restudy, the reality is that SPP has exceeded the bounds of its authority by restarting the study process for the Clear Creek Project years after Tenaska Clear Creek Project entered the queue. There simply is no basis for concluding that a study using a new model, new study assumptions, and a different study period constitutes anything other than an attempt by SPP to restart the study process in order to correct its own errors or to revisit assumptions that it now disagrees with.

Tenaska Clear Creek does not have the luxury of going back in time to take into account $66 million in additional costs that SPP now claims should be assigned to the Project. Tenaska Clear Creek invested hundreds of millions of dollars to construct a project based on the results of SPP's studies. Tenaska Clear Creek was justified in relying on these studies. Indeed, the interconnection process cannot achieve its objective of ensuring that customers receive the information necessary to make informed investment decisions if transmission providers can simply declare prior studies to invalid and restart the study process. Interconnection customers recognize that their cost responsibility can change in the event that the withdrawal of a higher-queued customer shifts the costs of network upgrades from the withdrawing customers to the Clear Creek Project. But there is no way for interconnection customers to take into account the risk that a transmission provider will use the withdrawal of a higher-queued project to engage in a "free for all" that has little relationship to the prior studies of the customer or the reason cited for the restudy. Decisive action that directs SPP to respect the results of the initial studies of the Clear Creek Project would not only respect the settled expectations of the Clear Creek Project, it would provide certainty to interconnection customers by affirming that the estimates set forth in interconnection studies mean something and can only be changed in a limited set of circumstances.

Granting Tenaska Clear Creek's request for relief would be consistent with the Commission's determination in *Neptune*. In that case, an interconnection customer filed a complaint against PJM Interconnection, L.L.C. ("PJM") requesting that the Commission find that PJM's decision to restudy its project to take into account changes in the higher-queued generation resources assumed in the study due to retirements that occurred after the interconnection customer's initial system impact studies was inconsistent with the PJM Tariff and Commission policy. The Commission agreed, finding that the changes at issue "could not have been considered as part of Neptune's business risk . . . and should not have been a basis for subsequent re-study." For that reason, the Commission issued an order prohibiting PJM from assigning approximately $22 million in additional costs to the customer and limiting the customer's cost responsibility to the costs identified in the earlier studies of the project. While some parties argued that limiting the costs borne by the interconnection customer would require other users of the grid to unfairly subsidize the customer's interconnection, the Commission found that it was not required to address how the remaining costs would be recovered; instead, the Commission left it to PJM and the PJM Transmission Owners to determine how these costs would be recovered in the event that the facilities, in fact, needed to be built., including, for instance, recovering the associated costs through transmission rates.[112]

The Commission should grant similar relief in this case. Like in *Neptune*, SPP is attempting to hold Tenaska Clear Creek accountable for changes that occurred after Tenaska Clear Creek's initial studies were completed and that could not have been considered as part of the Project's business risks. Whether the omission that SPP has identified is an error or simply a decision by SPP to revisit key study assumptions after the fact, the reality is that there was no way for Tenaska Clear Creek to take into account the risk that SPP would make fundamental modifications to the baseline used to evaluate the network upgrade responsibility of the Project, including adding in 4,500 MW of generation resources and transitioning to a new study model, years after the initial studies were complete and the Project had already entered commercial operation. Under the circumstances, the just and reasonable outcome is to find that Tenaska Clear

[112] *Neptune* Order on Rehearing at P 25.

Creek's costs should be limited to the costs that were promptly identified in its initial studies based on the facts and circumstances at the time that the Project commenced the SPP study process.

It is important to recognize that the conclusion that Tenaska Clear Creek should be required to fund the construction of these facilities is a product of SPP's decision to study the Clear Creek Project using NRIS analyses and thresholds—thresholds that SPP has elected not to apply to interconnection customers on other affected systems as part of its joint SPP-MISO study process. SPP's willingness to depart from a rigid application of its practice of applying more restrictive modeling practices to resources that are requesting NRIS on their host systems demonstrates that there is nothing in SPP's Tariff that requires it to apply this standard here or that doing so is just and reasonable. To the contrary, the evidence described above demonstrates that strictly applying this standard here given the exceptional circumstances in this case would lead to a result that is unjust, unreasonable, and unduly discriminatory.

In the event that SPP believes that these facilities should still be constructed, then SPP can allocate these costs in accordance with the existing terms and conditions of the SPP Tariff. Given the ample evidence demonstrating that facilities along the SPP seam have reached their limit, Tenaska Clear Creek believes that it would be appropriate for SPP to address these existing constraints and reliability issues through the regional or interregional planning processes. This is not a case where the network upgrades necessary to accommodate the interconnection of a customer will have incidental benefits to the network; to the contrary, the primary function of these facilities will be to benefit the network by strengthening the SPP-MISO-AECI seam. Given that, rather than allocating all of the costs of such upgrades on interconnection customers through the generator interconnection process, SPP should work with its neighboring transmission providers to implement regional and interregional solutions to ensure that costs are allocated equitably to those customers that benefit from a stronger network while also promoting reliability and removing barriers to entry.

If the Commission does not believe that it would be just and reasonable to incorporate these costs into regional rates, then the Commission should direct SPP to allocate the additional $66 million in a manner that better aligns with cost causation principles, including to the higher-queued customers that would have triggered the need for the upgrades in the first place if the omitted generation resources had been taken into account at the beginning of the process as well as lower-queued customers that will benefit from these upgrades.

SPP will argue that its Tariff does not provide it with a mechanism to assign these costs to other customers that will benefit from the construction of these upgrades and that there is no alternative to leaving Tenaska Clear Creek "holding the bag." To the extent that the SPP Tariff requires that Tenaska Clear Creek alone bear the consequences of SPP's missteps by being assigned 100% of the costs of the NRIS Upgrades—while other generation resources that caused the need for, or benefit from these, upgrades are completely insulated from these costs—then the Commission should find that the SPP Tariff is unjust, unreasonable, and unduly discriminatory and direct SPP to allocate the costs of these facilities in a manner that ensures that all customers that benefit from these facilities bear an equitable portion of the associated costs.

Tenaska Clear Creek believes that allocating costs to those projects that benefit from the NRIS Upgrades would better align with the cost causation principles, including those reflected in the SPP Tariff, than SPP's proposed "all or nothing approach." Notably, when conducting studies of customers interconnecting to the SPP system, SPP allocates the costs of network upgrades on a pro rata basis to those customers that contribute to the need for the upgrade.[113] Applying these same principles and methodologies here—which the Commission has already found to be just and reasonable when applied to customers on the SPP system—would ensure that the costs of the NRIS Upgrades are allocated equitably among interconnection customers.

Tenaska Clear Creek believes that it has provided ample record evidence to support a decision by the Commission granting the requested relief. If the Commission disagrees, however, there is more than enough evidence to support setting for hearing the issue of how the consequences of SPP's actions can be allocated equitably among those customers that will benefit from the NRIS Upgrades, including both those customers that ICF's analysis indicates would have triggered the need for the upgrades as well as lower-queued generation resources that will benefit from these upgrades in the event that the omitted generation had been included in their studies.

VII. RULE 206 REQUIREMENTS

The specific information required under Rule 206(b)(1) through (11), 18 C.F.R. § 385.206(b), of the Commission's Rules of Practice is set forth below. The basis for the complaint and the relief requested are set forth above.

A. Request for Fast Track Processing

This Complaint warrants fast track processing under Rules 206(h) and 206(b)(11) of the Commission's Rules of Practice and Procedure. 18 C.F.R. §§ 385.206(b)(1); 385.206(h). As explained above, a prompt ruling in this case is necessary to ensure that Tenaska Clear Creek is not held responsible for the costs of constructing upgrades necessary to address issues that pre-date the Clear Creek Project and to avoid further curtailments of the Clear Creek Project. Granting

[113] SPP OATT, Attachment V, Section 4.2.2(b) ("An allocation of the costs of each Network Upgrade to each Interconnection Customer shall be determined on a pro rata basis for the positive incremental power flow impacts of the requested service on such Network Upgrades in proportion to the total of all positive incremental power flow impacts on such Network Upgrade.").

this Complaint on an expedited basis will provide certainty to Tenaska Clear Creek that it is not responsible for these upgrades, and will also provide certainty to similarly situated interconnection customers that rely on SPP's adherence to its Tariff and the FPA. Tenaska Clear Creek therefore respectfully requests a Commission ruling on this complaint no later than 60 days after the submission of this Complaint.

B. Compliance with Rule 206 Requirements

1. *Rule 206(b)(1): Action or Inaction Alleged to Violate Statutory Standards or Regulatory Requirements*

Tenaska Clear Creek alleges that SPP's mishandling of the affected system studies of the Clear Creek Project and its allocation of network upgrade costs to the Project is unjust, unreasonable, and unduly discriminatory in violation of Sections 206, 306, and 309 of the FPA and Rule 206 of the Commission's Rules of Practice and Procedure for the reasons discussed in sections I-V of the foregoing complaint.

2. *Rule 206(b)(2): Legal Bases for Complaint*

The legal bases for Tenaska Clear Creek's complaint are set forth above in sections I-V of the complaint.

3. *Rule 206(b)(3) and 206(b)(4): Issues Presented as They Relate to the Complainant and Quantification of Financial Impact on Complainant*

As described above, SPP has proposed to allocate approximately $66 million in NRIS Upgrades to the Clear Creek Project in a manner inconsistent with Commission precedent.

4. *Rule 206(b)(5): Nonfinancial Impacts on Complainant*

As detailed in sections I-V, SPP's unjust, unreasonable, and unduly discriminatory treatment of Tenaska Clear Creek violates SPP's Tariff and the FPA. Allowing these violations to go unchecked by the Commission would decrease certainty for generators attempting to interconnect to the grid and discourage investment in new renewable generation facilities like the Clear Creek Project.

5. *Rule 206(b)(6): Related Proceedings*

There are currently no on-going, related proceedings.

6. *Rule 206(b)(7): Specific Relief Requested*

The specific relief requested is set forth in section VI of the foregoing complaint.

7. *Rule 206(b)(8) Documents that Support the Complaint*

Attached are the following exhibits:

Attachment 1, Testimony of Boone Staples, Director of Transmission Analysis at Tenaska, Inc.; Exhibits 1-20.

Attachment 2, Testimony of Judah L. Rose, Executive Director of ICF and the Chair of ICF's Energy Advisory division, and Himali Parmar, Consultant within ICF's Energy Advisory division; Exhibits 2-1, 2-2.

8. *Rule 206(b)(9): Dispute Resolution*

Prior to filing, Tenaska Clear Creek engaged in good faith negotiations with SPP in an attempt to resolve the issues outlined in the foregoing Complaint. Despite those discussions, the parties have been unable to reach a resolution

9. *Rule 206(b)(10): Form of Notice*

The form of notice required by the Commission's Rule 206(b)(10) is attached as Attachment 3.

10. *Rule 206(c): Service on Respondent*

Pursuant to Rule 206(c), concurrent with its filing with the Commission, Tenaska Clear Creek has served copies of this Complaint by email and U.S. mail on the contacts for SPP as listed on the Commission's list of Corporate Officials:

Barbara Sugg
President and Chief Executive Officer
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Telephone: 501-614-3245
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Nicole Wagner
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VIII. CONCLUSION

For the foregoing reasons, Tenaska Clear Creek respectfully requests that the Commission grant the specific relief requested herein and such other and further relief as the Commission may deem appropriate.

Respectfully submitted,

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Drew J. Fossum
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dfossum@tenaska.com

Dated: May 21, 2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tenaska Clear Creek Wind, LLC	)	
	)	
Complainant	)	
	)	Docket No. EL21-____-000
v.	)	
	)	
Southwest Power Pool, Inc.	)	
	)	
Respondent.	)	

NOTICE OF COMPLAINT

(   )

Take notice that on May 21, 2021, Tenaska Clear Creek Wind, LLC filed a formal complaint against Southwest Power Pool, Inc. pursuant to Sections 206, 306, and 309 of the Federal Power Act ("FPA") and Rule 206 of the Commission's Rules of Practice and Procedure, alleging that SPP's affected system studies for the Tenaska Clear Creek Wind Project are unjust, unreasonable, and contrary to Commission precedent.

Tenaska Clear Creek Wind, LLC certifies that copies of the complaint were served on the contacts for Southwest Power Pool, Inc. as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose,

Secretary.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon respondent Southwest Power Pool, Inc.

Dated at Washington, DC, this 21st day of May 2021.

/s/ Stephen J. Hug
Stephen J. Hug

ATTACHMENT 1

Testimony of Boone Staples on behalf of

Tenaska Clear Creek Wind, LLC

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tenaska Clear Creek Wind, LLC	)	
Complainant,	)	
	)	
v.	)	**Docket Nos. EL21-___-000**
	)	
Southwest Power Pool, Inc.	)	
Respondent.	)	

TESTIMONY OF BOONE STAPLES ON BEHALF OF
TENASKA CLEAR CREEK WIND, LLC

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Tenaska Clear Creek Wind, LLC	)	
Complainant,	)	
	)	
v.	)	**Docket No. EL21-___-000**
	)	
Southwest Power Pool, Inc.	)	
Respondent.	)	

<u>TESTIMONY OF BOONE STAPLES ON BEHALF OF TENASKA CLEAR CREEK WIND, LLC</u>

I. INTRODUCTION

Q1: Please state your name and business address.

A1: My name is Boone Staples. My business address is 300 East John Carpenter Freeway, Suite 1000, Irving, TX 75062.

Q2: On whose behalf are you testifying?

A2: I am testifying on behalf of Tenaska Clear Creek Wind, LLC ("Tenaska").

Q3: Please describe your educational background.

A3: I have a Bachelor of Science in electrical engineering from Texas A&M University, and I have a Masters of Science in electrical engineering from Southern Methodist University. I am a licensed professional engineer in Texas.

Q4: Please summarize your professional experience.

A4: I have been employed by Tenaska since 2007. I worked as a real-time System Operator in Tenaska's energy management group for roughly two years before moving to Tenaska's development group in 2009 to work as a Transmission Analyst. My current title is Director of Transmission Analysis.

Q5: What are your duties and responsibilities in your current position?

A5: In my current position, I am responsible for conducting and overseeing transmission analysis related to generator interconnection for Tenaska's development projects and operating plants in multiple Regional Transmission Operator ("RTO") and non-RTO areas, including the Southwest Power Pool, Inc. ("SPP") and the Midcontinent Independent System Operator, Inc. ("MISO"). I am also responsible for developing generator interconnection applications, and managing projects through the interconnection study process, as well as negotiating generator interconnection agreements and participating in interconnection-related stakeholder forums across various RTOs.

Q6: What is the purpose of your testimony in this proceeding?

A6: The purpose of this testimony is to support the complaint filed by Tenaska in this docket against SPP related to SPP's affected system study of the Clear Creek Project ("Project"), a wind-powered generator located in Maryville, Missouri. This testimony summarizes my experience acting on behalf of Tenaska in an effort to coordinate with SPP on the completion of the affected system study process.

II. PARTIES AND PROJECT OVERVIEW

Q7: Which entities are involved directly or indirectly in this proceeding?

A7: The entities directly involved in this proceeding are Tenaska Clear Creek Wind, LLC and SPP. The entity indirectly involved in this proceeding is Associated Electric Cooperative, Inc. ("AECI").

Q8: Please provide an overview of Tenaska Clear Creek Wind, LLC.

A8: Tenaska Clear Creek Wind, LLC is an affiliate of Tenaska. Tenaska Clear Creek Wind, LLC developed and now owns and operates the Clear Creek Project.

Q9: Please provide an overview of SPP.

A9: SPP is a non-profit organization and Commission-approved Regional Transmission Organization that administers open access transmission service over more than 48,000 miles of transmission lines in eight states, including Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas.

Q10: Please provide an overview of AECI.

A10: AECI is a generation and transmission cooperative that operates a high-voltage transmission system covering parts of Missouri, Iowa, and Oklahoma. The Clear Creek Project is interconnected to the transmission system owned by AECI.

Q11: Please provide an overview of the Clear Creek Project.

A11: The Clear Creek Project is a 242-MW wind-powered generation facility located north of Maryville in Nodaway County, Missouri. The Project is comprised of 111 wind turbine generators on approximately 31,000 acres. The output of the Clear Creek Project has been committed to AECI and the project has entered into an agreement with AECI for Network Resource Interconnection Service ("NRIS").

III. AFFECTED SYSTEM STUDY PROCESS

Q12: How did Tenaska begin the process of interconnecting the Clear Creek Project to AECI's transmission system?

A12: On May 2, 2017, Tenaska submitted an interconnection request to AECI. Following the submission of the interconnection request, AECI commenced a system impact study of the Clear Creek Project. AECI issued a system impact study report on November 15, 2017. After completion of the system impact study, AECI conducted a facilities study. On September 27, 2018, AECI issued a facilities study report for the Clear Creek Project.

Q13: What were the results of AECI's studies?

A13: AECI's studies identified a total of approximately $32 million in costs associated with the construction of interconnection facilities and network upgrades on the AECI system. Tenaska executed a GIA with AECI on December 27, 2018.

Q14: Did AECI's study process identify systems potentially affected by the Clear Creek Project's interconnection to AECI's transmission system?

A14: Yes. During the study process, AECI identified SPP and MISO as potentially affected systems and directed Tenaska to coordinate affected system studies with these systems. As a result, following the commencement of the AECI study process, Tenaska initiated affected system studies with both SPP and MISO.

Q15: Please describe Tenaska's initial coordination with SPP after AECI identified SPP as a potentially affected system.

A15: On January 3, 2018, I emailed SPP to request that an affected system study of the Tenaska Clear Creek Project be performed. After working with SPP to identify the information that they would need to process the request, on January 31, 2018, Tenaska executed an affected system interconnection system impact study agreement with SPP. On February 2, 2018, I sent an email to SPP providing a copy of the executed affected system interconnection system impact study agreement and technical data for the plant necessary to proceed with the affected system study. On February 5, 2018, Tenaska wired a study deposit of $15,000 to SPP. A copy of my correspondence with SPP regarding initiation of the study process is provided as Exhibit 1.

Q16: When did SPP return the executed study agreement?

A16: SPP returned the executed study agreement on January 23, 2019. A copy of the study agreement is provided as Exhibit 2.

Q17: Please describe the steps that SPP took to process the affected system study following the submission of Tenaska's request?

A17: SPP did not commence the study process until late 2018. After submitting the executed study agreement and deposit, I did not receive any further communications about the affected system study until August. On August 20, 2018, I sent an email to Ms. Alyssa Anderson, an engineer in SPP's Generation Interconnection Studies group requesting an update on the progress of the study and asking that the study be performed as soon as possible. A copy of this correspondence is provided as Exhibit 3.

Q18: What information did Ms. Anderson provide to Tenaska at the time Tenaska requested that an affected system study be performed?

A18: Ms. Anderson replied by email on August 20, 2018. At that time, Ms. Anderson informed me that the Clear Creek Project should be the next project in the queue to be studied and that she would provide an update on timing following further consultation with the contractor that had been engaged to conduct the study. Ms. Anderson added that affected system studies involving AECI usually take approximately four to five weeks to complete. Ms. Anderson also explained that since Tenaska had submitted its interconnection request to AECI on May 2, 2017, the Clear Creek Project would be "queued" between the SPP DISIS-2016-002 and SPP DISIS-2017-001 study groups. At that time, Ms. Anderson also informed me that SPP would be using the DISIS-2016-002 transfer case as the "base case" starting point for the study of the Clear Creek Project. Ms. Anderson indicated that the

Clear Creek Project would be dispatched on top of the DISIS-2016-002 study group to create the transfer case for the Clear Creek Project.

Q19: What is the DISIS-2016-002 transfer case?

A19: When conducting an interconnection study, SPP distinguishes between the "base case" and the "transfer case." The base case represents the SPP system prior to the introduction of the capacity of the customer being studied. The transfer case refers to the SPP system model following the addition of the interconnection customer's project. It is the transfer case that is used to evaluate whether any network upgrades need to be constructed in order to accommodate the interconnection of the customer. For the purpose of studying the Clear Creek Project, the transfer case for the DISIS-2016-002 study group was used as the base case for the Clear Creek Project. The DISIS-2016-002 study case was based on the 2017 Integrated Transmission Planning ("ITP") study model that SPP uses as the basis for its regional transmission planning studies. In order to create the base case for the Clear Creek Project, SPP modified the DISIS-2016-002 transfer case to reflect the addition of the generation resources in the DISIS-2016-002 study group and the network upgrades associated with these projects.

Q20: When did SPP complete its first affected system study of the Clear Creek Project?

A20: SPP issued an Affected System Impact Study, ASGI-2018-001, Rev. 0, on October 5, 2018. The study evaluated the Clear Creek Project using a rating of 230 MW, which reflects the amount of energy that can be injected into the grid under its generator interconnection agreement with AECI. This study is provided as Exhibit 4.

Q21: Please describe the study.

A21: The study described the results of the evaluation of the Clear Creek Project and provided further detail regarding the study model and assumptions. In the study, SPP explained that the base case considered any generating facilities that were: (1) directly interconnected to the SPP system; (2) interconnected to Affected Systems that may have an impact on the Interconnection Request; (3) projects with a pending higher-queued interconnection request; and (4) interconnection customers that had executed a generator interconnection agreement ("GIA") or an unexecuted GIA that had been filed with FERC. In the initial System Impact Study, SPP included a table listing 17 higher-queued projects on the SPP and MISO systems. The study also indicated that SPP's analysis was based on the assumption that network upgrades that had been assigned to Tenaska Clear Creek by AECI had been constructed.

Q22: Did the study identify any network upgrades on the SPP system associated with higher-queued projects that were being relied upon to accommodate the Clear Creek Project?

A22: Not specifically. The study indicated that network upgrades that had been identified in the SPP Transmission Expansion Plan or the Balanced Portfolio projects had been included in the base case, but that no other upgrades were included for the purpose of the affected system study.

Q23: What were the results of the study?

A23: The study identified $31.2 million in upgrades associated with Energy Resource Interconnection Service ("ERIS"). Specifically, the study proposed to require Tenaska Clear Creek to fund upgrades to the Maryville – Maryville 161 kV Circuit ($1.2 million) on the system of Kansas City Power & Light ("KCPL"), and a re-conductoring of the Creston – Maryville 161 kV Circuit ($30 million) on the system of the Western Area Power Administration Upper Great Plains Region ("WAPA").

Q24: What do you mean when you state that the upgrades were associated with ERIS?

A24: When performing affected system studies, SPP's analysis varies depending on whether the interconnection customer is requesting ERIS or NRIS on the host system (e.g., AECI). Because the Clear Creek Project is taking NRIS on the AECI system, SPP performed an analysis assuming that the project was dispatched based on ERIS and an analysis assuming that the project was dispatched using NRIS. The thresholds used by SPP to determine whether to assign an interconnection customer differ based on whether the project is being dispatched using ERIS or NRIS. For the purpose of the ERIS evaluation, a project will be allocated the costs of upgrading a facility if the distribution factor on a facility is 20% for outage-based thermal constraints and 3% for all other constraints. The distribution factor threshold for requests seeking NRIS is 3% for all constraints.

Q25: Did SPP identify any network upgrades associated with NRIS?

A25: No.

Q26: Please describe what happened following the receipt of the System Impact Study?

A26: On November 5, 2018, SPP revised the system impact study to correct an omission that SPP had identified after the issuance of the initial study. In particular, it revised the study to add a higher-queued MISO project that had inadvertently been omitted from the table of higher-queued interconnection requests. The correction did not impact the cost responsibility of the project for network upgrades. This revised study was designated as ASGI-2018-001, Rev. 1. A copy is provided as Exhibit 5.

Q27: **Were there any substantive changes to the study as a result of this revision?**

A27: No, there were no substantive changes except that following the revision, there were 18 higher-queued projects listed in the study.

Q28: Please describe the facilities study that was performed for the Clear Creek Project.

A28: After performing the system impact study, SPP tendered an Affected System Interconnection Facilities Study Agreement to Tenaska Clear Creek. Tenaska Clear Creek executed the Affected System Interconnection Facilities Study Agreement on October 31, 2018. The purpose of the Affected System Interconnection Facilities Study Agreement is to authorize SPP to move forward to work with the relevant SPP Transmission Owners to conduct a study to further refine the network upgrade cost estimates. The Facilities Study agreement obligates SPP to use reasonable efforts to complete the study and issue an Interconnection Facilities Study report within 90 days and to provide a cost estimate that is within 20% of the actual cost of constructing the network upgrades necessary to accommodate the interconnection of the project. SPP executed the facilities study agreement on March 13, 2019. A copy of the facilities study agreement is provided as Exhibit 6.

Q29: When did SPP issue a Facilities Study for the Clear Creek Project?

A29: SPP issued an Affected System Interconnection Facilities Study on February 12, 2019. A copy is provided as Exhibit 7. The Facilities Study Report also included individual reports from the transmission owners responsible for constructing the network upgrades identified in the system impact study, KCPL and WAPA. The February 12, 2019 Affected System Interconnection Facilities Study identified $16.3 million in network upgrades attributable to the Clear Creek Project, a nearly fifty percent decrease from SPP's initial $31.2 million Affected System Impact Study estimate.

Q30: Please explain the reason for the cost decrease?

A30: The decrease in costs was attributed to the fact that WAPA had determined that the costs associated with upgrading the Creston – Maryville 161 kV line had decreased to approximately $14.9 million.

Q31: Please describe the progress of the SPP affected system study process after issuance of the Facilities Study.

A31: Following the initial facilities study, SPP made two separate modifications to the system impact study for the Clear Creek Project.

First, on March 13, 2019, SPP issued a second revision of the Affected System Impact Study, ASGI-2018-001, Rev. 2. The second revision increased the studied capacity of the Clear Creek Project to 242 MW of capacity. Previously, the Clear Creek Project was studied at 230 MW, which reflects the maximum quantity of electricity that the Clear Creek Project can inject into the AECI system. In connection with performing the revised study, however, SPP staff took the new position that they were required to study the nameplate capacity of the facility.

Second, on March 15, 2019, SPP informed Tenaska Clear Creek that it was planning to modify the Affected System Impact Study to reflect a constraint that had been overlooked in the initial system impact study. At the time, SPP informed me that its previous studies of the Clear Creek Project had identified a constraint on the Bradyville (J611) – Maryville Line, but SPP had overlooked this constraint and failed to assign it to the Clear Creek Project in those previous studies. SPP further explained that since the constraint was not overloaded in the base case and only became constrained in the transfer case, Tenaska Clear Cree would be assigned the costs of constructing network upgrades to mitigate the constraint. SPP further explained that it had incorrectly categorized the constraint as not requiring mitigation because it believed that the constraint was on a portion of the transmission grid subject to MISO's control. A copy of my correspondence with SPP regarding the Bradyville (J611) – Maryville constraint is provided as Exhibit 8.

Q32: How large was constraint on the Bradyville (J611) – Maryville Line?

A32: SPP's study indicated that the line was overloaded at 106.376% of its rated capacity in the transfer case.

Q33: What was the impact of assigning responsibility to the Clear Creek Project to mitigate this constraint?

A33: The additional costs associated with mitigating the Braddyville (J611) –Maryville 161 kV line increased the total network upgrade costs assigned to the Clear Creek Project on the SPP system to $33.017 million, which represented approximately double the costs identified in the facilities study of the Clear Creek Project.

Q34: Did Tenaska discuss any alternatives to upgrading the Bradyville (J611) – Maryville 161 kV line?

A34: Yes. However, SPP informed us that since the line was overloaded by approximately 106% of its rated capacity, Tenaska Clear Creek was required to pay for upgrading the line to relieve the constraint. As a result, SPP issued a revised affected system impact study on March 21, 2019. A copy of the March 21 study is provided as Exhibit 9.

Q35: What happened following the posting of the March 21, 2019 study?

A35: SPP issued a revision of the Affected System Interconnection Facilities Study on April 8, 2019. The revised facilities study identified the network upgrades necessary to accommodate the entirety of the 242 MW of capacity at the Clear Creek Project. This revised facilities study identified a total of $33.535 million in network upgrade costs associated with mitigating constraints necessary for ERIS. The revised facilities study also indicated that no network upgrades were necessary for NRIS. A copy of the revised facilities study is provided as Exhibit 10.

Q36: Could you describe your experience with the MISO affected system study process?

A36: Yes. During this same period, Tenaska Clear Creek was coordinating with MISO to complete affected system studies. MISO completed an affected system study for the Clear Creek Project in June 2018 and a restudy of the Clear Creek Project in December 2018, after there were multiple withdrawals of higher-queued generators on MISO's system. Both the MISO initial study and the restudy concluded that no transmission upgrades were required to enable the Clear Creek Project to operate at full capacity, subject to the successful construction of MISO's multi-value projects, the Zachary – Maywood Line and Kansas – Sugar Creek Line. Both of these lines have been placed in service.

Q37: What steps did Tenaska take to move construction of the project forward following the April 8, 2019 revised Affected System Interconnection Facilities Study?

A37: Following SPP's issuance of the April 8, 2019 revised Affected System Interconnection Facilities Study, Tenaska began negotiating Facilities Construction Agreements ("FCA") with Kansas City Power and Light Company and WAPA.

Q38: Did Tenaska execute FCAs with KCPL or WAPA?

A38: Yes. Tenaska executed an FCA with KCPL on August 30, 2019, pursuant to which it agreed to fund upgrades to the Maryville – Maryville 161 kV line and to the Maryville substation. KCPL tendered a separate FCA to Tenaska to upgrade the Maryville – Braddyville 161 kV line. WAPA also tendered an FCA to Tenaska to upgrade the Maryville – Creston 161 kV line.

Q39: Have the latter two agreements been executed by the parties?

A39: The FCAs for upgrades of the Maryville – Braddyville 161 kV and Maryville – Creston 161 kV lines have not been executed by the parties, as those agreements remained subject to negotiation when Tenaska Clear Creek was notified of SPP's plan to restudy the Clear Creek Project.

Q40: Were the upgrades contemplated by the executed August 30, 2019 FCA between Tenaska and KCPL placed into service?

A40: Yes. The upgrades to the Maryville – Maryville 161 kV line and to the Maryville substation cost approximately $1.9 million and were placed in service on September 4, 2020.

IV. PROJECT CONSTRUCTION

Q41: Please describe the status of efforts to develop and construct the Clear Creek Project during the period when Tenaska was coordinating with SPP and MISO.

A41: Tenaska commenced construction of the Clear Creek Project on April 18, 2019.

Q42: Why did Tenaska Clear Creek commence construction while the affected system process was ongoing?

A42: At the time that construction of the Clear Creek Project commenced, Tenaska Clear Creek believed that it was nearing the end of the study process and that it had received sufficient information regarding the cost of network upgrades to make an informed decision to move forward. To put this in perspective, during this period, Tenaska Clear Creek: (1) had completed the AECI interconnection process, with Tenaska Clear Creek formally executing a GIA in December 2018; (2) had received affected system studies from MISO; (3) SPP had issued multiple affected system impact studies and facilities studies; and (4) had started negotiating FCAs with SPP transmission owners.

Q43: When was the Tenaska Clear Creek Project placed into service?

A43: The first turbines at the project were placed into service in December 2019 and the Clear Creek Project commenced commercial operation on May 4, 2020.

V. RESTUDY OF THE CLEAR CREEK PROJECT

Q44: Please explain when you were informed that SPP was planning to conduct another restudy of the Clear Creek Project.

A44: On November 1, 2019, Ms. Anderson emailed me to notify Tenaska that SPP was recommending another restudy of the Clear Creek Project. SPP explained that while there had not been a withdrawal in the immediately preceding SPP study group, DISIS-2016-002, there had been a withdrawal of a higher-queued MISO interconnection request, J570, two months earlier on August 5, 2019. As a result, SPP explained that it was recommending a restudy of the Clear Creek Project. A copy of my correspondence with SPP regarding the restudy is provided as Exhibit 11.

Q45: What higher-queued interconnection request withdrew from the queue?

A45: The higher-queued interconnection request at issue, J570, involved a request to interconnect a 150 MW generator to the MISO system.

Q46: Did SPP immediately commence the restudy after providing notice to Tenaska?

A46: No. Following my initial emails with Ms. Anderson, on January 27, 2020, Ms. Anderson sent me an email stating that after internal review, SPP was electing to move forward with the restudy of the Clear Creek Project.

Q47: In terms of financing and construction, at what stage was the Clear Creek Project when SPP notified Tenaska that it intended to move forward with its restudy of the Project?

A47: When SPP notified Tenaska of its recommendation to restudy the Clear Creek Project, approximately $266 million had been committed to be spent on the Clear Creek Project and approximately 50 turbines had been installed at the site. By the time that SPP notified Tenaska Clear Creek that it was moving forward with the restudy, approximately $308 million had been committed to be spent on the project and all turbines had been delivered to the site, with approximately 101 of the turbines fully erected.

Q48: What information did SPP provide regarding the methods it intended to use to conduct the restudy?

A48: Ms. Anderson informed Tenaska that it would perform the restudy using the same 2017 ITP model that was used for the evaluation of projects in the SPP-DISIS-2016-002 cluster and the initial Tenaska studies. Ms. Anderson further explained that there would be delays with the restudy given a backlog of pending studies. Ms. Anderson stated, however, that it was SPP's intent to complete the restudy by Q1 2020.

Q49: Did SPP complete the restudy in Q1 2020?

A49: No. On April 3, 2020, I emailed SPP requesting an update on the progress of the restudy process. On April 7, 2020, Jon Langford, the Affected System Study lead, replied and explained that the schedule for studying GIA-61 had not been set and that SPP was continuing to develop models to use for the restudy. At the time, Mr. Langford stated that it planned to engage a consultant in order to accelerate the analysis. Mr. Langford stated that he anticipated to have an update on the schedule for the restudy within 2 weeks. A copy of my correspondence with SPP requesting an update on the restudy is provided as Exhibit 12.

Q50: Did you respond to Mr. Langford?

A50: Yes. On April 8, 2020, I sent Mr. Langford an email asking him to provide an update once a schedule was established. I also asked him to explain the major differences between the original study and the restudy aside from the J570.

Q51: When did Mr. Langford reply?

A51: On April 16, 2020, Mr. Langford replied explaining that SPP would inform Tenaska when the study was finished and could provide more information on major differences between the original study and the restudy.

Q52: What was your next communication with SPP regarding the restudy?

A52: On May 7, 2020, I replied to SPP asking if SPP had an opportunity to make any progress in terms of establishing a study schedule or providing an explanation of the differences between the studies. Jennifer Swierczek, another member of the SPP team, replied that afternoon and stated that the Clear Creek Project was the next restudy that SPP planned to complete. At that time, Ms. Swierczek stated that since the original system impact study was over a year old and there had been several out of group withdrawals, SPP was planning to update the models used in the original analysis to reflect the latest information regarding interconnection request and network upgrades. Ms. Swierczek stated that SPP would send a study scope the following week outlining the study assumptions, deliverables, and timelines.

Q53: Did SPP provide a study scope to Tenaska the following week?

A53: No. The next time that I heard from Ms. Swierczek was on May 28, 2020.

Q54: Did SPP provide a study scope on May 28th?

A54: No. Ms. Swierczek instead sent me an email proposing a timeline for the completion of the restudy. Specifically, she stated that SPP intended to develop a study scope between June 15th to 19th and that SPP expected to complete the study sometime between August 24 and August 28.

Q55: Did SPP provide a study scope during the timeframe outlined in her May 28th email?

A55: No. On July 6, 2020, after having not received an update from SPP, I sent Ms. Swierczek and email requesting an update. In response, on July 7, 2020, SPP emailed me the draft study scope. A copy is provided as Exhibit 13.

Q56: Please describe the study scope.

A56: The study scope outlined the analyses that SPP planned to conduct as part of the restudy, including a high level overview of certain modeling assumptions and the interconnection customers that SPP planned to include in the study.

Q57: Were there any differences between the study scope and the previous analyses of the Clear Creek Project?

A57: Yes. Among other things, the analysis indicated that SPP planned to study the Clear Creek Project using the DISIS-2017-001 dispatched base cases as the starting point for the restudy. In other words, the study scope indicated that SPP planned to use the base case that had been established for the DISIS-2017-001 study cluster, which is based on the 2019 ITP. The DISIS-2017-001 is the SPP cluster that is immediately behind the Clear Creek Project in the queue.

Q58: Did you object to the use of the DISIS-2017-001 study model at that time?

A58: No, I did not.

Q59: Why not?

A59: There are a number of reasons.

First, the implication of changing to the use of a study model based on the 2019 ITP was not clear to me at the time. Although the study scope referenced the 2019 ITP, SPP did not provide any explanation of the key differences between the study model used as the basis for the initial studies of the Clear Creek Project and the model that SPP had proposed to use for the restudy.

Second, I was concerned about further delaying the restudy process. At the point that SPP provided a copy of the study scope, the Clear Creek Project had already commenced commercial operation. Given the difficulty we had in getting SPP to provide us with a study scope and move forward with the restudy process, I was concerned about the potential impact on the project.

Q60: Did the study scope identify differences between the interconnection customers and generation facilities that would be included in the restudy and the customers and generation resources that had been included in the earlier studies of the Clear Creek Project.

A60: No.

Q61: When was the study scope finalized?

A61: July 23, 2020.

Q62: When did SPP provide the results of the restudy?

A62: SPP provided a spreadsheet providing preliminary study results on October 22, 2020. SPP subsequently issued an initial Generator Interconnection Affected System Impact Restudy Report, ASGI-2018-001, Rev. 0 ("Restudy") on November 2, 2020. A copy of my correspondence with SPP regarding the restudy is provided as Exhibit 14, and the Restudy is provided as Exhibit 15.

Q63: Please describe the initial results of the Restudy provided to Tenaska in October and November 2020.

A63: The Restudy stated that Tenaska's cost responsibility for network upgrades on SPP's system had increased to $762,741,525. The Restudy provided that the increase in upgrade costs reflected the assignment of cost responsibility to the Clear Creek Project for more than 20 additional network upgrades, including rebuilding several 345 kV transmission facilities. Table 1, excerpted below from Table 7 of the draft report, provided an overview of the network upgrades assigned to the Clear Creek Project.

Table 1: Network Upgrades Assigned to Clear Creek Project (October/November 2020)

Upgrade Name	Upgrade Type	Cost Estimate
Rebuild Maryville - Maryville 161kV Ckt 1	ERIS	TBD
Rebuild Maryville – Braddyville 161 kV Ckt 1	ERIS	$18,952,900.00
Reconductor Creston – Maryville 161 kV Ckt 1	ERIS	$14,900,000.00
Build Choteau – Maid 161 kV Ckt 2	NRIS	$586,934.40
Build Cooper – Hoyt 345 kV Ckt 1	NRIS	$148,250,000.00
Build Eastown – Ketchum 345 kV Ckt 1	NRIS	$56,500,000.00
Build Fort Smith 161/345 kV XFMR Ckt 2	NRIS	$7,400,000.00
Build Fort Smith 345/500 kV XFMR Ckt 2	NRIS	$13,803,180.00
Build Hawthorne 161/345 kV XFMR Ckt 3	NRIS	$22,000,000.00
Build Sibley - Nashua 345 kV Ckt 1	NRIS	$130,000,000.00
Build Sibley 161/345 kV XFMR Ckt 2	NRIS	$1,499,595.00
Build St. Joe – Nashua 345 kV Ckt 2	NRIS	$69,800,000.00
Build Stranger - Craig 345 kV Ckt 1	NRIS	$81,000,000.00
Build Wolf Creek – Blackberry 345 kV Ckt 1	NRIS	Previously Assigned
Rebuild Council Bluffs - S3456 345 kV Ckt 1	NRIS	$2,510,992.00
Rebuild Maryville – Midway 161 kV	NRIS	$21,541,142.00
Rebuild Midway – Avenue City 161 kV Ckt 1	NRIS	$21,481,661.00
Rebuild Overton – Sibley 345 kV Ckt 1	NRIS	$101,443,516.16
Rebuild Sedalia - WAFBE SW 161 kV Ckt 1	NRIS	$29,525,000.00
Rebuild Sibley – Sibley PL 161 kV Ckt 1	NRIS	$1,164,086.56
Rebuild Slake South - Creston 161 kV Ckt 1	NRIS	$176,080.32
Rebuild St. Joe - Avenue City 161 kV Ckt 1	NRIS	$4,898,938.00
Rebuild WAFBW SW - WAFBE SW 161 kV Ckt 1	NRIS	$1,997,500.00
Rebuild WBURGE - WAFBW SW 161 kV Ckt 1	NRIS	$13,310,000.00

Notably, out of the additional upgrades, the study results that SPP provided in October showed extensive overloads in the base case of the facilities that SPP had assigned to the Project. Table 2 below shows the NRIS overloads in the base case and transfer case included in the October 2020 results.

Table 2: October 2020/November 2020 NRIS Overloads

Study	**Overloaded Facility Name**	**Area**	**Season**	**Base Case Loading**	**Transfer Case Loading[1]**
NRIS	Hawthorne - HawthornS5 161 kV line ckt 1	KCPL	19WP0	107.0%	115.5%
NRIS	Maryville - Maryville tie 161 kV line	AECI-KCPL	24SP0	144.3%	144.3%
NRIS	Nashua 161/345 kV transformer	KCPL	24SP0	126.9%	126.9%
NRIS	Hawthorne - Nashua 345 kV line	KCPL	24SP0	116.7%	118.3%
NRIS	Roan Ridge - Nashua 161 kV line	KCPL	24SP0	114.5%	115.8%
NRIS	Nashua - Shoal Creek 161 kV line	KCPL	24SP0	108.0%	109.1%
NRIS	Hawthorne 161/345 kV transformer ck 22	KCPL	20SP0	114.2%	113.6%
NRIS	Sibley 161/345 kV transformer	KCPL	24SP0	108.4%	108.8%
NRIS	Hawthorne 161/345 kV transformer ck 20	KCPL	24SP0	104.0%	103.9%
NRIS	GRDA 161/345 kV transformer	GRDA	24SP0	134.0%	133.4%
NRIS	WAFBW_SW5 - WAFBE_SW5 161 kV line	KCPL	24L0	103.0%	105.1%
NRIS	Sedalia - WAFB E 161 kV line	KCPL	19WP0	108.2%	110.7%
NRIS	Maryville - Midway 161 kV line	KCPL	24SP0	138.3%	181.1%
NRIS	Midway - Avenue City 161 kV line	KCPL	24SP0	131.9%	174.4%
NRIS	Stranger Creek - 87th Street 161 kV line	WERE	24WP0	115.3%	116.1%
NRIS	St. Joe - Avenue City 161 kV line	KCPL	24SP0	129.37%	171.6%
NRIS	St Joe - Nashua 345 kV line	KCPL	20SP0	110.3%	112.7%
NRIS	87th Street - Craig 161 kV line	WERE-KCPL	24SP0	107.6%	107.6%
NRIS	St Joe - Cooper 345 kV line	NPPD-KCPL	20SP0	111.4%	112.3%
NRIS	Warrensburg East - WAFBW_SW5 161 kV	KCPL	24L0	107.0%	109.1%
NRIS	S3456 - Council Bluffs 345 kV line	MEC-OPPD	19WP0	114.2%	120.0%

[1] In subsequent discussions, SPP has indicated that the study results of seasons where the base case and transfer case loading are the same may be the product of an "automation issue." Tenaska Clear Creek has not be able to verify this assertion.

Q64: Did SPP issue subsequent study results following the November 2020 study?

A64: Yes. On December 18, 2020, SPP provided Tenaska with updated study results indicating that the Project's cost responsibility for network upgrades on SPP's system had decreased to approximately $106.8 million. A copy of my correspondence with SPP regarding the December 2020 updated study results is provided as Exhibit 16.

Q65: What explanation did SPP provide Tenaska regarding the decrease in network upgrade costs between November 2, 2020 and December 18, 2020?

A65: SPP notified Tenaska that it altered its approach to NRIS dispatch. SPP clarified that the NRIS cases were developed from the 2019 ITP based models, and that ERIS units being dispatched in the NRIS models were excluded. SPP also provided that "[a]ny remaining . . . base case issues will be review by management for an appropriate action." A copy of my correspondence with SPP regarding the December 18, 2020 study results is provided as Exhibit 17.

Q66: Which network upgrades were included in the December 18, 2020 study results?

A66: A table of the network upgrades included in the December 18, 2020 study results is provided below.

Table 3: Network Upgrades Allocated to the Clear Creek Project, December 2020

Monitored Element Overload	Cost Estimate	Mitigation	Study
Creston - Maryville 161 kV Ckt 1	$14,900,000.00	Reconductor 62.34 miles of 161 kV to at least 230 MVA	ERIS
Maryville - Braddyville 161 kV Ckt 1	$18,652,900.00	Rebuild 16.74 miles of 161 kV to at least 196 MVA	ERIS
345408 7 OVERTON 345 541201 SIBLEY 7 345 1	$75,000.00	Replace 1600A wavetrap	NRIS
541201 SIBLEY 7 345 541202 SIBLEY 5 161 11	$1,5000,000.00	Rebuild 161//345 kV XMFR to at least 472 MVA	NRIS
541202 SIBLEY 5 161 541250 SIBLEYPL 161 1	$1,160,000.00	Rebuild 1.19 miles of 161 kV to at least 504 MVA	NRIS

541207 ARCHIE 5 161 541240 ADRIAN 5 161 1	$14,150,000.00	Rebuild line & terminal upgrades at both substations	NRIS
541251 MARYVLE 5 161 541369 MIDWAY 5 161 1	$21,500,000.00	Rebuild 19.5 miles of 161 kV to at least 283 MVA	NRIS
541253 ST. JOE 5 161 541394 AVENUECTY 5 161 1	$4,900,000.00	Rebuild 3.320 miles of 161 kV to at least 268 MVA	NRIS
541369 MIDWAY_5 161 541394 AVENUECTY 5 161 1	$21,500,000.00	Rebuild 20.54 mmiles of 161 kV to at least 271 MVA	NRIS
542980 NASHUA 7 345 543028 NASHUA-5 161 11	$8,500,000.00	Build second 650 MVA Nashua 345/161 kV transformer	NRIS
Total Cost	$106,837,900.00		

Q67: Did SPP revise the December 18, 2020 study?

A67: Yes. On January 8, 2021, SPP revised the December 18, 2020 results to remove Archie – Adrian 161 kV line identified in the preliminary December 18, 2020 results. This reduced the estimate of costs to $93 million. The table below outlines the upgrades allocated to the Clear Creek Project on January 8, 2021.

Table 4: Network Upgrades Allocated to the Clear Creek Project, January 2021

Monitored Element Overload	Cost Estimate	Mitigation	Study
Creston - Maryville 161 kV Ckt 1	$14,900,000.00	Reconductor 62.34 miles of 161 kV to at least 230 MVA	ERIS
Maryville - Braddyville 161 kV Ckt 1	$18,652,900.00	Rebuild 16.74 miles of 161 kV to at least 196 MVA	ERIS
345408 7 OVERTON 345 541201 SIBLEY 7 345 1	$75,000.00	Replace 1600A wavetrap	NRIS
541201 SIBLEY 7 345 541202 SIBLEY 5 161 11	$1,5000,000.00	Rebuild 161//345 kV XMFR to at least 472 MVA	NRIS
541202 SIBLEY 5 161 541250 SIBLEYPL 161 1	$1,160,000.00	Rebuild 1.19 miles of 161 kV to at least 504 MVA	NRIS
541251 MARYVLE 5 161 541369 MIDWAY 5 161 1	$21,500,000.00	Rebuild 19.5 miles of 161 kV to at least 283 MVA	NRIS
541253 ST. JOE 5 161 541394 AVENUECTY 5 161 1	$4,900,000.00	Rebuild 3.320 miles of 161 kV to at least 268 MVA	NRIS
541369 MIDWAY_5 161 541394 AVENUECTY 5 161 1	$21,500,000.00	Rebuild 20.54 mmiles of 161 kV to at least 271 MVA	NRIS
542980 NASHUA 7 345 543028 NASHUA-5 161 11	$8,500,000.00	Build second 650 MVA Nashua 345/161 kV transformer	NRIS
Total Cost	$92,687,900.00		

Q68: Following the December 18, 2020 study results, did SPP provide any additional information to Tenaska regarding its potential network upgrade costs?

A68: Yes. On January 29, 2021, SPP informed Tenaska that it intended to conduct a restudy of the NRIS upgrades after SPP discovered that there were issues with in the service designations (*e.g.*, NRIS/ERIS) assigned to MISO projects used in its earlier studies.

Q69: What was the total amount of upgrade costs allocated to Tenaska following SPP's completion of the NRIS restudy?

A69: On February 26, 2021, SPP informed Tenaska that following the NRIS restudy, SPP estimated Tenaska's total network upgrade cost to be approximately $91 million, consisting of $57,127,234 in NRIS upgrades and an estimated $34 million in ERIS upgrades. A copy of my correspondence with SPP regarding the NRIS restudy is provided as Exhibit 18.

Q70: Did SPP issue additional study results following the February 26, 2021 results? If so, please describe the results and the total costs allocated to the Clear Creek Project.

A70: Yes. On March 25, 2021, SPP posted an affected system study report proposing to assign $99 million in network upgrades to the Clear Creek Project. The table below shows the upgrades allocated to Clear Creek in the most recent study, and the study results are provided as Exhibit 19.

Table 5: ERIS and NRIS Upgrades Allocated Clear Creek (March 2021)

Upgrade Type	**Upgrade**	**Rate Cost**
ERIS	Reconductor Maryville to Creston 161 kV	$14,900,000.00
ERIS	Rebuild Maryville to Braddyville 161 kV	$18,652,900.00
NRIS	Rebuild Maryville to Midway 161 kV	$21,500,000.00
NRIS	Rebuild Midway to Avenue City 161 kV	$21,500,000.00
NRIS	Rebuild Avenue City to St. Joseph 161 kV	$4,900,000.00
NRIS	Add 2nd Nashua 345/161 kV Transformer	$8,500,000.00
NRIS	Rebuild Nashua to Roanridge 161 kV	$9,150,000.00
	ERIS	$33,552,900
	NRIS	$65,550,000
	Total	$99,102,900

Q71: Prior to providing Tenaska with the initial results of the Restudy, had SPP ever indicated to Tenaska that network upgrades would be required to accommodate NRIS?

A71: No. Prior to receiving the initial results of the restudy, SPP only indicated to Tenaska that costs would be allocated to the Clear Creek Project to accommodate ERIS.

VI. ANALYSIS OF THE RESTUDY

Q72. Why did the withdrawal of J570 result in such a significant increase in the network upgrade costs that were assigned to the Clear Creek Project?

A72: The withdrawal of J570 does not appear to be the reason for the dramatic increase in the network upgrade costs that were assigned to the Clear Creek Project. In fact, following the restudy, SPP has acknowledged that the cost responsibility of [the Clear Creek Project] in the original studies did not depend on the construction of network upgrades that had been identified as necessary to accommodate the interconnection of J570.

Q73: What factors have contributed to the significant increase in costs assigned to the Clear Creek Project?

A73: Tenaska Clear Creek has been working with SPP to understand the reasons for the significant increase in costs since receiving the results of the restudy. As a result of those efforts, I now understand that there are a number of distinct factors that have contributed to the results of the restudy, including significant modeling errors made by SPP in the initial studies of the Clear Creek Project, the presence of base case violations prior to the introduction of the Clear Creek Project, and differences between the 2017 ITP and 2019 ITP models.

A. Omitted Generation

Q74: Please describe the error that was made in the initial studies of the Clear Creek Project.

A74: In December 2020, in response to questions that Tenaska Clear Creek sent to SPP regarding the study, SPP revealed for the first time that it had made a major error in the initial studies of the Clear Creek Project. Specifically, SPP has explained that, in October 2020, SPP indicated that it had omitted approximately 20 higher-queued interconnection customers. In subsequent discussions with SPP, SPP revealed that the actual quantity of generation that had been omitted or incorrectly modeled was approximately 7 gigawatts of generation resource.

Q75: Did the draft restudy report that SPP initially provided in November 2020 acknowledge that SPP had omitted generation resources from the earlier version of the studies?

A75: No. SPP only acknowledged that it made this error in responding to questions that Tenaska Clear Creek following the receipt of the studies.

Q76: Was Tenaska Clear Creek the only customer that was affected by this error?

A76: No. During the course of our discussions, SPP acknowledged that the same omission had been made when studying the DISIS-2016-002 study cluster that immediately preceded the Clear Creek Project in the queue.

Q77: Other than the DISIS-2016-002 study cluster, were there any other customers that were affected by this error?

A77: I do not know. We have asked SPP whether the SPP studies that were performed for the following higher-queued interconnection customers that appear to have an impact on the constraints identified in restudy were affected by this same error: (1) GI-53, which is a 236.5 MW wind project interconnected to the AECI system; and (2) J611, a 110 MW wind project interconnected to the MISO system. However, SPP has declined to respond to this question.

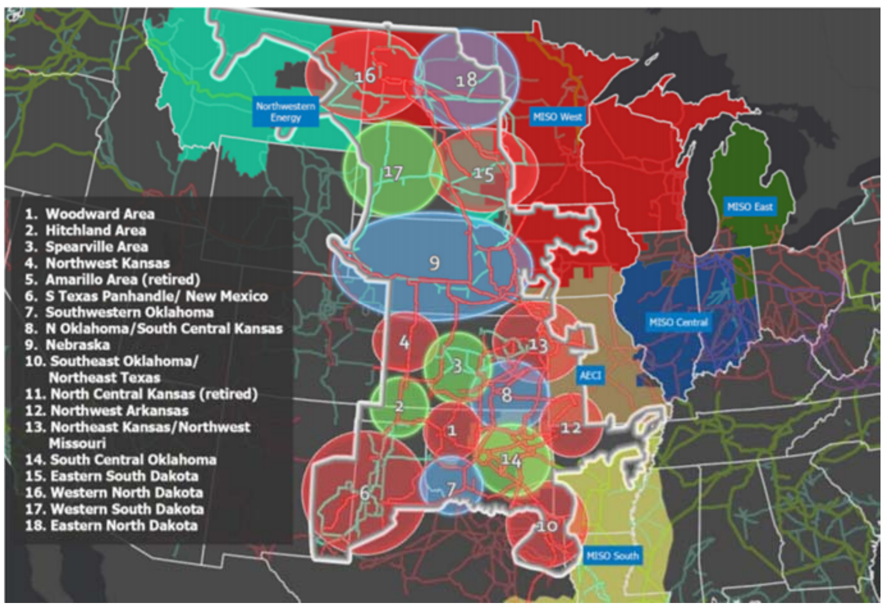
Q78: What steps has SPP taken to correct the error in the studies of the DISIS-2016-002 study cluster?

A78: To my knowledge, SPP has not taken any steps to correct the error by restudying the DISIS-2016-002 study cluster. Instead, SPP has taken the position that SPP believes that restudying the DISIS-2016-002 study cluster would not result in a different outcome for the Clear Creek Project. As a result, SPP has stated that it believes that a full restudy of DISIS-2016-002 is unnecessary.

Q79: When did SPP complete studies for the DISIS-2016-002 study cluster?

A79: The restudies of the DISIS-2016-002 study cluster are ongoing. Most recently, at an April 28, 2021 Generation Interconnection User Forum ("GIUF") meeting, SPP provided an update on its efforts to restudy certain study groups within the DISIS-2016-002 study cluster. As reflected in Figure 1 below, DISIS-2016-002 is broken up into 18 study groups.

Figure 1



At the GUIF meeting, SPP explained that, on April 23, 2021, it had posted a restudy of study groups 4, 9, 15, and 16, which had been conducted as a result of the withdrawal of a higher-queued or equal priority interconnection customer. SPP also stated that it anticipates completing a restudy of Group 8 by June 24, 2021.

Q80: Were the withdrawals limited to Groups 4, 8, 9, 15, and 16?

A80: No. At the GIUF meeting, SPP explained that there had been a withdrawal of a customer in Group 13, which is the study group closest to the Clear Creek Project. However, SPP has taken the position that no restudy of Group 13 should be performed because no other customers within the same study group were depending on the construction of network upgrades by the withdrawing customer. A copy of the presentation given at the GIUF meeting is attached as Exhibit 20.

Q81: What study model was used by SPP for the most recent restudy of Study Groups 4, 9, 15, and 16?

A81: The results of the restudy that was posted on April 23, 2021 indicate that the restudy was performed using the 2017 ITP, which is the study model that was used in the original studies of the Clear Creek Project. It is unclear why SPP is continuing to use the 2017 ITP model for the DISIS-2016-002 study clusters but required Clear Creek to be studied using the 2019 ITP. In communications with SPP following the receipt of the restudy results described above, SPP stated that it had encountered difficulties dispatching the 2017 ITP model and, as a result, had decided to use the 2019 ITP model set for the restudy of the Clear Creek Project.

B. Base Case Overloads

Q82: Why are there overloads in the base case?

A82: As described earlier in my testimony, each of the restudies that SPP has provided since October 2020 have included overloads in the base case before the introduction of the Clear Creek Project. While the magnitude of the base case overloads has varied with each iteration of the restudy, 5 of the 6 NRIS upgrades that SPP has proposed to assign to the Clear Creek Project have been overloaded in the base case in at least one of the restudies that SPP has provided.

The presence of overloads in the base case suggest that the interconnection of projects that are higher-queued to the Clear Creek Project have resulted in overloads of facilities included in the base case, including those facilities that SPP has proposed to allocate to Tenaska Clear Creek. These overloads also appear to be driven, in part, by SPP's decision to employ a new model and new study assumptions as part of the restudy process, including changes in dispatch assumptions and line ratings from the initial studies of the Clear Creek Project.

Q83: Have you asked SPP about the cause of these overloads?

A83: Yes.

Q84: Please describe SPP's explanation.

A84: SPP has acknowledged that the base case overloads are associated with the interconnection of projects that are higher-queued to the Clear Creek Project. SPP has taken the position, however, that the contribution of the higher-queued interconnection customers has not been significant enough to trigger a requirement for these customers to fund the construction of network upgrades.

Q85: Do you agree with SPP's explanation?

A85: No.

Q86: Why not?

A86: Following the receipt of the restudy results, Tenaska Clear Creek engaged ICF to evaluate the results of the restudy and SPP's explanation. ICF's analysis supports the conclusion that the interconnection of GI-53—a higher-queued customer interconnected to the AECI system—or J611—a higher-queued MISO customer—should have been assigned the cost of upgrading the facilities that are now being assigned to Clear Creek if the generation capacity that SPP has acknowledged was omitted from the initial studies of the Clear Creek Project was included in the affected system study performed by SPP of these customers.

Q87: Was the omitted generation included in the study of GI-53 and J611?

A87: Tenaska Clear Creek has asked SPP whether SPP erroneously excluded generation when studying GI-53 and J611. SPP has declined to respond to this question.

VERIFICATION OF BOONE STAPLES

Pursuant to 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing testimony is true and correct to the best of my knowledge, information, and belief.

Executed this 21st day of May, 2021

Boone Staples
Tenaska, Inc.
Director, Transmission Analysis

EXHIBIT 1:

SPP Correspondence on Initiation of Study Process

From: Staples, Boone [mailto:BStaples@tnsk.com]
Sent: Friday, February 02, 2018 3:05 PM
To: Christi Pinkerton <cpinkerton@spp.org>
Cc: Steve Purdy <spurdy@spp.org>; Sunny Raheem <sraheem@spp.org>
Subject: **External Email** RE: AECI affected system study

Christi,

Please find the signed study agreement and the interconnection request application we submitted to AECI which contains the technical data for the plant. The wind farm will consist of two types of Vestas turbines as noted in the attached data. Also, the one-line contains information on the gen-tie and equivalent collector system impedances.

I could not easily figure out where to load the files on GlobalScape, so I've attached them to this email. I will go back and work on uploading the dynamic models into GlobalScape.

The $15,000 deposit is being set up to be wired next week, I'll let you know when it goes through.

Thanks,
Boone Staples
Tenaska, Inc.
817-462-8050

From: Christi Pinkerton [mailto:cpinkerton@spp.org]
Sent: Monday, January 29, 2018 10:22 AM
To: Staples, Boone <BStaples@tnsk.com>
Subject: FW: AECI affected system study

****External Email. Use caution before opening attachments or clicking links.****

Good Morning Boone,

I wanted to check back with you regarding this request. Should we be expecting you to provide this?

Thank you,
Christi Pinkerton

From: Christi Pinkerton
Sent: Wednesday, January 03, 2018 11:57 AM
To: 'Staples, Boone' <BStaples@tnsk.com>; Steve Purdy <spurdy@spp.org>
Cc: Sunny Raheem <sraheem@spp.org>
Subject: RE: AECI affected system study

Good Morning Boone,
Attached is an Southwest Power Pool Affected System Interconnection System Impact Study Agreement for your request.

To be accepted into study, the following items are required:

Items with an * are required in the Affected System Study Agreement and Attachment A included with this email.

1. *The parameters of Generators (Nameplate kVA, power factor, maximum inverter power, etc.)
2. *The parameters of the pad mount transformers for the inverters. (MVA rating, impedance, and X/R ratio)
3. *The parameters of the substation main transformer. (Minimum MVA rating/Maximum MVA rating, impedance on the self-cooled MVA rating, X/R ratio)
4. The parameters of the transmission lead from the generation facility to the POI. (Impedance of the lead in PU on 100 MVA system base, B [line charging] in PU, and the length of the transmission lead)
5. PSS/E dynamic model (and user guide) for the inverters compatible with both PSS/E version 32 and PSS/E version 33.
6. *Affected system study deposit in the amount of $15,000 per request; wiring instructions can be found at http://sppoasis.spp.org/documents/swpp/transmission/studies/SPPBankingWireInstructions.pdf
7. *Collector system information in excel format (example attached)

Please let me know if you have questions or concerns.

Thank you,
Christi

From: Staples, Boone [mailto:BStaples@tnsk.com]
Sent: Wednesday, January 03, 2018 11:22 AM
To: Steve Purdy <spurdy@spp.org>
Cc: Christi Pinkerton <cpinkerton@spp.org>; Sunny Raheem <sraheem@spp.org>
Subject: **External Email** RE: AECI affected system study

Steve,

I would like to initiate the study as soon as possible. Could you please send me the requirements for requesting an affected systems study?

The plant is a 230 MW wind farm in Northwest Missouri (Nodaway County). The POI is AECI's Maryville 161kV bus. AECI has already notified SPP and sent the GI-061 SIS report.

Thank You,
Boone Staples
Tenaska, Inc.
817-462-8050

From: Steve Purdy [mailto:spurdy@spp.org]
Sent: Tuesday, November 28, 2017 1:20 PM
To: Staples, Boone <BStaples@tnsk.com>
Cc: Christi Pinkerton <cpinkerton@spp.org>; Sunny Raheem <sraheem@spp.org>
Subject: RE: AECI affected system study

****External Email. Use caution before opening attachments or clicking links.****

Boone: Based on a queue entry date of 5/3/2017, it would be queued between the DISIS-2016-002 and DISIS-2017-001 clusters. Once we get the request, we'll study it after the results of DISIS-2016-002 are complete.

Thanks,
Steve

From: Staples, Boone [mailto:BStaples@tnsk.com]
Sent: Tuesday, November 28, 2017 10:37 AM
To: Steve Purdy <spurdy@spp.org>
Cc: Christi Pinkerton <cpinkerton@spp.org>
Subject: **External Email** AECI affected system study

Hello Steve,

We have a somewhat advanced wind project in the AECI territory in Northwest MO (AECI queue# GI-061). Will you please answer the following questions pertaining to an SPP Affected System study?

1. What queue order will GI-061 will be treated as? The GIR has a timestamp of 5/3/2017 in the AECI queue.
2. What DISIS study group will GI-061 be studied with?

Thanks,
Boone Staples
Tenaska, Inc.
817-462-8050

EXHIBIT 2:

Impact Study Agreement

ASGI-2018-001

AFFECTED SYSTEM INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this 23rd day of January 2019 by and between Tenaska Clear Creek Wind, LLC a Company and existing under the laws of the State of Delaware ("Affected System Interconnection Customer") and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas ("Transmission Provider "). Affected System Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Affected System Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility located in Nodaway County, Missouri ; and

WHEREAS, Affected System Interconnection Customer desires to interconnect the Generating Facility with the Associated Electric Cooperative, Inc. System;

WHEREAS, Affected System Interconnection Customer has requested Transmission Provider to perform an Affected System Interconnection System Impact Study to assess the impact of interconnecting the Generating Facility to the Transmission Provider's Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

2.0 Affected System Interconnection Customer elects and Transmission Provider shall cause to be performed an Affected System Interconnection System Impact Study.

3.0 The scope of the Affected System Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Affected System Interconnection System Impact Study will be based on the technical information provided by Affected System Interconnection Customer in Attachment A., subject to any modifications in accordance with Section 4.4 of the GIP. Transmission Provider reserves the right to request additional technical information from Affected System Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Affected System Interconnection System Impact Study.

5.0 The Affected System Interconnection System Impact Study report shall provide the following information:

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection and

- description and non-binding, good faith estimated cost of facilities required to interconnect the Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues.

6.0 Affected System Interconnection Customer shall provide a deposit of $15,000 for the performance of the Affected System Interconnection System Impact Study. Transmission Provider's good faith estimate for the time of completion of the Definitive Interconnection System Impact Study is 120 days from the Effective Date of this Agreement.

Upon receipt of the Affected System Interconnection System Impact Study results, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Affected System Interconnection System Impact Study.

Any difference between the deposit and Affected System Interconnection Customer's study cost obligation shall be paid by or refunded to Interconnection Customer.

7.0 When the Affected System Interconnection System Impact Study is completed, Transmission Provider shall tender to Affected System Interconnection Customer an Affected System Facility Study Agreement to the extent that facilities are identified as necessary on Transmission Provider's Transmission System to accommodate the Affected System Interconnection Customer Generating Facility. When the Affected System Facility Study Agreement is completed, Transmission Provider shall tender an Affected System Construction Agreement pursuant to which Interconnection Customer agrees to pay the costs of the upgrades on the Transmission Provider's Transmission System necessary to accommodate the interconnection of the Affected System Interconnection Customer Generating Facility.

8.0 Miscellaneous. The Affected System Interconnection System Impact Study Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric industry, that are consistent with regional practices, Applicable Laws and Regulations and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the GIP and the GIA.

8.1 **General.** Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Attention: Manager, GI Studies

To Interconnection Customer:

Tenaska Clear Creek Wind, LLC
14302 FNB Parkway
Omaha, NE 68154
Attention: Boone Staples

8.2 **Alternative Forms of Notice.** Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

9.0 **Force Majeure**

9.1 **Economic Hardship.** Economic hardship is not considered a Force Majeure event.

9.2 **Default.** Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

10.0 **Indemnity**

10.1 **Indemnity**. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Partys' action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

10.1.1 **Indemnified Person**. If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

10.1.2 **Indemnifying Party**. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

10.1.3 **Indemnity Procedures**. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

10.2 **Consequential Damages.** Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.0 **Assignment**

11.1 **Assignment**. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

12.0 **Severability**

12.1 **Severability**. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

13.0 **Comparability**

13.1 **Comparability**. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

14.0 **Deposits and Invoice Procedures**

14.1 **General**. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

14.2 **Study Deposits**. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.

14.3 **Final Invoice**. Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

14.4 **Payment**. Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 1 to the GIP. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.

14.5 **Disputes.** In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due together with accrued interest in accordance with Section 3.6 of this Attachment V.

15.0 **Representations, Warranties, and Covenants**

15.1 **General**. Each Party makes the following representations, warranties and covenants:

15.1.1 **Good Standing**. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

15.1.2 **Authority**. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.1.3 **No Conflict**. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

15.1.4 **Consent and Approval**. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental

Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

16.0 **Breach, Cure and Default**

16.1 **General.** A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

16.2 **Events of Breach.** A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

16.3 **Cure and Default.** Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the "Non-Breaching Party"), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the "Breaching Party") and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

16.4 **Right to Compel Performance.** Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

17. **Miscellaneous**

17.1 **Binding Effect**. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

17.2 **Conflicts**. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

17.3 **Rules of Interpretation**. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

17.4 **Entire Agreement**. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

17.5 **No Third Party Beneficiaries.** This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

17.6 **Waiver**. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.7 **Headings**. The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

17.8 **Multiple Counterparts.** This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

17.9 **Amendment.** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

17.10 **Modification by the Parties**. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

17.11 **No Partnership**. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Southwest Power Pool, Inc.

By: ______________

Title: Director, R&D and Tariff Services

Date: 1/23/19

Affected System Interconnection Customer:

Tenaska Clear Creek Wind, LLC

By: Joel M. Link

Title: JOEL M. LINK
VICE PRESIDENT

Date: 1. 30. 2018

Attachment A
Affected System Interconnection System Impact
Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE AFFECTED SYSTEM INTERCONNECTION SYSTEM IMPACT STUDY

The Affected System Interconnection System Impact Study will be based upon the information set forth in the information provided by the Affected System Interconnection Customer, subject to any modifications in accordance with Section 4.4 of the GIP, and the following assumptions:

1. Point of Interconnection: AECI Maryville 161 kV bus

GENERATING FACILITY DATA FOR THE AFFECTED SYSTEM INTERCONNECTION SYSTEM IMPACT STUDY

UNIT RATINGS

Nameplate kVA ____________ °F _________ Voltage _____________
Prime Mover type __________________________
Power Factor: Lead ________ Lag _______
Speed (RPM) ________ Connection (e.g. Wye) _____________
Short Circuit Ratio ________ Frequency, Hertz ____________
Stator Amperes at Rated kVA _________ Field Volts _______________
Max Turbine Power: Summer MW ___________ °F ______
Winter MW ___________ °F ______

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = ____________________ kW sec/kVA
Moment-of-Inertia, WR^2 = ____________________ lb. $ft.^2$

REACTANCE DATA (PER UNIT-RATED KVA)

	DIRECT AXIS		QUADRATURE AXIS	
Synchronous – saturated	X_{dv}	_______	X_{qv}	_______
Synchronous – unsaturated	X_{di}	_______	X_{qi}	_______
Transient – saturated	X'_{dv}	_______	X'_{qv}	_______
Transient – unsaturated	X'_{di}	_______	X'_{qi}	_______
Subtransient – saturated	X''_{dv}	_______	X''_{qv}	_______
Subtransient – unsaturated	X''_{di}	_______	X''_{qi}	_______
Negative Sequence – saturated	$X2_v$	_______		
Negative Sequence – unsaturated	$X2_i$	_______		
Zero Sequence – saturated	$X0_v$	_______		
Zero Sequence – unsaturated	$X0_i$	_______		
Leakage Reactance	Xl_m			

FIELD TIME CONSTANT DATA (SEC)

Open Circuit	T'_{do}	________	T'_{qo}	________
Three-Phase Short Circuit Transient	T'_{d3}	________	T'_{q}	________
Line to Line Short Circuit Transient	T'_{d2}	________		
Line to Neutral Short Circuit Transient	T'_{d1}	________		
Short Circuit Subtransient	T''_{d}	________	T''_{q}	________
Open Circuit Subtransient	T''_{do}	________	T''_{qo}	________

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit	T_{a3}	________
Line to Line Short Circuit	T_{a2}	________
Line to Neutral Short Circuit	T_{a1}	________

NOTE: If requested information is not applicable, indicate by marking "N/A."

MW CAPABILITY AND PLANT CONFIGURATION GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive	R_1	________
Negative	R_2	________
Zero	R_0	________

Rotor Short Time Thermal Capacity I_2^2t = ________
Field Current at Rated kVA, Armature Voltage and PF = ________ amps
Field Current at Rated kVA and Armature Voltage, 0 PF = ________ amps
Three Phase Armature Winding Capacitance = ________ microfarad
Field Winding Resistance = ________ ohms ______ °C
Armature Winding Resistance (Per Phase) = ________ ohms ______ °C

CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity — Self-cooled/ Maximum Nameplate

_____________/_______________kVA

Voltage Ratio (Generator Side/System side/Tertiary)

_____________/_______________/_______________kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))

_____________/_______________/_______________

Fixed Taps Available ____

Present Tap Setting ____

Impedance: Positive Z_1 (on self-cooled kVA rating)______________ % ________ X/R

Impedance: Zero Z_0 (on self-cooled kVA rating)______________ % ________ X/R

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request:

____

Elevation: ____________ _____ Single Phase _____ Three Phase

Inverter manufacturer, model name, number, and version:

____

List of adjustable setpoints for the protective equipment or software:

____

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

INDUCTION GENERATORS

(*) Field Volts: ________________
(*) Field Amperes: ______________
(*) Motoring Power (kW): ________
(*) Neutral Grounding Resistor (If Applicable): ___________
(*) I_2^2t or K (Heating Time Constant): ___________
(*) Rotor Resistance: ____________
(*) Stator Resistance: ____________
(*) Stator Reactance: ____________
(*) Rotor Reactance: _____________
(*) Magnetizing Reactance: __________
(*) Short Circuit Reactance: __________
(*) Exciting Current: ______________
(*) Temperature Rise: ______________
(*) Frame Size: ______________
(*) Design Letter: _____________
(*) Reactive Power Required In Vars (No Load): ________
(*) Reactive Power Required In Vars (Full Load): ________
(*) Total Rotating Inertia, H: ________Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

EXHIBIT 3:

SPP Correspondence on Study Process

Stuart, Taylor

From: Alyssa Anderson <aanderson@spp.org>
Sent: Tuesday, August 28, 2018 12:39 PM
To: Staples, Boone
Cc: Chase Harrod; Anthony Cook
Subject: RE: Clear Creek affected system study

****External Email. Use caution before opening attachments or clicking links.****

Hi Boone,

Apologies for the late response. SPP dispatched the MISO higher queued, non-GIA generation according to the table highlighted below.
MISO generation will be dispatched in the same manner for the GIA-69 study.

Generally, for any SPP or SPP affected system study we will use our own dispatch methodology (tables below). We would only use the MISO dispatch methodology for affected system studies conducted for MISO.

Thanks,
Alyssa

From: Staples, Boone <BStaples@tnsk.com>
Sent: Tuesday, August 28, 2018 9:43 AM
To: Alyssa Anderson <aanderson@spp.org>
Cc: Chase Harrod <charrod@spp.org>; Anthony Cook <acook@spp.org>
Subject: **External Email** RE: Clear Creek affected system study

Good Morning,

Just checking in. Any updates on the questions below?

Thanks,
Boone

From: Staples, Boone
Sent: Friday, August 24, 2018 9:25 AM
To: 'Alyssa Anderson' <aanderson@spp.org>
Cc: Chase Harrod <charrod@spp.org>; Anthony Cook <acook@spp.org>
Subject: RE: Clear Creek affected system study

Alyssa,

Thanks for the helpful information. I have a couple follow-up questions.

- Is the highlighted portion below referring to the dispatch in SPP's ASIS for MISO queued generators?
- Will the MISO queue be dispatched according to the first table during the GI-61 affected system study, or the LBA/Fuel type dispatch?

Thanks,

Boone

From: Alyssa Anderson <aanderson@spp.org>
Sent: Thursday, August 23, 2018 3:50 PM
To: Staples, Boone <BStaples@tnsk.com>
Cc: Chase Harrod <charrod@spp.org>; Anthony Cook <acook@spp.org>
Subject: RE: Clear Creek affected system study

****External Email. Use caution before opening attachments or clicking links.****

Hi Boone,

I'll have to double check to see how Chase and Anthony dispatched the MISO generation in the DISIS-2016-002, but you are correct regarding the J611 project.
In the past we have dispatched MISO generation in SPP studies as follows:

Dispatch Type	In Group		Out Group	
	Renewable	Conventional	Renewable	Conventio
ERIS – HVER	100%	n/a	20%	n/a
ERIS – LVER	20%	100%	20%	100%
NRIS Spring & Light Load Seasons – ERIS Only Requests	Off	Off	Off	Off
NRIS Spring & Light Load Seasons – ERIS/NRIS Requests	100%	100%	20%	20%
NRIS Peak Seasons – ERIS Only Requests	Off	Off	Off	Off
NRIS Peak Seasons – ERIS/NRIS Requests	100%	100%	100%	100%

MISO has asked SPP to implement a different dispatch methodology (incorporating their LBA and Fuel-Type dispatching methodology) when we perform their affected system studies, but this is not a MISO ASIS. In some instances that dispatch methodology does not allow SPP to capture as many potential network upgrades since the dispatch is generally significantly less.

Unless I am mistaken, AECI requests are dispatched in the same manner as SPP requests as follows:

Dispatch Type	In Group		Out Group	
	Renewable	Conventional	Renewable	Conventio
ERIS – HVER	100%	n/a	20%	n/a
ERIS – LVER	20%	100%	20%	100%
NRIS Spring & Light Load Seasons – ERIS Only Requests	80%	n/a	20%	n/a

NRIS Spring & Light Load Seasons – ERIS/NRIS Requests	100%	100%	20%	20%
NRIS Peak Seasons – ERIS Only Requests	20% (solar in SP 80%)	80%	20% (solar in SP 80%)	80%
NRIS Peak Seasons – ERIS/NRIS Requests	100%	100%	100%	100%

In any event, your request will not be unjustly cost allocated network upgrades for which it is not responsible. The only unfortunate bit is that there will most likely be less capacity on the lines when the generation is dispatched at 100%. If the line was overloaded at 99% and your request pushes the line at or over 100% , then your request would be cost allocated a network upgrade.
We can include the BC and TC% loadings in the report if you would like the opportunity to compare.

Affected system requests may also request Limited Operation Interconnection Service (LOIS), which, if I'm not mistaken, allows the request to proceed with an AS-GIA at a particular amount acceptable to the system without the need for a specific upgrade/set of system conditions. However, that is generally a separate study.

Best,
Alyssa

From: Staples, Boone <BStaples@tnsk.com>
Sent: Thursday, August 23, 2018 3:17 PM
To: Alyssa Anderson <aanderson@spp.org>
Subject: **External Email** RE: Clear Creek affected system study

Hello Alyssa,

Thank you for the information. We may have a few follow-up questions. In the meantime, how will SPP dispatch queued units which are located in other systems, such as MISO and AECI? For example, the J611 wind project in MISO Aug-2016 West phase 1 study is dispatched at Pmax in the DISIS-2016-002 Group 13 model.

Regards,
Boone

From: Alyssa Anderson <aanderson@spp.org>
Sent: Monday, August 20, 2018 4:21 PM
To: Staples, Boone <BStaples@tnsk.com>
Cc: Steve Purdy <spurdy@spp.org>; Joseph M. Price <jmprice@spp.org>; Christi Pinkerton <cpinkerton@spp.org>
Subject: RE: Clear Creek affected system study

****External Email. Use caution before opening attachments or clicking links.****

Hi Boone,

The AECI project GIA-061 should be next in the SPP affected system study queue to be studied. We have a contractor that we are working with to complete this work and will be meeting with him to discuss the study work and timelines. Once we have worked out the details we will communicate the expected completion date to you and AECI.

Did you have any questions I can answer in particular? As GIA-061 was received by AECI on May 3, 2017, the project will be queued between the DISIS-2016-002 and DISIS-2017-001. As such we will be using the DISIS-2016-002 transfer cases as the "base cases"/starting point for this study and your request will be dispatched on top to create the new transfer cases.

SPP affected system studies for AECI usually take SPP approximately four - five weeks to complete, but the timeline may change depending on the capabilities of our contractor (this will be their first affected system study for SPP, at least to my knowledge).

Please let me know if there is anything else I can answer for you.

Best,

Alyssa Anderson
Engineer I, Generation Interconnection Studies
Southwest Power Pool
501-482-2379 | aanderson@spp.org

From: Staples, Boone <BStaples@tnsk.com>
Sent: Monday, August 20, 2018 2:25 PM
To: Alyssa Anderson <aanderson@spp.org>
Subject: **External Email** Clear Creek affected system study

Hello Alyssa,

We have a project in the AECI queue ("Clear Creek" GI-061) that needs an SPP affected system study. Hopefully Steve Purdy has contacted you about this already, but we need this study done ASAP. Would you mind calling me to discuss?

Regards,
Boone Staples
Tenaska, Inc.
817-462-8050

EXHIBIT 4:

First Affected System Impact Study Report

SPP Southwest Power Pool

GENERATOR INTERCONNECTION AFFECTED SYSTEM IMPACT STUDY REPORT

ASGI-2018-001

Published October 2018

By SPP Generator Interconnections Dept.

REVISION HISTORY

Date	Author	Change Description
10/5/2018	SPP	Affected System Impact Study for ASGI-2018-001 Report Revision 0 Issued

EXECUTIVE SUMMARY

An Affected System Interconnection Customer has requested an Affected System Impact Study (ASIS) consistent with Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection requests into the system of Associated Electric Cooperative Inc. (AECI). AECI request GIA-61, a 230 MW wind generating facility, has been assigned the SPP queue identifier ASGI-2018-001.

SPP has conducted this ASIS to evaluate potential impacts to the SPP Transmission System related to the interconnection of generators on the AECI Transmission System. ASGI-2018-001 is requesting the interconnection of 9 Vestas V110-2.0 MW and 106 Vestas V116-2.0 MW turbines for a total of 230 MW injection at the Point of Interconnection (POI) and associated facilities interconnecting to AECI at the Maryville 161kV substation in Nodaway County, MO.

The ASIS analysis has determined that several network upgrades will be required for ASGI-2018-001 to interconnect all 230 MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The required network upgrades identified have been outlined in **Table 4** of this report.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Transient stability analysis for this ASIS was not performed.

Nothing in this study should be construed as a guarantee of delivery or transmission service. If the customer(s) wishes to move power across the facilities of SPP, a separate request for transmission service must be made on Southwest Power Pool's OASIS by the Customer(s).

TABLE OF CONTENTS

PURPOSE

An Affected System Interconnection Customer has requested an Affected System Impact Study (ASIS) consistent with the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection requests into the system of Associated Electric Cooperative Inc. (AECI).

The purpose of this study is to evaluate the impacts of interconnecting the AECI GIA-061 request assigned the SPP queue identifier ASGI-2018-001. ASGI-2018-001 is requesting the interconnection of 9 Vestas V110-2.0 MW and 106 Vestas V116-2.0 MW turbines for a total of 230 MW injection at the Point of Interconnection (POI) and associated facilities interconnecting to AECI at the Maryville 161kV substation in Nodaway County, MO.

The ASIS considers the Base Case as well as all Generating Facilities (and with respect to (b) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the ASIS is commenced:

a) are directly interconnected to the Transmission System;
b) are interconnected to Affected Systems and may have an impact on the Interconnection Request;
c) have a pending higher queued Interconnection Request to interconnect to the Transmission System listed in **Table 1** or
d) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a re-study of this ASIS at the expense of the Customer(s).

Nothing within this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer(s) any right to receive transmission service rights. Should the Customer(s) require transmission service, those rights should be requested through SPP's Open Access Same-Time Information System (OASIS) or that of the applicable transmission provider.

This ASIS included prior queued generation interconnection requests. Requests listed within **Table 1** are assumed to have either full or partial interconnection service prior to the requested in-service date for this ASIS.

Table 1: Higher Queued Interconnection Requests Included in the Study

GI Number	Capacity	Type	Service	POI Bus
GEN-2008-129	80	CT	ER	Pleasant Hill 161kV
GEN-2010-036	4.6	Hydro	ER	6th Street 115kV
GEN-2011-011	50	Coal	ER	Iatan 345kV
GEN-2014-021	300	Wind	ER/NR	Tap Nebraska City - Mullin Creek (Holt) 345kV
GEN-2015-005	200.1	Wind	ER	Tap Nebraska City - Sibley (Ketchem) 345kV
ASGI-2016-003	6	Diesel	ER	Paola 161kV
GEN-2016-088	151.2	Wind	ER/NR	Transource Ketchem 345kV Station
GEN-2016-115	300	Wind	ER/NR	Holt County Switching Station 345kV
GEN-2016-149	302	Wind	ER/NR	Stranger Creek 345kV Sub

GEN-2016-150	302	Wind	ER/NR	Stranger Creek 345kV Sub
GEN-2016-157	252	Wind	ER/NR	West Gardner 345kV Sub
GEN-2016-158	252	Wind	ER/NR	West Gardner 345kV Sub
GEN-2016-168	20	Solar	ER/NR	Higginsville 69kV Sub
GEN-2016-174	302	Wind	ER/NR	Stranger Creek 345kV Sub
GEN-2016-176	302	Wind	ER/NR	Stranger Creek 345kV Sub
ASGI-2017-006	238	Wind	ER/NR	Maryville 161 kV
J570	150	Wind	ER/NR	Cooper - Atchison 345kV Line

Table 2: Current study requests under study

GI Number	Capacity	Type	Service	POI Bus
ASGI-2018-001	230	Wind	ER/NR	Maryville 161 kV

SPP's analysis for reviewing impacts for AECI GIA-61 was based on the following higher-queued planned projects being in-service by 12/31/2019:

Table 3: Higher Queued Network Upgrades Included in the Study

AECI Request	Mitigation	Assigned By	TO Estimated Cost
GIA-061	Upgrade Fairport - Gentry - Nodaway 161 kV	AECI	Please refer to AECI posted reports for cost allocation
	Upgrade Maryville 161/69 kV transformer		
	Uprate Stanberry - Darlington 69 kV		
	Uprate Darlington - Fairport 69 kV		

The following current study upgrades are required for full interconnection service of GIA-61:

Table 4: SPP Current Study Assigned Upgrades

AECI Request	Mitigation	Assigned By	TO Estimated Cost
GIA-061	Rebuild 'MARYVILLE - MARYVILLE 161KV CKT 1' to increase rating to 293/334 MVA	SPP	$1,200,000
	Reconductor 'CRESTON - MARYVILLE 161KV CKT 1' to at least 216 MVA	SPP	$30,000,000
	NRIS Only Upgrade: WAPA Creston terminal sufficient to achieve 171 MVA (TC) loading. NU only required if constraint observed by MEC.	SPP	$0

All upgrades assigned by SPP will require an Affected System Facilities Study agreement and deposit. These upgrades may require a Construction Agreement (CA) as a result of the Affected System Facilities Study.

Any changes to these assumptions may require a re-study of this ASIS at the expense of the Customer(s).

Nothing in this System Impact Study constitutes a request for transmission service or grants the Interconnection Customer(s) any rights to transmission service.

Posted SPP affected system reports can be located at the following Generation Interconnection Study URL: http://opsportal.spp.org/Studies/Gen

FACILITIES

GENERATING FACILITY

The Affected System Interconnection Customers' request the interconnection of 9 Vestas V110-2.0 MW and 106 Vestas V116-2.0 MW turbines. The turbines were modeled using a 0.95 power factor based on the assumption provided by AECI for a total of 230 MW injection at the Point of Interconnection (POI) and associated facilities interconnecting to AECI at the Maryville 161kV substation in Nodaway County, MO.

INTERCONNECTION FACILITIES

The ASGI-2018-001 Interconnection Customer has requested a connection to the Affected System via the Maryville 161kV substation in Nodaway County, MO. **Figure 1** illustrates the current study request, AECI GIA-061 (ASGI-2018-001) interconnecting at the Maryville 161 kV substation. The higher queued AECI GIA-053 request (ASGI-2017-006) shares this POI.

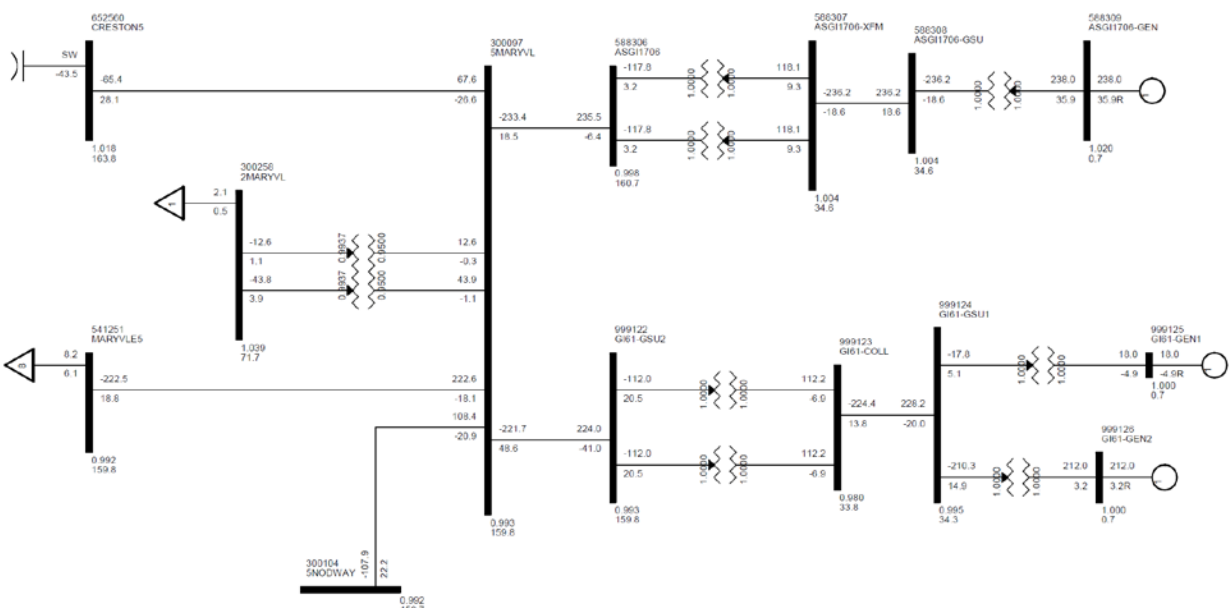


Figure 1: Proposed ASGI-2018-001 Configuration and Request Power Flow Model

BASE CASE NETWORK UPGRADES

The Network Upgrades included within the cases used for this Affected System Impact Study are those facilities that are a part of the SPP Transmission Expansion Plan or the Balanced Portfolio projects. These facilities have an approved Notification to Construct (NTC), or are in construction stages and expected to be in-service at the effective time of this study. No other upgrades were included for this ASIS. If for some reason, construction on these projects is delayed or discontinued, a restudy may be needed to determine the interconnection service availability of the Customer(s).

POWER FLOW ANALYSIS

Power flow analysis is used to determine if the transmission system can accommodate the injection from the request without violating thermal or voltage transmission planning criteria.

MODEL PREPARATION

Power flow analysis was performed using modified versions of the 2016 series of 2017 ITP Near-Term study models including these seasonal models:

- Year 1 (2017) Winter Peak (17WP)
- Year 2 (2018) Spring (18G)
- Year 2 (2018) Summer Peak (18SP)
- Year 5 (2021) Light (21L)
- Year 5 (2021) Summer (21SP)
- Year 5 (2021) Winter (21WP) peak
- Year 10 (2026) Summer (26SP) peak

To incorporate the Interconnection Customers' request, a re-dispatch of existing generation within SPP and AECI was performed with respect to the amount of the Customers' injection.

For Variable Energy Resources (VER) (solar/wind) in each power flow case, ERIS, is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas is dispatched at 20% nameplate of maximum generation. SPP projects are dispatched across the SPP footprint using load factor ratios. AECI projects are dispatched across the AECI footprint using load factor ratios.

Peaking units are not dispatched in the Year 2 spring and Year 5 light, or in the "High VER" summer and winter peaks. To study peaking units' impacts, the Year 1 winter peak, Year 2 summer peak, and Year 5 summer and winter peaks, and Year 10 summer peak models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

All generators (VER and peaking) that requested Network Resource Interconnection Service (NRIS) are dispatched in an additional analysis into the interconnecting Transmission Owner's (T.O.) area at 100% nameplate with Energy Resource Interconnection Service (ERIS) only requests at 80% nameplate. This method allows for identification of network constraints that are common between regional groupings to have affecting requests share the mitigating upgrade costs throughout the cluster.

STUDY METHODOLOGY AND CRITERIA

THERMAL OVERLOADS

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously mentioned.

For ERIS, thermal overloads are determined for system intact (n-0) (greater than or equal to 100% of Rate A - normal) and for contingency (n-1) (greater than or equal to 100% of Rate B – emergency) conditions.

The overloads are then screened to determine which of generator interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage based conditions (n-1),
- or 3% DF on contingent elements that resulted in a non-converged solution.

Interconnection Requests that requested NRIS are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also considered for transmission reinforcement under NRIS.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution Flowgates for SPP and first tier Non-SPP control area are monitored. Additional NERC Flowgates are monitored in second tier or greater Non-SPP control areas. Voltage monitoring was performed for SPP control area buses 69 kV and above.

VOLTAGE

For non-converged power flow solutions that are determined to be caused by lack of voltage support, appropriate transmission support will be determined to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

SPP Areas (69kV+):

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AEPW	0.95 – 1.05 pu	0.92 – 1.05 pu
GRDA	0.95 – 1.05 pu	0.90 – 1.05 pu
SWPA	0.95 – 1.05 pu	0.90 – 1.05 pu
OKGE	0.95 – 1.05 pu	0.90 – 1.05 pu
OMPA	0.95 – 1.05 pu	0.90 – 1.05 pu
WFEC	0.95 – 1.05 pu	0.90 – 1.05 pu
SWPS	0.95 – 1.05 pu	0.90 – 1.05 pu
MIDW	0.95 – 1.05 pu	0.90 – 1.05 pu
SUNC	0.95 – 1.05 pu	0.90 – 1.05 pu
KCPL	0.95 – 1.05 pu	0.90 – 1.05 pu
INDN	0.95 – 1.05 pu	0.90 – 1.05 pu
SPRM	0.95 – 1.05 pu	0.90 – 1.05 pu
NPPD	0.95 – 1.05 pu	0.90 – 1.05 pu
WAPA	0.95 – 1.05 pu	0.90 – 1.05 pu
WERE L-V	0.95 – 1.05 pu	0.93 – 1.05 pu
WERE H-V	0.95 – 1.05 pu	0.95 – 1.05 pu
EMDE L-V	0.95 – 1.05 pu	0.90 – 1.05 pu
EMDE H-V	0.95 – 1.05 pu	0.92 – 1.05 pu
LES	0.95 – 1.05 pu	0.90 – 1.05 pu
OPPD	0.95 – 1.05 pu	0.90 – 1.05 pu

SPP Buses with more stringent voltage criteria:

Bus Name/Number	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
TUCO 230kV 525830	0.925 – 1.05 pu	0.925 – 1.05 pu
Wolf Creek 345kV 532797	0.985 – 1.03 pu	0.985 – 1.03 pu
FCS 646251	1.001 – 1.047 pu	1.001 – 1.047 pu

Affected System Areas (115kV+):

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AECI	0.95 – 1.05 pu	0.90 – 1.05 pu
EES-EAI	0.95 – 1.05 pu	0.90 – 1.05 pu
LAGN	0.95 – 1.05 pu	0.90 – 1.05 pu
EES	0.95 – 1.05 pu	0.90 – 1.05 pu
AMMO	0.95 – 1.05 pu	0.90 – 1.05 pu
CLEC	0.95 – 1.05 pu	0.90 – 1.05 pu
LAFA	0.95 – 1.05 pu	0.90 – 1.05 pu
LEPA	0.95 – 1.05 pu	0.90 – 1.05 pu
XEL	0.95 – 1.05 pu	0.90 – 1.05 pu
MP	0.95 – 1.05 pu	0.90 – 1.05 pu
SMMPA	0.95 – 1.05 pu	0.90 – 1.05 pu
GRE	0.95 – 1.05 pu	0.90 – 1.10 pu
OTP	0.95 – 1.05 pu	0.90 – 1.05 pu
OTP-H (115kV+)	0.97 – 1.05 pu	0.92 – 1.10 pu
ALTW	0.95 – 1.05 pu	0.90 – 1.05 pu
MEC	0.95 – 1.05 pu	0.90 – 1.05 pu
MDU	0.95 – 1.05 pu	0.90 – 1.05 pu
SPC	0.95 – 1.05 pu	0.95 – 1.05 pu
DPC	0.95 – 1.05 pu	0.90 – 1.05 pu
ALTE	0.95 – 1.05 pu	0.90 – 1.05 pu

The constraints identified through the voltage scan are then screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage. In certain conditions, engineering judgement was used to determine whether or not a generator had impacts to voltage constraints.

RESULTS

The ASIS ACCC analysis indicates that the Affected System Interconnection Customer(s) can interconnect their generation into the AECI transmission system at the available MW listed in the results tables after all required upgrades listed within the DISIS-2016-002 studies or latest iteration thereof have been placed into service. ACCC results detailed in **Table 5** are dependent on higher queued SPP and AECI upgrades. Incremental SPP upgrades assigned to ASGI-2018-001 are identified within **Table 4.**

Constraints listed in **Table 7** do not require additional transmission reinforcement for Interconnection Service, but could require Interconnection Customer to reduce generation in operational conditions. These transmission constraints occur when this study's generation is dispatched into the AECI footprint for ERIS and NRIS.

CURTAILMENT AND SYSTEM RELIABILITY

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

CONCLUSION

An Affected System Interconnection Customer has requested an Affected System Impact Study (ASIS) under the Southwest Power Pool Open Access Transmission Tariff (OATT) for ASGI-2018-001. ASGI-2018-001 (230 MW) wind generating facilities are to be interconnected into the system of AECI. This ASIS was conducted to determine the impacts of interconnecting GIA-61 generation to the transmission system with all required Network Upgrades identified in the DISIS-2016-002 and those outlined in **Table 3** in service by 12/31/2019.

The ASIS analysis has determined that several network upgrades will be required for ASGI-2018-001 to interconnect all 230 MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The required network upgrades identified have been outlined in **Table 5** of this report.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Transient stability analysis was not completed for this ASIS.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a re-study of this ASIS at the expense of the Customer.

Nothing in this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service.

THERMAL AND STEADY STATE VOLTAGE CONSTRAINTS TABLES

Table 5: Thermal Constraints Requiring Additional Transmission Reinforcements

Dispatch Group	Scenario	Season	Source	Flow	Monitored Element	RATEA (MVA)	RATEB (MVA)	TDF	TC% LOADING	Contingency
13NR	0	18G	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.09986	100.6436	'BUNGE - RIVER BEND 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.08557	102.1823	'MARYVILLE - NODAWAY 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.09986	102.1842	'BUNGE - HASTINGS 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.08557	102.1863	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.08557	102.4485	'FAIRPORT - HARVIEL E 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.09736	105.3642	'CLARINDA - HASTINGS 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.10084	105.4711	'COUNCIL BLUFFS - RIVER BEND 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.10084	106.4841	'BUNGE - RIVER BEND 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.10084	108.0827	'BUNGE - HASTINGS 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.11455	108.6932	'CRESTON - MARYVILLE 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.09833	110.9844	'CLARINDA - HASTINGS 161KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	CRESTON - MARYVILLE 161KV CKT 1'	208	208	0.29651	103.6926	MARYVILLE - MARYVILLE 161KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52559	142.1455	CRESTON - MARYVILLE 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	119.6245	'MARYVILLE - NODAWAY 161KV CKT 1'
13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43178	100.7739	'GEN 86115 1-J611 G 0.6900'
13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43178	100.7739	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	101.6994	'GEN645012 2-NEBRASKA CITY 2'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	101.6994	'GEN645012 2-NEBRASKA CITY 2'

13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45182	101.7616	'FAIRPORT - ST JOE 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45182	101.7616	'FAIRPORT - ST JOE 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42911	101.8473	'ST JOE (STJOE T2) 345/161/13.8KV TRANSFORMER CKT 2'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42911	101.8473	'ST JOE (STJOE T2) 345/161/13.8KV TRANSFORMER CKT 2'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42909	101.8549	'ST JOE (STJOE T1) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42909	101.8549	'ST JOE (STJOE T1) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43239	101.8865	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43239	101.8865	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43045	101.945	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43045	101.945	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43262	102.2279	'SUB 3455 - SUB 3740 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43262	102.2279	'SUB 3455 - SUB 3740 345KV CKT 1'
13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43221	102.33	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43221	102.33	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43251	102.3859	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43251	102.3859	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42973	103.2707	'EASTOWN7 345.00 (EASTOWN 345)

										345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42973	103.2707	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	103.6517	'GEN999125 1-GI61-GEN1 0.6900'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	103.6517	'GEN999125 1-GI61-GEN1 0.6900'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43729	103.7393	'COOPER - FAIRPORT 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43729	103.7393	'COOPER - FAIRPORT 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	103.8699	'GEN635023 3-WALTER SCOTT UNIT 3'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	103.8699	'GEN635023 3-WALTER SCOTT UNIT 3'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	104.2577	'GEN344225 1-1CAL G1 25.000'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	104.2577	'GEN344225 1-1CAL G1 25.000'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4324	104.3619	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4324	104.3619	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	104.4022	'GEN635024 4-WALTER SCOTT UNIT 4'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	104.4022	'GEN635024 4-WALTER SCOTT UNIT 4'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	104.6913	'GEN300003 1-THOMAS HILL UNIT 3'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	104.6913	'GEN300003 1-THOMAS HILL UNIT 3'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.0044	'GEN336821 1-GRAND GULF UNIT'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.0044	'GEN336821 1-GRAND GULF UNIT'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43182	105.1862	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'

13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43182	105.1862	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.4066	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.4066	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.4669	'GEN335831 1-RIVERBEND UNIT#1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.4669	'GEN335831 1-RIVERBEND UNIT#1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.5878	'GEN337910 1-ARKANSAS NUCLEAR ONE UNIT #1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.5878	'GEN337910 1-ARKANSAS NUCLEAR ONE UNIT #1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43211	105.6193	'HAWTHORN - NASHUA 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43211	105.6193	'HAWTHORN - NASHUA 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43241	105.6888	'87th STREET - STRANGER CREEK 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43241	105.6888	'87th STREET - STRANGER CREEK 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	107.0436	System Intact
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	108.3275	'GEN645012 2-NEBRASKA CITY 2'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	108.3275	'GEN645012 2-NEBRASKA CITY 2'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4324	108.4737	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4324	108.4737	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43263	108.8509	'SUB 3455 - SUB 3740 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43263	108.8509	'SUB 3455 - SUB 3740 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43252	108.9637	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'

13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43252	108.9637	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45182	109.4013	'FAIRPORT - ST JOE 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45182	109.4013	'FAIRPORT - ST JOE 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42974	109.4526	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42974	109.4526	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	18SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52496	110.2204	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	18SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52496	110.2204	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	110.5082	'GEN635023 3-WALTER SCOTT UNIT 3'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	110.5082	'GEN635023 3-WALTER SCOTT UNIT 3'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	111.0393	'GEN635024 4-WALTER SCOTT UNIT 4'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	111.0393	'GEN635024 4-WALTER SCOTT UNIT 4'
13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52427	112.0055	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52427	112.0055	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52507	114.0733	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52507	114.0733	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	118.0773	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	118.0773	'GEN 86115 1-J611 G 0.6900'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	124.694	'GEN 86115 1-J611 G 0.6900'

13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	124.694	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52559	134.2668	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52559	134.2668	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52559	142.1455	'CRESTON - MARYVILLE 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	114.8031	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	114.8031	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	114.8482	'MARYVILLE - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	114.8482	'MARYVILLE - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	116.0229	'FAIRPORT - HARVIEL E 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	116.0229	'FAIRPORT - HARVIEL E 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	119.6245	'MARYVILLE - NODAWAY 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	119.647	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	119.647	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	125.0201	'FAIRPORT - HARVIEL E 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	125.0201	'FAIRPORT - HARVIEL E 161KV CKT 1'

Table 6: Voltage Constraints Requiring Additional Transmission Reinforcements

Dispatch Group	Season	Source	Flow	Monitored Element	RATEA (MVA)	RATEB (MVA)	TDF	TC% LOADING	Max MW Available	Contingency
Currently, None										

Table 7: Thermal Constraints Not Requiring Additional Transmission Reinforcements

Dispatch Group	Scenario	Season	Source	Flow	Monitored Element	RATEA (MVA)	RATEB (MVA)	TDF	TC% LOADING	Contingency
Currently none										

EXHIBIT 5:

Revised Affected System Impact Study Report

GENERATOR INTERCONNECTION AFFECTED SYSTEM IMPACT STUDY REPORT

ASGI-2018-001

Published November 2018

By SPP Generator Interconnections Dept.

REVISION HISTORY

Date	Author	Change Description
10/5/2018	SPP	Affected System Impact Study for ASGI-2018-001 Report Revision 0 Issued
11/5/2018	SPP	Correction to Table 1. J476, a higher queued MISO request, was studied in the original report but was accidentally excluded from the report.

EXECUTIVE SUMMARY

An Affected System Interconnection Customer has requested an Affected System Impact Study (ASIS) consistent with Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection requests into the system of Associated Electric Cooperative Inc. (AECI). AECI request GIA-61, a 230 MW wind generating facility, has been assigned the SPP queue identifier ASGI-2018-001.

SPP has conducted this ASIS to evaluate potential impacts to the SPP Transmission System related to the interconnection of generators on the AECI Transmission System. ASGI-2018-001 is requesting the interconnection of 9 Vestas V110-2.0 MW and 106 Vestas V116-2.0 MW turbines for a total of 230 MW injection at the Point of Interconnection (POI) and associated facilities interconnecting to AECI at the Maryville 161kV substation in Nodaway County, MO.

The ASIS analysis has determined that several network upgrades will be required for ASGI-2018-001 to interconnect all 230 MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The required network upgrades identified have been outlined in **Table 4** of this report.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Transient stability analysis for this ASIS was not performed.

Nothing in this study should be construed as a guarantee of delivery or transmission service. If the customer(s) wishes to move power across the facilities of SPP, a separate request for transmission service must be made on Southwest Power Pool's OASIS by the Customer(s).

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PURPOSE

An Affected System Interconnection Customer has requested an Affected System Impact Study (ASIS) consistent with the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection requests into the system of Associated Electric Cooperative Inc. (AECI).

The purpose of this study is to evaluate the impacts of interconnecting the AECI GIA-061 request assigned the SPP queue identifier ASGI-2018-001. ASGI-2018-001 is requesting the interconnection of 9 Vestas V110-2.0 MW and 106 Vestas V116-2.0 MW turbines for a total of 230 MW injection at the Point of Interconnection (POI) and associated facilities interconnecting to AECI at the Maryville 161kV substation in Nodaway County, MO.

The ASIS considers the Base Case as well as all Generating Facilities (and with respect to (b) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the ASIS is commenced:

a) are directly interconnected to the Transmission System;
b) are interconnected to Affected Systems and may have an impact on the Interconnection Request;
c) have a pending higher queued Interconnection Request to interconnect to the Transmission System listed in **Table 1** or
d) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a re-study of this ASIS at the expense of the Customer(s).

Nothing within this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer(s) any right to receive transmission service rights. Should the Customer(s) require transmission service, those rights should be requested through SPP's Open Access Same-Time Information System (OASIS) or that of the applicable transmission provider.

This ASIS included prior queued generation interconnection requests. Requests listed within **Table 1** are assumed to have either full or partial interconnection service prior to the requested in-service date for this ASIS.

Table 1: Higher Queued Interconnection Requests Included in the Study

GI Number	Capacity	Type	Service	POI Bus
GEN-2008-129	80	CT	ER	Pleasant Hill 161kV
GEN-2010-036	4.6	Hydro	ER	6th Street 115kV
GEN-2011-011	50	Coal	ER	Iatan 345kV
GEN-2014-021	300	Wind	ER/NR	Tap Nebraska City - Mullin Creek (Holt) 345kV
GEN-2015-005	200.1	Wind	ER	Tap Nebraska City - Sibley (Ketchem) 345kV
ASGI-2016-003	6	Diesel	ER	Paola 161kV
GEN-2016-088	151.2	Wind	ER/NR	Transource Ketchem 345kV Station
GEN-2016-115	300	Wind	ER/NR	Holt County Switching Station 345kV
GEN-2016-149	302	Wind	ER/NR	Stranger Creek 345kV Sub

GEN-2016-150	302	Wind	ER/NR	Stranger Creek 345kV Sub
GEN-2016-157	252	Wind	ER/NR	West Gardner 345kV Sub
GEN-2016-158	252	Wind	ER/NR	West Gardner 345kV Sub
GEN-2016-168	20	Solar	ER/NR	Higginsville 69kV Sub
GEN-2016-174	302	Wind	ER/NR	Stranger Creek 345kV Sub
GEN-2016-176	302	Wind	ER/NR	Stranger Creek 345kV Sub
ASGI-2017-006	238	Wind	ER/NR	Maryville 161 kV
J476	246	Wind	ER/NR	Atchison Co – Orient 345 kV
J570	150	Wind	ER/NR	Cooper - Atchison 345kV Line

Table 2: Current study requests under study

GI Number	Capacity	Type	Service	POI Bus
ASGI-2018-001	230	Wind	ER/NR	Maryville 161 kV

SPP's analysis for reviewing impacts for AECI GIA-61 was based on the following higher-queued planned projects being in-service by 12/31/2019:

Table 3: Higher Queued Network Upgrades Included in the Study

AECI Request	Mitigation	Assigned By	TO Estimated Cost
GIA-061	Upgrade Fairport - Gentry - Nodaway 161 kV	AECI	Please refer to AECI posted reports for cost allocation
	Upgrade Maryville 161/69 kV transformer		
	Uprate Stanberry - Darlington 69 kV		
	Uprate Darlington - Fairport 69 kV		

The following current study upgrades are required for full interconnection service of GIA-61:

Table 4: SPP Current Study Assigned Upgrades

AECI Request	Mitigation	Assigned By	TO Estimated Cost
GIA-061	Rebuild 'MARYVILLE - MARYVILLE 161KV CKT 1' to increase rating to 293/334 MVA	SPP	$1,200,000
	Reconductor 'CRESTON - MARYVILLE 161KV CKT 1' to at least 216 MVA	SPP	$30,000,000
	NRIS Only Upgrade: WAPA Creston terminal sufficient to achieve 171 MVA (TC) loading. NU only required if constraint observed by MEC.	SPP	$0

All upgrades assigned by SPP will require an Affected System Facilities Study agreement and deposit. These upgrades may require a Construction Agreement (CA) as a result of the Affected System Facilities Study.

Any changes to these assumptions may require a re-study of this ASIS at the expense of the Customer(s).

Nothing in this System Impact Study constitutes a request for transmission service or grants the Interconnection Customer(s) any rights to transmission service.

Posted SPP affected system reports can be located at the following Generation Interconnection Study URL: http://opsportal.spp.org/Studies/Gen

FACILITIES

GENERATING FACILITY

The Affected System Interconnection Customers' request the interconnection of 9 Vestas V110-2.0 MW and 106 Vestas V116-2.0 MW turbines. The turbines were modeled using a 0.95 power factor based on the assumption provided by AECI for a total of 230 MW injection at the Point of Interconnection (POI) and associated facilities interconnecting to AECI at the Maryville 161kV substation in Nodaway County, MO.

INTERCONNECTION FACILITIES

The ASGI-2018-001 Interconnection Customer has requested a connection to the Affected System via the Maryville 161kV substation in Nodaway County, MO. **Figure 1** illustrates the current study request, AECI GIA-061 (ASGI-2018-001) interconnecting at the Maryville 161 kV substation. The higher queued AECI GIA-053 request (ASGI-2017-006) shares this POI.

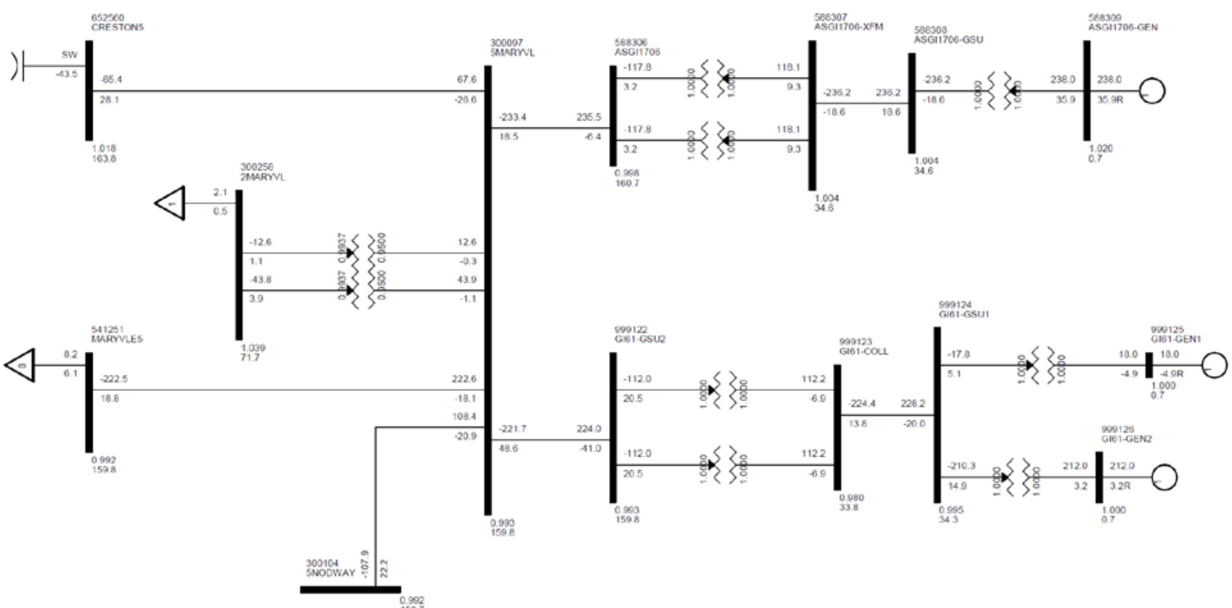


Figure 1: Proposed ASGI-2018-001 Configuration and Request Power Flow Model

BASE CASE NETWORK UPGRADES

The Network Upgrades included within the cases used for this Affected System Impact Study are those facilities that are a part of the SPP Transmission Expansion Plan or the Balanced Portfolio projects. These facilities have an approved Notification to Construct (NTC), or are in construction stages and expected to be in-service at the effective time of this study. No other upgrades were included for this ASIS. If for some reason, construction on these projects is delayed or discontinued, a restudy may be needed to determine the interconnection service availability of the Customer(s).

POWER FLOW ANALYSIS

Power flow analysis is used to determine if the transmission system can accommodate the injection from the request without violating thermal or voltage transmission planning criteria.

MODEL PREPARATION

Power flow analysis was performed using modified versions of the 2016 series of 2017 ITP Near-Term study models including these seasonal models:

- Year 1 (2017) Winter Peak (17WP)
- Year 2 (2018) Spring (18G)
- Year 2 (2018) Summer Peak (18SP)
- Year 5 (2021) Light (21L)
- Year 5 (2021) Summer (21SP)
- Year 5 (2021) Winter (21WP) peak
- Year 10 (2026) Summer (26SP) peak

To incorporate the Interconnection Customers' request, a re-dispatch of existing generation within SPP and AECI was performed with respect to the amount of the Customers' injection.

For Variable Energy Resources (VER) (solar/wind) in each power flow case, ERIS, is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas is dispatched at 20% nameplate of maximum generation. SPP projects are dispatched across the SPP footprint using load factor ratios. AECI projects are dispatched across the AECI footprint using load factor ratios.

Peaking units are not dispatched in the Year 2 spring and Year 5 light, or in the "High VER" summer and winter peaks. To study peaking units' impacts, the Year 1 winter peak, Year 2 summer peak, and Year 5 summer and winter peaks, and Year 10 summer peak models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

All generators (VER and peaking) that requested Network Resource Interconnection Service (NRIS) are dispatched in an additional analysis into the interconnecting Transmission Owner's (T.O.) area at 100% nameplate with Energy Resource Interconnection Service (ERIS) only requests at 80% nameplate. This method allows for identification of network constraints that are common between regional groupings to have affecting requests share the mitigating upgrade costs throughout the cluster.

STUDY METHODOLOGY AND CRITERIA

THERMAL OVERLOADS

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously mentioned.

For ERIS, thermal overloads are determined for system intact (n-0) (greater than or equal to 100% of Rate A - normal) and for contingency (n-1) (greater than or equal to 100% of Rate B – emergency) conditions.

The overloads are then screened to determine which of generator interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage based conditions (n-1),
- or 3% DF on contingent elements that resulted in a non-converged solution.

Interconnection Requests that requested NRIS are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also considered for transmission reinforcement under NRIS.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution Flowgates for SPP and first tier Non-SPP control area are monitored. Additional NERC Flowgates are monitored in second tier or greater Non-SPP control areas. Voltage monitoring was performed for SPP control area buses 69 kV and above.

VOLTAGE

For non-converged power flow solutions that are determined to be caused by lack of voltage support, appropriate transmission support will be determined to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

SPP Areas (69kV+):

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AEPW	0.95 – 1.05 pu	0.92 – 1.05 pu
GRDA	0.95 – 1.05 pu	0.90 – 1.05 pu
SWPA	0.95 – 1.05 pu	0.90 – 1.05 pu
OKGE	0.95 – 1.05 pu	0.90 – 1.05 pu
OMPA	0.95 – 1.05 pu	0.90 – 1.05 pu
WFEC	0.95 – 1.05 pu	0.90 – 1.05 pu
SWPS	0.95 – 1.05 pu	0.90 – 1.05 pu
MIDW	0.95 – 1.05 pu	0.90 – 1.05 pu
SUNC	0.95 – 1.05 pu	0.90 – 1.05 pu
KCPL	0.95 – 1.05 pu	0.90 – 1.05 pu
INDN	0.95 – 1.05 pu	0.90 – 1.05 pu
SPRM	0.95 – 1.05 pu	0.90 – 1.05 pu
NPPD	0.95 – 1.05 pu	0.90 – 1.05 pu
WAPA	0.95 – 1.05 pu	0.90 – 1.05 pu
WERE L-V	0.95 – 1.05 pu	0.93 – 1.05 pu
WERE H-V	0.95 – 1.05 pu	0.95 – 1.05 pu
EMDE L-V	0.95 – 1.05 pu	0.90 – 1.05 pu
EMDE H-V	0.95 – 1.05 pu	0.92 – 1.05 pu
LES	0.95 – 1.05 pu	0.90 – 1.05 pu
OPPD	0.95 – 1.05 pu	0.90 – 1.05 pu

SPP Buses with more stringent voltage criteria:

Bus Name/Number	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
TUCO 230kV 525830	0.925 – 1.05 pu	0.925 – 1.05 pu
Wolf Creek 345kV 532797	0.985 – 1.03 pu	0.985 – 1.03 pu
FCS 646251	1.001 – 1.047 pu	1.001 – 1.047 pu

Affected System Areas (115kV+):

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AECI	0.95 – 1.05 pu	0.90 – 1.05 pu
EES-EAI	0.95 – 1.05 pu	0.90 – 1.05 pu
LAGN	0.95 – 1.05 pu	0.90 – 1.05 pu
EES	0.95 – 1.05 pu	0.90 – 1.05 pu
AMMO	0.95 – 1.05 pu	0.90 – 1.05 pu
CLEC	0.95 – 1.05 pu	0.90 – 1.05 pu
LAFA	0.95 – 1.05 pu	0.90 – 1.05 pu
LEPA	0.95 – 1.05 pu	0.90 – 1.05 pu
XEL	0.95 – 1.05 pu	0.90 – 1.05 pu
MP	0.95 – 1.05 pu	0.90 – 1.05 pu
SMMPA	0.95 – 1.05 pu	0.90 – 1.05 pu
GRE	0.95 – 1.05 pu	0.90 – 1.10 pu
OTP	0.95 – 1.05 pu	0.90 – 1.05 pu
OTP-H (115kV+)	0.97 – 1.05 pu	0.92 – 1.10 pu
ALTW	0.95 – 1.05 pu	0.90 – 1.05 pu
MEC	0.95 – 1.05 pu	0.90 – 1.05 pu
MDU	0.95 – 1.05 pu	0.90 – 1.05 pu
SPC	0.95 – 1.05 pu	0.95 – 1.05 pu
DPC	0.95 – 1.05 pu	0.90 – 1.05 pu
ALTE	0.95 – 1.05 pu	0.90 – 1.05 pu

The constraints identified through the voltage scan are then screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage. In certain conditions, engineering judgement was used to determine whether or not a generator had impacts to voltage constraints.

RESULTS

The ASIS ACCC analysis indicates that the Affected System Interconnection Customer(s) can interconnect their generation into the AECI transmission system at the available MW listed in the results tables after all required upgrades listed within the DISIS-2016-002 studies or latest iteration thereof have been placed into service. ACCC results detailed in **Table 5** are dependent on higher queued SPP and AECI upgrades. Incremental SPP upgrades assigned to ASGI-2018-001 are identified within **Table 4.**

Constraints listed in **Table 7** do not require additional transmission reinforcement for Interconnection Service, but could require Interconnection Customer to reduce generation in operational conditions. These transmission constraints occur when this study's generation is dispatched into the AECI footprint for ERIS and NRIS.

CURTAILMENT AND SYSTEM RELIABILITY

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

CONCLUSION

An Affected System Interconnection Customer has requested an Affected System Impact Study (ASIS) under the Southwest Power Pool Open Access Transmission Tariff (OATT) for ASGI-2018-001. ASGI-2018-001 (230 MW) wind generating facilities are to be interconnected into the system of AECI. This ASIS was conducted to determine the impacts of interconnecting GIA-61 generation to the transmission system with all required Network Upgrades identified in the DISIS-2016-002 and those outlined in **Table 3** in service by 12/31/2019.

The ASIS analysis has determined that several network upgrades will be required for ASGI-2018-001 to interconnect all 230 MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The required network upgrades identified have been outlined in **Table 5** of this report.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Transient stability analysis was not completed for this ASIS.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a re-study of this ASIS at the expense of the Customer.

Nothing in this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service.

THERMAL AND STEADY STATE VOLTAGE CONSTRAINTS TABLES

Table 5: Thermal Constraints Requiring Additional Transmission Reinforcements

Dispatch Group	Scenario	Season	Source	Flow	Monitored Element	RATEA (MVA)	RATEB (MVA)	TDF	TC% LOADING	Contingency
13NR	0	18G	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.09986	100.6436	'BUNGE - RIVER BEND 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.08557	102.1823	'MARYVILLE - NODAWAY 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.09986	102.1842	'BUNGE - HASTINGS 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.08557	102.1863	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.08557	102.4485	'FAIRPORT - HARVIEL E 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.09736	105.3642	'CLARINDA - HASTINGS 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.10084	105.4711	'COUNCIL BLUFFS - RIVER BEND 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.10084	106.4841	'BUNGE - RIVER BEND 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.10084	108.0827	'BUNGE - HASTINGS 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.11455	108.6932	'CRESTON - MARYVILLE 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'ADAMS 5 161.00 - CRESTON 161KV CKT 1'	154	154	0.09833	110.9844	'CLARINDA - HASTINGS 161KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	CRESTON - MARYVILLE 161KV CKT 1'	208	208	0.29651	103.6926	MARYVILLE - MARYVILLE 161KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52559	142.1455	CRESTON - MARYVILLE 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	119.6245	'MARYVILLE - NODAWAY 161KV CKT 1'
13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43178	100.7739	'GEN 86115 1-J611 G 0.6900'
13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43178	100.7739	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	101.6994	'GEN645012 2-NEBRASKA CITY 2'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	101.6994	'GEN645012 2-NEBRASKA CITY 2'

13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45182	101.7616	'FAIRPORT - ST JOE 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45182	101.7616	'FAIRPORT - ST JOE 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42911	101.8473	'ST JOE (STJOE T2) 345/161/13.8KV TRANSFORMER CKT 2'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42911	101.8473	'ST JOE (STJOE T2) 345/161/13.8KV TRANSFORMER CKT 2'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42909	101.8549	'ST JOE (STJOE T1) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42909	101.8549	'ST JOE (STJOE T1) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43239	101.8865	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43239	101.8865	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43045	101.945	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43045	101.945	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43262	102.2279	'SUB 3455 - SUB 3740 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43262	102.2279	'SUB 3455 - SUB 3740 345KV CKT 1'
13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43221	102.33	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43221	102.33	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43251	102.3859	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43251	102.3859	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42973	103.2707	'EASTOWN7 345.00 (EASTOWN 345)

										345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42973	103.2707	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	103.6517	'GEN999125 1-GI61-GEN1 0.6900'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	103.6517	'GEN999125 1-GI61-GEN1 0.6900'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43729	103.7393	'COOPER - FAIRPORT 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43729	103.7393	'COOPER - FAIRPORT 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	103.8699	'GEN635023 3-WALTER SCOTT UNIT 3'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	103.8699	'GEN635023 3-WALTER SCOTT UNIT 3'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	104.2577	'GEN344225 1-1CAL G1 25.000'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	104.2577	'GEN344225 1-1CAL G1 25.000'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4324	104.3619	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4324	104.3619	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	104.4022	'GEN635024 4-WALTER SCOTT UNIT 4'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	104.4022	'GEN635024 4-WALTER SCOTT UNIT 4'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	104.6913	'GEN300003 1-THOMAS HILL UNIT 3'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	104.6913	'GEN300003 1-THOMAS HILL UNIT 3'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.0044	'GEN336821 1-GRAND GULF UNIT'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.0044	'GEN336821 1-GRAND GULF UNIT'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43182	105.1862	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'

13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43182	105.1862	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.4066	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.4066	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.4669	'GEN335831 1-RIVERBEND UNIT#1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.4669	'GEN335831 1-RIVERBEND UNIT#1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.5878	'GEN337910 1-ARKANSAS NUCLEAR ONE UNIT #1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	105.5878	'GEN337910 1-ARKANSAS NUCLEAR ONE UNIT #1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43211	105.6193	'HAWTHORN - NASHUA 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43211	105.6193	'HAWTHORN - NASHUA 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43241	105.6888	'87th STREET - STRANGER CREEK 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43241	105.6888	'87th STREET - STRANGER CREEK 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	107.0436	System Intact
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	108.3275	'GEN645012 2-NEBRASKA CITY 2'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	108.3275	'GEN645012 2-NEBRASKA CITY 2'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4324	108.4737	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4324	108.4737	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43263	108.8509	'SUB 3455 - SUB 3740 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43263	108.8509	'SUB 3455 - SUB 3740 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43252	108.9637	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'

13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43252	108.9637	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45182	109.4013	'FAIRPORT - ST JOE 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45182	109.4013	'FAIRPORT - ST JOE 345KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42974	109.4526	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.42974	109.4526	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
13ALL	0	18SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52496	110.2204	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	18SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52496	110.2204	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	110.5082	'GEN635023 3-WALTER SCOTT UNIT 3'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	110.5082	'GEN635023 3-WALTER SCOTT UNIT 3'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	111.0393	'GEN635024 4-WALTER SCOTT UNIT 4'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	111.0393	'GEN635024 4-WALTER SCOTT UNIT 4'
13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52427	112.0055	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52427	112.0055	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52507	114.0733	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52507	114.0733	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	118.0773	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43271	118.0773	'GEN 86115 1-J611 G 0.6900'
13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	124.694	'GEN 86115 1-J611 G 0.6900'

13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43272	124.694	'GEN 86115 1-J611 G 0.6900'
13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52559	134.2668	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52559	134.2668	'CRESTON - MARYVILLE 161KV CKT 1'
13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.52559	142.1455	'CRESTON - MARYVILLE 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	114.8031	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	114.8031	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	114.8482	'MARYVILLE - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	114.8482	'MARYVILLE - NODAWAY 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	116.0229	'FAIRPORT - HARVIEL E 161KV CKT 1'
13NR	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64721	116.0229	'FAIRPORT - HARVIEL E 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	119.6245	'MARYVILLE - NODAWAY 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	119.647	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	119.647	'HARVIEL E - NODAWAY 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	125.0201	'FAIRPORT - HARVIEL E 161KV CKT 1'
13NR	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.64775	125.0201	'FAIRPORT - HARVIEL E 161KV CKT 1'

Table 6: Voltage Constraints Requiring Additional Transmission Reinforcements

Dispatch Group	Season	Source	Flow	Monitored Element	RATEA (MVA)	RATEB (MVA)	TDF	TC% LOADING	Max MW Available	Contingency
Currently, None										

Table 7: Thermal Constraints Not Requiring Additional Transmission Reinforcements

Dispatch Group	Scenario	Season	Source	Flow	Monitored Element	RATEA (MVA)	RATEB (MVA)	TDF	TC% LOADING	Contingency
Currently none										

EXHIBIT 6:

Facilities Study Agreement

AFFECTED SYSTEM INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this 13th of March 2019 by and between Tenaska Clear Creek Wind, LLC a limited liability company and existing under the laws of the State of Missouri ("Affected System Customer") and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Affected System Customer has notified Transmission Provider of the proposed development of a Generating Facility or generating capacity addition to an existing Generating Facility on the transmission or distribution system that may possibly affect Transmission Providers Transmission System, and

WHEREAS, Transmission Provider has completed an Affected System Generation Interconnection System Impact Study (the "System Impact Study") and provided the results of said study to Affected System Customer; and

WHEREAS, Affected System Customer has requested Transmission Provider to perform an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Generating Facility to the Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

2.0 Affected System Customer elects and Transmission Provider shall cause an Interconnection Facilities Study consistent with Section 8.0 of this GIP to be performed in accordance with the Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 The Interconnection Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the Generating Facility to the Transmission System and (ii) shall address the short circuit, instability, and power flow issues identified in the Definitive Interconnection System Impact Study.

5.0 The time for completion of the Interconnection Facilities Study is specified in Attachment A.

Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice. Any difference between the applicable deposits specified under Section 8.2 of the GIP and Interconnection Customer's share of study costs shall be paid by or refunded to Interconnection Customer, as appropriate per Section 13.3 of the GIP.

The estimated cost of the Facilities Study is $10,000 which may be deducted from existing Affected System Customer's previous deposits.

6.0 Reserved.

7.0 Governing Law

7.1 **Governance.** The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

7.2 **Applicability.** This Agreement is subject to all applicable federal and state Laws and Regulations.

7.3 **Reservation of Rights.** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

8.0 Notices.

8.1 **General.** Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Attention: Manager, GI Studies

To Interconnection Customer:

Tenaska Clear Creek Wind, LLC
14302 FNB Parkway
Omaha, NE 68154
Attention: Vice President

8.2 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

9.0 Force Majeure

9.1 Economic Hardship. Economic hardship is not considered a Force Majeure event.

9.2 Default. Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

10.0 Indemnity

10.1 Indemnity. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Partys' action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

10.1.1 **Indemnified Person.** If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

10.1.2 **Indemnifying Party.** If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

10.1.3 **Indemnity Procedures.** Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

10.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

11.0 Assignment

11.1 Assignment. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

12.0 Severability

12.1 Severability. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

13.0 Comparability

13.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

14.0 Deposits and Invoice Procedures

14.1 General. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

14.2 Study Deposits. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.

14.3 Final Invoice. Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

14.4 Payment. Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 1 to the GIP. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.

14.5 Disputes. In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due together with accrued interest in accordance with Section 3.6 of this Attachment V.

15.0 Representations, Warranties, and Covenants

15.1 General. Each Party makes the following representations, warranties and covenants:

15.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

15.1.2 Authority. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.1.3 No Conflict. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

15.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

16.0 Breach, Cure and Default

16.1 General. A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

16.2 Events of Breach. A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

16.3 Cure and Default. Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the "Non-Breaching Party"), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the "Breaching Party") and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

16.4 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

17. Miscellaneous

17.1 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

17.2 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

17.3 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

17.4 Entire Agreement. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

17.5 No Third Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

17.6 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.7 Headings. The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

17.8 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

17.9 Amendment. The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

17.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

17.11 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Southwest Power Pool, Inc.

By: [signature]

Title: Director, R&D and Tariff Services

Date: 3/13/15

Tenaska Clear Creek Wind, LLC

By: ______________________

Title: Vice President

Date: 10/31/18

Attachment A To Affected Interconnection Facilities Study Agreement

INTERCONNECTION CUSTOMER SCHEDULE ELECTION FOR CONDUCTING THE INTERCONNECTION FACILITIES STUDY

Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer within the following number of days after receipt of an executed copy of this Interconnection Facilities Study Agreement:

- ninety (90) Calendar Days with no more than a +/- 20 percent cost estimate contained in the report.

Attachment B to Appendix 2
Interconnection Facilities
Study Agreement

DATA FORM TO BE PROVIDED BY INTERCONNECTION CUSTOMER WITH THE INTERCONNECTION FACILITIES STUDY AGREEMENT

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the Transmission System Number of generation connections: 1

On the one line diagram indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line diagram indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

Will an alternate source of auxiliary power be available during CT/PT maintenance?
__X__Yes _____ No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? _____Yes __X__No (Please indicate on one line diagram).

What type of control system or PLC will be located at the Generating Facility?

Regarding PLC, the Generating Facility will use VestasOnline™ Business SCADA System. The Power Plant Controller (PPC) component is based on the ControlLogix PLC manufactured by Rockwell.

What protocol does the control system or PLC use?

The internal PPC equipment operates on its own private Local Area Network. The PPC communicates with VestasOnline Server using the 'AB' protocol. The VestasOnline Server will utilize the KepServer suite as the 'AB' communication driver. The PPC communicates to the turbine controllers using a standard Vestas protocol named 'Roadrunner' for fast, high priority control, and data exchange. Also, the VestasOnline system will include interface to the substation RTU. These communications are via TCP using DNP3.

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

See attached

Physical dimensions of the proposed interconnection station:
____400' x 380'____

Bus length from generation to interconnection station:
____

Line length from interconnection station to Transmission Provider's transmission line:
8 miles

Tower number observed in the field. (Painted on tower leg)* ____________

Number of third party easements required for transmission lines*:
____

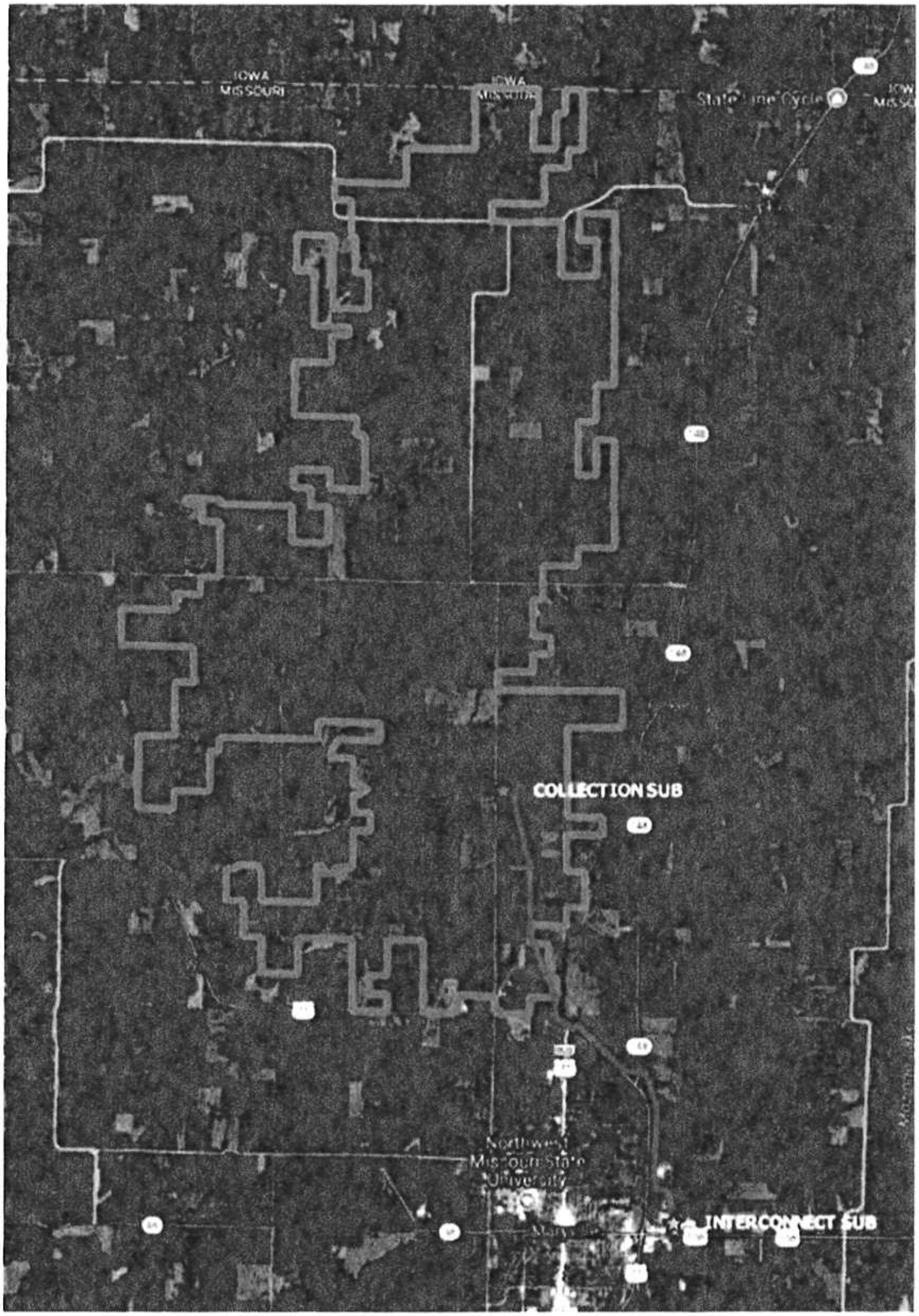
* To be completed in coordination with Transmission Provider.

Is the Generating Facility in the Transmission Provider's service area?

_____Yes   __X__No   Local provider: N.W. Electric

Please provide proposed schedule dates:

Begin Construction	Date: 3/1/2019
Generator step-up transformer receives back feed power	Date: 7/1/2019
Generation Testing	Date: 8/1/2019
Commercial Operation	Date: 12/1/2019


IOWA
MISSOURI
IOWA
MISSOURI
State Line Cycle
COLLECTION SUB
Northwest Missouri State University
INTERCONNECT SUB

SINGLE-LINE DIAGRAM
ASGI-2018-001 (AECI GI-61)

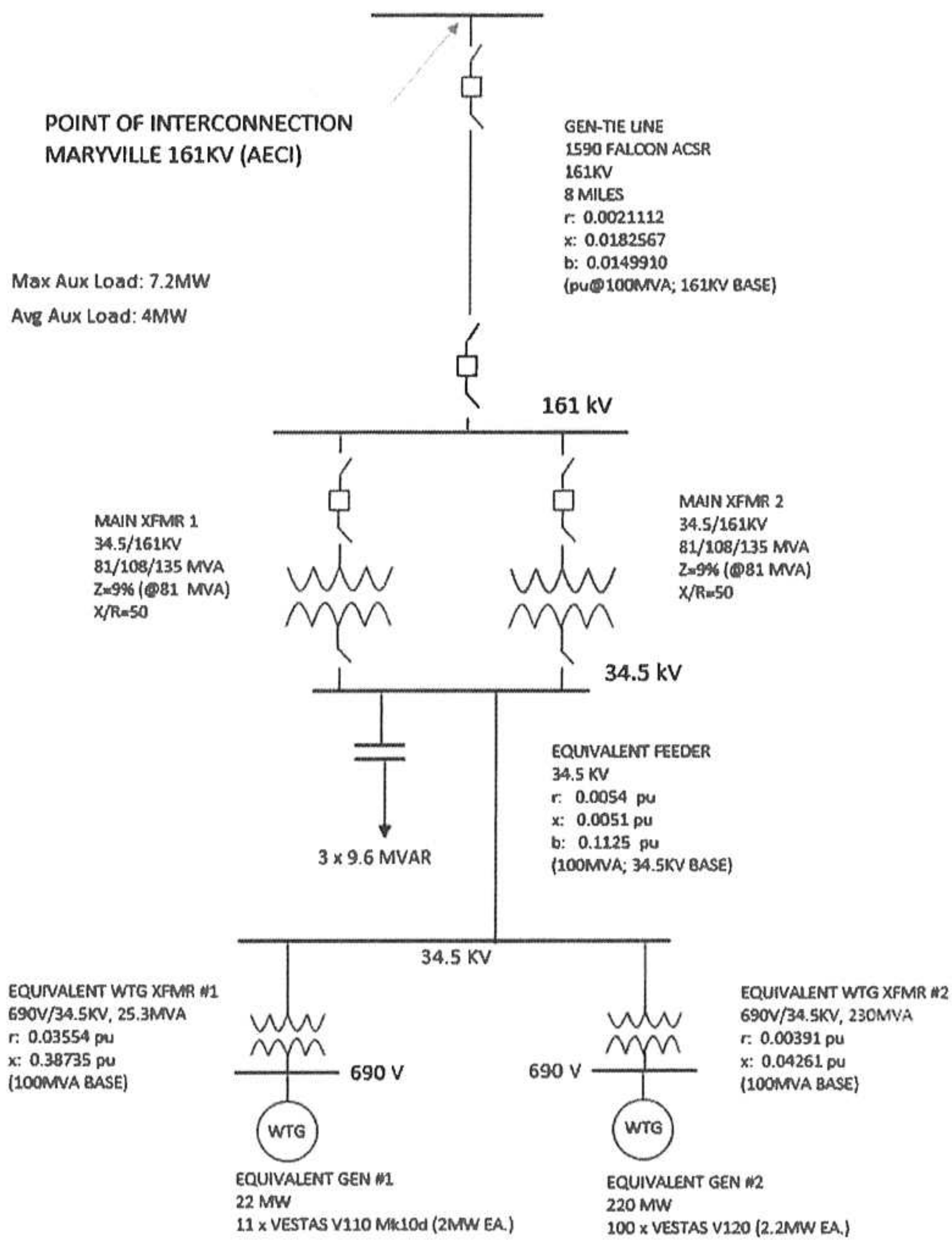


EXHIBIT 7:

First Facilities Study

AFFECTED SYSTEM INTERCONNECTION FACILITIES STUDY REPORT

Kansas City Power & Light (KCPL), Western Area Power Administration (WAPA)

Network Upgrade(s)

ASGI-2018-001

Published February 2019

By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
2/12/2019	SPP	Initial draft report issued.	

CONTENTS

SUMMARY

INTRODUCTION

This Affected System Interconnection Facilities Study (AS-IFS) for Interconnection Request ASGI-2018-001 (GIA-61) is for a proposed 230.00 MW generating facility to be connected to the facilities of Associated Electric Cooperative, Inc. located in Nodaway County, MO. The Affected System Interconnection Request was studied prior queued to the DISIS-2017-001 Impact Study for Affected System Impact Review for Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The Interconnection Customer's requested in-service date is December 31, 2019.

The affected Transmission Owners, Kansas City Power & Light (KCPL) and Western Area Power Administration (WAPA), performed a detailed AS-IFS at the request of SPP. The full reports are included in Appendix A. The proposed in-service date for the generating facility is 12/31/2021. SPP has determined that full Interconnection Service will be available after the SPP Network Upgrades are completed.

The primary objective of the AS-IFS is to identify necessary Network Upgrades, cost estimates, and associated construction lead times needed to grant the requested Interconnection Service.

PHASE(S) OF INTERCONNECTION SERVICE

It is not expected that Interconnection Service will occur in phases. However, Interconnection Service will not be available until all Interconnection Facilities and Network Upgrade(s) can be placed in service.

CREDITS/COMPENSATION FOR AMOUNTS ADVANCED FOR NETWORK UPGRADES

Interconnection Customer shall be entitled to compensation in accordance with Attachment Z2 of the SPP OATT for the cost of SPP creditable-type Network Upgrades, including any tax gross-up or any other tax-related payments associated with the Network Upgrades, that are not otherwise refunded to the Interconnection Customer. Compensation shall be in the form of either revenue credits or incremental Long Term Congestion Rights (iLTCR).

GENERATING FACILITY

The Generating Facility is proposed to consist of twelve (12) Vestas V110 2.0 MW turbines and one hundred six (106) Vestas V116 2.0 MW turbines for a total generating nameplate capacity of 230.00 MW.

AFFECTED SYSTEM NETWORK UPGRADE(S)

To facilitate interconnection, the Affected System Transmission Owner will perform work as shown below necessary for the acceptance of the Interconnection Customer's Interconnection Facilities.

Table 1 lists the Interconnection Customer's estimated cost responsibility for Affected System Non-Shared Network Upgrade(s) and provides an estimated lead time for completion of construction. The estimated lead time begins when the Facilities Construction Agreement has been fully executed.

Table 1: Affected System Non-Shared Network Upgrade(s)

Affected System Network Upgrades Description	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)	Estimated Lead Time
KCPL NUs: Rebuild 'MARYVILLE - MARYVILLE 161KV CKT 1': (1) transmission line rebuild: KCP&L will replace existing wood structures and 795 ACSR conductor with new steel structures and 1192 ACSS conductor. Line has a total of four dead-end structures. (2) Maryville sub bus upgrades: upgrade 161kV strain bus and breaker jumpers for 1200-amp capability. (3) Maryville relaying upgrades: install new line differential relay panels for Line #11 and differential relays for transformer #33.	$1,417,500	100%	$1,417,500	16 Months
WAPA NUs: Reconductor 62.4 miles of the Creston – Maryville 161kV transmission line using 556.5 ACSS Parakeet conductor, including new insulators assemblies and hardware to accommodate the higher temperature conductor. The proposed use of the ACSS type conductor eliminates the need to replace the existing transmission line structures previously identified in the earlier conceptual cost estimates.	$14,900,000	100%	$14,900,000	29 months
Total	**$16,317,500**	**100%**	**$16,317,500**	**29 months**

The Interconnection Customer's share of costs for Shared Network Upgrades is estimated in **Table 2** below.

Table 2: Interconnection Customer Shared Network Upgrades

Shared Network Upgrades Description	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)
None	$0	N/A	$0
Total	**$0**	**N/A**	**$0**

All studies have been conducted assuming that higher-queued Interconnection Request(s) and the associated Network Upgrade(s) will be placed into service. If higher-queued Interconnection Request(s) withdraw from the queue, suspend or terminate service, the Interconnection Customer's share of costs may be revised. Restudies, conducted at the customer's expense, will determine the Interconnection Customer's revised allocation of Shared Network Upgrades.

OTHER AFFECTED SYSTEM NETWORK UPGRADE(S)

Certain Other Affected System Network Upgrades are **currently not the cost responsibility** of the Interconnection Customer but will be required for full Interconnection Service.

Table 3: Interconnection Customer Other Affected System Network Upgrade(s)

Other Network Upgrade(s) Description	Current Cost Assignment	Estimate In-Service Date
None	N/A	N/A

Depending upon the status of higher- or equally-queued customers, the Interconnection Request's in-service date is at risk of being delayed or Interconnection Service is at risk of being reduced until the in-service date of these Other Network Upgrades.

CONCLUSION

After all Affected System Network Upgrades have been placed into service, Interconnection Service for 230.00 MW can be granted. Interconnection Service will be delayed until the Affected System Non-Shared Network Upgrade(s) and Other Affected System Network Upgrade(s) are completed. The Interconnection Customer's estimated cost responsibility for Affected System Non-Shared Network Upgrades is summarized in the table below.

Table 4: Cost Summary

Description	Allocated Cost Estimate
KCPL Affected System Network Upgrades	$1,417,500
WAPA Affected System Network Upgrades	$14,900,000
Total	**$16,317,500**

A draft Facilities Construction Agreement (CA) will be provided to the Interconnection Customer consistent with the final results of this AS-IFS report. The Affected System Transmission Owner and Interconnection Customer will have 60 days to negotiate the terms of the CA consistent with the SPP OATT.

APPENDIX A: TRANSMISSION OWNER'S INTERCONNECTION FACILITIES STUDY REPORT

Kansas City Power & Light Company

Affected System Interconnection Facilities Study for Southwest Power Pool

Generation Interconnection Request AECI GIA-61

ASGI-2018-001

Prepared by: Kansas City Power & Light Transmission Planning
December 20, 2018

Executive Summary

In accordance with the Southwest Power Pool (SPP) Generator Interconnection Procedures (GIP) 8.10 and 8.11, SPP Generator Interconnection (GI) Staff requested an Affected System Interconnection Facilities Study with associated interconnection costs and lead times for the proposed Network Upgrade of the Maryville-Maryville AEC 161kV transmission line of the Kansas City Power & Light (KCP&L) transmission system. These upgrades are assigned to the Affected System Interconnection Customer(s) as part of the recently completed ASGI-2018-001 SPP Affected System Impact Study.

KCP&L performed the following Facility Study to satisfy the SPP GI Staff request for a generator interconnection request on the Associated Electric Cooperative Incorporated (AECI) transmission system. The request for interconnection was placed with AECI and designated as AECI GIA-61. The customer requests interconnection service for a 238-MW wind farm at the existing Maryville AEC 161kV substation in Northwest Missouri, near Maryville, Missouri. The customer has proposed a commercial operation date of December 31, 2019. Required Network Upgrade on the KCP&L transmission system involves rebuilding the Maryville-Maryville AEC 161kV transmission line. This is an existing, short (~0.5 mile) transmission tie line between 161 kV substations owned by KCP&L and AECI. The existing line uses 795 ACSR conductor and has a current rating of 225 Mva. The proposed upgrade will use 1192 ACSS conductor which will result in an increased emergency rating to 334 Mva. Network Upgrades will include terminal equipment and relaying at the KCP&L Maryville substation.

The total cost for KCP&L to rebuild the Maryville-Maryville AEC 161kV line and upgrade terminal equipment the KCP&L Maryville substation, is estimated at $1,417,500. This estimate is accurate to +/- twenty (20) percent, based on current prices. However, recent cost fluctuations in materials are very significant and the accuracy of this estimate at the time of actual procurement and construction cannot be assured.

This Facility Study does not guarantee the availability of transmission service necessary to deliver the additional generation to any specific point inside or outside the SPP transmission system. The transmission network facilities may not be adequate to deliver the additional generation output to the transmission system. If the customer requests firm transmission service under the SPP Tariff at a future date, Network Upgrades or other new construction may be required to provide the service requested under the SPP Tariff.

Identification of Facilities Requiring Network Upgrades

SPP conducted an affected system study for AECI's GIA-61 request and observed thermal overloads on KCP&L's Maryville-Maryville AEC 161kV transmission line (PSSE branch 541251-300097) in several seasons. The overloads included base case (N-0) and contingent conditions (N-1). Highest overload was approximately 142%. No voltage exceedances were identified on the KCP&L transmission system.

SPP requested that KCP&L provide mitigations for the thermal overloads on its system in the affected system study. KCP&L Transmission Planning determined that rebuilding the existing transmission line with larger conductor would eliminate the thermal overloads. KCP&L Engineering was asked to provide cost estimates to rebuild the existing transmission line and upgrade any terminal equipment to achieve a 1200-amp capability. That estimate is provided below.

KCP&L transmission line rebuild 0.5 mile	$ 765,000
KCP&L Maryville sub bus upgrades	$ 60,000
KCP&L Maryville relaying upgrades	$ 300,000
KCP&L AFUDC & contingencies	$ 292,500
Total	$1,417,500

Description of transmission owner network upgrades

KCP&L transmission line rebuild: KCP&L will replace existing wood structures and 795 ACSR conductor with new steel structures and 1192 ACSS conductor. Line has a total of four dead-end structures.

KCP&L Maryville sub bus upgrades: upgrade 161kV strain bus and breaker jumpers for 1200-amp capability.

KCP&L Maryville relaying upgrades: install new line differential relay panels for Line #11 and differential relays for transformer #33.

Engineering, Procurement, and Construction Schedule: A nominal schedule for KCP&L to design, procure equipment and construct a 161kV transmission line of this type is approximately 16 months. According to good business practice, the KCP&L engineering and procurement process cannot begin until the parties have executed a mutually agreeable Engineering & Construction Agreement.

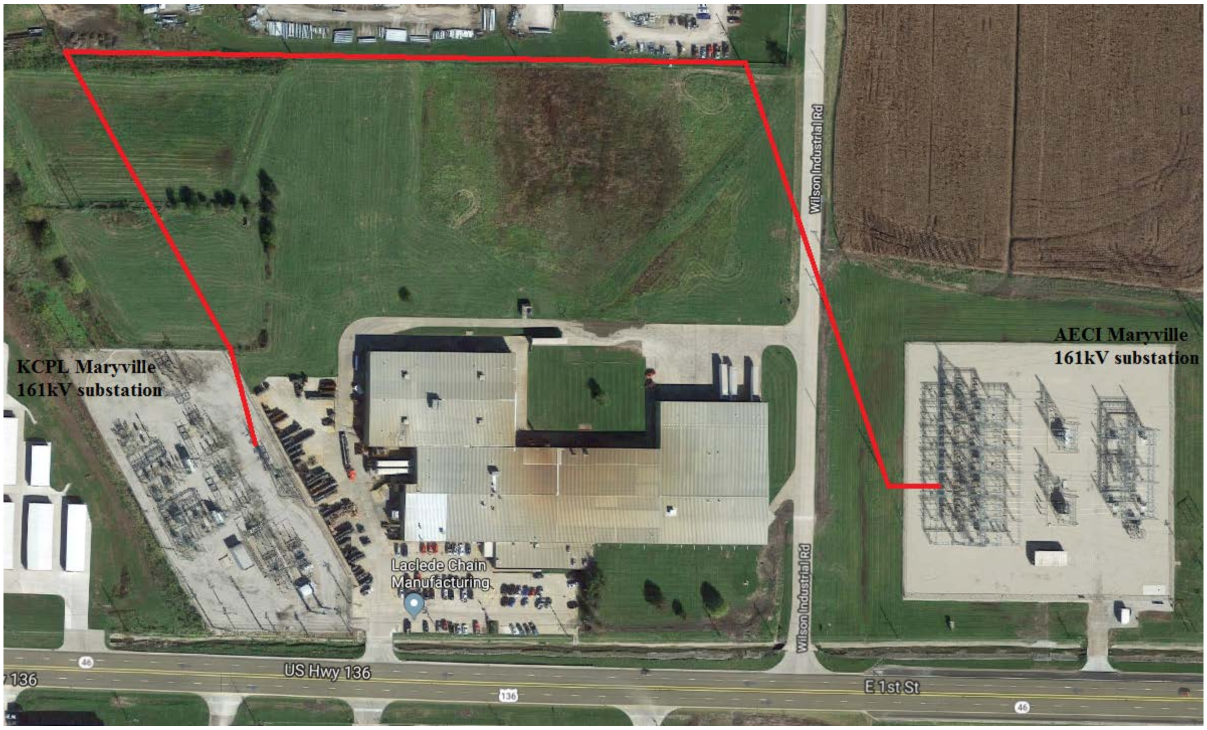
Short Circuit Fault Duty Evaluation

KCP&L engineering staff reviewed short circuit analysis performed by AECI for the proposed generation interconnections at the AECI Maryville substation to determine if the added generation would cause the available fault currents to exceed the interrupting capability of any existing KCP&L circuit breakers. The calculated fault currents were within KCP&L's circuit breaker interrupting capability with the addition of the AECI GIA-61 wind farm.

Other Required Network Upgrades

AECI will be responsible for any upgrades at its Maryville sub to provide an emergency rating of at least 334 Mva.

Figure 1: Maryville-Maryville AEC 161kV transmission line



Affected System Facilities Study Report

Southwest Power Pool, Inc. ASGI-2018-001

Western Area
Power Administration

Upper Great Plains Region

January 2019

1.0 Background:

The Western Area Power Administration Upper Great Plains Region (WAPA-UGP[1]) received a request from the Southwest Power Pool Inc. (SPP) for an Affected System Facilities Study in accordance with the SPP Open Access Transmission Tariff (Tariff). Associated Electric Cooperative Inc. (AECI) has a generator interconnection request GIA-61 for an interconnection customer in their queue for a 230 MW wind generating facility with Point of Interconnection at the Maryville 161 kV Substation in Nodaway County, MO. WAPA-UGP owns the Creston-Maryville 161 kV Transmission Line and has included this facility under the SPP Tariff. AECI submitted a request to SPP for an Affected System Impact Study (ASIS). SPP assigned queue identifier ASGI-2018-001 to AECI's request.

2.0 Status of Existing Studies applicable to Request:

SPP completed the SPP ASGI-2018-001 ASIS with report dated November 2018. The SPP ASGI-2018-001 ASIS identified the need to reconductor WAPA-UGP's Creston-Maryville 161 kV Transmission Line to at least 216 MVA in order to accommodate the additional loading due to ASGI-2018-001.

This Affected System Facility Study evaluates impacts of ASGI-2018-001 to the Creston-Maryville 161 kV Transmission Line and the required facility upgrades to accommodate the 216 MVA rating.

3.0 Study Requirements:

WAPA-UGP has performed this Affected System Facilities Study to determine a good faith estimate of (i) the cost estimate for the required upgrades, and the interconnection customer's appropriate share of the cost of any required upgrades, and (ii) the time required to complete construction. This Affected System Facilities Study includes an evaluation of the following:

3.1 Develop/compile cost estimates for all WAPA-UGP labor, overheads, equipment additions, modifications, etc.

3.2 Review and document any other interconnection/control area requirements. Document these additional requirements (such as indication/metering, monitoring, control, relaying) and include these in the cost estimate.

3.3 Develop an overall time schedule for completion of the necessary addition/modifications.

4.0 Study Results:

WAPA-UGP performed the following tasks to evaluate the additions to the system to accommodate the line rating increase request as studied and outlined in Section 3.0 above:

[1] WAPA-UGP is also referred to as "Western-UGP" in the SPP Tariff.

4.1 **Facility additions:** The evaluation of facilities to accommodate the required rating of 216 MVA for WAPA-UGP's Creston-Maryville kV Transmission Line identified the following requirements:

- Reconductor 62.4 miles of the Creston-Maryville 161 kV Transmission Line using 556.5 ACSS Parakeet conductor, including new insulators assemblies and hardware to accommodate the high temperature conductor. The proposed use of the ACSS type conductor eliminates the need to replace the existing transmission line structures previously identified in the earlier conceptual cost estimates.

WAPA-UGP's estimated cost for labor, overhead, materials, and other miscellaneous costs to address the ASGI-2018-001 impacts (i.e. to achieve the identified 216 MVA rating) are outlined in Attachment A. The total cost is estimated to be $14,900,000. The interconnection customer is responsible for the entire cost of the project.

4.2 **Contractual Agreements:** A construction agreement and Environmental Review agreement are required for the advancement of funds and to address environmental requirements for the work at WAPA-UGP's Creston-Maryville 161 kV Transmission Line to proceed. SPP will tender a facilities construction agreement for negotiation and execution between the parties. The interconnection customer will be responsible for the actual costs of the line reconductor, and WAPA-UGP will require advance funding to proceed with the project. Upon completion of the work WAPA-UGP will own, operate, and maintain the modifications and improvements to WAPA-UGP's Creston-Maryville 161 kV Transmission Line.

4.3 **Interconnection/Control Area Requirements:** N/A

4.4 **Schedule:** WAPA-UGP's estimated milestone schedule for the reconductor of WAPA-UGP's Creston-Maryville 161 kV Transmission Line is shown in Attachment A. The schedule is subject to execution of a facilities construction agreement, advance funding being provided, outage availability, and completion of an Environmental Review by the timeframes identified in the facilities construction agreement.

5.0 Environmental Review:

WAPA-UGP is a federal agency under the U.S. Department of Energy and is subject to the National Environmental Policy Act (NEPA), 42 U.S.C §4321, et seq., as amended. WAPA-UGP anticipates an Environmental Assessment (EA) level of NEPA review will be required for the reconductor of the Creston-Maryville 161 kV Transmission Line. WAPA-UGP's general cost estimate for an EA level of NEPA review is $100,000. WAPA-UGP will tender an Environmental Review agreement authorizing WAPA-UGP, at interconnection customer's expense, to perform the Environmental Review including EA level of NEPA review.

6.0 Facilities Study Cost:

WAPA-UGP will audit the Affected System Facilities Study costs and provide a summary of these costs to SPP.

ATTACHMENT A

ESTIMATED COSTS FOR CRESTON-MARYVILLE 161 KV TRANSMISSION LINE RECONDUCTOR

ITEM	ESTIMATED COST	PAYMENT SCHEDULE
Planning and project management	$325,000	Upon Execution of Construction Agreement
Design, Specifications, and Contract Administration	$425,000	Upon Execution of Construction Agreement
Creston-Maryville 1061 kV Reconductor	$14,150,000	July 2020
TOTAL ESTIMATED PROJECT COST	**$14,900,000**	

ESTIMATED SCHEDULE

ACTIVITY	BEGIN	COMPLETE
Planning / Engineering Design	July 2019*	July 2020
Issue Construction Contract	September 2020	N/A
Award Construction Contract	November 2020	N/A
Construction	November 2020	November 2021
In-Service-Date	(milestone)	**December 2021***

*Subject to execution of facilities construction agreement, advance funding being provided, outage availability, and completion of an Environmental Review prior to the start of construction.

EXHIBIT 8:

SPP Correspondence on March 2019 Revisions

From: Alyssa Anderson <aanderson@spp.org>
Sent: Friday, March 15, 2019 2:47 PM
To: Welniak, Jim <jwelniak@TENASKA.com>
Cc: Steve Purdy <spurdy@spp.org>; Staples, Boone <BStaples@tnsk.com>
Subject: RE: ASGI-2018-001 (AECI GIA-61) Affected System Impact Restudy

****External Email. Use caution before opening attachments or clicking links.****

I believe you may be referring to the following statement in the previously posted AS-LOIS for GIA-61:

Updates to the base cases included higher queued withdrawn projects, updates to higher queued network upgrades, and a reduced set of non-SPP projects included in the analysis (which were found to be electrically remote enough to exclude from the analysis).

I meant to say the following changes to the cases had been made:

(1) Included higher queued network upgrades
(2) Included electrically relevant projects
(3) Removed withdrawn generation
(4) Excluded electrically remote projects

While J611 – Maryville 161 kV was previously identified as a "non-AECI" thermal constraint, KCPL has pointed out that *any* constraint on the SPP transmission system caused by current study generation (not base case overloaded) requires mitigation. I had incorrectly categorized this constraint as not for mitigation because it was a KCPL-MEC constraint as opposed to a KCPL/WAPA-AECI constraint.

Table 6: Scenario 1 – ERIS Affected System (non-AECI) Thermal Constraints

Group	Season(s) Constraint Observed	MONT COMMONNAME	RATING	TDF	BC% LOADING	TC% LOADING	CONT NA
13ALL	26SP	'J611 161.00 - MARYVILLE 161KV CKT 1'	171	0.28978	64.51482	104.0337	'CRESTOI MARYVIL 161KV CI

From: Welniak, Jim <jwelniak@TENASKA.com>
Sent: Friday, March 15, 2019 2:28 PM
To: Alyssa Anderson <aanderson@spp.org>
Cc: Steve Purdy <spurdy@spp.org>; Staples, Boone <BStaples@tnsk.com>
Subject: **External Email** RE: ASGI-2018-001 (AECI GIA-61) Affected System Impact Restudy

Alyssa,

As noted in the prior versions of the ASGI-2018-001_LOIS reports it was noted that the 'J611 – Maryville 161 kV CKT 1' constraint was "found to be electrically remote enough to exclude from the analysis". Is that situation not applicable to the ASGI-2018-001 (AECI GIA-61) Affected System Impact Restudy?

Regards,
Jim Welniak

From: Alyssa Anderson <aanderson@spp.org>
Sent: Friday, March 15, 2019 1:51 PM
To: Welniak, Jim <jwelniak@TENASKA.com>
Cc: Steve Purdy <spurdy@spp.org>
Subject: ASGI-2018-001 (AECI GIA-61) Affected System Impact Restudy

****External Email. Use caution before opening attachments or clicking links.****

Mr. Welniak,

I realize we have already spoken in some detail regarding the J611 – Maryville 161 kV constraint, but I thought it might be beneficial to relay the information via email for your reference.

It has come to our attention that the J611 (MEC) – Maryville (KCPL) 161 kV constraint listed in Appendix A (Thermal Constraints for Mitigation) of the ASGI-2018-001 affected system impact restudy was not addressed in the report. This constraint becomes overloaded during the 2026 summer peak for the contingency of Creston – Maryville 161 kV line. This constraint requires mitigation as it is not overloaded in the base case and is constrained due to current study generation in the transfer case.

I have spoken with Katy Onen (KCPL) regarding the network upgrade required to mitigate the constraint per the study results. She has communicated that a reconductor would be necessary, but her team could not provide a cost estimate until early next week.

Katy and her team are still evaluating if the previous network upgrade assigned for the Maryville – Maryville 161 kV constraint is sufficient for need observed in the updated report.

SPP will update the impact study reports once SPP receives a cost estimate for the reconductor of J611 (MEC) – Maryville (KCPL) 161 kV. Simultaneously with the posting of the impact studies, SPP will request the facility study for the newly identified network upgrade.

Respectfully,

Alyssa Anderson
Engineer II, Generation Interconnection Studies
Southwest Power Pool
501-482-2379 | aanderson@spp.org

EXHIBIT 9:

March 2019 Results

AFFECTED SYSTEM IMPACT STUDY

ASGI-2018-001 (AECI GIA-61)

Published March 2019

By SPP Generator Interconnections Dept.

REVISION HISTORY

Date	Author	Change Description
10/5/2018	SPP	Affected System Impact Study for ASGI-2018-001 Report Revision 0 Issued
11/5/2018	SPP	Correction to Table 1. J476, a higher queued MISO request, was studied in the original report but was accidentally excluded from the report.
3/13/2019	SPP	Affected System Impact Restudy for ASGI-2018-001 Issued to account for addition in request capacity.
3/21/2019	SPP	J611 – Maryville 161 kV CKT 1 constraint cost allocated to GIA-61.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

AECI Interconnection Request GIA-61 has requested an Affected System Impact Study (ASIS) consistent with Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection into the system of Associated Electric Cooperative Inc. (AECI). GIA-61, a 242 MW[1] wind generating facility, has been assigned the SPP queue identifier ASGI-2018-001.

A restudy for ASGI-2018-001 was completed due to the addition of five (5) turbines totaling 12 MW to the GIA-61 project. The addition is considered as part of the project and has been incorporated as such. The project consists of 11 Vestas V110-2.0 MW and 100 Vestas V116-2.2 MW turbines for a total of 242[1] MW total capacity at the Maryville 161 kV substation in Nodaway County, MO.

The ASIS analysis has determined that several network upgrades will be required for ASGI-2018-001 to interconnect all 242[1] MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The required network upgrades identified have been outlined in **Table 11** of this report.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Transient stability analysis for this ASIS was not performed.

Nothing in this study should be construed as a guarantee of delivery or transmission service. If the customer(s) wishes to move power across the facilities of SPP, a separate request for transmission service must be made on Southwest Power Pool's OASIS by the Customer(s).

[1] While GIA-61 intends to limit the injection at the Point of Interconnection to 230 MW, SPP must study the full request at full capacity.

INTRODUCTION

PURPOSE

AECI Interconnection Request GIA-61 has requested an Affected System Impact Study (ASIS) consistent with Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection into the system of Associated Electric Cooperative Inc. (AECI).

A restudy for ASGI-2018-001 was completed due to the addition of five (5) turbines totaling 12 MW to the GIA-61 project. The addition is considered as part of the project and has been incorporated as such. The project consists of 11 Vestas V110-2.0 MW and 100 Vestas V116-2.2 MW turbines for a total of 242[1] MW total capacity at the Maryville 161 kV substation in Nodaway County, MO.

STUDY ASSUMPTIONS

The ASIS considers the Base Case as well as all Generating Facilities (and with respect to (b) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the ASIS is commenced:

a) are directly interconnected to the Transmission System;
b) are interconnected to Affected Systems and may have an impact on the Interconnection Request;
c) have a pending higher queued Interconnection Request to interconnect to the Transmission System;
d) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a re-study of this ASIS at the expense of the Customer(s).

Nothing within this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer(s) any right to receive transmission service rights. Should the Customer(s) require transmission service, those rights should be requested through SPP's Open Access Same-Time Information System (OASIS) or that of the applicable transmission provider.

This ASIS included prior queued generation interconnection requests. Requests listed within **Table 1 Table 2** are assumed to have either full or partial interconnection service prior to the requested in-service date for this ASIS.

POWER FLOW ANALYSIS

Power flow analysis was used to determine if the transmission system can accommodate the injection from the request without violating thermal or voltage transmission planning criteria.

MODEL SELECTION

Power flow analysis was performed using modified versions of the 2016 series of 2017 ITP Near-Term study models including these seasonal models:

- Year 1 (2017) Winter Peak (17WP)
- Year 2 (2018) Spring (18G)
- Year 2 (2018) Summer Peak (18SP)
- Year 5 (2021) Light (21L)
- Year 5 (2021) Summer (21SP)
- Year 5 (2021) Winter (21WP) peak
- Year 10 (2026) Summer (26SP) peak

BASE CASE NETWORK UPGRADES

The Network Upgrades included within the cases used for this ASIS are a part of the SPP Transmission Expansion Plan, Balanced Portfolio, or Integrated System (IS) Integration Study projects and have in-service dates prior to the customer's requested in-service date. These facilities have an approved Notification to Construct (NTC), or are in construction stages and expected to be in-service at the effective time of this study. Other upgrades included for this ASIS were higher queued network upgrades identified in Midcontinent ISO (MISO) studies. If for some reason, construction on these projects is delayed or discontinued, a restudy may be needed at the expense of the customer to determine the interconnection service availability of the Customer if construction on these projects is delayed or discontinued.Interconnection Requests Included in the Analysis

INTERCONNECTION REQUESTS INCLUDED IN THE ANALYSIS

HIGHER QUEUED SPP AND AECI REQUESTS

Table 1: Higher Queued Group 13 Requests

Generation Interconnection Number	GEN Area	PMAX	Service	Type	Status
GEN-2008-129	KCPL	80	ER	CT	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2010-036	WERE	5.9	ER	Hydro	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2011-011	KCPL	50	ER	Coal	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2014-021	KCPL	300	ER/NR	Wind	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2015-005	KCPL	200.1 1	ER	Wind	IA FULLY EXECUTED/COMMERCIAL OPERATION
ASGI-2016-003	KCPL	12	ER	Diesel	FACILITY STUDY STAGE
ASGI-2017-006[2]	AECI	238	ER/NR	Wind	AECI FACILITY STUDY STAGE

[2] **Excluded from Scenario 2 per study assumptions**

GEN-2016-088	KCPL	151.2	ER/NR	Wind	FACILITY STUDY STAGE
GEN-2016-115	KCPL	300	ER	Wind	FACILITY STUDY STAGE
GEN-2016-149	WERE	302	ER	Wind	FACILITY STUDY STAGE
GEN-2016-150	WERE	302	ER	Wind	FACILITY STUDY STAGE
GEN-2016-157	KCPL	252	ER	Wind	FACILITY STUDY STAGE
GEN-2016-158	KCPL	252	ER	Wind	FACILITY STUDY STAGE
GEN-2016-174	WERE	302	ER	Wind	FACILITY STUDY STAGE
GEN-2016-176	WERE	302	ER	Wind	FACILITY STUDY STAGE

HIGHER QUEUED MISO REQUESTS

Table 2: Higher Queued MISO Requests

Study	Gen Name	ERIS PMAX (MW)	NRIS PMAX (MW)	Service	Group	Type	Status
DIS-12-2-PQ	H081	201	0	ER	15 E-SD	Wind	Done
DIS-13-1-PQ	G858-H081	78	78	NR	15 E-SD	Wind	Done
DIS-14-2-PQ	J285	250	250	NR	09 NEB	Wind	Done
DIS-14-2-PQ	J343	150	150	NR	09 NEB	Wind	Done
DIS-14-2-PQ	J344	168	168	NR	09 NEB	Wind	Done
DIS-14-2-PQ	J316	150	150	NR	16 W-ND	Wind	Done
DIS-15-1-PQ	J411	300	300	NR	09 NEB	Wind	Done
DIS-15-1-PQ	J416	200.5	200.5	NR	09 NEB	Wind	Done
DIS-15-1-PQ	G736	200	200	NR	15 E-SD	Wind	Done
DIS-15-1-PQ	J385	100	100	NR	15 E-SD	Solar	Done
DIS-15-1-PQ	J391	50	50	NR	15 E-SD	Gas	Done
DIS-15-1-PQ	J400	62	62	NR	15 E-SD	Solar	Done
DIS-15-1-PQ	J407	200	200	NR	15 E-SD	Wind	Done
DIS-15-1-PQ	J426	100	100	NR	15 E-SD	Wind	Done
DIS-15-2-PQ	J412	200	200	NR	09 NEB	Wind	Done
DIS-15-2-PQ	J438	167	167	NR	09 NEB	Wind	Done
DIS-15-2-PQ	J455	294.8	0	ER	09 NEB	Wind	Done
DIS-15-2-PQ	J436	150	0	ER	15 E-SD	Wind	Done
DIS-15-2-PQ	J437	150	0	ER	15 E-SD	Wind	Done
DIS-15-2-PQ	J442	200	200	NR	15 E-SD	Wind	Done
DIS-16-1-PQ	J499	340	340	NR	09 NEB	Wind	Active
DIS-16-1-PQ	J500	500	500	NR	09 NEB	Wind	Active
DIS-16-1-PQ	J527	250	250	NR	09 NEB	Wind	Active
DIS-16-1-PQ	J528	200	200	NR	09 NEB	Wind	Active
DIS-16-2-PQ	J583	200	200	NR	09 NEB	Wind	Active
DIS-16-2-PQ	J611	110	110	NR	13 NE-KS & NW-MO	Wind	Active
DIS-16-2-PQ	J476	246	246	NR	13 NE-KS & NW-MO	Wind	Active
DIS-17-1-PQ	J570	150	150	NR	13 NE-KS & NW-MO	Wind	Active

CURRENT STUDY AECI REQUESTS

Table 3: Current Study Requests

Generation Interconnection Number	GEN Area	PMAX	Service	Group	Type	Status
ASGI-2018-001	AECI	230	ER/NR	13 NE-KS & NW-MO	Wind	CURRENT STUDY

All upgrades assigned by SPP will require an Affected System Facilities Study agreement and deposit. These upgrades may require a Construction Agreement (CA) as a result of the Affected System Facilities Study.

Any changes to these assumptions may require a restudy of this ASIS at the expense of the Customer(s).

Posted SPP affected system reports can be located at the following Generation Interconnection Study URL: http://opsportal.spp.org/Studies/Gen

DISPATCH OF REQUESTS

SPP & AECI REQUESTS

Please refer to **Table 4** for an overview of SPP dispatch criteria.

Table 4: SPP GIR Power Flow Fuel Type Dispatch

Dispatch Type	Season	Service Type	Renewable (in group)	Renewable (out of group)	Conventional (in group)	Conventional (out of group)
ERIS HVER	All	All	100%	20%	N/A	N/A
ERIS LVER	Peak	All	20%	20%	100%	100%
NRIS HVER	Spring and Light Load	ERIS	80%	20%	N/A	N/A
		NRIS	100%	20%	100%	20%
NRIS LVER	Peak	ERIS	20%[3]	20%[2]	80%	80%
		NRIS	100%	100%	100%	100%

For Variable Energy Resources (VER) (solar/wind) in each power flow case, Energy Resource Interconnection Service (ERIS), is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas is dispatched at 20% nameplate of maximum generation. SPP projects are dispatched across the SPP footprint using load factor ratios.

Peaking units are not dispatched in the Year 2 spring and Year 5 light, or in the "High VER" summer and winter peaks. To study peaking units' impacts, the Year 1 winter peak, Year 2 summer peak, and Year 5 summer and winter peaks, models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

All SPP generators (VER and peaking) that requested Network Resource Interconnection Service (NRIS) are dispatched in an additional analysis into the interconnecting Transmission Owner's (T.O.) area at 100% nameplate with Energy Resource Interconnection Service (ERIS) only requests at 80% nameplate. All affected system generators (VER and peaking) that requested Network Resource Interconnection Service (NRIS) are dispatched based on their respective NRIS amounts in an additional

[3] Solar in SP 80%

analysis into the direct connect transmission system. This method allows for identification of network constraints that are common between regional groupings and have affecting requests share the mitigating upgrade costs throughout the cluster.

MISO REQUESTS

To incorporate higher queued MISO interconnection requests, a re-dispatch of existing generation within MISO was performed with respect to the amount of the Customers' injection. **Table 5** outlines the dispatch of MISO requests in the SPP models.

MISO projects are dispatched across the SPP footprint using load factor ratios. All MISO generation dispatched by SPP was sunk to the MISO Classic (West) footprint, whether ERIS or NRIS.

Table 5: Dispatch of MISO Requests in SPP Models

Dispatch Type	Season	Service Type	Renewable (in group)	Renewable (out of group)	Conventional (in group)	Conventional (out of group)
ERIS HVER	All	All	100%	20%	N/A	N/A
ERIS LVER	Peak	All	20%	20%	100%	100%
NRIS	Spring and Light Load	ERIS	Off	Off	Off	Off
		NRIS	100%	20%	100%	20%
	Peak	ERIS	Off	Off	Off	Off
		NRIS	100%	100%	100%	100%

HVER – High Variable Energy Resource Dispatch
LVER – Low Variable Energy Resource Dispatch
N/A – units are not dispatched up from base case amounts
Renewable – Includes wind, solar, and storage
Conventional – Includes nuclear, hydro, coal, cc, CT, oil, waste heat

TRANSMISSION REINFORCEMENT MITIGATION CRITERIA

THERMAL OVERLOADS

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously mentioned.

For ERIS, thermal overloads are determined for system intact (n-0) (greater than or equal to 100% of Rate A - normal) and for contingency (n-1) (greater than or equal to 100% of Rate B – emergency) conditions.

The overloads are then screened to determine which of generator interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage based conditions (n-1),
- or 3% DF on contingent elements that resulted in a non-converged solution.

Interconnection Requests that requested NRIS are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also considered for transmission reinforcement under NRIS.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution Flowgates for SPP and first tier Non-SPP control area are monitored. Additional NERC Flowgates are monitored in second tier or greater Non-SPP control areas. Voltage monitoring was performed for SPP control area buses 69 kV and above.

VOLTAGE

For non-converged power flow solutions that are determined to be caused by lack of voltage support, appropriate transmission support will be determined to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

Table 6: SPP Areas (69kV+):

Transmission Owner	**Voltage Criteria (System Intact)**	**Voltage Criteria (Contingency)**
AEPW	0.95 – 1.05 pu	0.92 – 1.05 pu
GRDA	0.95 – 1.05 pu	0.90 – 1.05 pu
SWPA	0.95 – 1.05 pu	0.90 – 1.05 pu
OKGE	0.95 – 1.05 pu	0.90 – 1.05 pu
OMPA	0.95 – 1.05 pu	0.90 – 1.05 pu
WFEC	0.95 – 1.05 pu	0.90 – 1.05 pu
SWPS	0.95 – 1.05 pu	0.90 – 1.05 pu
MIDW	0.95 – 1.05 pu	0.90 – 1.05 pu
SUNC	0.95 – 1.05 pu	0.90 – 1.05 pu
KCPL	0.95 – 1.05 pu	0.90 – 1.05 pu
INDN	0.95 – 1.05 pu	0.90 – 1.05 pu
SPRM	0.95 – 1.05 pu	0.90 – 1.05 pu
NPPD	0.95 – 1.05 pu	0.90 – 1.05 pu
WAPA	0.95 – 1.05 pu	0.90 – 1.05 pu
WERE L-V	0.95 – 1.05 pu	0.93 – 1.05 pu
WERE H-V	0.95 – 1.05 pu	0.95 – 1.05 pu
EMDE L-V	0.95 – 1.05 pu	0.90 – 1.05 pu
EMDE H-V	0.95 – 1.05 pu	0.92 – 1.05 pu
LES	0.95 – 1.05 pu	0.90 – 1.05 pu
OPPD	0.95 – 1.05 pu	0.90 – 1.05 pu

Table 7: SPP Buses with more stringent voltage criteria

Bus Name/Number	**Voltage Criteria (System Intact)**	**Voltage Criteria (Contingency)**
TUCO 230kV 525830	0.925 – 1.05 pu	0.925 – 1.05 pu
Wolf Creek 345kV 532797	0.985 – 1.03 pu	0.985 – 1.03 pu
FCS 646251	1.001 – 1.047 pu	1.001 – 1.047 pu

Table 8: Affected System Areas (115kV+):

Transmission Owner	**Voltage Criteria (System Intact)**	**Voltage Criteria (Contingency)**
AECI	0.95 – 1.05 pu	0.90 – 1.05 pu
EES-EAI	0.95 – 1.05 pu	0.90 – 1.05 pu
LAGN	0.95 – 1.05 pu	0.90 – 1.05 pu

EES	0.95 – 1.05 pu	0.90 – 1.05 pu
AMMO	0.95 – 1.05 pu	0.90 – 1.05 pu
CLEC	0.95 – 1.05 pu	0.90 – 1.05 pu
LAFA	0.95 – 1.05 pu	0.90 – 1.05 pu
LEPA	0.95 – 1.05 pu	0.90 – 1.05 pu
XEL	0.95 – 1.05 pu	0.90 – 1.05 pu
MP	0.95 – 1.05 pu	0.90 – 1.05 pu
SMMPA	0.95 – 1.05 pu	0.90 – 1.05 pu
GRE	0.95 – 1.05 pu	0.90 – 1.10 pu
OTP	0.95 – 1.05 pu	0.90 – 1.05 pu
OTP-H (115kV+)	0.97 – 1.05 pu	0.92 – 1.10 pu
ALTW	0.95 – 1.05 pu	0.90 – 1.05 pu
MEC	0.95 – 1.05 pu	0.90 – 1.05 pu
MDU	0.95 – 1.05 pu	0.90 – 1.05 pu
SPC	0.95 – 1.05 pu	0.95 – 1.05 pu
DPC	0.95 – 1.05 pu	0.90 – 1.05 pu
ALTE	0.95 – 1.05 pu	0.90 – 1.05 pu

The constraints identified through the voltage scan are then screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage. In certain conditions, engineering judgement was used to determine whether or not a generator had impacts to voltage constraints.

CURTAILMENT AND SYSTEM RELIABILITY

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. It is likely that the Customer(s) may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

FACILITIES

GENERATING FACILITY

The 242[1] MW wind generation facility was studied using 11 Vestas V110-2.0 MW and 100 Vestas V116-2.2 MW turbines for the Affected System Impact Restudy. The generator step-up transformer and collector substation transformer were modeled per AECI provided parameters.

INTERCONNECTION FACILITIES

The ASGI-2018-001 Interconnection Customer has requested a connection to AECI via the Maryville 161 kV substation in Nodaway County, MO. The higher queued AECI GIA-053 request (ASGI-2017-006) shares this POI.

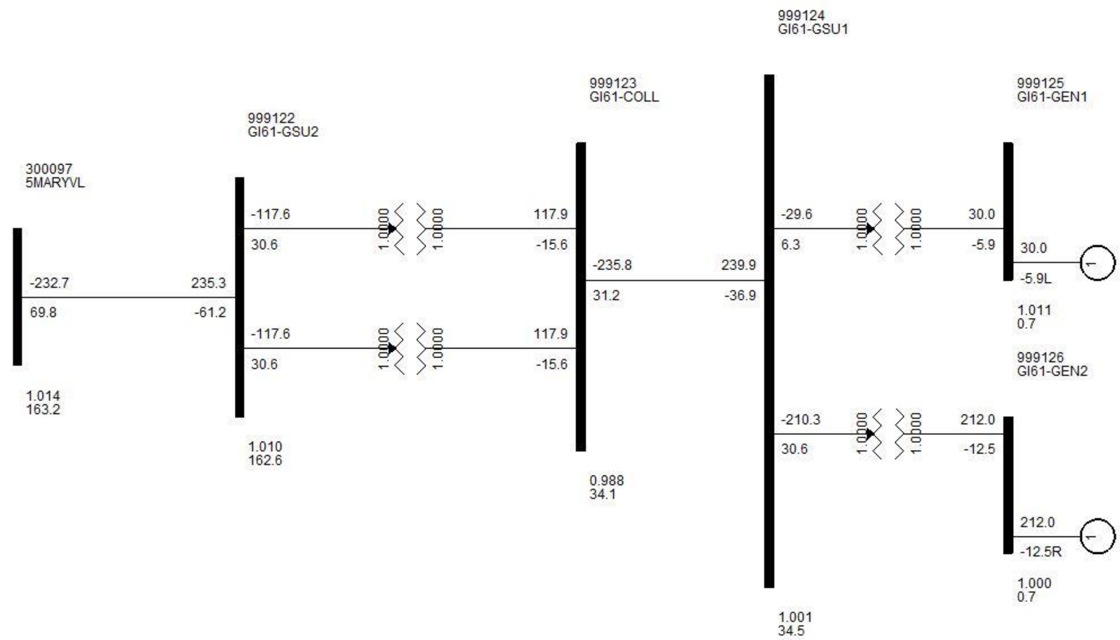


Figure 1: SPP Affected System Impact Study Power Flow Configuration

RESULTS

The ASIS analysis has determined that several network upgrades will be required for ASGI-2018-001 to interconnect all 242[1] MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). **Table 9** outlines the network upgrades identified by AECI. Please refer to the AECI facility study reports for upgrade details and costs. **Table 10** details the most severe ERIS constraints observed in all seasons and provides the MW amount GIA-61 would need to reduce to in order to eliminate the need for the associated network upgrade, listed in **Table 11**.

Table 9: AECI Assigned Network Upgrades

Upgrade Description	**Est. In-Service**
Upgrade Maryville transformer 161/69 kV #1 to 56 MVA	Summer 2020
Uprate Fairport – Darlington 69 kV to 100 C (12.5 mi)	Summer 2020
Uprate Darlington – Stanberry 69 kV to 100 C (10.22 mi)	Summer 2020
Rebuild Gentry – Fairport with 1192 ACSR, 100 C (9.901 mi)	Summer 2021
Rebuild Nodaway – Gentry section 2 with 1192 ACST, 100 C (200.65 mi)	Summer 2021

Table 10: Most Severe Scenario 1 ERIS Constraints

Season	**Constraint**	**From Area**	**To Area**	**Rating**	**TDF**	**BC % Loading**	**TC % Loading**	**MVA Needed**	**MW Available (Reduce to Eliminate Constraint)**	**Contingency**
26SP	'CRESTON - MARYVILLE 161KV CKT 1'	AECI	WAPA	208	0.30336	79.45205	113.9291	237	146	'MARYVILLE - MARYVILLE 161KV CKT 1'
26SP	J611 161.00 - MARYVILLE 161KV CKT 1	KCPL	MEC	171	0.28977	65.23734	106.3776	182	204	'CRESTON - MARYVILLE 161KV CKT 1'
26SP	'MARYVILLE - MARYVILLE 161KV CKT 1'	AECI	KCPL	229	0.53501	98.45406	152.0506	349	19	'CRESTON - MARYVILLE 161KV CKT 1'

Table 11: SPP Assigned Network Upgrades

Upgrade Description	**Cost Estimate[4]**	**Est. In-Service**
Rebuild Maryville – Maryville 161 kV (KCPL)	$1,417,500	Summer 2020[5]
Reconductor Creston – Maryville 161 kV (WAPA)	$14,900,000	Winter 2021[6]
Reconductor J611 – Maryville 161 kV (KCPL)	$16,700,000	TBD

No NRIS thermal constraints were observed.

No ERIS or NRIS voltage constraints were observed.

[4] Cost estimates are subject to change, pending affected system facility study reevaluation
[5] According to good business practice, the KCP&L engineering and procurement process cannot begin until the parties have executed a mutually agreeable Engineering & Construction Agreement.
[6] Subject to execution of facilities construction agreement, advance funding being provided, outage availability, and completion of an Environmental Review prior to the start of construction.

Constraints listed in **Appendix B** do not require additional transmission reinforcement for Interconnection Service, but could require Interconnection Customer to reduce generation in operational conditions. These transmission constraints occur when this study's generation is dispatched into the AECI footprint for ERIS and NRIS.

CONCLUSION

AECI Interconnection Request GIA-61 has requested an Affected System Impact Study (ASIS) consistent with Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection into the system of Associated Electric Cooperative Inc. (AECI). GIA-61, a 242[1] MW wind generating facility, has been assigned the SPP queue identifier ASGI-2018-001.

SPP has conducted this ASIS restudy to reevaluate potential impacts to the SPP Transmission System related to the interconnection of generators on the AECI Transmission System. ASGI-2018-001 is requesting the interconnection of 100 Vestas V120-2.2 MW and 11 Vestas V110-2.0 MW turbines for a total of 242[1] MW total capacity at the Maryville 161 kV substation in Nodaway County, MO.

The ASIS analysis has determined that several network upgrades will be required for ASGI-2018-001 to interconnect all 242[1] MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The required network upgrades identified have been outlined in **Table 11** of this report.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Transient stability analysis was not completed for this ASIS.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a re-study of this ASIS at the expense of the Customer.

Nothing in this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service.

APPENDIX A-T: THERMAL CONSTRAINTS FOR MITIGATION

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CRESTON - MARYVILLE 161KV CKT 1'	208	208	0.30336	79.45205	113.9291	MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CRESTON - MARYVILLE 161KV CKT 1'	208	208	0.30336	79.45205	113.9291	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CRESTON - MARYVILLE 161KV CKT 1'	208	208	0.3034	74.2732	108.0624	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CRESTON - MARYVILLE 161KV CKT 1'	208	208	0.3034	74.2732	108.0624	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CRESTON - MARYVILLE 161KV CKT 1'	208	208	0.22562	79.89336	105.5322	'CLARINDA - J611 161.00 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CRESTON - MARYVILLE 161KV CKT 1'	208	208	0.22564	75.5481	100.8723	'CLARINDA - J611 161.00 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	J611 161.00 - MARYVILLE 161KV CKT 1'	152	171	0.28977	65.23734	106.3776	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'J611 161.00 - MARYVILLE 161KV CKT 1'	152	171	0.28977	65.23734	106.3776	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'J611 161.00 - MARYVILLE 161KV CKT 1'	152	171	0.22491	71.66108	101.1567	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'J611 161.00 - MARYVILLE 161KV CKT 1'	152	171	0.32715	54.15165	100.169	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	System Intact
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	-9999	9999	''P11:345:OPPD:NEBCTY1G''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	-9999	9999	''P11:345:OPPD:NEBCTY1G''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.652	93.74796	158.3756	FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.652	93.74796	158.3756	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.652	92.19286	156.9834	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.652	92.19286	156.9834	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53501	98.45406	152.0506	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53501	98.45406	152.0506	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53501	98.45406	152.0506	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53501	98.45406	152.0506	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65196	82.42882	146.8043	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65196	82.42882	146.8043	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65196	80.89707	145.4065	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65196	80.89707	145.4065	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.535	90.28297	143.8177	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.535	90.28297	143.8177	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.535	90.28297	143.8177	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.535	90.28297	143.8177	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53377	73.22704	130.1721	CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53377	73.22704	130.1721	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53377	73.22704	130.1721	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53377	73.22704	130.1721	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.5345	72.9738	130.0825	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.5345	72.9738	130.0825	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.5345	72.9738	130.0825	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.5345	72.9738	130.0825	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	85.598	128.6286	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	85.598	128.6286	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65256	55.0605	123.1425	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65256	55.0605	123.1425	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	18SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53441	65.65626	122.9352	CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	18SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53441	65.65626	122.9352	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	79.19566	122.4146	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	79.19566	122.4146	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65136	51.93092	121.1272	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65136	51.93092	121.1272	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65184	51.05003	120.4549	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65184	51.05003	120.4549	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65256	49.42321	118.2194	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65256	49.42321	118.2194	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65256	49.39995	118.1625	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65256	49.39995	118.1625	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45305	72.20605	116.9694	'MARYVILLE 161/69KV TRANSFORMER CKT 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45305	72.20605	116.9694	'MARYVILLE 161/69KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65163	47.06892	115.9076	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65163	47.06892	115.9076	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65136	46.22759	115.7661	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65136	46.22759	115.7661	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	72.63326	115.7645	'GEN635024 4-WALTER SCOTT UNIT 4'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	72.63326	115.7645	'GEN635024 4-WALTER SCOTT UNIT 4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65136	46.1968	115.7055	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65136	46.1968	115.7055	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39865	75.87371	115.5135	'COUNCIL BLUFFS - RIVER BEND 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39865	75.87371	115.5135	'COUNCIL BLUFFS - RIVER BEND 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53379	59.1344	115.4125	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53379	59.1344	115.4125	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53379	59.1344	115.4125	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53379	59.1344	115.4125	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	72.06203	115.1789	'GEN635023 3-WALTER SCOTT UNIT 3'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	72.06203	115.1789	'GEN635023 3-WALTER SCOTT UNIT 3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44465	71.88763	115.1551	'FAIRPORT - OSBORN 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44465	71.88763	115.1551	'FAIRPORT - OSBORN 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65184	45.36699	115.0636	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65184	45.36699	115.0636	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65184	45.33529	115.0004	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65184	45.33529	115.0004	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65163	45.64099	114.6323	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65163	45.64099	114.6323	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65163	45.61599	114.5737	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65163	45.61599	114.5737	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	18SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65248	44.92714	114.4862	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	18SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65248	44.92714	114.4862	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44458	70.91499	114.2479	'5REX 161.00 - OSBORN 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44458	70.91499	114.2479	'5REX 161.00 - OSBORN 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65196	44.29164	114.1797	'MARYVILLE - NODAWAY 161KV CKT 1'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65196	44.29164	114.1797	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39865	74.49845	114.1151	'BUNGE - RIVER BEND 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39865	74.49845	114.1151	'BUNGE - RIVER BEND 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44458	70.51817	113.876	'5MPLTAP 161.00 - 5REX 161.00 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44458	70.51817	113.876	'5MPLTAP 161.00 - 5REX 161.00 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44278	70.60353	113.8652	'FAIRPORT - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44278	70.60353	113.8652	'FAIRPORT - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43694	71.0454	113.8508	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43694	71.0454	113.8508	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43968	70.60006	113.7734	''P23:345:OPPD:S3456-S3459&T4''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43968	70.60006	113.7734	''P23:345:OPPD:S3456-S3459&T4''
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43983	70.49049	113.6529	''P23:345:OPPD:S3458-MULLNCR' '
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43983	70.49049	113.6529	''P23:345:OPPD:S3458-MULLNCR' '
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43971	70.33579	113.5041	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43971	70.33579	113.5041	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43971	70.33579	113.5041	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43971	70.33579	113.5041	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43983	70.2356	113.411	''P23:345:OPPD:S3456-S3455''
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43983	70.2356	113.411	''P23:345:OPPD:S3456-S3455''
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43983	70.17307	113.3465	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43983	70.17307	113.3465	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43983	70.17307	113.3465	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43983	70.17307	113.3465	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	18SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65248	43.46441	113.1007	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	18SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65248	43.46441	113.1007	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43959	69.90481	113.0643	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43959	69.90481	113.0643	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43959	69.90481	113.0643	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43959	69.90481	113.0643	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	18SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65248	43.44195	113.0448	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	18SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.65248	43.44195	113.0448	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44458	69.53422	113.0399	'5MPLTAP 161.00 - LATHROP 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44458	69.53422	113.0399	'5MPLTAP 161.00 - LATHROP 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.82461	113.039	'SHERBURNE CO 345/26.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.82461	113.039	'SHERBURNE CO 345/26.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.91933	112.9875	''P22:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.91933	112.9875	''P22:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.91933	112.9875	''P23:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.91933	112.9875	''P23:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43766	70.17445	112.8452	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43766	70.17445	112.8452	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.66196	112.7897	'GEN645012 2-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.66196	112.7897	'GEN645012 2-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.61571	112.7334	'GEN645011 1-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.61571	112.7334	'GEN645011 1-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.51382	112.6856	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.51382	112.6856	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.50645	112.677	'MONTICELLO 345/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	69.50645	112.677	'MONTICELLO 345/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44591	69.16935	112.6628	'MCKSBRG 3 161.00 - WINTER SET JUNCTION 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44591	69.16935	112.6628	'MCKSBRG 3 161.00 - WINTER SET JUNCTION 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2217-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2217-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2564-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2564-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2604-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2604-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2606-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	'2606-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	111.3563	System Intact
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45304	65.68601	110.1429	'MARYVILLE 161/69KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.45304	65.68601	110.1429	'MARYVILLE 161/69KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53564	53.89311	110.0614	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53564	53.89311	110.0614	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53564	53.89311	110.0614	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.53564	53.89311	110.0614	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43945	63.93917	110.0413	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43945	63.93917	110.0413	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43932	66.8858	110.0114	''P23:345:WERE:STRA_345-100::''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43932	66.8858	110.0114	''P23:345:WERE:STRA_345-100::''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4399	67.10977	109.9493	''P55:345:GMO:SIBLEY_BUS_11:VALID PRIOR TO 6''
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4399	67.10977	109.9493	''P55:345:GMO:SIBLEY_BUS_11:VALID PRIOR TO 6''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	67.11488	109.9219	'GEN335831 1-RIVERBEND UNIT#1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	67.11488	109.9219	'GEN335831 1-RIVERBEND UNIT#1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43932	66.91331	109.8873	''P55:345:KCPL:HAWTHORN_BUS_20''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43932	66.91331	109.8873	''P55:345:KCPL:HAWTHORN_BUS_20''
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	67.03553	109.832	'GEN336153 1-WATERFORD UNIT#3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	67.03553	109.832	'GEN336153 1-WATERFORD UNIT#3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43895	66.64028	109.4896	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43895	66.64028	109.4896	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43895	66.64028	109.4896	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43895	66.64028	109.4896	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43982	66.46594	109.4715	'ARBR HL 3 345.00 - FALLOW 3 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43982	66.46594	109.4715	'ARBR HL 3 345.00 - FALLOW 3 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43892	66.60703	109.4541	''P23:345:OPPD:S3456-S3458&T4''
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43892	66.60703	109.4541	''P23:345:OPPD:S3456-S3458&T4''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	66.68516	109.4258	'GEN336821 1-GRAND GULF UNIT'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	66.68516	109.4258	'GEN336821 1-GRAND GULF UNIT'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	66.39663	109.4145	'GEN635024 4-WALTER SCOTT UNIT 4'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	66.39663	109.4145	'GEN635024 4-WALTER SCOTT UNIT 4'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	66.2353	109.2781	'THOMAS HILL 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	66.2353	109.2781	'THOMAS HILL 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43916	63.17028	109.2504	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	17WP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43916	63.17028	109.2504	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43982	66.10162	109.1237	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43982	66.10162	109.1237	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44426	65.35659	109.0583	''P42:345:NPPD:BKR-CPR-3322''
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44426	65.35659	109.0583	''P42:345:NPPD:BKR-CPR-3322''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44426	65.34589	109.0461	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44426	65.34589	109.0461	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44426	65.34589	109.0461	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44426	65.34589	109.0461	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	65.82553	108.9636	'GEN300003 1-THOMAS HILL UNIT 3'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	65.82553	108.9636	'GEN300003 1-THOMAS HILL UNIT 3'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43959	66.15941	108.8332	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43959	66.15941	108.8332	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	65.83976	108.8299	'GEN635023 3-WALTER SCOTT UNIT 3'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	65.83976	108.8299	'GEN635023 3-WALTER SCOTT UNIT 3'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39866	69.22877	108.6819	'COUNCIL BLUFFS - RIVER BEND 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39866	69.22877	108.6819	'COUNCIL BLUFFS - RIVER BEND 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	65.9633	108.65	'GEN344225 1-1CAL G1 25.000'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	65.9633	108.65	'GEN344225 1-1CAL G1 25.000'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44464	65.48912	108.6133	'FAIRPORT - OSBORN 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44464	65.48912	108.6133	'FAIRPORT - OSBORN 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43693	65.12086	107.9433	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43693	65.12086	107.9433	'EASTOWN7 345.00 (EASTOWN 345) 345/161/13.8KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44457	64.5399	107.7172	'5REX 161.00 - OSBORN 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44457	64.5399	107.7172	'5REX 161.00 - OSBORN 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44277	64.58263	107.5948	'FAIRPORT - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44277	64.58263	107.5948	'FAIRPORT - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43967	64.49294	107.5069	''P23:345:OPPD:S3456-S3459&T4''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43967	64.49294	107.5069	''P23:345:OPPD:S3456-S3459&T4''
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44457	64.16312	107.3552	'5MPLTAP 161.00 - 5REX 161.00 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44457	64.16312	107.3552	'5MPLTAP 161.00 - 5REX 161.00 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43981	64.34547	107.3378	''P23:345:OPPD:S3458-MULLNCR' '
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43981	64.34547	107.3378	''P23:345:OPPD:S3458-MULLNCR' '
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39866	67.89876	107.3073	'BUNGE - RIVER BEND 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39866	67.89876	107.3073	'BUNGE - RIVER BEND 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43969	64.2432	107.2406	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43969	64.2432	107.2406	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43969	64.2432	107.2406	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43969	64.2432	107.2406	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43981	64.09819	107.0933	''P23:345:OPPD:S3456-S3455''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43981	64.09819	107.0933	''P23:345:OPPD:S3456-S3455''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43981	64.03698	107.0292	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43981	64.03698	107.0292	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43981	64.03698	107.0292	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43981	64.03698	107.0292	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43765	64.33198	106.9086	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43765	64.33198	106.9086	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43958	63.81206	106.791	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43958	63.81206	106.791	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43958	63.81206	106.791	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43958	63.81206	106.791	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.77172	106.6633	''P22:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.77172	106.6633	''P22:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.77172	106.6633	''P23:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.77172	106.6633	''P23:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.63222	106.6596	'SHERBURNE CO 345/26.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.63222	106.6596	'SHERBURNE CO 345/26.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44457	63.25202	106.5581	'5MPLTAP 161.00 - LATHROP 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44457	63.25202	106.5581	'5MPLTAP 161.00 - LATHROP 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44587	63.11849	106.4614	'MCKSBRG 3 161.00 - WINTER SET JUNCTION 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44587	63.11849	106.4614	'MCKSBRG 3 161.00 - WINTER SET JUNCTION 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.51014	106.4451	'GEN645012 2-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.51014	106.4451	'GEN645012 2-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43628	64.01561	106.4285	'ST JOE (STJOE T1) 345/161/13.8KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43628	64.01561	106.4285	'ST JOE (STJOE T1) 345/161/13.8KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4363	64.0061	106.4211	'ST JOE (STJOE T2) 345/161/13.8KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4363	64.0061	106.4211	'ST JOE (STJOE T2) 345/161/13.8KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.46476	106.3909	'GEN645011 1-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.46476	106.3909	'GEN645011 1-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.33895	106.3138	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	63.33895	106.3138	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	105.5306	'GEN999125 1-GI61-GEN1 0.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43992	68.33688	105.5306	'GEN999125 1-GI61-GEN1 0.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39831	66.02423	105.4178	'CLARINDA - HASTINGS 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.39831	66.02423	105.4178	'CLARINDA - HASTINGS 161KV CKT 1'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2217-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2217-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2564-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2564-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2604-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2604-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2606-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	62.22908	105.0328	'2606-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43989	60.80931	103.7964	''P55:345:GMO:SIBLEY_BUS_11:VALID PRIOR TO 6''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43989	60.80931	103.7964	''P55:345:GMO:SIBLEY_BUS_11:VALID PRIOR TO 6''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4583	59.22162	103.7297	'FAIRPORT - ST JOE 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4583	59.22162	103.7297	'FAIRPORT - ST JOE 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4583	59.22162	103.7297	'FAIRPORT - ST JOE 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4583	59.22162	103.7297	'FAIRPORT - ST JOE 345KV CKT 1'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	61.07829	103.6768	'GEN335831 1-RIVERBEND UNIT#1'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	61.07829	103.6768	'GEN335831 1-RIVERBEND UNIT#1'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	61.06245	103.6318	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	61.06245	103.6318	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	61.00392	103.5891	'GEN336153 1-WATERFORD UNIT#3'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	61.00392	103.5891	'GEN336153 1-WATERFORD UNIT#3'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43931	60.79401	103.5236	''P55:345:KCPL:HAWTHORN_BUS_20''
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43931	60.79401	103.5236	''P55:345:KCPL:HAWTHORN_BUS_20''
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43893	60.82464	103.4367	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43893	60.82464	103.4367	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43893	60.82464	103.4367	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43893	60.82464	103.4367	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4389	60.79855	103.4076	''P23:345:OPPD:S3456-S3458&T4''
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.4389	60.79855	103.4076	''P23:345:OPPD:S3456-S3458&T4''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43982	60.63492	103.3838	'ARBR HL 3 345.00 - FALLOW 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43982	60.63492	103.3838	'ARBR HL 3 345.00 - FALLOW 3 345.00 345KV CKT 1'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	60.66751	103.1954	'GEN336821 1-GRAND GULF UNIT'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	60.66751	103.1954	'GEN336821 1-GRAND GULF UNIT'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44425	59.46183	103.0765	''P42:345:NPPD:BKR-CPR-3322''
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44425	59.46183	103.0765	''P42:345:NPPD:BKR-CPR-3322''
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44425	59.4511	103.062	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44425	59.4511	103.062	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44425	59.4511	103.062	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.44425	59.4511	103.062	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43982	60.26226	103.0272	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43982	60.26226	103.0272	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	60.20711	102.9833	'THOMAS HILL 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	60.20711	102.9833	'THOMAS HILL 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43958	60.03843	102.7322	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43958	60.03843	102.7322	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	59.78932	102.7223	'GEN300003 1-THOMAS HILL UNIT 3'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	59.78932	102.7223	'GEN300003 1-THOMAS HILL UNIT 3'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	59.92558	102.4507	'GEN344225 1-1CAL G1 25.000'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43991	59.92558	102.4507	'GEN344225 1-1CAL G1 25.000'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43934	54.95275	100.6197	'GEN 86115 1-J611 G 0.6900'
FDNS	13ALL	0	18G	ASGI_18_01	'FROM->TO'	'MARYVILLE - MARYVILLE 161KV CKT 1'	229	229	0.43934	54.95275	100.6197	'GEN 86115 1-J611 G 0.6900'

APPENDIX B-T: THERMAL CONSTRAINTS NOT FOR MITIGATION

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	-9999	9999	''P11:161:OPPD:N OMA 5G''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	-9999	9999	''P11:345:OPPD:NEBCTY1G''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	-9999	9999	''P11:345:OPPD:NEBCTY1G''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	-9999	9999	''P11:161:OPPD:N OMA 5G''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	-9999	9999	''P11:345:OPPD:NEBCTY1G''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	-9999	9999	''P11:161:OPPD:N OMA 5G''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	-9999	9999	''P11:345:OPPD:NEBCTY1G''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	-9999	9999	''P11:161:OPPD:N OMA 5G''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	-9999	9999	''P11:345:OPPD:NEBCTY1G''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.29097	96.47076	134.8137	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.29097	96.47076	134.8137	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2841	98.30142	134.2683	'MARYVILLE - MIDWAY 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32617	89.76637	132.5273	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.327	89.63885	132.4665	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2841	95.54444	131.5582	'AVENUECTY 5 161.00 - MIDWAY 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2841	95.13544	131.1374	'AVENUECTY 5 161.00 - MIDWAY TAP 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2841	95.13528	131.1337	'MIDWAY TAP - ST JOE 161KV CKT Z1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32776	85.70175	130.1967	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	97.02798	129.8302	System Intact
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	96.78891	129.7944	System Intact
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28767	91.90267	129.3567	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28767	91.90267	129.3567	'CRESTON - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32776	84.88715	129.2471	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32776	84.85543	129.2443	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.327	85.92039	129.0172	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.327	85.90862	129.0111	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32617	86.06403	129.0005	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32617	86.05434	128.9948	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	99.964	128.5385	'J475 POI 345.00 - ORIENT 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22443	99.9869	128.3834	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22443	99.9869	128.3834	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22468	99.89574	128.3045	''P23:345:OPPD:S3458-MULLNCR' '
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	99.80079	128.2675	'SHERBURNE CO 345/26.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22468	99.52419	127.9436	''P23:345:OPPD:S3456-S3455''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22468	99.38741	127.8108	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22468	99.38741	127.8108	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	99.14206	127.2047	'2217-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	99.14206	127.2047	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	99.14206	127.2047	'2564-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	99.14206	127.2047	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	99.14206	127.2047	'2604-NEBRASKA CITY 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	99.14206	127.2047	'2606-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	98.58014	127.0412	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	98.54577	127.0067	'MONTICELLO 345/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	98.22473	126.7433	'OTTUMWA 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	98.20798	126.6767	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22455	98.08901	126.4808	'7MAYWOOD 345.00 - 7SPENCER 345.00 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32569	83.70074	126.2804	'FAIRPORT - HARVIEL E 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	97.8265	126.2799	'GEN645012 2-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	97.69868	126.149	'GEN645011 1-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	97.66789	126.1219	'COAL CREEK 230/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	97.62112	126.0818	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	97.61444	126.0751	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	97.61955	126.0735	'COAL CREEK 230/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	97.52499	125.9997	'ARNOLD 161/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.23251	96.65299	125.9797	'MARYVILLE 161/69KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	97.16441	125.6329	'GEN659103 1-ANTELOPE VALLEY UNIT1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	97.16441	125.6329	'GEN659107 2-ANTELOPE VALLEY UNIT2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32712	82.13304	125.5555	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	97.4248	125.4927	'GEN336170 1-GULF OXY U4'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22476	97.3728	125.4505	''P42:500:OKGE:SB_FTTH8581''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22476	97.35056	125.4277	''P42:500:OKGE:SB_FTTH8583''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22476	97.34748	125.4246	'ARKANSAS NUCLEAR ONE - FT SMITH 500KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22476	97.34748	125.4246	'ARKANSAS NUCLEAR ONE - FT SMITH 500KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22471	96.98422	125.4119	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22471	96.98422	125.4119	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	97.33442	125.4018	'GEN337757 1-DUKE HOTSPRINGS STG1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.92092	125.3884	'GEN659111 2-LELAND OLDS UNIT2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22574	96.76557	125.2541	'COOPER - MONOLITH 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.7742	125.204	''P22:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.7742	125.204	''P23:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	97.14149	125.1984	''P12:069:WERE:2MAD-TEC_69_1::''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.74216	125.198	'BIG STONE 230/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.72152	125.1617	'GEN635214 4-NEAL UNIT 4'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.21859	97.8812	125.1585	'MCKSBRG 3 161.00 - WINTER SET JUNCTION 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22675	96.52355	125.1446	''P23:345:WERE:STRA_345-100::''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	97.11269	125.1243	'GEN588273 1-G16-150-GEN10.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	97.10184	125.115	'GEN588263 1-G16-176-GEN10.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	97.06665	125.0862	'GEN588253 1-G16-174-GEN10.6900'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.64418	125.0757	'GEN645025 5-NORTH OMAHA 5'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.62049	125.0745	'SQUARE BUTTE - YNG2 4 230.00 230KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.62054	125.0745	'YNG2 4 230.00 230/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.61493	125.0659	''P45:345:UMZB:# 2515 #: SGQ IN NB. BREAKER FAULT (7196;7092;7292)''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.89825	125.0446	'GEN635059 W-ADAMS W1 0.6000'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	97.0034	125.0384	'GEN588243 1-G16-149-GEN10.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22482	96.94337	125.0278	'ARBR HL 3 345.00 - FALLOW 3 345.00 345KV CKT 1'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.8906	124.9612	'GEN336151 1-WATERFORD UNIT#1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.89057	124.9612	'GEN336152 1-WATERFORD UNIT#2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.89056	124.9455	''P23:345:AEPW:RIVERSIDE CB 3429A NBTB''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.88507	124.9402	''P23:345:AEPW:RIVERSIDE CB 3433A NBTB''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.46127	124.9209	'ALMA 161 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.45683	124.9134	'GEN640011 2-GERALD GENTLEMAN STATION UNIT 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.44235	124.9011	'GEN659118 1-LARAMIE RIVER UNIT1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22736	96.22365	124.8729	'FAIRPORT - OSBORN 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.76643	124.8374	'GEN336222 1-LITTLE GYPSY UNIT#2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.71944	124.802	'GEN542956 2-LACYGNE UNIT #2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.33562	124.7897	'COYOTE 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.32862	124.7852	'GEN640010 1-GERALD GENTLEMAN STATION UNIT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.70354	124.7738	'GEN501811 1-RODEMACHER UNIT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22575	96.18201	124.7501	'HAWTHORN - NASHUA 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.29074	124.743	''P42:345:UMZB:# 2494 #: LO IN ND. STUCK BREAKER (2196)''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.29074	124.743	''P42:345:UMZB:# 2495 #: LO IN ND. STUCK BREAKER (2396)''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	96.23631	124.7329	'ATCHSN 3 345.00 - J475 POI 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22536	96.21075	124.7008	''P23:345:WERE:87TH_345_BKRS:''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22534	96.21573	124.7	'87th STREET - STRANGER CREEK 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22674	96.01255	124.6986	'FAIRPORT - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	95.68279	124.6981	'GEN635024 4-WALTER SCOTT UNIT 4'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22482	96.53701	124.6335	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.54755	124.6182	'GEN334433 1-SABINE UNIT 3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.44193	124.498	'GEN532651 1-JEFFREY ENERGY CENTER UNIT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.27065	124.4954	'THOMAS HILL 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	96.01625	124.4765	'GENOA 161 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.36867	124.4528	'GEN542955 1-LACYGNE UNIT #1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.34096	124.4121	'GEN334441 1-SABINE UNIT 5'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.35617	124.4093	'GEN532653 1-JEFFREY ENERGY CENTER UNIT 3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.35576	124.4089	'GEN532652 1-JEFFREY ENERGY CENTER UNIT 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	95.89883	124.3534	'BOUNDARY DAM 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22553	95.86118	124.3531	''P23:345:WERE:STRA_345-99:''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22364	95.05573	124.3066	'J475 POI 345.00 - ORIENT 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	95.87983	124.2793	'GEN635050 3-SHENENDOAH'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.19438	124.2665	'GEN336801 1-BAXTER WILSON UNIT #1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	95.80218	124.2572	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	95.80194	124.257	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	95.79475	124.2521	'CHEMOLITE - LS POWER 7 115.00 115KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	95.78953	124.2441	'SHAND 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	95.758	124.2301	'ATCHSN 3 345.00 - J570POI 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	95.758	124.2301	'ATCHSN 3 345.00 - J570POI 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.15299	124.2239	'GEN335204 1-NELSON UNIT 4'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22729	95.54542	124.2232	'5REX 161.00 - OSBORN 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.13487	124.2058	'GEN501812 1-RODEMACHER UNIT 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22383	96.32718	124.177	'BONDURANT - MONTEZUMA 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	95.71931	124.1766	'FARIBALT GEN115.00 - FEP TAP 115KV CKT Z'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2279	95.67725	124.1545	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.04054	124.1131	'GEN336191 1-LITTLE GYPSY UNIT#3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.02275	124.0955	'GEN336464 1-MICHOUD UNIT #3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	94.88281	124.0844	'GEN635024 4-WALTER SCOTT UNIT 4'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	96.00375	124.0764	'GEN335614 1-WILLOW GLENN UNIT#4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28384	86.93745	124.0585	'MARYVILLE - MIDWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.96796	124.0409	'GEN303007 1-1BC2 U2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28294	87.03568	123.9749	'MARYVILLE - MIDWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.84125	123.9187	'GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.83082	123.902	'GEN334440 1-SABINE UNIT 4'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.79266	123.8661	'GEN303008 1-1BC2 U3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.77557	123.8477	'GEN335206 1-NELSON UNIT 6'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.76355	123.8371	'GEN303006 1-1BC2 U1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22641	95.63509	123.8175	'COOPER - ST JOE 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.73481	123.8072	'GEN337692 1-LAKE CATHERINE UNIT #4'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.68233	123.762	'GEN345671 2-1RUSH G2 18.000'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.68146	123.7612	'GEN345670 1-1RUSH G1 18.000'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22402	95.80588	123.7228	'HOLT 7 345.00 - MULLNCR7 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22402	95.80141	123.7228	'KETCHEM7 345.00 - MULLNCR7 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	99.14206	123.6237	'GEN999125 1-GI61-GEN1 0.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.50613	123.5887	'GEN344896 3-1LAB G3 20.000'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.50578	123.5883	'GEN344895 2-1LAB G2 20.000'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.50577	123.5883	'GEN344897 4-1LAB G4 20.000'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.50547	123.588	'GEN344894 1-1LAB G1 20.000'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.47319	123.5683	'GEN542951 5-HAWTHORN UNIT #5'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.47804	123.5511	'GEN501813 1-RODEMACHER UNIT 3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22494	95.49896	123.5505	''P23:345:WERE:JEC_345-20:''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22982	94.87426	123.5333	''P42:345:NPPD:BKR-CPR-3322''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22981	94.83139	123.4902	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22981	94.83139	123.4902	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	94.43171	123.466	'GEN635023 3-WALTER SCOTT UNIT 3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.32104	123.3976	'GEN338388 1-1PLUM PT U1 23.000'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.31311	123.3527	''P23:345:WERE:JEC_345-19:''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	95.31274	123.3524	''P23:345:WERE:JEC_345-15:''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32569	80.04784	123.1135	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.32569	80.03977	123.1096	'HARVIEL E - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22479	93.62561	123.0547	'J475 POI 345.00 - ORIENT 3 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	94.95912	123.0356	'GEN336251 1-NINEMILE POINT UNIT#4'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	94.9242	122.9974	'GEN501801 1-DOLET HILLS UNIT1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	94.91105	122.9881	'GEN336831 1-BAXTER WILSON SES'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	94.90779	122.9851	'GEN337041 1-GERALD ANDRUS'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	94.87453	122.9516	'GEN336252 1-NINEMILE POINT UNIT#5'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	93.70449	122.9258	'GEN635023 3-WALTER SCOTT UNIT 3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22546	94.78057	122.8837	''P23:345:WERE:JEC_345-16::''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22498	94.37682	122.4393	''P23:345:WERE:WOLF_345-50::''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	93.90188	122.358	'2217-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	93.90188	122.358	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	93.90188	122.358	'2564-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	93.90188	122.358	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	93.90188	122.358	'2604-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	93.90188	122.358	'2606-NEBRASKA CITY 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	94.23882	122.3396	'GEN542957 1-IATAN UNIT #1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22321	93.20475	122.2408	''P23:345:OPPD:S3456-S3459&T4''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	94.17327	122.2317	''P23:345:WERE:WOLF_345-60::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	93.0237	122.1724	'SHERBURNE CO 345/26.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	94.08259	122.1629	'GEN338143 1-INDEPENDENCE UNIT #1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22289	93.18929	122.1606	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22289	93.18929	122.1606	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	94.07193	122.1523	'GEN338146 1-INDEPENDENCE UNIT #2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22288	94.10108	122.0529	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22288	94.10108	122.0529	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22404	92.8064	122.0183	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22404	92.8064	122.0183	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22282	94.01563	121.9661	''P23:345:OPPD:S3456-S3458&T4''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22431	92.72673	121.9565	''P23:345:OPPD:S3456-S3459&T4''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22325	92.70169	121.7671	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22325	92.70169	121.7671	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22435	92.24596	121.4924	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22435	92.24596	121.4924	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	93.30849	121.4004	'GEN542962 2-IATAN UNIT #2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	93.02454	121.0908	'GEN335831 1-RIVERBEND UNIT#1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	91.84655	121.0786	'OTTUMWA 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	91.61835	120.7671	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	92.62057	120.6905	'GEN336153 1-WATERFORD UNIT#3'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	92.17252	120.6268	'GEN336170 1-GULF OXY U4'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	92.13664	120.6073	'7CALAWY 1 345.00 345/25.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	92.13294	120.5884	'GEN501811 1-RODEMACHER UNIT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	92.08337	120.5388	'GEN337757 1-DUKE HOTSPRINGS STG1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22481	91.99574	120.47	'ARBR HL 3 345.00 - FALLOW 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.90245	120.3556	'GEN337692 1-LAKE CATHERINE UNIT #4'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22364	91.15904	120.3508	'ATCHSN 3 345.00 - J475 POI 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.89096	120.3366	''P12:069:WERE:2MAD-TEC_69_1::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	91.17449	120.3332	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.21861	92.69064	120.3036	'MCKSBRG 3 161.00 - WINTER SET JUNCTION 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.87286	120.2708	'GEN588273 1-G16-150-GEN10.6900'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.86164	120.261	'GEN588263 1-G16-176-GEN10.6900'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.82493	120.231	'GEN588253 1-G16-174-GEN10.6900'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	91.05266	120.2018	'MONTICELLO 345/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.75726	120.1794	'GEN588243 1-G16-149-GEN10.6900'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.72113	120.1756	'GEN336151 1-WATERFORD UNIT#1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.72088	120.1753	'GEN336152 1-WATERFORD UNIT#2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.62624	120.0808	'GEN336222 1-LITTLE GYPSY UNIT#2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22481	91.57349	120.0661	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	-999	120.0509	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	-999	120.0183	'MONTICELLO 345/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.52153	119.9905	'GEN542956 2-LACYGNE UNIT #2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	90.80453	119.9478	'COAL CREEK 230/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28294	82.93549	119.9308	'AVENUECTY 5 161.00 - MIDWAY 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	90.74579	119.8892	'COAL CREEK 230/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28384	82.69817	119.8773	'AVENUECTY 5 161.00 - MIDWAY 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.4016	119.8549	'GEN334433 1-SABINE UNIT 3'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	90.67307	119.8351	'ARNOLD 161/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	90.55196	119.7035	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	90.54427	119.6959	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	90.33522	119.6755	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.03507	119.6588	'THOMAS HILL 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.20523	119.6584	'GEN334441 1-SABINE UNIT 5'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.21523	119.6547	'GEN532651 1-JEFFREY ENERGY CENTER UNIT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	-999	119.6435	'OTTUMWA 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.17754	119.642	'GEN542955 1-LACYGNE UNIT #1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22381	91.39082	119.6186	'BONDURANT - MONTEZUMA 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22356	90.51782	119.6156	''P23:345:OPPD:S3456-S3455''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.13213	119.5684	'GEN532653 1-JEFFREY ENERGY CENTER UNIT 3'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.13171	119.568	'GEN532652 1-JEFFREY ENERGY CENTER UNIT 2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	90.39558	119.5471	'AS KING 345/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28294	82.51302	119.5103	'AVENUECTY 5 161.00 - MIDWAY TAP 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28294	82.51202	119.5098	'MIDWAY TAP - ST JOE 161KV CKT Z1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22356	90.39958	119.5055	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22356	90.39958	119.5055	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22639	90.92522	119.5051	'COOPER - ST JOE 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22364	90.33045	119.4984	'ATCHSN 3 345.00 - J570POI 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22364	90.33045	119.4984	'ATCHSN 3 345.00 - J570POI 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22356	90.38713	119.4892	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22356	90.38713	119.4892	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22356	90.38705	119.4891	''P23:345:OPPD:S3458-MULLNCR' '
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	91.02802	119.4851	'GEN336801 1-BAXTER WILSON UNIT #1'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28384	82.2749	119.4564	'AVENUECTY 5 161.00 - MIDWAY TAP 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28384	82.27396	119.4564	'MIDWAY TAP - ST JOE 161KV CKT Z1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.97861	119.4343	'GEN335204 1-NELSON UNIT 4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22462	90.09277	119.3805	''P23:345:OPPD:S3456-S3455''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.89668	119.3537	'GEN336191 1-LITTLE GYPSY UNIT#3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	90.01052	119.3383	'COAL CREEK 230/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.87737	119.3344	'GEN336464 1-MICHOUD UNIT #3'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.87212	119.3279	'GEN501812 1-RODEMACHER UNIT 2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	90.19829	119.3266	'GEN635214 4-NEAL UNIT 4'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.85793	119.3149	'GEN335614 1-WILLOW GLENN UNIT#4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22479	89.92247	119.3066	'ATCHSN 3 345.00 - J475 POI 345.00 345KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	91.17028	119.3051	'GEN344225 1-1CAL G1 25.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22463	90.00156	119.2939	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22463	90.00156	119.2939	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.95935	119.2871	'COAL CREEK 230/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22463	89.99043	119.279	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22463	89.99043	119.279	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22463	89.99035	119.2789	''P23:345:OPPD:S3458-MULLNCR' '
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	90.05502	119.2057	'GEN645012 2-NEBRASKA CITY 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	84.41103	119.161	System Intact
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.68522	119.1405	'GEN334440 1-SABINE UNIT 4'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22401	90.83713	119.1383	'HOLT 7 345.00 - MULLNCR7 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22401	90.83055	119.1367	'KETCHEM7 345.00 - MULLNCR7 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.75759	119.0928	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.7413	119.0894	'ARNOLD 161/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.75109	119.0863	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.61857	119.0772	'GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.91943	119.0669	'GEN645011 1-NEBRASKA CITY 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22358	89.97986	119.0482	'7MAYWOOD 345.00 - 7SPENCER 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22358	89.97804	119.0454	'7MONTGMRY 345.00 - 7SPENCER 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2298	89.91842	118.9917	''P42:345:NPPD:BKR-CPR-3322''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.65018	118.985	'AS KING 345/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.52729	118.9847	'GEN303008 1-1BC2 U3'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	90.89499	118.9749	'GEN336821 1-GRAND GULF UNIT'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.50741	118.9633	'GEN335206 1-NELSON UNIT 6'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.49792	118.9555	'GEN303006 1-1BC2 U1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22979	89.87453	118.947	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22979	89.87453	118.947	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.61398	118.9466	'GEN645012 2-NEBRASKA CITY 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.55962	118.8948	'GEN645011 1-NEBRASKA CITY 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.3941	118.8594	'GEN345671 2-1RUSH G2 18.000'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.39336	118.8587	'GEN345670 1-1RUSH G1 18.000'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.37465	118.8326	'GEN303007 1-1BC2 U2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22789	89.96375	118.8242	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	93.90188	118.7945	'GEN999125 1-GI61-GEN1 0.6900'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.48113	118.7945	'GEN635214 4-NEAL UNIT 4'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.35977	118.7858	'GEN542951 5-HAWTHORN UNIT #5'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.21009	118.6664	'GEN501813 1-RODEMACHER UNIT 3'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.48441	118.6503	'GEN659103 1-ANTELOPE VALLEY UNIT1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.48441	118.6503	'GEN659107 2-ANTELOPE VALLEY UNIT2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.17512	118.64	'GEN344896 3-1LAB G3 20.000'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.17477	118.6396	'GEN344895 2-1LAB G2 20.000'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.17477	118.6396	'GEN344897 4-1LAB G4 20.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22451	89.38736	118.6394	'7MAYWOOD 345.00 - 7SPENCER 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.17447	118.6393	'GEN344894 1-1LAB G1 20.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22451	89.38316	118.636	'7MONTGMRY 345.00 - 7SPENCER 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.47972	118.6281	'BIG STONE 230/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25683	86.20128	118.6102	'FAIRPORT 345/161KV TRANSFORMER CKT 3'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.15606	118.5745	''P23:345:WERE:JEC_345-19::''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.15569	118.5741	''P23:345:WERE:JEC_345-15::''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	90.0491	118.5092	'GEN338388 1-1PLUM PT U1 23.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22479	89.11514	118.4783	'ATCHSN 3 345.00 - J570POI 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22479	89.11514	118.4783	'ATCHSN 3 345.00 - J570POI 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.30704	118.4605	'GEN600002 3-SHERBURNE CNTY G3'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.24366	118.4088	'GEN659111 2-LELAND OLDS UNIT2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.05044	118.397	'GEN659103 1-ANTELOPE VALLEY UNIT1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.05044	118.397	'GEN659107 2-ANTELOPE VALLEY UNIT2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.2293	118.3507	''P22:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.2293	118.3507	''P23:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	89.89154	118.3498	'GEN336251 1-NINEMILE POINT UNIT#4'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.13672	118.3083	'GEN635213 3-NEAL UNIT 3'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22457	89.0658	118.2655	'COOPER - MOORE 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.11427	118.2591	''P45:345:UMZB:# 2515 #: SGQ IN NB. BREAKER FAULT (7196;7092;7292)''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	89.78748	118.2465	'GEN337041 1-GERALD ANDRUS'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.09866	118.2461	'SQUARE BUTTE - YNG2 4 230.00 230KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.09866	118.2461	'YNG2 4 230.00 230/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	89.78613	118.2449	'GEN336831 1-BAXTER WILSON SES'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	89.7648	118.2233	'GEN336252 1-NINEMILE POINT UNIT#5'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.8688	118.2008	'BIG STONE 230/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22457	88.99516	118.1937	''P42:345:NPPD:BKR-MOR-3302''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.82724	118.1733	'GEN659111 2-LELAND OLDS UNIT2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22447	88.97891	118.1727	''P42:345:NPPD:BKR-MOR-3308''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.02651	118.1724	''P42:345:UMZB:# 2506 #: AVS IN ND. STUCK BREAKER (3796)''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22564	88.6916	118.1648	'FAIRPORT - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22402	90.1461	118.1275	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	89.35737	118.1208	'GEN635059 W-ADAMS W1 0.6000'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	89.6644	118.1186	'GEN501801 1-DOLET HILLS UNIT1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.77764	118.1078	'SQUARE BUTTE - YNG2 4 230.00 230KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.77766	118.1078	'YNG2 4 230.00 230/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.95803	118.1059	'COYOTE 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	89.09625	118.0906	'GEN635059 W-ADAMS W1 0.6000'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.84797	118.0827	'GEN629075 1-OTTUMWA GENERATOR FOR OTTUMWA UNIT NO 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.91036	118.068	'ALMA 161 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.23182	87.84998	118.042	'MARYVILLE 161/69KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.72929	118.0391	''P22:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.72929	118.0391	''P23:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.23282	87.72787	118.0332	'MARYVILLE 161/69KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22567	88.65321	118.0197	'COOPER - MONOLITH 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.67422	118.0046	'COYOTE 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22667	88.46397	117.9872	'FAIRPORT - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22465	88.69345	117.968	'HAWTHORN - NASHUA 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.78833	117.9349	''P42:345:UMZB:# 2494 #: LO IN ND. STUCK BREAKER (2196)''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.78833	117.9349	''P42:345:UMZB:# 2495 #: LO IN ND. STUCK BREAKER (2396)''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22566	88.45353	117.9139	'HAWTHORN - NASHUA 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.55977	117.9095	'GEN635213 3-NEAL UNIT 3'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.75648	117.9059	'BOUNDARY DAM 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.56882	117.9052	'ALMA 161 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.57414	117.9026	''P45:345:UMZB:# 2515 #: SGQ IN NB. BREAKER FAULT (7196;7092;7292)''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22625	88.48626	117.8941	'FAIRPORT - OSBORN 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22285	89.55419	117.8825	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22285	89.55419	117.8825	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22138	88.96713	117.8806	''P23:345:OPPD:S3456-S3459''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	89.06008	117.8655	'GEN300025 1-NODAWAY UNIT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.53142	117.8635	'MAPLE RIVER - PILSBRY4 230.00 230KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.68589	117.8357	'MAPLE RIVER - PILSBRY4 230.00 230KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.68415	117.8339	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.68404	117.8338	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.49564	117.8248	''P42:345:UMZB:# 2506 #: AVS IN ND. STUCK BREAKER (3796)''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.66761	117.8216	'GEN600000 1-SHERBURNECNTY G1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22279	89.49044	117.8165	''P23:345:OPPD:S3456-S3458&T4''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.64455	117.7942	'BRADA - NBEC 4 230.00 230KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.44196	117.7792	'GEN600002 3-SHERBURNE CNTY G3'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.6217	117.771	'SHAND 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	88.95505	117.7669	'GEN300026 1-NODAWAY UNIT 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22725	88.27198	117.7487	'FAIRPORT - OSBORN 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.37406	117.7102	'GEN640011 2-GERALD GENTLEMAN STATION UNIT 2'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	88.89603	117.7039	'NODAWAY 161/13.8KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.48901	117.647	'GEN600001 2-SHERBURNE CNTY G2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22528	88.13955	117.6426	''P23:345:WERE:87TH_345_BKRS::''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	88.65784	117.6368	'GEN300026 1-NODAWAY UNIT 2'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22496	89.19668	117.6334	''P23:345:WERE:WOLF_345-50::''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28478	78.9782	117.62	'MARYVILLE - MIDWAY 161KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.28767	117.6175	''P42:345:UMZB:# 2494 #: LO IN ND. STUCK BREAKER (2196)''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.28767	117.6175	''P42:345:UMZB:# 2495 #: LO IN ND. STUCK BREAKER (2396)''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	89.15198	117.6099	'GEN337653 1-WHITE BLUFF UNIT #2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.27213	117.6094	'GEN640010 1-GERALD GENTLEMAN STATION UNIT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.47483	117.6088	'GEN645025 5-NORTH OMAHA 5'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	89.18443	117.6049	'GEN542957 1-IATAN UNIT #1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	88.78934	117.6034	'NODAWAY 161/13.8KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22525	88.10025	117.596	'87th STREET - STRANGER CREEK 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22426	88.29177	117.5882	''P23:345:WERE:87TH_345_BKRS::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.42941	117.5854	'GENOA 161 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.42947	117.5826	'CHEMOLITE - LS POWER 7 115.00 115KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.42596	117.5721	'GEN615002 2-COAL CREEK'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.22691	117.567	'GEN659118 1-LARAMIE RIVER UNIT1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.23409	117.566	'BOUNDARY DAM 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22457	88.34953	117.5658	''P42:345:NPPD:BKR-CPR-3310''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	88.57851	117.5595	'NODAWAY 161/13.8KV TRANSFORMER CKT 2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.39836	117.5449	'GEN615001 1-COAL CREEK'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22424	88.25053	117.5412	'87th STREET - STRANGER CREEK 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22664	87.90179	117.533	''P23:345:WERE:STRA_345-100::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.37075	117.5292	'GEN659118 1-LARAMIE RIVER UNIT1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.18586	117.5038	'GEN645025 5-NORTH OMAHA 5'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	89.06063	117.4929	''P23:345:WERE:WOLF_345-60::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.2992	117.4527	'OLIVER COUNTY 1 - SQUARE BUTTE 230KV CKT Z1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.11402	117.4525	'GENOA 161 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.11543	117.4478	'SHAND 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.28883	117.4432	'GEN600005 1-MONTICELLO'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.10362	117.4362	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	88.10342	117.436	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22563	87.97477	117.4097	''P23:345:WERE:STRA_345-100::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.25349	117.4045	'CODETTE - NIPAWIN 230KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.16128	117.3148	'FARIBALT GEN115.00 - FEP TAP 115KV CKT Z'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22262	88.14063	117.2873	''P23:345:OPPD:S3456-S3459''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	87.93738	117.2745	'GEN600000 1-SHERBURNECNTY G1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	87.92796	117.2637	'CHEMOLITE - LS POWER 7 115.00 115KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	88.80477	117.2631	'GEN337652 1-WHITE BLUFF UNIT #1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	88.79932	117.2601	'GEN338143 1-INDEPENDENCE UNIT #1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	88.79056	117.2511	'GEN338146 1-INDEPENDENCE UNIT #2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22617	87.88607	117.2475	'5REX 161.00 - OSBORN 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.0875	117.2437	'GEN600003 1-PRAIRIE ISLAND G1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.08431	117.2405	'GEN600004 2-PRAIRIE ISLAND G2'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.08398	117.2397	'GEN600006 1-AS KING'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	87.90515	117.2383	'BRADA - NBEC 4 230.00 230KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25721	84.70853	117.2274	''P42:345:NPPD:BKR-C-3322-2''
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25721	84.67986	117.1983	''P12:345:NPPD:3517:COOPER 3:ST JOE 3:BTB''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	88.04235	117.1937	'LANSING WEST 161/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	87.83113	117.167	'FARIBALT GEN115.00 - FEP TAP 115KV CKT Z'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22413	87.82448	117.1528	'7OVERTON 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22413	87.82448	117.1528	'7OVERTON 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22718	87.59198	117.1523	'5REX 161.00 - OSBORN 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22364	87.98402	117.1425	'COOPER - J570POI 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22544	87.63191	117.1331	''P23:345:WERE:STRA_345-99::''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22513	87.59711	117.1292	'7OVERTON 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22513	87.59711	117.1292	'7OVERTON 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	88.17244	116.6677	'GEN542962 2-IATAN UNIT #2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28478	77.82066	116.5066	'AVENUECTY 5 161.00 - MIDWAY 161KV CKT 1'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	87.74369	116.2064	'GEN335831 1-RIVERBEND UNIT#1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	87.72749	116.1859	'GEN337910 1-ARKANSAS NUCLEAR ONE UNIT #1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28478	77.33006	116.0876	'AVENUECTY 5 161.00 - MIDWAY TAP 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28478	77.3147	116.083	'MIDWAY TAP - ST JOE 161KV CKT Z1'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	87.33881	115.8026	'GEN336153 1-WATERFORD UNIT#3'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	86.2471	115.4046	'2217-NEBRASKA CITY 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	86.2471	115.4046	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	86.2471	115.4046	'2564-NEBRASKA CITY 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	86.2471	115.4046	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	86.2471	115.4046	'2604-NEBRASKA CITY 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	86.2471	115.4046	'2606-NEBRASKA CITY 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	86.03458	115.3728	'2217-NEBRASKA CITY 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	86.03458	115.3728	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	86.03458	115.3728	'2564-NEBRASKA CITY 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	86.03458	115.3728	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	86.03458	115.3728	'2604-NEBRASKA CITY 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	86.03458	115.3728	'2606-NEBRASKA CITY 2'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	86.82853	115.2886	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	84.11897	114.6877	'GEN635024 4-WALTER SCOTT UNIT 4'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	81.38807	114.5747	System Intact
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	85.73441	114.2302	'GEN344225 1-1CAL G1 25.000'
FDNSLock	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	85.6032	114.0741	'GEN336821 1-GRAND GULF UNIT'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	84.25371	113.617	'7CALAWY 1 345.00 345/25.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.46147	113.6164	'GEN336801 1-BAXTER WILSON UNIT #1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.47312	113.6122	''P23:345:AEPW:RIVERSIDE CB 3429A NBTB''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.45844	113.5979	''P23:345:AEPW:RIVERSIDE CB 3433A NBTB''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.4248	113.5796	'GEN336191 1-LITTLE GYPSY UNIT#3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	84.23676	113.5777	'GEN336801 1-BAXTER WILSON UNIT #1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22476	84.23421	113.5713	'PONY CREEK - RLHILLS3 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22537	84.19299	113.5516	'COOPER - ST JOE 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.39242	113.5474	'GEN336464 1-MICHOUD UNIT #3'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22401	85.34042	113.547	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.38173	113.5366	'GEN335614 1-WILLOW GLENN UNIT#4'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.37316	113.5328	'GEN335204 1-NELSON UNIT 4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	84.18349	113.5243	'GEN336191 1-LITTLE GYPSY UNIT#3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	84.15479	113.4956	'GEN336464 1-MICHOUD UNIT #3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	84.14993	113.4896	'GEN335204 1-NELSON UNIT 4'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.11654	113.4874	'GEN300003 1-THOMAS HILL UNIT 3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	84.14288	113.4837	'GEN335614 1-WILLOW GLENN UNIT#4'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28256	76.2382	113.4308	'MARYVILLE - MIDWAY 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.25817	113.4236	'7CALAWY 1 345.00 345/25.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22378	84.21974	113.3944	'PONY CREEK - RLHILLS3 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22983	83.37336	113.3921	''P42:345:NPPD:BKR-CPR-3322''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.27642	113.3815	'GEN588273 1-G16-150-GEN10.6900'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.26585	113.3717	'GEN588263 1-G16-176-GEN10.6900'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.20511	113.3644	'GEN334440 1-SABINE UNIT 4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22983	83.33357	113.3522	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22983	83.33357	113.3522	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	84.05617	113.3432	'GEN588273 1-G16-150-GEN10.6900'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.22715	113.3397	'GEN588253 1-G16-174-GEN10.6900'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	84.04453	113.333	'GEN588263 1-G16-176-GEN10.6900'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.97077	113.3101	'GEN334440 1-SABINE UNIT 4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	84.00575	113.3	'GEN588253 1-G16-174-GEN10.6900'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.15572	113.2826	'GEN588243 1-G16-149-GEN10.6900'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.10894	113.2654	'GEN336251 1-NINEMILE POINT UNIT#4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.93241	113.2411	'GEN588243 1-G16-149-GEN10.6900'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	84.06062	113.2236	'GEN542956 2-LACYGNE UNIT #2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.80647	113.1477	'GEN336251 1-NINEMILE POINT UNIT#4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.78665	113.1361	'GEN542956 2-LACYGNE UNIT #2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22297	84.16851	113.1287	'BONDURANT - MONTEZUMA 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	83.7859	113.0523	'GEN300025 1-NODAWAY UNIT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.84666	113.0121	'GEN542955 1-LACYGNE UNIT #1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22505	82.22264	112.984	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22505	82.22264	112.984	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22376	83.71967	112.9384	'ARBR HL 3 345.00 - FALLOW 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22474	83.55116	112.929	'ARBR HL 3 345.00 - FALLOW 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22489	83.63461	112.9033	'NODAWAY 161/13.8KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.75016	112.892	'GEN532651 1-JEFFREY ENERGY CENTER UNIT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.50318	112.8551	'GEN542955 1-LACYGNE UNIT #1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.70829	112.8478	'GEN336252 1-NINEMILE POINT UNIT#5'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22404	83.65982	112.8447	'HOLT 7 345.00 - MULLNCR7 345.00 345KV CKT 1'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.52083	112.8433	'GEN532651 1-JEFFREY ENERGY CENTER UNIT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22404	83.65255	112.8421	'KETCHEM7 345.00 - MULLNCR7 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.69422	112.835	'GEN337041 1-GERALD ANDRUS'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22308	83.82771	112.8152	'HILLS - MONTEZUMA 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.67181	112.8101	'GEN532653 1-JEFFREY ENERGY CENTER UNIT 3'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.67142	112.8098	'GEN532652 1-JEFFREY ENERGY CENTER UNIT 2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.46558	112.8084	'GEN337041 1-GERALD ANDRUS'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.45818	112.8	'GEN336252 1-NINEMILE POINT UNIT#5'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.45923	112.7999	'GEN501812 1-RODEMACHER UNIT 2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.65086	112.7911	'GEN336831 1-BAXTER WILSON SES'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.42205	112.7644	'GEN336831 1-BAXTER WILSON SES'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.44227	112.7616	'GEN532653 1-JEFFREY ENERGY CENTER UNIT 3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.44186	112.7612	'GEN532652 1-JEFFREY ENERGY CENTER UNIT 2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22877	82.90793	112.7291	''P42:345:NPPD:BKR-CPR-3322''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.56613	112.7165	'GEN501812 1-RODEMACHER UNIT 2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22877	82.86073	112.6819	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22877	82.86073	112.6819	'COOPER - FAIRPORT 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.08362	112.6601	'THOMAS HILL 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.23368	112.6343	'THOMAS HILL 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.25936	112.6017	'GEN303007 1-1BC2 U2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22376	83.48767	112.595	'BONDURANT - MONTEZUMA 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22376	83.33109	112.5822	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25683	79.66748	112.5801	'FAIRPORT 345/161KV TRANSFORMER CKT 3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.21852	84.08371	112.5587	'MCKSBRG 3 161.00 - WINTER SET JUNCTION 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22289	83.5928	112.5582	'HOLT 7 345.00 - MULLNCR7 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22289	83.5862	112.5555	'KETCHEM7 345.00 - MULLNCR7 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.19067	112.533	'GEN303008 1-1BC2 U3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22474	83.13388	112.5246	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.16592	112.5083	'GEN303006 1-1BC2 U1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.15018	112.4911	'GEN335206 1-NELSON UNIT 6'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.30245	112.4426	'GEN303007 1-1BC2 U2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22163	83.43826	112.4393	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22163	83.43826	112.4393	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.27189	112.4119	'GEN303008 1-1BC2 U3'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.24592	112.386	'GEN303006 1-1BC2 U1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.24025	112.3791	'GEN335206 1-NELSON UNIT 6'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.02464	112.3785	'GEN345671 2-1RUSH G2 18.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	83.02388	112.3778	'GEN345670 1-1RUSH G1 18.000'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.21762	84.02123	112.3594	'MCKSBRG 3 161.00 - WINTER SET JUNCTION 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22158	83.33878	112.337	''P23:345:OPPD:S3456-S3458&T4''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22385	83.1362	112.2636	''P23:345:WERE:JEC_345-20::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.08926	112.2505	'GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.90571	112.2466	'GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	83.0601	112.2459	'GEN542951 5-HAWTHORN UNIT #5'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.89578	112.2371	'GEN501813 1-RODEMACHER UNIT 3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.83699	112.1925	'GEN344896 3-1LAB G3 20.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.83663	112.1922	'GEN344895 2-1LAB G2 20.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.83663	112.1922	'GEN344897 4-1LAB G4 20.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.83634	112.1919	'GEN344894 1-1LAB G1 20.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.81458	112.1611	'GEN338388 1-1PLUM PT U1 23.000'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	82.97035	112.1226	'GEN345671 2-1RUSH G2 18.000'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	82.96949	112.1219	'GEN345670 1-1RUSH G1 18.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.72173	112.1184	'GEN542951 5-HAWTHORN UNIT #5'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	82.97821	112.1174	'GEN501813 1-RODEMACHER UNIT 3'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22486	82.77943	112.0905	''P23:345:WERE:JEC_345-20::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22383	82.91628	112.0282	''P23:345:WERE:JEC_345-19::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22383	82.91595	112.0279	''P23:345:WERE:JEC_345-15::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	82.83667	111.9761	'GEN338388 1-1PLUM PT U1 23.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22281	82.7067	111.9343	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22281	82.7067	111.9343	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	82.76712	111.9215	'GEN344896 3-1LAB G3 20.000'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	82.76672	111.9211	'GEN344895 2-1LAB G2 20.000'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	82.7667	111.9211	'GEN344897 4-1LAB G4 20.000'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	82.76636	111.9208	'GEN344894 1-1LAB G1 20.000'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22275	82.63986	111.8634	''P23:345:OPPD:S3456-S3458&T4''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.55251	111.8502	''P23:345:WERE:JEC_345-19::''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	82.55218	111.8499	''P23:345:WERE:JEC_345-15::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	86.2471	111.8339	'GEN999125 1-GI61-GEN1 0.6900'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	86.03458	111.7959	'GEN999125 1-GI61-GEN1 0.6900'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	81.01885	111.7413	'SHERBURNE CO 345/26.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	-999	111.7206	'GEN501801 1-DOLET HILLS UNIT1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	82.4515	111.6437	'GEN501801 1-DOLET HILLS UNIT1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2572	78.53518	111.4729	''P42:345:NPPD:BKR-C-3322-2''
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2572	78.50523	111.443	''P12:345:NPPD:3517:COOPER 3:ST JOE 3:BTB''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28256	74.16718	111.3286	'AVENUECTY 5 161.00 - MIDWAY 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22672	81.84891	111.3282	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2258	80.52348	111.3259	'J475 POI 345.00 - ORIENT 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	81.97637	111.3213	'GEN337653 1-WHITE BLUFF UNIT #2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22438	82.03701	111.2096	''P23:345:WERE:JEC_345-16::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	81.99972	111.2006	'GEN337653 1-WHITE BLUFF UNIT #2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	81.74033	111.0874	'GEN338143 1-INDEPENDENCE UNIT #1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22389	81.96107	111.0846	''P23:345:WERE:WOLF_345-50::''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	81.72754	111.0749	'GEN338146 1-INDEPENDENCE UNIT #2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	81.88636	111.064	'GEN542957 1-IATAN UNIT #1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	81.71379	111.0578	'GEN337652 1-WHITE BLUFF UNIT #1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22539	81.68862	111.046	''P23:345:WERE:JEC_345-16::''

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22383	81.888	111.0052	''P23:345:WERE:WOLF_345-60::''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22775	81.29161	110.9598	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	81.72256	110.9194	'GEN337652 1-WHITE BLUFF UNIT #1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	81.71356	110.9099	'GEN338146 1-INDEPENDENCE UNIT #2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28256	73.66443	110.9082	'AVENUECTY 5 161.00 - MIDWAY TAP 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.28256	73.64816	110.9058	'MIDWAY TAP - ST JOE 161KV CKT Z1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	81.70682	110.9057	'GEN338143 1-INDEPENDENCE UNIT #1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2249	81.55885	110.8713	''P23:345:WERE:WOLF_345-50::''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	81.48824	110.8644	'GEN542957 1-IATAN UNIT #1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	81.47608	110.7821	''P23:345:WERE:WOLF_345-60::''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	81.32201	110.5646	'GEN635024 4-WALTER SCOTT UNIT 4'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	79.73891	110.5	'MONTICELLO 345/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	80.9653	110.2072	'GEN542962 2-IATAN UNIT #2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	80.84326	110.1912	'GEN335831 1-RIVERBEND UNIT#1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	79.34775	110.1249	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	80.76278	110.1061	'GEN337910 1-ARKANSAS NUCLEAR ONE UNIT #1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22522	79.19328	110.0407	''P23:345:OPPD:S3456-S3459&T4''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	80.81429	110.0161	'GEN335831 1-RIVERBEND UNIT#1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	80.52218	109.9706	'GEN542962 2-IATAN UNIT #2'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	80.75444	109.9526	'GEN337910 1-ARKANSAS NUCLEAR ONE UNIT #1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	79.09573	109.8997	'GEN635214 4-NEAL UNIT 4'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	80.49555	109.8449	'GEN336153 1-WATERFORD UNIT#3'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22762	78.48408	109.685	''P23:345:WERE:STRA_345-100::''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	80.45284	109.6468	'GEN336153 1-WATERFORD UNIT#3'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22527	78.91891	109.6329	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22527	78.91891	109.6329	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	78.76005	109.5514	'ARNOLD 161/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	78.74005	109.5316	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	78.73395	109.5257	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	78.70431	109.4975	'OTTUMWA 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	78.65384	109.4465	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	79.99309	109.3391	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	78.52097	109.3176	'GEN600002 3-SHERBURNE CNTY G3'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	78.48129	109.2633	'GEN635023 3-WALTER SCOTT UNIT 3'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	78.46198	109.2346	'GEN635059 W-ADAMS W1 0.6000'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	79.9522	109.1466	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.97401	108.7962	'GEN645012 2-NEBRASKA CITY 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.90604	108.72	'BIG STONE 230/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.7907	108.6053	'GEN659103 1-ANTELOPE VALLEY UNIT1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.7907	108.6053	'GEN659107 2-ANTELOPE VALLEY UNIT2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22762	77.3503	108.5702	'FAIRPORT - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	79.12688	108.4792	'SHERBURNE CO 345/26.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.60547	108.4279	'GEN600005 1-MONTICELLO'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.58555	108.4065	'GEN659111 2-LELAND OLDS UNIT2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	79.0418	108.4035	'GEN336821 1-GRAND GULF UNIT'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.57284	108.3986	'GEN600001 2-SHERBURNE CNTY G2'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22483	78.90578	108.3129	'GEN344225 1-1CAL G1 25.000'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22555	77.54104	108.3047	''P23:345:OPPD:S3456-S3455''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22556	77.51934	108.2915	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22556	77.51934	108.2915	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22292	78.819	108.2748	'J475 POI 345.00 - ORIENT 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22556	77.48084	108.2649	''P23:345:OPPD:S3458-MULLNCR' '
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22556	77.48103	108.2649	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22556	77.48103	108.2649	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22199	79.06761	108.2545	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22199	79.06761	108.2545	'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.3469	108.1756	''P42:345:UMZB:# 2506 #: AVS IN ND. STUCK BREAKER (3796)''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22577	77.31499	108.1441	''P45:345:UMZB:# 2515 #: SGQ IN NB. BREAKER FAULT (7196;7092;7292)''
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	78.90426	108.1187	'GEN336821 1-GRAND GULF UNIT'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.26311	108.0941	'COAL CREEK 230/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.26221	108.0939	'COAL CREEK 230/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22608	76.76323	108.0664	'7OVERTON 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22608	76.76323	108.0664	'7OVERTON 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.2002	108.0337	'GEN600000 1-SHERBURNECNTY G1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.15908	107.9934	''P42:345:UMZB:# 2494 #: LO IN ND. STUCK BREAKER (2196)''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.15908	107.9934	''P42:345:UMZB:# 2495 #: LO IN ND. STUCK BREAKER (2396)''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22244	78.72465	107.9843	''P23:345:OPPD:S3456-S3459&T4''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.14771	107.9833	'ALMA 161 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22668	77.06688	107.9764	'COOPER - MONOLITH 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22755	76.68284	107.9209	'CHILLICOTHE - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22547	77.17177	107.9144	'7MONTGMRY 345.00 - 7SPENCER 345.00 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22547	77.17233	107.9136	'7MAYWOOD 345.00 - 7SPENCER 345.00 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.23338	76.19167	107.9099	'MARYVILLE 161/69KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.06705	107.9048	'GEN600003 1-PRAIRIE ISLAND G1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	77.06418	107.9019	'GEN600004 2-PRAIRIE ISLAND G2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	76.99464	107.8347	'GEN629075 1-OTTUMWA GENERATOR FOR OTTUMWA UNIT NO 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	76.97963	107.8181	'BOUNDARY DAM 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22382	78.55766	107.7906	'GEN344225 1-1CAL G1 25.000'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22623	76.74977	107.7867	''P23:345:WERE:87TH_345_BKRS::''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	76.93548	107.7752	'SHAND 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22662	76.71871	107.7627	'HAWTHORN - NASHUA 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	76.90788	107.7484	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	76.90794	107.7484	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2262	76.67807	107.7161	'87th STREET - STRANGER CREEK 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22765	76.45134	107.7047	'CHILLICOTHE - MEADVILLE 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22765	76.42968	107.6898	'MEADVILLE - THOMAS HILL 161KV CKT 1'

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22249	78.28535	107.5794	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22249	78.28535	107.5794	'SUB 3456 - SUB 3458 NEB CTY 345KV CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22404	78.08852	107.3634	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22289	77.78128	106.8292	'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	77.32417	106.6994	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	77.30762	106.6915	'SHERBURNE CO 345/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	77.17154	106.5805	'OTTUMWA 161/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	77.16907	106.5499	'MONTICELLO 345/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	76.84968	106.241	'COAL CREEK 230/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	76.84214	106.2313	'ARNOLD 161/22.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	76.57773	106.0064	'GEN635214 4-NEAL UNIT 4'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	76.60282	106.0002	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	76.59555	105.9931	'PRAIRIE ISLAND 345/20.0KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	75.03203	105.9209	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	75.03203	105.9209	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	75.03203	105.9209	'2606-NEBRASKA CITY 2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22283	76.23592	105.5718	''P23:345:OPPD:S3456-S3455''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22283	76.13249	105.4779	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22283	76.13249	105.4779	'SUB 3458 NEB CTY - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22283	76.12041	105.4598	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22283	76.12041	105.4598	'SUB 3455 - SUB 3740 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22283	76.12035	105.4597	''P23:345:OPPD:S3458-MULLNCR' '
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25636	71.79472	105.3708	'FAIRPORT 345/161KV TRANSFORMER CKT 3'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.92829	105.3138	'GEN645012 2-NEBRASKA CITY 2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.88316	105.2979	'GEN600002 3-SHERBURNE CNTY G3'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.82301	105.2127	'GEN645011 1-NEBRASKA CITY 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22062	75.97548	105.1252	''P23:345:OPPD:S3456-S3459''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.76708	105.1056	'GEN635059 W-ADAMS W1 0.6000'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.63544	105.0403	'GEN635023 3-WALTER SCOTT UNIT 3'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22498	75.1254	104.9765	'FAIRPORT - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.54865	104.9746	'BIG STONE 230/24.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2568	71.31371	104.9662	''P42:345:NPPD:BKR-C-3322-2''
FDNS	13ALL	0	21WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.2568	71.28629	104.939	''P12:345:NPPD:3517:COOPER 3:ST JOE 3:BTB''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.45038	104.8666	'GEN659103 1-ANTELOPE VALLEY UNIT1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.45038	104.8666	'GEN659107 2-ANTELOPE VALLEY UNIT2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22278	75.44796	104.7906	'7MAYWOOD 345.00 - 7SPENCER 345.00 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22278	75.44431	104.7876	'7MONTGMRY 345.00 - 7SPENCER 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25549	71.3665	104.7393	'FAIRPORT 345/161KV TRANSFORMER CKT 3'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.24292	104.6648	''P22:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.24292	104.6648	''P23:345:OPPD:S3458 NEBCTY2G''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.21731	104.64	'GEN659111 2-LELAND OLDS UNIT2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22312	75.17104	104.605	''P45:345:UMZB:# 2515 #: SGQ IN NB. BREAKER FAULT (7196;7092;7292)''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22503	74.88844	104.5353	''P23:345:WERE:STRA_345-100::''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22398	74.88181	104.4899	'HAWTHORN - NASHUA 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.03041	104.4689	''P42:345:UMZB:# 2506 #: AVS IN ND. STUCK BREAKER (3796)''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	75.029	104.4593	'GEN629075 1-OTTUMWA GENERATOR FOR OTTUMWA UNIT NO 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.95047	104.3903	'GEN600000 1-SHERBURNECNTY G1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.94263	104.3866	'GEN600001 2-SHERBURNE CNTY G2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22292	74.84919	104.3571	'ATCHSN 3 345.00 - J475 POI 345.00 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.81725	104.2616	''P42:345:UMZB:# 2494 #: LO IN ND. STUCK BREAKER (2196)''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.81725	104.2616	''P42:345:UMZB:# 2495 #: LO IN ND. STUCK BREAKER (2396)''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.81502	104.2606	'GEN615002 2-COAL CREEK'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22561	74.4053	104.2072	'FAIRPORT - OSBORN 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22358	74.6824	104.205	''P23:345:WERE:87TH_345_BKRS::''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.69987	104.1459	'GEN600005 1-MONTICELLO'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22356	74.61805	104.1438	'87th STREET - STRANGER CREEK 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22542	73.23083	104.1066	'HILLS - MONTEZUMA 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.23076	73.62917	104.0893	'MARYVILLE 161/69KV TRANSFORMER CKT 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22568	73.12003	104.0223	'ARBR HL 3 345.00 - FALLOW 3 345.00 345KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25588	70.55087	104.0136	''P42:345:NPPD:BKR-C-3322-2''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.21944	73.78176	104.0066	'CRESTON - MCKSBRG 3 161.00 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.21944	73.78176	104.0066	'CRESTON - MCKSBRG 3 161.00 161KV CKT 1'
FDNS	13ALL	0	17WP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25588	70.51855	103.9814	''P12:345:NPPD:3517:COOPER 3:ST JOE 3:BTB''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	73.02773	103.9677	'GEN303007 1-1BC2 U2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.47094	103.9232	'ALMA 161 161/24.0KV TRANSFORMER CKT 1'
FDNSLock	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.47089	103.9177	'GEN629074 1-ARNOLD LOWSIDE OF GSU XFMR'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22372	73.21056	103.9135	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22372	73.21056	103.9135	'COUNCIL BLUFFS - SUB 3456 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.44537	103.8981	'GEN600003 1-PRAIRIE ISLAND G1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.44202	103.8948	'GEN600004 2-PRAIRIE ISLAND G2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22365	73.17583	103.8821	''P23:345:OPPD:S3456-S3458&T4''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.3691	103.839	'GEN659118 1-LARAMIE RIVER UNIT1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.3844	103.8379	'BOUNDARY DAM 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.33874	103.7933	'SHAND 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.31462	103.7698	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.3139	103.7691	'POPLAR RIVER 230/18.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.74876	103.7443	'GEN345670 1-1RUSH G1 18.000'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22505	72.96273	103.7222	'KETCHEM7 345.00 - MULLNCR7 345.00 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22376	74.16149	103.7117	''P23:345:WERE:STRA_345-99::''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22505	72.94754	103.7109	'HOLT 7 345.00 - MULLNCR7 345.00 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.67725	103.6947	'GEN588273 1-G16-150-GEN10.6900'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.67152	103.6899	'GEN588263 1-G16-176-GEN10.6900'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22867	72.2607	103.6786	'EASTOWN7 345.00 - IATAN 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.7287	103.6763	'GEN335206 1-NELSON UNIT 6'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.65846	103.6749	'GEN588253 1-G16-174-GEN10.6900'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22406	74.03859	103.6689	''P55:345:KCPL:HAWTHORN_BUS_20''

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	BC%LOADING (% MVA)	TC%LOADING (% MVA)	CONTINGENCY
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22388	74.13694	103.6653	'COOPER - MOORE 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.20761	103.6653	'AS KING 345/20.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22292	74.0928	103.65	'ATCHSN 3 345.00 - J570POI 345.00 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22292	74.0928	103.65	'ATCHSN 3 345.00 - J570POI 345.00 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.6497	103.6478	'GEN588243 1-G16-149-GEN10.6900'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	73.91599	103.6467	'CHILLICOTHE - HICKORY CREEK 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22378	74.11906	103.6345	''P42:345:NPPD:BKR-MOR-3308''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22343	74.06117	103.6336	'7OVERTON 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22343	74.06117	103.6336	'7OVERTON 345.00 - SIBLEY 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22555	73.86382	103.6295	'5REX 161.00 - OSBORN 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22388	74.08014	103.6167	''P42:345:NPPD:BKR-MOR-3302''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.61035	103.6002	'GEN542951 5-HAWTHORN UNIT #5'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22568	72.68377	103.5935	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.58778	103.5855	'GEN344894 1-1LAB G1 20.000'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	74.11765	103.5775	'OLIVER COUNTY 1 - SQUARE BUTTE 230KV CKT Z1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.50452	103.5075	'GEN338388 1-1PLUM PT U1 23.000'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.37558	103.3504	'GEN532653 1-JEFFREY ENERGY CENTER UNIT 3'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	72.09921	103.0631	'GEN501801 1-DOLET HILLS UNIT1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.21944	72.84098	102.9301	'MCKSBRG 3 161.00 - WINTER SET JUNCTION 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22581	71.83	102.8053	''P23:345:WERE:JEC_345-20::''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	71.74094	102.7638	'GEN337653 1-WHITE BLUFF UNIT #2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	71.72208	102.7141	''P23:345:WERE:JEC_345-19::''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	71.60401	102.6282	'GEN338143 1-INDEPENDENCE UNIT #1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	71.59617	102.6209	'GEN338146 1-INDEPENDENCE UNIT #2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	71.53935	102.567	'GEN337652 1-WHITE BLUFF UNIT #1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	75.03203	102.3298	'GEN999125 1-GI61-GEN1 0.6900'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22471	71.54048	102.3049	'BONDURANT - MONTEZUMA 345KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25772	67.55324	102.0194	'FAIRPORT 345/161KV TRANSFORMER CKT 3'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25821	67.32358	101.9847	''P42:345:NPPD:BKR-C-3322-2''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.25821	67.30771	101.9691	''P12:345:NPPD:3517:COOPER 3:ST JOE 3:BTB''
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	70.92577	101.9687	'GEN335831 1-RIVERBEND UNIT#1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	72.34496	101.8442	'2217-NEBRASKA CITY 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	72.34496	101.8442	'2218-NEBRASKA CITY 2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	72.34496	101.8442	'2564-NEBRASKA CITY 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	72.34496	101.8442	'2566-NEBRASKA CITY 2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	72.34496	101.8442	'2604-NEBRASKA CITY 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	72.34496	101.8442	'2606-NEBRASKA CITY 2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	70.71976	101.7648	'GEN337910 1-ARKANSAS NUCLEAR ONE UNIT #1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	70.65665	101.7049	'GEN336153 1-WATERFORD UNIT#3'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	70.51723	101.5561	'GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22491	99.14206	101.5414	'GEN999126 1-GI61-GEN2 0.6900'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	70.10205	101.1587	'GEN337911 1-ARKANSAS NUCLEAR ONE UNIT #2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	70.07738	101.0763	'GEN542962 2-IATAN UNIT #2'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	69.57026	100.64	'GEN336821 1-GRAND GULF UNIT'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	69.53798	100.5976	'GEN344225 1-1CAL G1 25.000'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	70.65609	100.1924	'GEN303006 1-1BC2 U1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.21693	71.23476	100.0922	'CRESTON - MCKSBRG 3 161.00 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.21693	71.23476	100.0922	'CRESTON - MCKSBRG 3 161.00 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22583	69.00443	100.0658	''P23:345:WERE:WOLF_345-50::''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22424	70.43406	100	'COOPER - ST JOE 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	70.45879	100	'7CALAWY 1 345.00 345/25.0KV TRANSFORMER CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22578	68.90366	100	''P23:345:WERE:WOLF_345-60::''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	70.30137	99.8	''P12:069:WERE:2MAD-TEC_69_1::''
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22306	70.23104	99.8	'ARBR HL 3 345.00 - RCCN TRL 3 345.00 345KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	70.17077	99.7	'GEN542955 1-LACYGNE UNIT #1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	70.08492	99.7	'GEN542956 2-LACYGNE UNIT #2'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	70.05437	99.7	'GEN588243 1-G16-149-GEN10.6900'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	70.07467	99.7	'GEN588253 1-G16-174-GEN10.6900'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	70.09343	99.7	'GEN588263 1-G16-176-GEN10.6900'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'CLARINDA - J611 161.00 161KV CKT 1'	152	171	0.22313	70.10034	99.7	'GEN588273 1-G16-150-GEN10.6900'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'FAIRPORT - HARVIEL E 161KV CKT 1'	227	227	0.5641	76.18049	134.1575	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'FAIRPORT - HARVIEL E 161KV CKT 1'	227	227	0.5641	76.18049	134.1575	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'FAIRPORT - HARVIEL E 161KV CKT 1'	227	227	0.56407	64.86012	122.3689	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'FAIRPORT - HARVIEL E 161KV CKT 1'	227	227	0.56407	64.86012	122.3689	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'FAIRPORT - HARVIEL E 161KV CKT 1'	227	227	0.41124	65.33533	107.2228	'CLARINDA - J611 161.00 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'FAIRPORT - HARVIEL E 161KV CKT 1'	227	227	0.56534	47.52797	107.1528	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	18G	ASGI_18_01	'TO->FROM'	'FAIRPORT - HARVIEL E 161KV CKT 1'	227	227	0.56534	47.52797	107.1528	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'FAIRPORT - HARVIEL E 161KV CKT 1'	227	227	0.56336	41.96207	102.8835	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'FAIRPORT - HARVIEL E 161KV CKT 1'	227	227	0.56336	41.96207	102.8835	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'GI61-GSU2 161.00 - MARYVILLE 161KV CKT 1'	223	223	1	7.643852	108.1651	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'GI61-GSU2 161.00 - MARYVILLE 161KV CKT 1'	223	223	1	7.643852	108.1651	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'FROM->TO'	'GI61-GSU2 161.00 - MARYVILLE 161KV CKT 1'	223	223	1	7.526816	108.0937	'MARYVILLE - NODAWAY 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'HARVIEL E - NODAWAY 161KV CKT 1'	227	227	0.5641	73.80905	131.8539	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'HARVIEL E - NODAWAY 161KV CKT 1'	227	227	0.5641	73.80905	131.8539	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'HARVIEL E - NODAWAY 161KV CKT 1'	227	227	0.56407	62.45282	120.054	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21SP	ASGI_18_01	'TO->FROM'	'HARVIEL E - NODAWAY 161KV CKT 1'	227	227	0.56407	62.45282	120.054	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'TO->FROM'	'HARVIEL E - NODAWAY 161KV CKT 1'	227	227	0.41124	62.96305	104.949	'CLARINDA - J611 161.00 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'HARVIEL E - NODAWAY 161KV CKT 1'	227	227	0.56336	39.75549	100.7945	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	21L	ASGI_18_01	'TO->FROM'	'HARVIEL E - NODAWAY 161KV CKT 1'	227	227	0.56336	39.75549	100.7945	'MARYVILLE - MARYVILLE 161KV CKT 1'
FDNS	13ALL	0	26SP	ASGI_18_01	'FROM->TO'	'MARYVILLE 161/69KV TRANSFORMER CKT 2'	50	50	0.05336	77.03009	99.7	System Intact

EXHIBIT 10:

Second Facilities Study

Southwest Power Pool

AFFECTED SYSTEM INTERCONNECTION FACILITIES STUDY REPORT

Kansas City Power & Light (KCPL), Western Area Power Administration (WAPA)

Network Upgrade(s)

ASGI-2018-001

Published April 2019

By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
2/6/2019	SPP	Initial draft report issued.	
4/4/2019	SPP	Revised draft report issued to account for change in facility capacity.	
4/8/2019	SPP	Revision to draft report regarding full interconnection service provisions	

CONTENTS

SUMMARY

INTRODUCTION

This Affected System Interconnection Facilities Study (AS-IFS) for Interconnection Request ASGI-2018-001 (GIA-61) is for a proposed 242 MW generating facility to be connected to the facilities of Associated Electric Cooperative, Inc. located in Nodaway County, MO. The Affected System Interconnection Request was studied prior queued to the DISIS-2017-001 Impact Study for Affected System Impact Review for Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The Interconnection Customer's requested in-service date is December 31, 2019.

The affected Transmission Owners, Kansas City Power & Light (KCPL) and Western Area Power Administration (WAPA), performed a detailed AS-IFS at the request of SPP. The full reports are included in Appendix A. SPP has determined that full Interconnection Service will be available after the SPP Network Upgrades are completed.

The primary objective of the AS-IFS is to identify necessary Network Upgrades, cost estimates, and associated construction lead times needed to grant the full requested Interconnection Service.

PHASE(S) OF INTERCONNECTION SERVICE

It is not expected that Interconnection Service will occur in phases. However, full Interconnection Service will not be available until all Interconnection Facilities and Network Upgrade(s) can be placed in service.

CREDITS/COMPENSATION FOR AMOUNTS ADVANCED FOR NETWORK UPGRADES

Interconnection Customer shall be entitled to compensation in accordance with Attachment Z2 of the SPP OATT for the cost of SPP creditable-type Network Upgrades, including any tax gross-up or any other tax-related payments associated with the Network Upgrades, that are not otherwise refunded to the Interconnection Customer. Compensation shall be in the form of either revenue credits or incremental Long Term Congestion Rights (iLTCR).

GENERATING FACILITY

The Generating Facility is proposed to consist of 11 Vestas V110-2.0 MW and 100 Vestas V116-2.2 MW turbines for a total of 242 MW total capacity at the Maryville 161 kV substation in Nodaway County, MO.

AFFECTED SYSTEM NETWORK UPGRADE(S)

To facilitate interconnection, the Affected System Transmission Owner will perform work as shown below necessary for the acceptance of the Interconnection Customer's Interconnection Facilities.

Table 1 lists the Interconnection Customer's estimated cost responsibility for Affected System Non-Shared Network Upgrade(s) and provides an estimated lead time for completion of construction. The estimated lead time begins when the Facilities Construction Agreement has been fully executed.

Table 1: Affected System Non-Shared Network Upgrade(s)

Affected System Network Upgrades Description	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)	Estimated Lead Time
KCPL NUs: **KCP&L Maryville-AECI line rebuild:** KCP&L will replace existing wood structures and 795 ACSR conductor with new steel structures and 1192 ACSS conductor. Line has a total of four dead-end structures. **KCP&L Maryville sub bus upgrades:** upgrade 161kV strain bus, breaker disconnects, CTs, and breaker jumpers for 2000-amp capability. Bus will be limited to 1415 amps by 1.25" copper tube bus. **KCP&L Maryville relaying upgrades:** install new line differential relay panels for Line #11 and differential relays for transformer #33. **KCP&L Maryville-Clarinda line rebuild:** KCP&L will replace existing wood structures and 397.5 ACSR conductor with new steel structures and 1192 ACSS conductor on its portion of transmission line in Missouri.	$18,652,900	100%	$18,652,900	27 Months
WAPA NUs: Reconductor 62.4 miles of the Creston – Maryville 161kV transmission line using 556.5 ACSS Parakeet conductor, including new insulators assemblies and hardware to accommodate the higher temperature conductor. The proposed use of the ACSS type conductor eliminates the need to replace the existing transmission line structures previously identified in the earlier conceptual cost estimates.	$14,900,000	100%	$14,900,000	29 months
Total	**$33,552,900**	**100%**	**$33,552,900**	**29 months**

The Interconnection Customer's share of costs for Shared Network Upgrades is estimated in **Table 2** below.

Table 2: Interconnection Customer Shared Network Upgrades

Shared Network Upgrades Description	Total Cost Estimate ($)	Allocated Percent (%)	Allocated Cost Estimate ($)
None	$0	N/A	$0
Total	**$0**	**N/A**	**$0**

All studies have been conducted assuming that higher-queued Interconnection Request(s) and the associated Network Upgrade(s) will be placed into service. If higher-queued Interconnection Request(s) withdraw from the queue, suspend or terminate service, the Interconnection Customer's share of costs may be revised. Restudies, conducted at the customer's expense, will determine the Interconnection Customer's revised allocation of Shared Network Upgrades.

OTHER AFFECTED SYSTEM NETWORK UPGRADE(S)

Certain Other Affected System Network Upgrades are **currently not the cost responsibility** of the Interconnection Customer but will be required for full Interconnection Service.

Table 3: Interconnection Customer Other Affected System Network Upgrade(s)

Other Network Upgrade(s) Description	Current Cost Assignment	Estimate In-Service Date
None	N/A	N/A

Depending upon the status of higher- or equally-queued customers, the Interconnection Request's in-service date is at risk of being delayed or full Interconnection Service is at risk of being reduced until the in-service date of these Other Network Upgrades.

CONCLUSION

After all Affected System Network Upgrades have been placed into service, full Interconnection Service for 242.00 MW can be granted. Full Interconnection Service will be delayed until the Affected System Non-Shared Network Upgrade(s) and Other Affected System Network Upgrade(s) are completed. The Interconnection Customer's estimated cost responsibility for Affected System Non-Shared Network Upgrades is summarized in the table below.

Table 4: Cost Summary

Description	Allocated Cost Estimate
KCPL Affected System Network Upgrades	$18,652,900
WAPA Affected System Network Upgrades	$14,900,000
Total	**$33,552,900**

A draft Facilities Construction Agreement (CA) will be provided to the Interconnection Customer consistent with the final results of this AS-IFS report. The Affected System Transmission Owner and Interconnection Customer will have 60 days to negotiate the terms of the CA consistent with the SPP OATT.

APPENDIX A: TRANSMISSION OWNER'S INTERCONNECTION FACILITIES STUDY REPORT

Kansas City Power & Light Company

Affected System Interconnection Facilities Study for Southwest Power Pool

Generation Interconnection Request AECI GIA-61

ASGI-2018-001

Revision 1

Prepared by: Kansas City Power & Light Transmission Planning
March 28, 2019

Executive Summary

In accordance with the Southwest Power Pool (SPP) Generator Interconnection Procedures (GIP) 8.10 and 8.11, SPP Generator Interconnection (GI) Staff requested an Affected System Interconnection Facilities Study with associated interconnection costs and lead times for the proposed Network Upgrade of the Maryville-Maryville AEC 161kV transmission line and the Maryville-Clarinda 161kV line of the Kansas City Power & Light (KCP&L) transmission system. These upgrades are assigned to the Affected System Interconnection Customer(s) as part of the recently completed ASGI-2018-001 SPP Affected System Impact Study.

KCP&L performed the following Facility Study to satisfy the SPP GI Staff request for a generator interconnection request on the Associated Electric Cooperative Incorporated (AECI) transmission system. The request for interconnection was placed with AECI and designated as AECI GIA-61. The customer requests interconnection service for a 238-MW wind farm at the existing Maryville AEC 161kV substation in Northwest Missouri, near Maryville, Missouri. The customer has proposed a commercial operation date of December 31, 2019. Required Network Upgrade on the KCP&L transmission system involves rebuilding the Maryville-Maryville AEC 161kV transmission line and KCPL's portion of the Maryville-Clarinda 161kV line. Maryville-Maryville AECI is an existing, short (~0.5 mile) transmission tie line between 161 kV substations owned by KCP&L and AECI. The existing line uses 795 ACSR conductor and has a current rating of 225 Mva. The proposed upgrade will use 1192 ACSS conductor which will result in an increased emergency rating to 394 Mva. Network Upgrades will include terminal equipment and relaying at the KCP&L Maryville substation. KCPL's portion of the Maryville-Clarinda 161kV line is approximately 16.7 miles of existing transmission line using 397.5 ACSR conductor. The proposed upgrade will use 1192 ACSS conductor which will result in an increased emergency rating to 208 Mva. No terminal upgrades are needed for the Clarinda line terminal at Maryville.

The total cost for KCP&L to rebuild the Maryville-Maryville AEC 161kV line and upgrade terminal equipment the KCP&L Maryville substation, is estimated at $1,908,900. The total cost for KCP&L to rebuild its portion of Maryville-Clarinda 161kV line is estimate at $17,000,000. These estimates are accurate to +/- twenty (20) percent, based on current prices. However, recent cost fluctuations in materials are very significant and the accuracy of this estimate at the time of actual procurement and construction cannot be assured.

This Facility Study does not guarantee the availability of transmission service necessary to deliver the additional generation to any specific point inside or outside the SPP transmission system. The transmission network facilities may not be adequate to deliver the additional generation output to the transmission system. If the customer requests firm transmission service under the SPP Tariff at a future date, Network Upgrades or other new construction may be required to provide the service requested under the SPP Tariff.

Identification of Facilities Requiring Network Upgrades

SPP conducted an affected system study for AECI's GIA-61 request and observed thermal overloads on KCP&L's Maryville-Maryville AEC 161kV transmission line (PSSE branch 541251-300097) in several seasons. The overloads included base case (N-0) and contingent conditions (N-1). Highest overload was approximately 158%. Overloads were also identified on KCPL's portion of the Maryville-Clarinda 161kV line with highest overloads approximately 6% above the emergency rating. No voltage exceedances were identified on the KCP&L transmission system.

SPP requested that KCP&L provide mitigations for the thermal overloads on its system in the affected system study. KCP&L Transmission Planning determined that rebuilding the existing transmission line with larger conductor would eliminate the thermal overloads. KCP&L Engineering was asked to provide cost estimates to rebuild the existing transmission line and upgrade any terminal equipment to achieve a 1415-amp capability. That estimate is provided below.

KCP&L Maryville-AECI rebuild 0.5 mile	$ 865,000
KCP&L Maryville sub bus upgrades	$ 350,000
KCP&L Maryville relaying upgrades	$ 300,000
KCP&L Maryville-Clarinda rebuild 16.7 mi	$16,100,000
KCP&L AFUDC & contingencies	$ 1,037,900
Total	$18,652,900

Description of transmission owner network upgrades

KCP&L Maryville-AECI line rebuild: KCP&L will replace existing wood structures and 795 ACSR conductor with new steel structures and 1192 ACSS conductor. Line has a total of four dead-end structures.

KCP&L Maryville sub bus upgrades: upgrade 161kV strain bus, breaker disconnects, CTs, and breaker jumpers for 2000-amp capability. Bus will be limited to 1415 amps by 1.25" copper tube bus.

KCP&L Maryville relaying upgrades: install new line differential relay panels for Line #11 and differential relays for transformer #33.

KCP&L Maryville-Clarinda line rebuild: KCP&L will replace existing wood structures and 397.5 ACSR conductor with new steel structures and 1192 ACSS conductor on its portion of transmission line in Missouri.

Engineering, Procurement, and Construction Schedule: A nominal schedule for KCP&L to design, procure equipment and construct the Maryville-Maryville 161kV transmission line is approximately 16 months. The estimated schedule to design, procure material and construct KCP&L's portion of the Maryville-Clarinda 161kV line is approximately 27 months. It will not be possible to have simultaneous construction outages for these two transmission lines. According to good business practice, the KCP&L engineering and procurement process cannot begin until the parties have executed a mutually agreeable Engineering & Construction Agreement.

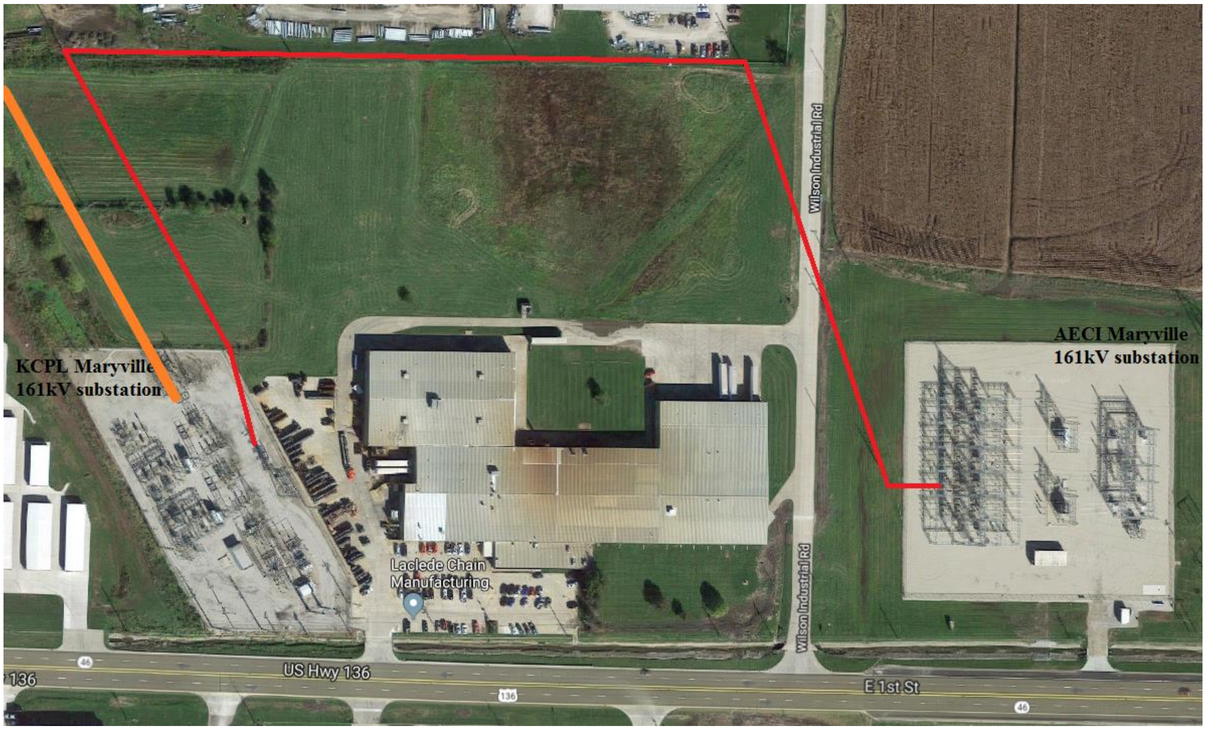
Short Circuit Fault Duty Evaluation

KCP&L engineering staff reviewed short circuit analysis performed by AECI for the proposed generation interconnections at the AECI Maryville substation to determine if the added generation would cause the available fault currents to exceed the interrupting capability of any existing KCP&L circuit breakers. The calculated fault currents were within KCP&L's circuit breaker interrupting capability with the addition of the AECI GIA-61 wind farm.

Other Required Network Upgrades

AECI will be responsible for any upgrades at its Maryville sub to provide an emergency rating of at least 363 Mva. Mid-American Energy Company will be responsible for any upgrades on its portion of the Maryville-Clarinda line to achieve an emergency rating of at least 182 Mva.

**Figure 1: Maryville-Maryville AEC 161kV transmission line (red)
Maryville-Clarinda 161kV line (orange)**



Affected System Facilities Study Report

Southwest Power Pool, Inc. ASGI-2018-001

Western Area Power Administration

Upper Great Plains Region

January 2019[1]

[1] Revised April 2019 to address change in requested uprate from 216 MVA to 237 MVA.

1.0 Background:

The Western Area Power Administration Upper Great Plains Region (WAPA-UGP[2]) received a request from the Southwest Power Pool Inc. (SPP) for an Affected System Facilities Study in accordance with the SPP Open Access Transmission Tariff (Tariff). Associated Electric Cooperative Inc. (AECI) has a generator interconnection request GIA-61 for an interconnection customer in their queue for a 242 MW wind generating facility with Point of Interconnection at the Maryville 161 kV Substation in Nodaway County, MO. WAPA-UGP owns the Creston-Maryville 161 kV Transmission Line and has included this facility under the SPP Tariff. AECI submitted a request to SPP for an Affected System Impact Study (ASIS). SPP assigned queue identifier ASGI-2018-001 to AECI's request.

2.0 Status of Existing Studies applicable to Request:

SPP completed the SPP ASGI-2018-001 ASIS with report dated November 2018. The SPP ASGI-2018-001 ASIS identified the need to reconductor WAPA-UGP's Creston-Maryville 161 kV Transmission Line to at least 237 MVA in order to accommodate the additional loading due to ASGI-2018-001.

This Affected System Facility Study evaluates impacts of ASGI-2018-001 to the Creston-Maryville 161 kV Transmission Line and the required facility upgrades to accommodate the 237 MVA rating.

3.0 Study Requirements:

WAPA-UGP has performed this Affected System Facilities Study to determine a good faith estimate of (i) the cost estimate for the required upgrades, and the interconnection customer's appropriate share of the cost of any required upgrades, and (ii) the time required to complete construction. This Affected System Facilities Study includes an evaluation of the following:

3.1 Develop/compile cost estimates for all WAPA-UGP labor, overheads, equipment additions, modifications, etc.

3.2 Review and document any other interconnection/control area requirements. Document these additional requirements (such as indication/metering, monitoring, control, relaying) and include these in the cost estimate.

3.3 Develop an overall time schedule for completion of the necessary addition/modifications.

4.0 Study Results:

WAPA-UGP performed the following tasks to evaluate the additions to the system to accommodate the line rating increase request as studied and outlined in Section 3.0 above:

[2] WAPA-UGP is also referred to as "Western-UGP" in the SPP Tariff.

4.1 **Facility additions:** The evaluation of facilities to accommodate the required rating of 237 MVA for WAPA-UGP's Creston-Maryville kV Transmission Line identified the following requirements:

- Reconductor 62.4 miles of the Creston-Maryville 161 kV Transmission Line using 556.5 ACSS Parakeet conductor, including new insulators assemblies and hardware to accommodate the high temperature conductor. The proposed use of the ACSS type conductor eliminates the need to replace the existing transmission line structures previously identified in the earlier conceptual cost estimates.

WAPA-UGP's estimated cost for labor, overhead, materials, and other miscellaneous costs to address the ASGI-2018-001 impacts (i.e. to achieve the identified 237 MVA rating) are outlined in Attachment A. The total cost is estimated to be $14,900,000. The interconnection customer is responsible for the entire cost of the project.

4.2 **Contractual Agreements:** A construction agreement and Environmental Review agreement are required for the advancement of funds and to address environmental requirements for the work at WAPA-UGP's Creston-Maryville 161 kV Transmission Line to proceed. SPP will tender a facilities construction agreement for negotiation and execution between the parties. The interconnection customer will be responsible for the actual costs of the line reconductor, and WAPA-UGP will require advance funding to proceed with the project. Upon completion of the work WAPA-UGP will own, operate, and maintain the modifications and improvements to WAPA-UGP's Creston-Maryville 161 kV Transmission Line.

4.3 **Interconnection/Control Area Requirements:** N/A

4.4 **Schedule:** WAPA-UGP's estimated milestone schedule for the reconductor of WAPA-UGP's Creston-Maryville 161 kV Transmission Line is shown in Attachment A. The schedule is subject to execution of a facilities construction agreement, advance funding being provided, outage availability, and completion of an Environmental Review by the timeframes identified in the facilities construction agreement.

5.0 Environmental Review:

WAPA-UGP is a federal agency under the U.S. Department of Energy and is subject to the National Environmental Policy Act (NEPA), 42 U.S.C §4321, et seq., as amended. WAPA-UGP anticipates an Environmental Assessment (EA) level of NEPA review will be required for the reconductor of the Creston-Maryville 161 kV Transmission Line. WAPA-UGP's general cost estimate for an EA level of NEPA review is $100,000. WAPA-UGP will tender an Environmental Review agreement authorizing WAPA-UGP, at interconnection customer's expense, to perform the Environmental Review including EA level of NEPA review.

6.0 Facilities Study Cost:

WAPA-UGP will audit the Affected System Facilities Study costs and provide a summary of these costs to SPP.

ATTACHMENT A

ESTIMATED COSTS FOR CRESTON-MARYVILLE 161 KV TRANSMISSION LINE RECONDUCTOR

ITEM	ESTIMATED COST	PAYMENT SCHEDULE
Planning and project management	$325,000	Upon Execution of Construction Agreement
Design, Specifications, and Contract Administration	$425,000	Upon Execution of Construction Agreement
Creston-Maryville 1061 kV Reconductor	$14,150,000	July 2020
TOTAL ESTIMATED PROJECT COST	**$14,900,000**	

ESTIMATED SCHEDULE

ACTIVITY	BEGIN	COMPLETE
Planning / Engineering Design	July 2019*	July 2020
Issue Construction Contract	September 2020	N/A
Award Construction Contract	November 2020	N/A
Construction	November 2020	November 2021
In-Service-Date	(milestone)	**December 2021***

*Subject to execution of facilities construction agreement, advance funding being provided, outage availability, and completion of an Environmental Review prior to the start of construction.

EXHIBIT 11:

SPP Correspondence on Restudy

Staples, Boone

From:	Jennifer Swierczek <jswierczek@spp.org>
Sent:	Thursday, May 7, 2020 3:06 PM
To:	Staples, Boone; Jon Langford; Alyssa Anderson
Cc:	Welniak, Jim; William Holden; Christi Pinkerton
Subject:	RE: Potential Affected System Impact Restudy for AECI GIA-61
Follow Up Flag:	Follow up
Flag Status:	Flagged

****External Email. Use caution before opening attachments or clicking links.****

Boone,

We appreciate your patience as we have been working through several higher queued impact restudies. Your affected system restudy is up next to be studied.

As the models used for the original impact study are over a year old and there have been several out of group withdrawals in addition to the J570 withdrawal, SPP intends to update the models used in the original analysis to reflect the latest interconnection request and network upgrade information.

To expedite your impact study, SPP intends to use MEPPI to assist with the ACCC/TDF analysis, LOIS calculations, and report.

We will be putting a scope together next week to send to MEPPI regarding the study assumptions, deliverables, and timeline. We will send the scope document to you for Tenaska's feedback.
Once the scope has been finalized, we will send to MEPPI for a cost estimate. If Tenaska is ok with the cost, SPP will kick off the study starting tentatively June 1st.

Again, we appreciate your patience as we work to deliver you accurate study results. Please let us know your thoughts about the approach, if you have any questions or concerns regarding your system impact restudy.

Best,
Jennifer Swierczek
jswierczek@spp.org
501.614.3522 (O)
501.454.3574 (C)

From: Staples, Boone <BStaples@tnsk.com>
Sent: Thursday, May 07, 2020 12:49 PM
To: Jon Langford <jlangford@spp.org>; Alyssa Anderson <aanderson@spp.org>; Jennifer Swierczek <jswierczek@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; William Holden <wholden@spp.org>
Subject: **External Email** RE: Potential Affected System Impact Restudy for AECI GIA-61

Hi Jon, Others,

Has SPP been able to make progress on these two items yet?

Thanks,
Boone Staples
Tenaska, Inc.
817-462-8050

From: Jon Langford <jlangford@spp.org>
Sent: Thursday, April 16, 2020 8:57 AM
To: Staples, Boone <BStaples@tnsk.com>; Alyssa Anderson <aanderson@spp.org>; Jennifer Swierczek <jswierczek@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; William Holden <wholden@spp.org>
Subject: RE: Potential Affected System Impact Restudy for AECI GIA-61

****External Email. Use caution before opening attachments or clicking links.****

Boone,

We will definitely let you know when we expect to have the study finished. We will also provide information on the major differences between the original study and the restudy.

Thanks.

--
Jon Langford

From: Staples, Boone <BStaples@tnsk.com>
Sent: Wednesday, April 8, 2020 4:08 PM
To: Jon Langford <jlangford@spp.org>; Alyssa Anderson <aanderson@spp.org>; Jennifer Swierczek <jswierczek@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; William Holden <wholden@spp.org>
Subject: **External Email** RE: Potential Affected System Impact Restudy for AECI GIA-61

Thanks for the update Jon. Will you please let me know when you expect to have this finished, and what are some of the major differences between the original study and the restudy aside from the J570 withdrawal?

Regards,
Boone

From: Jon Langford <jlangford@spp.org>
Sent: Tuesday, April 7, 2020 9:41 PM
To: Staples, Boone <BStaples@tnsk.com>; Alyssa Anderson <aanderson@spp.org>; Jennifer Swierczek <jswierczek@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton

<cpinkerton@spp.org>; William Holden <wholden@spp.org>
Subject: RE: Potential Affected System Impact Restudy for AECI GIA-61

****External Email. Use caution before opening attachments or clicking links.****

Good Evening Boone,

My name is Jon Langford and I am the team lead for Affected System Studies for SPP.

We spoke to AECI yesterday and provided them an update on this project. We are currently working on building schedules for the studies SPP has to perform for the affected systems. GIA-61 has not officially be set, but Alyssa and one of our engineers are currently developing the models we will use for the study. We do plan to utilize a consultant in order to accelerate the analysis.

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Also, we do have a new supervisor that is in charge of our schedules and resource allocation. Her name is Jennifer Swierczek and I have included her on this email. Please feel free to reach out to her if you have any additional questions.

Hope you have a great week.

--
Jon Langford, PE | Generator Interconnection
501-688-1794
Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223

From: Staples, Boone <BStaples@tnsk.com>
Sent: Friday, April 3, 2020 1:11 PM
To: Alyssa Anderson <aanderson@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; Jon Langford <jlangford@spp.org>; William Holden <wholden@spp.org>
Subject: **External Email** RE: Potential Affected System Impact Restudy for AECI GIA-61

Hi Alyssa,

I hope you are all well and good. Would you please provide an update on the status of the restudy discussed below?

Thanks,
Boone Staples
Tenaska, Inc.
817-462-8050

From: Alyssa Anderson <aanderson@spp.org>
Sent: Monday, January 27, 2020 11:58 AM
To: Staples, Boone <BStaples@tnsk.com>

Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; Jon Langford <jlangford@spp.org>; William Holden <wholden@spp.org>
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We apologize for not having better news for you at this time. Please let us know if you have any questions or concerns regarding your impact restudy.

Best,
Alyssa Anderson

From: Alyssa Anderson
Sent: Tuesday, January 14, 2020 3:24 PM
To: 'Staples, Boone' <BStaples@tnsk.com>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; Jon Langford <jlangford@spp.org>
Subject: RE: Potential Affected System Impact Restudy for AECI GIA-61

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I have scheduled a meeting internally next Tuesday to discuss if it would be possible to study GIA-61 at the POI (230 MW) since this project is intended to be physically limited. We will also revisit the seasons used to determine the seasonal limit, which currently include the ten year out seasonal case.

Until the folks here have a chance to meet, let's hold off on meeting again as a group next Thursday. There may not be a need to meet if senior staff determine it best to maintain the current course.

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Tenaska, Inc.
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To: Tolbert, Todd <TTolbert@AECI.org>; Staples, Boone <BStaples@tnsk.com>
Cc: Jarriel, Josh (jjarriel@aeci.org) <jjarriel@aeci.org>; McGeeney Chris <cmcgeeney@AECI.org>; Welniak, Jim <jwelniak@TENASKA.com>; Jon Langford <jlangford@spp.org>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; HweePing Won <hwon@spp.org>; Andy Barton <abarton@spp.org>
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Given the proximity of the request (POI was Cooper – Atchinson 245 kV), I would recommend a restudy be completed to determine if the network upgrades are still required.

I am not sure how this affects the other processes which are going on currently (i.e. Facilities Construction Agreement). There are not many policy or procedure documents surrounding this type of situation, so the SPP team will need to work with AECI to determine the best course of action.

Best,

Alyssa Anderson
Engineer II, Generation Interconnection Studies
Southwest Power Pool
501-482-2379 | aanderson@spp.org

EXHIBIT 12:

SPP Correspondence on Scope of Restudy

Staples, Boone

From: Jennifer Swierczek <jswierczek@spp.org>
Sent: Tuesday, July 7, 2020 12:21 PM
To: Staples, Boone; Jon Langford; Alyssa Anderson
Cc: Welniak, Jim; William Holden; Christi Pinkerton
Subject: RE: Potential Affected System Impact Restudy for AECI GIA-61

****External Email. Use caution before opening attachments or clicking links.****

Hi Boone,

Yes, the scope will be sent for your review today. Christi will send the scope this afternoon. If Tenaska has any comments, please provide them, or if needed, Christi can schedule a scope meeting between AECI, SPP, Tenaska and MEPPI.

Also the scope will be provided to MEPPI today for their review, schedule and cost estimate. We are suggesting a completion date of August 24-28, and want them to confirm.

2 weeks from today, Christi can send the final scope document along with cost and timing from MEPPI. If Tenaska is okay with the scope, schedule and cost we would schedule a kickoff meeting with AECI, Tenaska, and TOs.

Thanks,
Jennifer

From: Staples, Boone <BStaples@tnsk.com>
Sent: Monday, July 06, 2020 5:03 PM
To: Jennifer Swierczek <jswierczek@spp.org>; Jon Langford <jlangford@spp.org>; Alyssa Anderson <aanderson@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>
Subject: **External Email** RE: Potential Affected System Impact Restudy for AECI GIA-61

Hello Jennifer,

Checking in. Would you mind providing an update?

Thanks,
Boone Staples
Tenaska, Inc.
817-462-8050

From: Jennifer Swierczek <jswierczek@spp.org>
Sent: Monday, June 1, 2020 12:59 PM
To: Staples, Boone <BStaples@tnsk.com>; Jon Langford <jlangford@spp.org>; Alyssa Anderson <aanderson@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>
Subject: RE: Potential Affected System Impact Restudy for AECI GIA-61

****External Email. Use caution before opening attachments or clicking links.****

Boone,

The scope document will be provided June 15 to 19, per timeline below.

Thanks,
Jennifer

From: Staples, Boone <BStaples@tnsk.com>
Sent: Friday, May 29, 2020 1:18 PM
To: Jennifer Swierczek <jswierczek@spp.org>; Jon Langford <jlangford@spp.org>; Alyssa Anderson <aanderson@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>
Subject: **External Email** RE: Potential Affected System Impact Restudy for AECI GIA-61

Jennifer,

Thanks, but did you mean to attach the draft scope?

Regards,
Boone

From: Jennifer Swierczek <jswierczek@spp.org>
Sent: Thursday, May 28, 2020 4:52 PM
To: Staples, Boone <BStaples@tnsk.com>; Jon Langford <jlangford@spp.org>; Alyssa Anderson <aanderson@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>
Subject: RE: Potential Affected System Impact Restudy for AECI GIA-61

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Boone,

Here is a draft scope and target timeline, in estimate form for restudy GIA-61 (ASGI-2018-001). We will need to confirm the scope and timeline prior to kicking off the study.

- Scope development target week of June 15 to 19
- Consultant kickoff target week of June 29 to July 3
- Study completion target week of August 24 to 28 (estimate 8 weeks could be sooner)

Thank you,

Jennifer Swierczek | Supervisor, Generator Interconnection Studies | jswierczek@spp.org | 501-614-3522 | 501-454-3574
Southwest Power Pool | SPP.org | twitter.com/SPPorg | facebook.com/SouthwestPowerPool
Helping our members work together to keep the lights on...today and in the future

---

From: Jennifer Swierczek
Sent: Thursday, May 07, 2020 3:06 PM
To: 'Staples, Boone' <BStaples@tnsk.com>; Jon Langford <jlangford@spp.org>; Alyssa Anderson <aanderson@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>
Subject: RE: Potential Affected System Impact Restudy for AECI GIA-61

Boone,

We appreciate your patience as we have been working through several higher queued impact restudies. Your affected system restudy is up next to be studied.

As the models used for the original impact study are over a year old and there have been several out of group withdrawals in addition to the J570 withdrawal, SPP intends to update the models used in the original analysis to reflect the latest interconnection request and network upgrade information.

To expedite your impact study, SPP intends to use MEPPI to assist with the ACCC/TDF analysis, LOIS calculations, and report.

We will be putting a scope together next week to send to MEPPI regarding the study assumptions, deliverables, and timeline. We will send the scope document to you for Tenaska's feedback.
Once the scope has been finalized, we will send to MEPPI for a cost estimate. If Tenaska is ok with the cost, SPP will kick off the study starting tentatively June 1st.

Again, we appreciate your patience as we work to deliver you accurate study results. Please let us know your thoughts about the approach, if you have any questions or concerns regarding your system impact restudy.

Best,
Jennifer Swierczek
jswierczek@spp.org
501.614.3522 (O)
501.454.3574 (C)

From: Staples, Boone <BStaples@tnsk.com>
Sent: Thursday, May 07, 2020 12:49 PM
To: Jon Langford <jlangford@spp.org>; Alyssa Anderson <aanderson@spp.org>; Jennifer Swierczek <jswierczek@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; William Holden <wholden@spp.org>
Subject: **External Email** RE: Potential Affected System Impact Restudy for AECI GIA-61

Hi Jon, Others,

Has SPP been able to make progress on these two items yet?

Thanks,

Boone Staples
Tenaska, Inc.
817-462-8050

From: Jon Langford <jlangford@spp.org>
Sent: Thursday, April 16, 2020 8:57 AM
To: Staples, Boone <BStaples@tnsk.com>; Alyssa Anderson <aanderson@spp.org>; Jennifer Swierczek <jswierczek@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; William Holden <wholden@spp.org>
Subject: RE: Potential Affected System Impact Restudy for AECI GIA-61

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Boone,

We will definitely let you know when we expect to have the study finished. We will also provide information on the major differences between the original study and the restudy.

Thanks.

--
Jon Langford

From: Staples, Boone <BStaples@tnsk.com>
Sent: Wednesday, April 8, 2020 4:08 PM
To: Jon Langford <jlangford@spp.org>; Alyssa Anderson <aanderson@spp.org>; Jennifer Swierczek <jswierczek@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; William Holden <wholden@spp.org>
Subject: **External Email** RE: Potential Affected System Impact Restudy for AECI GIA-61

Thanks for the update Jon.   Will you please let me know when you expect to have this finished, and what are some of the major differences between the original study and the restudy aside from the J570 withdrawal?

Regards,
Boone

From: Jon Langford <jlangford@spp.org>
Sent: Tuesday, April 7, 2020 9:41 PM
To: Staples, Boone <BStaples@tnsk.com>; Alyssa Anderson <aanderson@spp.org>; Jennifer Swierczek <jswierczek@spp.org>
Cc: Welniak, Jim <jwelniak@TENASKA.com>; William Holden <wholden@spp.org>; Christi Pinkerton <cpinkerton@spp.org>; William Holden <wholden@spp.org>
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Given the proximity of the request (POI was Cooper – Atchinson 245 kV), I would recommend a restudy be completed to determine if the network upgrades are still required.

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Alyssa Anderson
Engineer II, Generation Interconnection Studies
Southwest Power Pool
501-482-2379 | aanderson@spp.org

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EXHIBIT 13:

SPP Scope Document

SPP AFFECTED SYSTEM IMPACT RESTUDY AND LIMITED OPERATION IMPACT STUDY OF AECI GIA-61 (ASGI-2018-001)

Published July 2020

By SPP Generator Interconnections Dept.

REVISION HISTORY

Date	Author	Revision	Change Description
7/14/2020	SPP	R0	Draft scope for affected system impact restudy of AECI GIA-61
7/17/2020	SPP	R1	Scenario A removed from scope and Appendix B generators moved to external document (GenList.csv).
7/23/2020	SPP	R2	Scenarios A and B more clearly defined as separate impact studies. Language updated to reflect change in starting model set.

TABLE OF CONTENTS

INTRODUCTION

An Affected System Impact Study (ASIS) evaluates the impact of the proposed interconnection on the reliability of the Transmission System. The ASIS may include steady-state power flow, transient stability, and short-circuit analyses. The ASIS considers the Base Case[1], as well as all Interconnection Requests in the SPP and Affected System Queues and all generating facilities (and with respect to (ii and iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the ASIS is commenced:

(i) are directly interconnected to the Transmission System;

(ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request;

(iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; or

(iv) have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

In the event the ASIS determines network upgrades are required for full interconnection service, a Limited Operation Impact Study (LOIS), shall quantify the amount of interconnection capacity available to the Interconnection Customer prior to the in-service date of such upgrade(s). The Interconnection Customer shall be notified of the amount of interconnection capacity available under the Limited Operation condition. The Interconnection Customer may choose to proceed with Limited Operation. The Interconnection Customer may also be subject to conditions in Section 8.7 of the GIP[2].

Unless otherwise indicated, the analysis for Limited Operation assumes that all higher-queued[3] interconnection projects will go into commercial operation before the completion of all higher queued Network Upgrades[4] identified. If additional interconnection requests not included in the Limited Operation study assumptions (with queue priority equal to or higher than the study projects) request to begin commercial operation, the Limited Operation amount may need to be reevaluated to ensure that interconnection service continues to be available for the customer's request.

The Limited Operation analysis addresses the effects of interconnecting the generator to the rest of the transmission system for the system topology and conditions as identified under the following assumptions:

1. Exclude all previously assigned transmission system upgrades identified in the higher queued DISIS studies or other SPP planning processes that are not expected to be in-service on the requested commercial operation date from the models.

[1] The Base Case (also referred to as the BASE case) refers to the latest ITP model utilized by the Generation Interconnection department for study.
[2] Affected system interconnection requests which are not subject to the GIP may be subject to SPP Business Practice 7300 and/or the Joint Operating Agreement (JOA) between the host TO and SPP.
[3] Per Attachment V Section 4.1.3, "Once an Interconnection Customer has met all requirements for an Interconnection Facilities Study, its Interconnection Queue Position shall be deemed higher than those in the DISIS queue."
[4] Higher queued network upgrades are those facilities which have been assigned to higher queued interconnection requests or were included in the ITP model assumptions.

2. Include all previously assigned transmission system upgrades identified in the higher queued DISIS studies or other SPP planning processes that are expected to be in-service on the requested commercial operation date in the models.

In addition to the study assumptions outlined above, the LOIS considers the Base Case[1] as well as all Generating Facilities (and with respect to any identified Network Upgrades associated with such higher queued interconnection) that, on the date the LOIS is commenced:

1. are directly interconnected to the Transmission System;
2. are interconnected to Affected Systems and may have an impact on the Interconnection Request;
3. have a pending higher queued Interconnection Request or projects to interconnect to the Transmission System[3]; or
4. have no Queue Position but have executed an (L/S)GIA or requested that an unexecuted (L/S)GIA be filed with FERC.

SCOPE

The ASIS and LOIS for AECI GIA-61 will be evaluated for power flow analysis only. Stability and short circuit analysis will not be evaluated. GIA-61 is a 242 MW[5] wind request interconnecting at the Maryville 161 kV substation in Nodaway County, MO.

STUDY KICKOFF

SPP will provide at Kickoff the DISIS-2017-001 base case models along with the requested model updates to be made for the ASIS and LOIS. SPP will also provide at kickoff the required files for dispatch, ACCC, and TDF analysis.

MODEL DEVELOPMENT

SPP will provide to the Consultant the DISIS-2017-001 dispatched base cases as the starting point for the analysis. Prior to dispatch, the Consultant will implement the required model updates as provided at kickoff. After the updates are implemented, the models may be dispatched.

To generate the base and transfer models, the Consultant will turn off any lower queued generation and scale the host footprint accordingly. Once all lower queued generation has been adjusted, the models may be adjusted for the current study generation. To generate the transfer models, as GIA-61 will already be dispatched in the DISIS-2017-001 base cases, to generate the GIA-61 base cases, the Consultant will turn off the GIA-61 request and scale the AECI footprint according to SPP dispatch methodology for each ERIS and NRIS model set. Lastly, for the LOIS only, the Consultant will adjust the model to remove any generation from the model which is not expected to be in-service during those seasonal models. The list of generators to exclude from the analysis will be provided at kickoff.

The ASIS will serve to identify if any of the previously identified network upgrades are still required for full interconnection service under the assumption that all higher queued interconnection requests and network upgrades are in-service. The LOIS will serve to identify the available capacity for GIA-61 during the 2020 summer and winter seasons. Each impact study will also utilize the 2024 light, summer, and winter seasons to determine if changes in topology or load alleviate near-term constraints.

Table 2 and Table 3 outline the network upgrades assigned from AECI and the SPP network upgrades under reevaluation, respectively. The requested interconnection requests and network upgrades to be added/removed from each model set will be provided at kickoff. Table 4 details the total number of cases to be created per impact study.

[5] While GIA-61 has indicated that the injection at the POI will be limited to 230 MW, SPP must evaluate the capacity of the request from the generator.

Table 1: Summary of Group 13 Scenarios

Impact Study	Interconnection Requests	Base Case Network Upgrades
GIA-61 G13 Restudy	All requests higher and equally queued to GIA-61	DIS1602 and higher (no network upgrades from the DPPFEB17-West will be included as they are under reevaluation)
GIA-61 G13 LOIS	Only higher and equally queued requests expected to be in-service per seasonal model. List of interconnection requests to be included/excluded from the analysis will be provided at kickoff.	Only higher queued network upgrades expected to be in-service per seasonal model. List of network upgrades to be included/excluded from the analysis will be provided at kickoff.

Table 2: AECI Assigned Network Upgrades

Upgrade	Description	Status
A1	Rebuild Gentry-Fairport 161 kV	Complete
A2	Rebuild Nodaway-Gentry 161 kV	Complete
A3	Upgrade Maryville 161/69 kV Transformer	Complete
A4	Uprate Darlington to Stanberry 69 kV	Summer 2021
A5	Rebuild Darlington to Fairport 69 kV	Complete

Table 3: Network Upgrades under Reevaluation

SPP Transmission Owner	Network Upgrade Key	Description	Lead Time (Months)	Estimated In-Service Date[6]
KCPL	K1	Maryville-AECI line rebuild: KCP&L will replace existing wood structures and 795 ACSR conductor with new steel structures and 1192 ACSS conductor. Line has a total of four dead-end structures.	27	11/30/2022
KCPL	K2	Maryville sub bus upgrades: upgrade 161kV strain bus, breaker disconnects, CTs, and breaker jumpers for 2000-amp capability. Bus will be limited to 1415 amps by 1.25” copper tube bus.	27	
KCPL	K3	Maryville relaying upgrades: install new line differential relay panels for Line #11 and differential relays for transformer #33.	27	
KCPL	K4	Maryville-Clarinda line rebuild: KCP&L will replace existing wood structures and 397.5 ACSR conductor with new steel structures and 1192 ACSS conductor on its portion of transmission line in Missouri.	27	
WAPA	W1	62.4 miles of the Creston – Maryville 161kV transmission line using 556.5 ACSS Parakeet conductor, including new insulators assemblies and hardware to accommodate the higher temperature conductor. The proposed use of the ACSS type conductor eliminates the need to replace the existing transmission line structures previously identified in the earlier conceptual cost estimates.	29	6/1/2024

[6] Given a FERC effective date of 8/30/2020 for Facility Construction Agreement between GIA-61 and KCPL, the estimated ISD of the KCPL network upgrades (with a lead time of 27 months) would be 11/30/2022.
As the WAPA network upgrades identified in the original impact study have a lead time of 29 months, to include the WAPA network upgrades in the 2024 seasonal models, the GIA-61 and WAPA would need to have an effective date of no later than 1/1/2022.

Table 4: Maximum Total Case Count per Scenario

Scenario	Group(s)	Requests	Fuel Types	Seasonal Cases	ERIS HVER Cases	ERIS LVER Cases (Peak)	NRIS HVER Cases (G, L)	NRIS HVER Cases (Peak)	Total Case Count
ASIS	13	1	Wind	20G 20SP 20WP 24L 24SP 24WP	Group13ALL (6 BC, 6 TC)	N/A	Group13NR (2 BC, 2 TC)	Group00NR (4 BC, 4 TC)	24
LOIS	13	1	Wind	20G 20SP 20WP 24L 24SP 24WP	Group13ALL (6 BC, 6 TC)	N/A	Group13NR (2 BC, 2 TC)	Group00NR (4 BC, 4 TC)	24

POWERFLOW ANALYSIS

ERIS and NRIS constraints identified in each scenario will be incrementally mitigated per the Constraint Identification and Mitigation Procedures. Mitigation will be tested to ensure no further constraints are caused. Cost estimates will be developed for the mitigation along with estimated lead-times for construction. If the estimated construction time is later than the in-service proposed date, a Limited Operation amount will be calculated per seasonal case for the most limiting constraint.

ASIS REPORT, POSTING, AND FINAL STUDY PACKAGE

The study assumptions, methods, results, and conclusions will be described in a technical report for the interconnection customer and affected parties to understand the impacts of the proposed generation on the SPP transmission system.

The Consultant will provide a report for SPP's review for each impact study. SPP will work with the Consultant, affected Transmission Owners, host Transmission Owner, and Interconnection Customer to ensure the report is clear, cohesive, and meets the needs of the Interconnection Customer.

SPP will post the ASIS report to SPP OASIS and notify all affected parties in accordance with SPP business practices.

The Consultant will provide to SPP a final study package consisting of all materials which would be required to replicate the study, either by SPP or by another Consultant on behalf of an interconnection customer. The Consultant will also provide to SPP any other materials such as PSS/E models, idevs, Python scripts, etc. which were developed for this analysis.

STUDY TASKS AND DELIVERABLES

Table 5 outlines the tasks required to be completed for each impact study. Subtasks have been added to clarify the work requested to aid project management decisions and the Consultant Work Order development. The subtasks below should be treated as deliverables, either for SPP or the Consultant. SPP recommends these subtasks be completed in the order they are listed. Any subtask that does not receive SPP sign-off by will be considered incomplete.

SPP requests that the Consultant provide in the Work Order a schedule outlining the proposed completion dates of the subtasks below. SPP requests the Consultant aim to complete both impact studies by August 30th, 2020.

Model development, ACCC/TDF analysis, and Cost Allocation must be conducted in accordance with SPP procedures and methods. SPP reserves the right to review any subtask outlined below, even if a review is not explicitly noted.

The Consultant will be responsible for coordinating, hosting, and conducting weekly meetings to discuss the progress, road-blocks, and next steps of the study. SPP reserves the right to modify the frequency of these meetings as needed during the course of the study.

The following Tasks will apply to each cluster study.

Table 5: Tasks and Subtasks per Impact Study

Task	Subtask

Dispatch of Base and Transfer Cases	Consultant develops base and transfer cases for the impact studies outlined in the scope. Consultant provides draft base and transfer cases to SPP for review.
	SPP reviews draft base and transfer cases and provides feedback on models.
	Consultant incorporates feedback on dispatch for base and transfer cases. Consultant provides final base and transfer cases to SPP for review.
	SPP provides feedback on final case set.
ERIS ACCC & TDF Constraint Identification, Mitigation, and Testing	ACCC and TDF analysis for ERIS thermal and non-converged constraints
	ERIS thermal and non-converged constraint review and mitigation
	ERIS thermal and non-converged constraint mitigation testing
	ERIS thermal and non-converged constraint review and mitigation
	ACCC and TDF analysis for ERIS voltage constraints
	ERIS voltage constraint review and mitigation
	ERIS voltage constraint mitigation testing
	ERIS voltage constraint review and mitigation
NRIS ACCC & TDF Constraint Identification, Mitigation, and Testing	ACCC and TDF analysis for NRIS thermal and non-converged constraints
	NRIS thermal and non-converged constraint review and mitigation
	NRIS thermal and non-converged constraint mitigation testing
	ACCC and TDF analysis for NRIS voltage constraints
	NRIS voltage constraint review and mitigation
	NRIS voltage constraint mitigation testing
Network Upgrade Review and Cost Allocation	Coordination with TOs regarding network upgrade costs
	Cost allocation TDF analysis
	Generate cost allocation reports with GI report database
Report Development, Review, and Posting	Draft report
	Draft report review
	Final report
	Final report review
	Provide final report to AECI, SPP sends email notification of posting to customers

POWER FLOW ANALYSIS

Power flow analysis determines if the transmission system can accommodate the injection from the request without violating thermal or voltage transmission planning criteria.

MODEL PREPARATION

Power flow analysis will use the latest models available for the study queue, which are modified versions of the 2018 series of 2019 ITP Near-Term study models including these seasonal models:

SPP uses a group dispatch methodology for both SPP and Affected System Impact Studies. SPP generator interconnection requests will be dispatched across the SPP footprint using load factor ratios. Affected system interconnection requests will be dispatched across their respective footprint using the load factor ratios.

For Variable Energy Resources (VER) (solar/wind) in each power flow case, ERIS, is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas is dispatched at 20% nameplate of maximum generation.

Peaking units are not dispatched in the Year 2 spring and Year 5 light, or in the “High VER” summer and winter peaks. To study peaking units’ impacts, the Year 1 winter peak, Year 2 summer peak, and Year 5 summer and winter peaks, and Year 10 summer peak models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

All generators (VER and peaking) that requested NRIS are dispatched in an additional analysis into the interconnecting Transmission Owner’s (T.O.) area at 100% nameplate with ERIS only requests at 80% nameplate. This method allows for identification of network constraints that are common between regional groupings to have affecting requests share the mitigating upgrade costs throughout the cluster.

Table 6: SPP Dispatch Criteria

Dispatch Type	Season	Service Type	Renewable in group	Renewable out of group	Conventional in group	Conventional out of group
ERIS HVER	All	All	100%	20%*	N/A	N/A
ERIS LVER	Peak	All	20%	20%	100%	100%
NRIS	Spring and Light Load	ERIS	80%	20%	N/A	N/A
		NRIS	100%	20%	100%	20%
	Peak	ERIS	20% (solar: 80% in SP)	20% (solar: 80% in SP)	80%	80%
		NRIS	100%	100%	100%	100%

*For light 10% for DISIS-2016-002 or 0% for DISIS-2017-001 forward

CONSTRAINT IDENTIFICATION AND MITIGATION PROCEDURES

For each ASIS, the Consultant will conduct steady state power flow analysis per the section of this document and determine which constraints meet SPP mitigation criteria.

ERIS THERMAL NON-CONVERGED CONSTRAINT IDENTIFICATION AND MITIGATION

For each ASIS, the Consultant shall identify mitigation for all non-converged ERIS thermal constraints and provide suggested mitigation for SPP's review.

SPP may confer with the affected TO and provide feedback regarding the suggested mitigation.

The Consultant will implement the mitigation to resolve the non-converged ERIS thermal constraints. The Consultant will continue to iteratively identify, mitigate, and test non-converged ERIS thermal mitigation until no non-converged ERIS thermal constraints remain.

Final non-converged ERIS thermal mitigations will be included in the system intact and contingency ERIS thermal constraint identification analysis.

ERIS THERMAL SYSTEM INTACT AND CONTINGENCY CONSTRAINT IDENTIFICATION AND MITIGATION

For each ASIS, the Consultant shall identify mitigation for all system intact and contingency ERIS thermal constraints and provide suggested mitigation for SPP's review.

SPP may confer with the affected TO and provide feedback regarding the suggested mitigation.

The Consultant will implement the mitigation to resolve the system intact and contingency ERIS thermal constraints. The Consultant will continue to iteratively identify, mitigate, and test system intact and contingency ERIS thermal mitigation until no system intact and contingency ERIS thermal constraints remain.

Final system intact and contingency ERIS thermal mitigations will be included in the ERIS voltage constraint identification analysis.

ERIS VOLTAGE CONSTRAINT IDENTIFICATION AND MITIGATION

For each ASIS, the Consultant shall identify mitigation for all ERIS voltage constraints and provide suggested mitigation for SPP's review.

SPP may confer with the affected TO and provide feedback regarding the suggested mitigation.

The Consultant will implement the mitigation to resolve the ERIS voltage constraints. The Consultant will continue to iteratively identify, mitigate, and test ERIS voltage mitigation until no system intact and contingency ERIS voltage constraints remain.

All ERIS mitigations will be included in the NRIS non-converged constraint identification analysis.

NRIS THERMAL NON-CONVERGED CONSTRAINT IDENTIFICATION AND MITIGATION

For each ASIS, the Consultant shall identify mitigation for all non-converged NRIS thermal constraints and provide suggested mitigation for SPP's review.

SPP may confer with the affected TO and provide feedback regarding the suggested mitigation.

The Consultant will implement the mitigation to resolve the non-converged NRIS thermal constraints. The Consultant will continue to iteratively identify, mitigate, and test non-converged NRIS thermal mitigation until no non-converged NRIS thermal constraints remain.

Final non-converged NRIS thermal mitigations will be included in the system intact and contingency NRIS thermal constraint identification analysis.

NRIS THERMAL SYSTEM INTACT AND CONTINGENCY CONSTRAINT IDENTIFICATION AND MITIGATION

For each ASIS, the Consultant shall identify mitigation for all system intact and contingency NRIS thermal constraints and provide suggested mitigation for SPP's review.

SPP may confer with the affected TO and provide feedback regarding the suggested mitigation.

The Consultant will implement the mitigation to resolve the system intact and contingency NRIS thermal constraints. The Consultant will continue to iteratively identify, mitigate, and test system intact and contingency NRIS thermal mitigation until no system intact and contingency NRIS thermal constraints remain.

Final system intact and contingency NRIS thermal mitigations will be included in the NRIS voltage constraint identification analysis.

NRIS VOLTAGE CONSTRAINT IDENTIFICATION AND MITIGATION

For each ASIS, the Consultant shall identify mitigation for all NRIS voltage constraints and provide suggested mitigation for SPP's review.

SPP may confer with the affected TO and provide feedback regarding the suggested mitigation.

The Consultant will implement the mitigation to resolve the NRIS voltage constraints. The Consultant will continue to iteratively identify, mitigate, and test NRIS voltage mitigation until no system intact and contingency NRIS voltage constraints remain.

NETWORK UPGRADE COST ESTIMATES, ALTERNATIVE SOLUTIONS, AND LIMITED OPERATION AVAILABLITY

Identified constraints and proposed network upgrades identified in each analyses will be provided to Transmission Owners (TOs) for review. TOs will have ten business days to provide alternative constraint solutions, high-level good-faith cost estimates, and approximate construction lead time/in-service dates for all network upgrades identified.

Alternative mitigation solutions will be evaluated and the recommended solution will be selected by SPP for inclusion in the study report.

If the proposed mitigation is not expected to be in-service before the interconnection customers proposed in-service date, a Limited Operation availability will be calculated for each interconnection request based on the most limiting constraint observed in the analysis.

ASIS REPORT, POSTING, AND FINAL STUDY PACKAGE

The study assumptions, methods, results, and conclusions will be described in a technical report for the interconnection customer and affected parties to understand the impacts of the proposed generation on the SPP transmission system.

For each impact cluster study, the Consultant will provide a draft report for SPP's review. A report is required for each cluster study. The draft report will initially be reviewed by SPP engineering staff, tariff services staff, and the affected TOs. The draft will be returned to the Consultant for editing. Upon receipt and review of the updated draft, the AFS team will provide to GI management the updated draft for review. The AFS team will provide GI management's comments to the Consultant for inclusion in the report. The Consultant will update the report and provide the final report for all parties to review.

SPP will post the ASIS report to SPP OASIS and notify all affected parties in accordance with SPP business practices.

The Consultant will provide to SPP a final study package consisting of all materials which would be required to replicate the study, either by SPP or by another Consultant on behalf of an interconnection

DISPATCH SCENARIOS

SPP uses scenario numbers to keep track of case sets. The initial scenario (Scenario 0) should not contain any current study network upgrades. The final scenario (Scenario 1) should contain all of the network upgrades from all groups. Scenario 1 should not result in any constraints for mitigation on the SPP transmission system.

The following scenarios are recommended for the ERIS analysis:

Scenario	Description
0	No current study network upgrades included
1	All current study network upgrades included from all groups (ERIS only)

It is recommended that the ERIS analysis be completed first as these network upgrades should be included in Scenario 0 of the NRIS analysis.

The following scenarios are recommended for the NRIS analysis:

Scenario	Description
0	ERIS current study network upgrades included
1	All current study network upgrades included from all groups (ERIS and NRIS)

STUDY METHODOLOGY AND CRITERIA

SOLVE PARAMETERS

All models must solve with the "tight solve" parameters prior to ACCC and TDF.

The following solution parameters should be used:

- Fixed slope decoupled Newton-Raphson
- Tap adjustment – stepping
- Switch shunt adjustments – enable all
- Area interchange control – tie lines and loads
- Adjust phase shift
- Adjust DC taps
- VAR limits – apply immediately
- Must solve within five iterations, three or less is preferred

SPP will provide a slow and tight solve idev for reference.

THERMAL OVERLOADS

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously mentioned.

For Energy Resource Interconnection Service (ERIS), thermal overloads are determined for system intact (n-0) (greater than or equal to 100% of Rate A - normal) and for contingency (n-1) (greater than or equal to 100% of Rate B – emergency) conditions.

The overloads are then screened to determine which of generator interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage based conditions (n-1), or
- 3% DF on contingent elements that resulted in a non-converged solution.

Interconnection Requests that requested Network Resource Interconnection Service (NRIS) are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also considered for transmission reinforcement under NRIS.

Contingencies

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

- All branches, ties, shunts, and generators within the following areas:
  - SPP Internal Areas for 60kV – 999kV facilities:
    - 515 – 546, 640, 641, 642, 645, 650, 652, 659. 998, 999
  - SPP External Areas for 100kV – 999kV facilities:
    - 327, 330, 351, 356, 502-504, 600, 615, 620, 627, 635, 672, 680
- NERC, SPP, and Tier 1 Permanent Contingent Flowgates
- SPP T.O. Specific P1, P2, P4, and P5 TPL-004-1 Contingencies
- SPP T.O. Specific Op Guide Implementation

Monitored Facilities

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution

Flowgates for SPP and first tier Non-SPP control areas are monitored. Additional NERC Flowgates are monitored in second tier or greater Non-SPP control areas. Voltage monitoring was performed for SPP control area buses 69 kV and above.

- All branches (thermal)/ buses(voltage) and ties within the following areas:
  - SPP Internal Areas for 60kV – 999kV facilities:
    - 515 – 546, 640 – 659, 998, 999
- NERC, SPP, and Tier 1 Permanent Monitor Flowgates (thermal)

VOLTAGE

For non-converged power flow solutions that are determined to be caused by lack of voltage support, appropriate transmission support will be determined to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

<u>SPP Areas (69kV+):</u>

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AEPW	0.95 – 1.05 pu	0.92 – 1.05 pu
GRDA		0.90 – 1.05 pu
SWPA		
OKGE		
OMPA		
WFEC		
SWPS		
MIDW		
SUNC		
KCPL		
INDN		
SPRM		
NPPD		
WAPA		
WERE L-V		0.93 – 1.05 pu
WERE H-V		0.95 – 1.05 pu
EMDE L-V		0.90 – 1.05 pu
EMDE H-V		0.92 – 1.05 pu
LES		0.90 – 1.05 pu
OPPD		

SPP Buses with more stringent voltage criteria:

Bus Name/Number	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
TUCO 230kV 525830	0.925 – 1.05 pu	0.925 – 1.05 pu
Wolf Creek 345kV 532797	0.985 – 1.03 pu	0.985 – 1.03 pu

FCS 646251	1.001 – 1.047 pu	1.001 – 1.047 pu

Affected System Areas (115kV+):

Transmission Owner	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
AECI	0.95 – 1.05 pu	0.90 – 1.05 pu
EES-EAI		
LAGN		
EES		
AMMO		
CLEC		
LAFA		
LEPA		
XEL		
MP		
SMMPA		
GRE		0.90 – 1.10 pu
OTP		0.90 – 1.05 pu
OTP-H (115kV+)	0.97 – 1.05 pu	0.92 – 1.10 pu
ALTW	0.95 – 1.05 pu	0.90 – 1.05 pu
MEC		
MDU		
SPC		0.95 – 1.05 pu
DPC		0.90 – 1.05 pu
ALTE		

The constraints identified through the voltage scan are then screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage.

RESULTS

ACCC with associated FCITC TDF results will be provided as part of the report for this Study.

The analysis will determine and verify the amount of generation that can be connected to the SPP transmission system without system constraints that require mitigation assuming only the upgrades that are expected to be in service at the expected time of interconnection Commercial Operation Date.

COST ALLOCATION

Use SPP provided cost allocation tools along with training provided by SPP.

Alternative calculation:

Calculation of Impact Factor for a particular request:

- Request X, Upgrade Project 1 = PTDF (%)(X) * MW(X) = X1
- Request Y, Upgrade Project 1 = PTDF (%)(Y) * MW(Y) = Y1
- Request Z , Upgrade Project 1 = PTDF (%)(Z) * MW(Z) = Z1

Allocation of Cost for a particular project:

- Request X's Project 1 Cost Allocation ($) = Network Upgrade Project 1 Cost($) * X1
- X1 + Y1 + Z1

If the current study interconnection request requires a network upgrade for full interconnection service, the study resource will determine the Limited Operation amount available to the request prior to all required network upgrades being in-service.

LIMITED OPERATION ANALYSIS

The results of the Power Flow Analysis and Stability Analysis identify the system constraints that require mitigation. The Limited Operation Analysis evaluates the most limiting of these constraints for each current study request and identifies an amount of available interconnection service.

Power Flow Analysis results include the thermal overload amount, circuit rating, size and TDF of each current study request. An initial Limited Operation amount is calculated by identifying the impact of each request on each constraint and identifying a reduced size of each request proportional to the thermal constraint that would result in a circuit loading within the applicable rating.

The Limited Operation amount is calculated according to the following equation:

$$\text{Limited Operation amount} = \text{Request MW} - \frac{\text{MVA Rating} * (\text{Overload PU} - 1)}{\text{Request TDF}}$$

With the initial Limited Operation amount request sizes applied to the study cases, ACCC is repeated to verify that the thermal constraints are not observed or the calculation and verification is repeated until all thermal constraints are mitigated.

Power Flow Analysis results for voltage violations are then further mitigated by identifying the contribution of each request and determination of the required impact reduction is conducted and verified through ACCC to determine the Power Flow Analysis Limited Operation amount for each request.

Stability Analysis constraints, if any, are evaluated with the Power Flow Analysis Limited Operation amount for each request and determination of the required impact reduction is conducted and verified through Dynamic Simulation Analysis to determine the Limited Operation amount for each request.

EXHIBIT 14:

SPP Correspondence on Restudy Results

From:	Spencer Magby
To:	Staples, Boone; Tolbert, Todd
Cc:	Alyssa Anderson; Jon Langford
Subject:	GIA-61 Draft Report & Appendices
Date:	Tuesday, November 3, 2020 1:39:20 PM
Attachments:	Appendix G-T Thermal_Report_Formatted.xlsx Appendix H-T Thermal_Report_Formatted.xlsx SPP-AFS_AECI-GIA-061_ASIS_Restudy_DRAFT_R3.docx

» EXTERNAL EMAIL «

» EXTERNAL- EMAIL «

Boone and Todd,

Attached is the GIA-61 draft report your review and discussion. I have also attached the updated appendices (G & H). These will be added to the report prior to posting.

Let us know if you have any questions!

Thank You,

Spencer Magby
Engineer I | Generation Interconnection
Southwest Power Pool, Inc.
Phone: 501.688.1780 |**email:** smagby@spp.org
Helping our members work together to keep the lights on...today and in the future

EXHIBIT 15:

Restudy Results

GENERATOR INTERCONNECTION AFFECTED SYSTEM IMPACT RESTUDY REPORT

AECI GIA-61 (ASGI-2018-001)

Published November 2020

By SPP Generator Interconnections Dept.

REVISION HISTORY

Date	Author	Change Description
11/4/2020	SPP	Affected System Impact Restudy for ASGI-2018-001 Report Revision 0 Issued

EXECUTIVE SUMMARY

An Affected System Interconnection Customer has requested a restudy of an Affected System Impact Study (ASIS) consistent with Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection requests into the system of Associated Electric Cooperative Inc. (AECI). AECI request GIA-61, a 242 MW wind generating facility, has been assigned the SPP queue identifier ASGI-2018-001.

SPP has conducted this ASIS to evaluate the impact of GIA-61 on the safety and reliability of the Transmission System. This study identifies and details the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications. This ASIS reevaluated potential impacts to the SPP Transmission System related to the interconnection of generators on the AECI Transmission System due to higher queued withdrawals and changes to higher queued assigned network upgrades.

ASGI-2018-001 is requesting the interconnection of 11 Vestas V110-2.0 MW and 100 Vestas V116-2.2 MW turbines for a total of 242 MW of generation. This generation will be limited to 230 MW of injection at the Point of Interconnection (POI) and associated facilities interconnecting to AECI at the Maryville 161kV substation in Nodaway County, MO.

The ASIS analysis has determined that network upgrades will be required for ASGI-2018-001 to interconnect all 242 MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The required network upgrades identified have been outlined in **Table 7** of this report.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Transient stability analysis for this ASIS was not performed.

Nothing in this study should be construed as a guarantee of delivery or transmission service. If the customer(s) wishes to move power across the facilities of SPP, a separate request for transmission service must be made on Southwest Power Pool's OASIS by the Customer(s).

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POWER FLOW ANALYSIS

Power flow analysis is used to determine if the transmission system can accommodate the injection from the request without violating thermal or voltage transmission planning criteria.

STUDY ASSUMPTIONS AND MODEL BUILD

SPP utilized the group 13 DISIS-2017-001 base case models as the starting point for this analysis. To create the GIA-61 base cases the GIA-61 study units were dispatched down to 0 MW and scaled against conventional units in the AECI footprint based on a load-ratio share.

All higher queued interconnection requests are assumed to be in-service in this ASIS analysis. The higher queued generation which was considered in-scope and subsequently re-dispatched per SPP criteria are provided in the GenList.csv[1]. Please refer to the DISIS Manual for information regarding grouping and dispatch methodology.

Table 1: Current Study Interconnection Requests

GI Number	Capacity	Type	Service	Group	POI Bus
ASGI-2018-001	242[2]	Wind	ER/NR	13 - Northeast Kansas/Northwest Missouri	Maryville 161 kV

Network upgrades which were included in the 19ITP models were left as-is. Higher queued network upgrades which have been assigned out of the SPP GI process have been added to all seasonal models regardless of estimated in-service date consistent with DISIS procedures.

The MISO Cardinal – Hickory Creek MVP Project was added to the study models in which it is expected to be in-service (2023 Winter Peak and later seasons).

The following current study network upgrades were added to all seasonal models with the exception of the Darlington – Stanberry 69 kV uprate, which was added to all seasonal models summer 2021 and later.

Table 2: Current Study Network Upgrades Assigned to GIA-61

Network Upgrade	Status
Rebuild Gentry-Fairport 161 kV	Complete
Rebuild Nodaway-Gentry 161 kV	Complete
Upgrade Maryville 161/69 kV Transformer	Complete
Uprate Darlington to Stanberry 69 kV	Summer 2021
Rebuild Darlington to Fairport 69 kV	Complete
Rebuild Maryville – Maryville 161 kV	Complete

[1] Interconnection requests not already existing in the 19ITP model added to all seasonal cases regardless of estimated in-service date

[2] Capacity to be limited at the Point of Interconnection to 230 MW

Reactive support in the MISO footprint was required to achieve a solved case in several NRIS models. These upgrades are not assigned to the current study customer as they are considered dispatch discrepancies between the MISO and SPP processes.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a restudy of this ASIS at the expense of the Customer(s).

Nothing in this System Impact Study constitutes a request for transmission service or grants the Interconnection Customer(s) any rights to transmission service.

STUDY METHODOLOGY AND CRITERIA

Please refer to the DISIS Manual for information regarding constraint identification, mitigation, and cost allocation.

FACILITIES

GENERATING FACILITY

The Affected System Interconnection Customers' request the interconnection 11 Vestas V110-2.0 MW and 100 Vestas V116-2.2 MW turbines. The turbines were modeled using a 0.95 power factor based on the assumption provided by AECI for a total of 242 MW and associated facilities interconnecting to AECI at the Maryville 161kV substation in Nodaway County, MO.

INTERCONNECTION FACILITIES

The ASGI-2018-001 Interconnection Customer has requested a connection to the Affected System via the Maryville 161kV substation in Nodaway County, MO. **Figure 1** illustrates the current study request, AECI GIA-061 (ASGI-2018-001) interconnecting at the Maryville 161 kV substation.

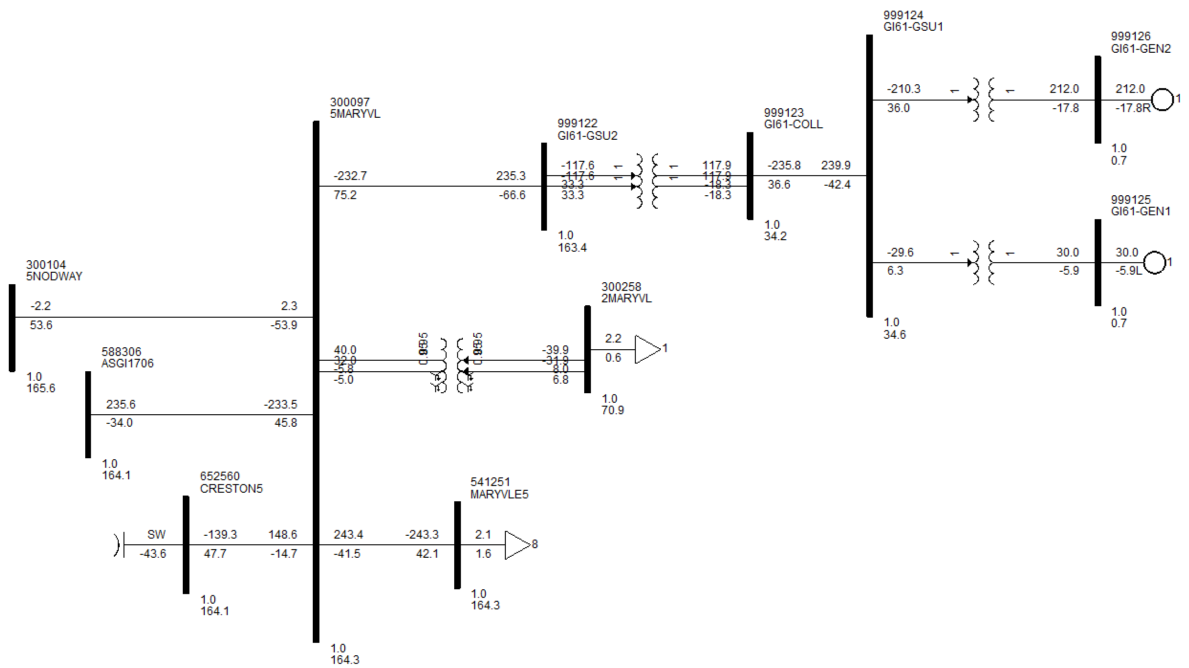

Figure 1: PSS/E configuration of GIA-61 in SPP ASIS

RESULTS

The ASIS analysis indicates that GIA-61 cannot interconnect into the AECI transmission system at full capacity without negatively impacting the SPP transmission system. As GIA-61 is already in-service, an LOIS will be required to refine the amount of Limited Operation available prior to the completion of the network upgrades identified in this analysis.

The results detailed in this analysis assumed all higher queued interconnection requests and network upgrades were in-service. As not all higher queued interconnection requests and network upgrades are in-service at this time, the LOIS will serve to identify if any capacity is available prior to the estimated in-service dates of all assigned network upgrades.

ERIS CONSTRAINTS

The following table outlines the most limiting ERIS constraints. No ERIS voltage constraints were observed in the ASIS.

Please note that the Evergy facilities related to the Maryville – Maryville 161 kV tie are rated sufficiently for the observed need in this ASIS. Constraints related to these facilities have been included in Appendix H for informational purposes only.

Table 3: Most Limiting ERIS Thermal Constraints

Monitored Element	Most Limiting Season	Limiting Rate A/B (MVA)	TC% Loading (% MVA)	Most Limiting Contingency	Mitigation
Maryville – Braddyville 161 kV Ckt 1	24SP	171	114.6	82313[3]	Rebuild Maryville – Braddyville 161 kV Ckt 1
Creston – Maryville 161 kV Ckt 1	24SP	208	110	Maryville – Maryville 161 kV Ckt 1	Reconductor Creston – Maryville 161 kV Ckt 1

NRIS CONSTRAINTS

The following table outlines the most limiting NRIS constraints.

Please note that there were multiple contingencies which are outlined in Appendix G which resulted in a non-converged case. While adding reactive support in the MISO system helped to alieve these constraints, low voltage near Iatan 345 kV, St. Joe 345 kV, and Nashua 345 kV prevented more severely strained seasons from reaching convergence during severe external contingencies. The addition of Wolf Creek – Blackberry 345 kV Ckt 1 (previously assigned), Nashua – Sibley 345 kV Ckt 1, and St. Joe – Nashua 345 kV Ckt 1 were added to alleviate low voltage in these areas. A third bus tie and transformer were also added in Scenario 2 to alleviate low voltage and allow convergence during severe internal and external contingencies.

[3] Please refer to the Contingency Mapping Workbook for additional details

Table 4: Scenario Descriptions

Scenario	Mitigation
0	The only network upgrades applied are those which are already in-service or assigned as MISO MVP Network Upgrades. These upgrades are applied only to seasons as they are expected to be in-service.
1	This scenario is reserved for studies which involve multiple groups. This scenario serves to verify that upgrades from other groups do not cause additional constraints once all mitigation from all groups is applied.
2	Two iterations of Scenario 2 were required to resolve all non-converged constraints observed in this analysis.
3	Two iterations of Scenario 3 were required to resolve all remaining thermal and voltage constraints as rebuilding some facilities caused increase flow and subsequent overloading on other facilities.

Table 5: Most Limiting NRIS Thermal Constraints per Scenario

Monitored Element	Scenario	Most Limiting Season	Limiting Rate A/B (MVA)	TC% Loading (% MVA)	Most Limiting Contingency	Mitigation
Multiple Non-Converged Contingencies	0				System Intact	Wolf Creek – Blackberry 345 kV Ckt 1, Stranger – Craig 345 kV Ckt 1, St. Joe – Nashua 345 kV Ckt 1, Nashua – Sibley 345 kV Ckt 1, 3rd Hawthorn Bus Tie, 3rd Hawthorn 161/345 kV XFMR
'87TH 7 - CRAIG 7 - 1'	0	20SP0	1202	114.4	P23:345:KCPL:NASHUA_R9-11::NASHUA-HAWTHORN-IATAN	
'HAWTH 7 - HAWTHORN20 - 20'	0	20SP0	550	109	P23:345:GMO:SIBLEY_R3-8::SIBLEY-PHILL-OVERTON_1	
'HAWTH 7 - HAWTHORN22 - 22'	0	20SP0	605	119.2	P23:161-345:KCPL:218HAWTHORN_R10-20::HAWTHORN-SIBLEY-HAWT20	
'HAWTH 7 - NASHUA 7 - 1'	0	20SP0	1136	126.6	P23:345:WERE:STRA_345-100::	
'IATAN 7 - G17-030-TAP - 1'	0	20SP0	1136	100.6	P23:161-345:GMO-KCPL:STJOE_R2-22::STJOE-NASHUA-STJOET33_1	
'NASHUA 5 - LBRTYWT5 - 1'	0	20SP0	224	116.2	HAWTH 7 - NASHUA 7 - 1	
'NASHUA 7 - NASHUA11 - 11'	0	20SP0	715	140	P23:161-345:KCPL:HAWTHORN_R11-20::HAWTHORN-NASHUA-HAWT20	
'NASHUA-5 - SHOLCRK5 - 1'	0	20SP0	334	108.7	P23:345:KCPL:NASHUA_R9-11::NASHUA-HAWTHORN-IATAN	
'RNRIDGE5 - NASHUA-5 - 1'	0	24SP0	334	115.6	HAWTH 7 - NASHUA 7 - 1	
'ST JOE 3 - EASTOWN7 - 1'	0	20SP0	1136	107.9	P23:161-345:GMO-KCPL:STJOE_R2-22::STJOE-NASHUA-STJOET33_1	
'ST JOE 3 - NASHUA 7 - 1'	0	20SP0	1136	115.5	P23:161-345:GMO:EASTOWNE_R11-14::EASTOWNE-STJOE-EASTNT1_1	
'STRANGR7 - 87TH 7 - 1'	0	20SP0	1195	127.8	P23:345:KCPL:NASHUA_R9-11::NASHUA-HAWTHORN-IATAN	
'CRESTON8 - SLAKES 8 - 1'	2	24L2	72	106.7	CRESTON8 - SLAKEN 8 - 1	Rebuild Creston - Slake South 161 kV Ckt 1
'EASTOWN7 - G17-030-TAP - 1'	2	20SP2	1136	107.1	P23:161-345:GMO-KCPL:STJOE_R2-22::STJOE-NASHUA-STJOET33	Build Eastown - Ketchum 345 kV Ckt

'ST JOE 3 - COOPER 3 - 1'	2	20SP2	1195	123.8	P23:161-345:GMO-AECI:STJOE_R3-22::STJOE-FAIRPORT-STJOET33_1	1, Build Cooper - Hoyt 345 kV Ckt 1
'GRDA1 7 - GRDAUTO1 - 1'	2	24SP2	560	139.2	MAID 5 - 5CHOTEAU1 - 1	Build Choteau - Maid 161 kV Ckt 2
'MARYVLE5 - MIDWAY_5 - 1'	2	20SP2	171	191.6	5GENTRY - 5FAIRPT - 1	Rebuild Maryville-Midway 161 kV
'MIDWAY_5 - AVENUECTY 5 - 1'	2	20SP2	171	182.4	5GENTRY - 5FAIRPT - 1	Rebuild Midway-Avenue City 161 kV
'S3456 3 - CBLUFFS3 - 1'	2	19WP2	956	119.9	ARBR HL 3 - GRIMES 3 - 1	Rebuild S3456 - C Bluffs 345 kV Ckt 1
'SEDALIA5 - WAFBE_SW5 - 1'	2	24WP2	167	121.8	P23:345:GMO:SIBLEY_R3-8::SIBLEY-PHILL-OVERTON_1	Rebuild WAFBE SW - Sedalia 161 kV
'SIBLEY 5 - SIBLEYPL - 1'	0	20SP0	446	128.5	P23:345:GMO:SIBLEY_R3-8::SIBLEY-PHILL-OVERTON	Rebuild Sibley - Sibley PL 161 kV Ckt 1
'SIBLEY 7 - 7OVERTON - 1'	2	24WP2	956	106.9	P12:345:MEC:SYCAMORE-BONDURANT-GDMEC	Rebuild Overton - Sibley 345 kV Ckt 1
'SIBLEY 7 - SIBLEY11 - 11'	2	19WP2	440	117.7	P23:345:GMO:SIBLEY_R3-8::SIBLEY-PHILL-OVERTON	Build Sibley 161-345 kV XFMR Ckt 2
'ST JOE 5 - AVENUECTY 5 - 1'	2	20SP2	171	180.8	5GENTRY - 5FAIRPT - 1	Rebuild St Joe - Avenue City 161 kV
'WAFBW_SW5 - WAFBE_SW5 - 1'	2	24WP2	167	128.3	P23:345:GMO:SIBLEY_R3-8::SIBLEY-PHILL-OVERTON_1	Rebuild WAFBW_SW - WAFBE_SW 161 kV Ckt 1
'WBURGE 5 - WAFBW_SW5 - 1'	2	24WP2	167	132.6	P23:345:GMO:SIBLEY_R3-8::SIBLEY-PHILL-OVERTON_1	Rebuild WAFBW_SW - WBURGE 161 kV Ckt 1

Table 6: Most Limiting NRIS Voltage Constraints

Monitored Element	Most Limiting Season	Most Limiting Contingency	BC Voltage	TC Voltage	Voltage Diff	Vmin	Vmax	Mitigation
'T.S.E.-2 69.0'	24L3	80958[3]	1.06555	1.08636	0.02081	0.92	1.05	Fort Smith 345-161 kV XFMR Ckt 2, Fort Smith 345-500 kV XFMR Ckt 2
'WILLPIP2 69.0'	24L3	80958[3]	1.05517	1.07929	0.02412	0.92	1.05	

ERIS AND NRIS NETWORK UPGRADE COST ALLOCATION

Table 7: Network Upgrades Required for Interconnection Service

Upgrade Name	Upgrade Type	Cost Estimate
Rebuild Maryville - Maryville 161kV Ckt 1	ERIS	TBD[4]
Rebuild Maryville – Braddyville 161 kV Ckt 1	ERIS	$18,952,900.00
Reconductor Creston – Maryville 161 kV Ckt 1	ERIS	$14,900,000.00
Build Choteau – Maid 161 kV Ckt 2	NRIS	$586,934.40
Build Cooper – Hoyt 345 kV Ckt 1	NRIS	$148,250,000.00
Build Eastown – Ketchum 345 kV Ckt 1	NRIS	$56,500,000.00
Build Fort Smith 161/345 kV XFMR Ckt 2	NRIS	$7,400,000.00
Build Fort Smith 345/500 kV XFMR Ckt 2	NRIS	$13,803,180.00
Build Hawthorne 161/345 kV XFMR Ckt 3	NRIS	$22,000,000.00
Build Sibley - Nashua 345 kV Ckt 1	NRIS	$130,000,000.00
Build Sibley 161/345 kV XFMR Ckt 2	NRIS	$1,499,595.00
Build St. Joe – Nashua 345 kV Ckt 2	NRIS	$69,800,000.00
Build Stranger - Craig 345 kV Ckt 1	NRIS	$81,000,000.00
Build Wolf Creek – Blackberry 345 kV Ckt 1	NRIS	Previously Assigned
Rebuild Council Bluffs - S3456 345 kV Ckt 1	NRIS	$2,510,992.00
Rebuild Maryville – Midway 161 kV	NRIS	$21,541,142.00
Rebuild Midway – Avenue City 161 kV Ckt 1	NRIS	$21,481,661.00
Rebuild Overton – Sibley 345 kV Ckt 1	NRIS	$101,443,516.16
Rebuild Sedalia - WAFBE SW 161 kV Ckt 1	NRIS	$29,525,000.00
Rebuild Sibley – Sibley PL 161 kV Ckt 1	NRIS	$1,164,086.56
Rebuild Slake South - Creston 161 kV Ckt 1	NRIS	$176,080.32
Rebuild St. Joe - Avenue City 161 kV Ckt 1	NRIS	$4,898,938.00
Rebuild WAFBW SW - WAFBE SW 161 kV Ckt 1	NRIS	$1,997,500.00
Rebuild WBURGE - WAFBW SW 161 kV Ckt 1	NRIS	$13,310,000.00

[4] AECI to update their facilities as required to meet KCPL ratings

FACILITY STUDY AND FACILITIES CONSTRUCTION AGREEMENT

All upgrades assigned by SPP will require an Affected System Facilities Study agreement and deposit. These upgrades may require a Facilities Construction Agreement (FCA) as a result of the Affected System Facilities Study.

While SPP does not assign network upgrades on facilities which are not under the SPP Tariff, additional network upgrades may be required for tie line facilities to meet the MVA need observed in the analysis per host TO GIA language.

CURTAILMENT AND SYSTEM RELIABILITY

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

CONCLUSION

An Affected System Interconnection Customer has requested restudy of an Affected System Impact Study (ASIS) under the Southwest Power Pool Open Access Transmission Tariff (OATT) for ASGI-2018-001. ASGI-2018-001 (242 MW) wind generating facilities are to be interconnected into the system of AECI. This restudy ASIS was conducted to determine the impacts of interconnecting GIA-61 generation to the transmission system under the assumption that all higher queued interconnection request and network upgrades are in-service.

The ASIS analysis has determined that full interconnection service is not available at this time and that network upgrades will be required for ASGI-2018-001 to interconnect all 242 MW of generation with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The required network upgrades identified have been outlined in **Table 7** in this report.

As GIA-61 is already in-service, an LOIS will be required to refine the amount of Limited Operation available prior to the completion of the network upgrades identified in this analysis. The LOIS will serve to identify if any capacity is available prior to the estimated in-service dates of all assigned network upgrades.

It should be noted that although this ASIS analyzed many of the most probable contingencies, it is not an all-inclusive list that can account for every operational situation. Additionally, the generator may not be able to inject any power onto the Transmission System due to constraints that fall below the threshold of mitigation for a Generator Interconnection request. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Transient stability analysis was not completed for this ASIS.

Any changes to these assumptions, for example, one or more of the previously queued requests not included within this study execute an interconnection agreement and commencing commercial operation, may require a re-study of this ASIS at the expense of the Customer.

Nothing in this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service

APPENDIX G-T: THERMAL POWER FLOW ANALYSIS (CONSTRAINTS REQUIRING TRANSMISSION REINFORCEMENT)

APPENDIX G-V: VOLTAGE POWER FLOW ANALYSIS (CONSTRAINTS REQUIRING TRANSMISSION REINFORCEMENT)

APPENDIX H-T: THERMAL POWER FLOW ANALYSIS (OTHER CONSTRAINTS NOT REQUIRING TRANSMISSION REINFORCEMENT)

APPENDIX H-V: VOLTAGE POWER FLOW ANALYSIS (OTHER CONSTRAINTS NOT REQUIRING TRANSMISSION REINFORCEMENT)

EXHIBIT 16:

SPP Correspondence December 2020

Email Containing Study Assumptions Used in 12/11/20 SPP NRIS study results

» EXTERNAL EMAIL «

» EXTERNAL- EMAIL «

And just a note - this is more than likely the main reason you observed the change in dispatch between the two coal units.

--
Jon Langford

From: Staples, Boone <BStaples@tnsk.com>
Sent: Thursday, December 10, 2020 8:38 AM
To: Jon Langford <jlangford@spp.org>
Subject: **External Email** RE: GI-61 NRIS Restudy Meeting - 2020-12-08 - Notes

Thanks Jon.

From: Jon Langford <jlangford@spp.org>
Sent: Thursday, December 10, 2020 8:37 AM
To: Staples, Boone <BStaples@tnsk.com>
Subject: RE: GI-61 NRIS Restudy Meeting - 2020-12-08 - Notes

» EXTERNAL EMAIL «

» EXTERNAL- EMAIL «

Boone,

This was in reference to the difference between how the ITP base cases used in each study were dispatched (original – 17IPT; latest – 19ITP). The 19ITP utilized more Operation/Markets data, I assume to develop cost curves for each resource. A block dispatch is really just taking a set of available generators and, if starting from the ground up, determine what order and by how much each generator would be dispatched to meet load.

--
Jon Langford

From: Staples, Boone <BStaples@tnsk.com>
Sent: Wednesday, December 9, 2020 11:22 PM
To: Jon Langford <jlangford@spp.org>
Subject: **External Email** RE: GI-61 NRIS Restudy Meeting - 2020-12-08 - Notes

Thanks Jon. This looks helpful, we'll review. In the meantime, what exactly did you mean by "block dispatch" during the call?

Regards,
Boone

From: Jon Langford <jlangford@spp.org>
Sent: Wednesday, December 9, 2020 11:58 AM
To: Onnen, Katy <katy.onnen@evergy.com>; Staples, Boone <BStaples@tnsk.com>; Todd Tolbert <TTolbert@AECI.org>; McGeeney Chris <cmcgeeney@AECI.org>
Cc: Timothy Kopp <tkopp@epeconsulting.com>; Alyssa Anderson <aanderson@spp.org>; Spencer Magby <smagby@spp.org>; Jennifer Swierczek <jswierczek@spp.org>
Subject: GI-61 NRIS Restudy Meeting - 2020-12-08 - Notes

» EXTERNAL EMAIL «

» EXTERNAL- EMAIL «

Hello Everyone,

Below are notes from Tuesday's meeting describing the updated NRIS analysis:

- Update performed by consultant EPE
- Current schedule for results is Friday, 12/11
- Updated analysis will consist only of updating NRIS cases
- Updated NRIS dispatch is as follows:
  - NRIS cases developed from the 19ITP base model sets
  - Exclusion of ERIS units being dispatched in the NRIS models
    - Existing ERIS that are dispatched in the base model sets represent units with firm transmission rights
      - These will remain at their initial values, but will not be dispatched up
      - Will be included in the sink reference for dispatching
    - Higher queued or current study ERIS units without firm service will remain offline and will not be dispatch
  - Higher queue dispatch will utilize a system wide, Pmax-proportional scale to the appropriate area
    - SPP sink reference will include all resources excluding nuclear
    - Other sink reference sink will include all resources

- Study units will be dispatched utilizing the same dispatch methodology as above for their appropriate area
- Cases will be solved Interchange Disabled

- TDF Reference/Sink will match with appropriate area's Dispatch Reference/Sink
  - More accurate TDFs
- Contingency analysis performed with interchange disabled
  - More accurate TDFs
- No change to SPP's NRIS DFAX mitigation threshold – 3% TDF
- Any remaining BC base case issues will be review by management for an appropriate action

Also, below is a chart of how we dispatch our models. Please note that the area marked in RED is what we are excluding from the NRIS dispatch methodology:

Table 1: Generation Dispatch in the Power Flow Models

Model			Generator Dispatch				
Dispatch Scenario	Seasons	Code	Requested Service Type	In Group		Out Group	
				Renew.	Conv.	Renew.	Conv.
HVER	Winter, Summer, Spring, Light	01, 02, 03...18	Both	100%	n/a	20%**	n/a
LVER	Winter and Summer	00	Both	20%	100%	20%	100%
NR	Spring and Light Load	01NR, 02NR, 03NR... 18NR	ERIS	80%	n/a	20%	n/a
			NRIS	100%	100%	20%	20%
	Winter and Summer	00NR	ERIS	20%*	80%	20%*	80%
			NRIS	100%	100%	100%	100%

*Solar 80% in Summer Peak
**For light 10% for DISIS-2016-002 or 0% for DISIS-2017-001 forward

Also, as discussion on the call, we have provided notes from our consultant, EPE, on why the TDF's don't always line up with certain studies. A lot of the below issues are mitigated by the above changes:

Distribution Factors are calculated using a linear, DC solution. Therefore, changes in system losses, Mvar flows, etc. do not factor into the DF calculation. The DC method assumes 100% MW at the source, will travel to the sink system with no losses. Several additional factors can result in differences between reported distribution factors and actual changes in line flows:

- Source/Sink differences from actual dispatch
  - If the units used to sink generation changes does not 100% match the reference system to calculate DF, the line flow change and reported DF will not match.
  - Even with the same sink between dispatch and reference systems, losses may go up or down for each line. This affects the overall "net" change the system must make to remain balanced. Sometimes the sink generators will reduce more/less depending on the change in losses. This can, in turn, change the actual flow

up/down on a given line as well as change how much power of the source travels across the line.

- Solving with area interchange – Related to above, solving with AI enabled further deviates from the DC calculation. Area swing machines will adjust to account for changes flows/losses. This can have a significant impact if the swing machine is near a given line/constraint/study area.
- Heavy line loading or voltage deltas – Stressed systems can results in sizeable flow changes as a result of small adjustments. If a heavily loaded line (high losses) gains some counterflow/relief, it can result in line loading relief in excess of DF * MW. The opposite can be true if increasing loading on an already heavily loaded line (small increase as losses increase).
- Participation factors – Related to dispatch, it is important not only to have the exact same reference points, but to also have the same participation amount at each point. Participation can be based on MW reserves, PMAX, etc. If this is not consistent between actual dispatch changes and DF calculation, a difference in flow change vs. DF * MW size will be noticed.

Please let us know if you have any questions.

--
Jon Langford, PE | Generator Interconnection
501-688-1794
Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223

EXHIBIT 17:

SPP Correspondence on December 18, 2020 Study Results

Staples, Boone

From: aanderson@spp.org
Sent: Friday, December 18, 2020 11:07 AM
To: dkelley@spp.org; jfreitas@spp.org; jswierczek@spp.org; jlangford@spp.org; smagby@spp.org
Cc: jlangford@spp.org; jswierczek@spp.org; smagby@spp.org
Subject: GIA-61 AFS NRIS Only Sensitivity Models, Input Files, and Results

» EXTERNAL EMAIL «

» EXTERNAL- EMAIL «

SPP Southwest Power Pool

Good Morning,

Linked below are the GIA-61 AFS ERIS and NRIS Only study files, results, and preliminary cost estimates. While constraints caused by contingencies not requiring mitigation have been removed, please note that these results are not filtered for SPP mitigation criteria. Please refer to the DISIS Manual for further information regarding mitigation criteria (http://opsportal.spp.org/documents/studies/DISIS_Manual.pdf).

The results and preliminary cost estimates linked below are currently under review by SPP staff. We are still working with Transmission Owners regarding updated line loadings, recommended mitigation, and planning level cost estimates.

SPP was notified by Evergy of an updated rating (now in effect) for Stranger - 87th 345 kV Ckt 1, which meets the observed need for this study. Also, as the Evergy Maryville tie upgrades are now in-service, the updated rating for Evergy facilities meets the observed need for SPP. Additional mitigation may be required between GIA-61 and MISO on those facilities.

While WAPA and CIPCO have confirmed that Anita - Anita Tap 161 kV is not under the SPP tariff and therefore does not require mitigation by SPP, additional mitigation may be required between GIA-61 and CIPCO for those facilities.

Please let us know if you have any questions or concerns regarding the models, contingency files, or results.

Best,
Alyssa Anderson

File List :
GIA-61 ER & NR Preliminary Cost Estimates.xlsx
P Contingencies for Mitigation.xlsx
ERIS S0 Thermal Results.xlsx
NRIS Only Thermal Results.xlsx
S0_ER_v33.zip
sub2019.sub
mon2019.mon
BCmon2019.mon
con2019-1.con
GIA61_NRCASES.zip

Click here to begin exchanging files.

Link expiration: 12/25/2020 12:00:00 AM

EXHIBIT 18:

SPP Correspondence on NRIS Restudy

From: David Kelley <dkelley@spp.org>
Date: February 26, 2021 at 6:06:11 PM CST
To: boone.staples@gmail.com
Subject: Updated GI-61 NRIS Preliminary Results

Boone,

I'd like to touchbase with you early next week on this if I can. Could you let me know when you have a few minutes to chat?

Sent from my iPhone

> On Feb 26, 2021, at 5:10 PM, Jon Langford <jlangford@spp.org> wrote:
>
> Hey Boone,
>
> I hope you are doing well this afternoon. We wanted to provide you with some preliminary study results from our consultant. They are attached. Our consultant is following up with the appropriate TOs for confirmation of estimates and seeing if there are any potential mitigations that may be in place or upcoming in which we are not aware.
>
> Just as a reminder, the NRIS upgrades included in the attached document are not inclusive of the additional ~$34M ERIS Network Upgrades included in the first draft report provided.
>
> We will be working over the next week to implement all study results into a complete draft report and will provide when completed.
>
> I'll be out of the office on Monday and Tuesday, but Alyssa/Jennifer can address questions you may have. Hope you have a great weekend.

--
Jon Langford, PE | Generator Interconnection
501-688-1794
Southwest Power Pool
201 Worthen Drive
Little Rock, AR 72223

<SPP_ASIS_of_MISO_GIA61_Results_and_Upgrades_2.xlsx>

EXHIBIT 19:

March 2021 Results

Southwest Power Pool

GENERATOR INTERCONNECTION AFFECTED SYSTEM IMPACT RESTUDY REPORT

AECI GIA-61 (ASGI-2018-001)

Published March 2021

By SPP Generator Interconnections Dept.

TABLE OF CONTENTS

INTRODUCTION

The purpose of this Affected System Impact Restudy was to determine the impact of GIA-61 on the SPP transmission system due to changes in the study assumptions used in the Affected System Impact Study report posted in March 2019.[1] Changes from prior study assumptions include the withdrawal of higher queued interconnection requests, network upgrades, topology, and load. This restudy report supersedes and replaces prior affected system impact studies for GIA-61.

While results from this analysis will be considered final, a restudy may be required should significant changes to the study assumptions occur[2].

SPP utilized Siemens Power Technologies International PSS®E Version 33.11.0, PSS®E MUST, and PowerGEM's TARA 2002 for this analysis.

SPP worked with Electric Power Engineers Inc. (EPE) to update power flow cases to reflect the groups under study and developed a total of twenty-eight (28) cases, specifically 14 Base Cases (BC) and 14 Transfer Cases (TC). SPP and EPE performed power flow analysis on the study models to determine if the transmission system could accommodate the injection from the current study generation interconnection request without violating SPP's transmission planning criteria outlined below in the Study Methodology Criteria section.

This Affected System Impact Study (ASIS) was conducted consistent with the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) and SPP Business Practices to determine impacts to the SPP transmission system.

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[1] The Affected System Study report posted in March 2019 acknowledged the potential for a required restudy. See page 2 of March 2019 study report posted at: https://opsportal.spp.org/documents/studies/files/2018_Generation_Studies/ASGI-2018-001_ASIS_RESTUDY_FINAL.pdf

[2] Significant changes to study assumptions include but are not limited to interconnection request withdrawals and/or changes to higher queued network upgrades included in the base case.

REVISION HISTORY

Date	Author	Change Description
3/24/2021	SPP	ASGI-2018-001 Affected System Impact Restudy Report Issued
3/25/2021	SPP	Minor edits to introduction

POWER FLOW ANALYSIS

BASE CASE MODEL BUILD AND DISPATCH

The DISIS-2017-001 BASE cases were used as the starting point for this restudy as the DISIS-2017-001 BASE cases included the most up-to-date higher queued generation interconnection requests, load, topology, and transmission facility ratings at the time this restudy was initiated.

DISIS-2017-001 BASE models:

- Year 1 (2019) Winter Peak (19WP)
- Year 2 (2020) Spring (20G)
- Year 2 (2020) Summer Peak (20SP)
- Year 5 (2024) Light (24L)
- Year 5 (2024) Summer Peak (24SP)
- Year 5 (2024) Winter Peak (24WP)
- Year 10 (2029) Summer Peak (29SP)

The DISIS-2017-001 BASE cases contain all higher and equally queued interconnection requests to the DISIS-2017-001 cluster; however, not all interconnection requests are dispatched. To create the GIA-61 BASE cases, interconnection requests were modeled as out of service if they did not already exist in the ITP cases. Unless otherwise indicated, in-scope interconnection requests were added or modified in the BASE model to reflect their requested capacity per service type. Appendix A and Appendix B outline the current study and higher queued in-scope interconnection requests included in the GIA-61 BASE cases, respectively. The GIA-61 BASE cases contain all higher and equally queued network upgrades to GIA-61. Appendix C outlines the network upgrades included in the GIA-61 BASE cases.

Also included in the GIA-61 BASE cases are the current study upgrades assigned by AECI, listed in **Table 2**. These upgrades were added to all seasonal models with the exception of the Darlington – Stanberry 69 kV uprate, which was added to seasonal models summer 2021 and later.

Table 3: Current Study Assigned AECI Network Upgrades

Network Upgrade	Status
Rebuild Gentry-Fairport 161 kV	Complete
Rebuild Nodaway-Gentry 161 kV	Complete
Upgrade Maryville 161/69 kV Transformer	Complete
Uprate Darlington to Stanberry 69 kV	Summer 2021
Rebuild Darlington to Fairport 69 kV	Complete
Rebuild Maryville – Maryville 161 kV	Complete

GROUPING

Appendix A and Appendix B interconnection requests are assigned into sixteen (16) active regional groups. **Table 1** outlines all active groups. Please note that groups 5 and 11 are inactive.

Based on electrical connectivity to transmission in the Northwestern Missouri region, SPP assigned GIA-61 to group 13.

Table 1: Active SPP Groupings

Group #	Area	Group #	Area
1	Woodward, OK	10	Southeast OK/Northeast TX
2	Hitchland, OK	12	Northwest AR
3	Spearville, KS	13	Northwest MO
4	Northwest KS	14	South Central OK
6	South TX Panhandle/New Mexico	15	East SD
7	Southwest OK	16	West ND
8	North OK/South Central KS	17	West SD
9	Nebraska	18	East ND

DISPATCH OF BASE AND TRANSFER CASES

The following procedures are based on SPP Business Practice 7250:

The number of base cases (BC) and transfer cases (TC) required for each impact study depends on the service requested and fuel type of the current study requests. As GIA-61 represents a High Variable Energy Resource (HVER) requesting Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS), SPP developed an HVER dispatch scenario and an NRIS dispatch scenario. In total, 28 cases were required, as shown in **Table 2**.

Table 2: GIA-61 Study Cases

Seasonal Case	ERIS HVER	NRIS
+1 Winter Peak (i.e. 19WP)	1 per group	1 per study
+1 Spring (i.e. 20G)	1 per group	1 per group
+1 Summer Peak (i.e. 20SP)	1 per group	1 per study
+5 Light Load (i.e. 24L)	1 per group	1 per group
+5 Summer Peak (i.e. 24SP)	1 per group	1 per study
+5 Winter Peak (i.e. 24WP)	1 per group	1 per study
+10 Summer Peak (i.e. 29SP)	1 per group	1 per study
GIA-61	28 cases (14 BC/14TC)	

ERIS DISPATCH

To create the ERIS base cases, SPP dispatched all in-scope higher queued generators listed in Appendix B per **Table 3**. For SPP generation, the change in generation was offset using non-study SPP conventional generation based on a Load Ratio Share (LRS) and scaled using a block order. For AECI generation, the change in generation as offset using non-study AECI conventional generation based on LRS and scaled using a block order. For the remaining generation, SPP offset the change in generation using LRS and scaled proportionally to the respective host RTO footprint.

To create the ERIS transfer cases, SPP dispatched the current study generator listed in Appendix A per **Table 3**. The change in generation was offset using non-study AECI conventional generation based on LRS and scaled using a block order.

NRIS DISPATCH

To create the NRIS base cases, EPE dispatched all in-scope higher queued generators listed in Appendix B per **Table 3**. For changes to non-SPP generation, for each RTO region, EPE used the system swing to offset the change in generation and scaled proportionally to the appropriate RTO footprint.

To create the NRIS transfer cases, EPE dispatched the current study generator listed in Appendix A per **Table 3**. SPP used the system swing to offset the change in generation and scaled the AECI area proportionally until the system swing was within range.

Table 3: SPP Dispatch Criteria

Dispatch Type	Season	Service Type	Renewable in group	Renewable out group	Conventional in group	Conventional out group
ERIS HVER	All	All	100%	0%	0%	0%
ERIS LVER	Peak	All	20%	20%	100%	100%
NRIS	Spring and Light Load	NRIS	100%	20%	100%	20%
	Peak	NRIS	100%	100%	100%	100%

* SPP did not dispatch up existing higher queued units with firm service if Pgen > SPP Dispatch Criteria

STUDY METHODOLOGY/CRITERIA

Solve Parameters

- Fixed slope decoupled Newton-Raphson
- Tap adjustment – stepping
- Switch shunt adjustments – enable all
- ERIS: Area interchange enabled
- NRIS: Area interchange disabled
- Adjust phase shift
- Adjust DC taps
- VAR limits – apply immediately
- Model solved within five iterations

Thermal Overloads

SPP identified ERIS constraints by performing AC Contingency Calculation (ACCC) analysis using Siemens Power Technologies International PSS®E Version 33.11.0 and PSS®E MUST. EPE identified NRIS constraints by performing AC Contingency Calculation (ACCC) analysis using PowerGem's TARA 2002.

Thermal overloads are determined for system intact (n-0) (greater than or equal to 100% of Rate A - normal) and for contingency (N-1) (greater than or equal to 100% of Rate B – emergency) conditions.

The methodology below is based on SPP Business Practice 7250:

Energy Resource Interconnection Service (ERIS):
For ERIS, SPP screens overloads to determine which generator interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage-based conditions (N-1), or
- 3% DF on contingent elements that resulted in a non-converged solution.

Network Resource Interconnection Service (NRIS):
For NRIS, SPP screens overloads to determine which generator interconnection requests have at least 3% Distribution Factor (DF) for system intact conditions (n-0), outage-based conditions (N-1), or on contingent elements that resulted in a non-converged solution.

Contingencies

The contingency set includes all SPP control area branches and ties 69 kV and above, first tier Non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

- All branches, ties, shunts, and generators within the following areas:
  - SPP Internal Areas for 65kV – 999kV facilities:
    - 515 – 546, 640, 641, 642, 645, 650, 652, 659
  - SPP External Areas for 100kV – 999kV facilities:
    - 327, 330, 351, 356, 502-504, 600, 615, 620, 627, 635, 672, 680
- NERC, SPP, and Tier 1 Permanent Contingent Flowgates
- SPP T.O. Specific P1, P2, P4, and P5 TPL-004-1 Contingencies
- SPP T.O. Specific Op Guide Implementation

Monitored Facilities

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution Flowgates for SPP and first tier Non-SPP control areas are monitored. Additional NERC SPP monitors flowgates in second tier or greater non-SPP control areas. SPP performed voltage monitoring for SPP control area buses 69 kV and above.

- All branches (thermal)/ buses(voltage) and ties within the following areas:
  - SPP Internal Areas for 65kV – 999kV facilities:
    - 515 – 546, 640 – 659
- NERC, SPP, and Tier 1 Permanent Monitor Flowgates (thermal)

Voltage

For non-converged power flow solutions that caused by a lack of voltage support, appropriate transmission support will be determined to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

Table 4: SPP Areas (69 kV+)

<table>
<tr><th>Transmission Owner</th><th>Voltage Criteria (System Intact)</th><th>Voltage Criteria (Contingency)</th></tr>
<tr><td>AEPW</td><td rowspan="21">0.95 – 1.05 pu</td><td>0.92 – 1.05 pu</td></tr>
<tr><td>GRDA</td><td rowspan="14">0.90 – 1.05 pu</td></tr>
<tr><td>KACY</td></tr>
<tr><td>SWPA</td></tr>
<tr><td>OKGE</td></tr>
<tr><td>OMPA</td></tr>
<tr><td>WFEC</td></tr>
<tr><td>SWPS</td></tr>
<tr><td>MIDW</td></tr>
<tr><td>SUNC</td></tr>
<tr><td>KCPL</td></tr>
<tr><td>INDN</td></tr>
<tr><td>SPRM</td></tr>
<tr><td>NPPD</td></tr>
<tr><td>WAPA</td></tr>
<tr><td>WERE L-V</td><td>0.93 – 1.05 pu</td></tr>
<tr><td>WERE H-V</td><td>0.95 – 1.05 pu</td></tr>
<tr><td>EMDE L-V</td><td>0.90 – 1.05 pu</td></tr>
<tr><td>EMDE H-V</td><td>0.92 – 1.05 pu</td></tr>
<tr><td>LES</td><td rowspan="2">0.90 – 1.05 pu</td></tr>
<tr><td>OPPD</td></tr>
</table>

Table 5: SPP Buses with more stringent voltage criteria

Bus Name/Number	Voltage Criteria (System Intact)	Voltage Criteria (Contingency)
TUCO 230kV 525830	0.925 – 1.05 pu	0.925 – 1.05 pu
Wolf Creek 345kV 532797	0.985 – 1.03 pu	0.985 – 1.03 pu
FCS 646251	1.001 – 1.047 pu	1.001 – 1.047 pu

Table 6: Affected System Areas (115kV+)

<table>
<tr><th>Transmission Owner</th><th>Voltage Criteria (System Intact)</th><th>Voltage Criteria (Contingency)</th></tr>
<tr><td>AECI</td><td rowspan="13">0.95 – 1.05 pu</td><td rowspan="11">0.90 – 1.05 pu</td></tr>
<tr><td>EES-EAI</td></tr>
<tr><td>LAGN</td></tr>
<tr><td>EES</td></tr>
<tr><td>AMMO</td></tr>
<tr><td>CLEC</td></tr>
<tr><td>LAFA</td></tr>
<tr><td>LEPA</td></tr>
<tr><td>XEL</td></tr>
<tr><td>MP</td></tr>
<tr><td>SMMPA</td></tr>
<tr><td>GRE</td><td>0.90 – 1.10 pu</td></tr>
<tr><td>OTP</td><td>0.90 – 1.05 pu</td></tr>
<tr><td>OTP-H (115kV+)</td><td>0.97 – 1.05 pu</td><td>0.92 – 1.10 pu</td></tr>
<tr><td>ALTW</td><td rowspan="6">0.95 – 1.05 pu</td><td rowspan="3">0.90 – 1.05 pu</td></tr>
<tr><td>MEC</td></tr>
<tr><td>MDU</td></tr>
<tr><td>SPC</td><td>0.95 – 1.05 pu</td></tr>
<tr><td>DPC</td><td rowspan="2">0.90 – 1.05 pu</td></tr>
<tr><td>ALTE</td></tr>
</table>

The constraints identified through the voltage scan are then screened for the following for each interconnection request.

- 3% DF on the contingent element and
- 2% change in pu voltage

IDENTIFICATION AND MITIGATION OF NETWORK CONSTRAINTS

SPP works with affected Transmission Owners to identify the limiting element for each constraint and determine the appropriate mitigation.

ERIS THERMAL NON-CONVERGED CONSTRAINT IDENTIFICATION AND MITIGATION

While low voltage was observed near the Rock Creek Wind Farm, Evergy confirmed that non-convergence in this area was due to a reactive modeling error at this facility. Once resolved, SPP confirmed that there were no non-converged constraints meeting mitigation criteria.

ERIS THERMAL SYSTEM INTACT AND CONTINGENCY CONSTRAINT IDENTIFICATION AND MITIGATION

As observed in **Table 7**, the same set ERIS constraints observed in the original impact study were observed again in this restudy. The change in model series (2017 ITP DISIS-2016-002 BASE to 2019 ITP DISIS-2017-001 BASE) did not adversely affect the impact study results.

It should be noted that while the Evergy facilities related to the Maryville – Maryville 161 kV tie are rated sufficiently for the observed need, the AECI equipment limits the rating for this line at 278 MVA. While no action is required by SPP at this time for this facility, the interconnection customer may be required to upgrade the AECI facilities in accordance with their Generation Interconnection Agreement (GIA).

Table 7: ERIS Thermal Constraints and Mitigation

Monitored Facility	Mitigation
Maryville – Braddyville 161 kV Ckt 1	Rebuild Maryville – Braddyville 161 kV Ckt 1
Creston – Maryville 161 kV Ckt 1	Reconductor Creston – Maryville 161 kV Ckt 1

ERIS VOLTAGE CONSTRAINT IDENTIFICATION AND MITIGATION

No ERIS voltage constraints met mitigation criteria.

NRIS THERMAL NON-CONVERGED CONSTRAINT IDENTIFICATION AND MITIGATION

Some NRIS non-convergent constraints were observed in the ACCC analysis.

NRIS non-convergent constraints related to contingencies on the Council Bluff to S3456 345 kV line were related to incorrect modeling of the POI for J1122. The correct modeling of the POI for J1122 mitigated these non-convergent issues.

For remaining NRIS non-convergent issues, EPE checked the DFAX of the project against the contingent elements and found that none of those elements met the criteria for mitigation.

NRIS THERMAL SYSTEM INTACT AND CONTINGENCY CONSTRAINT IDENTIFICATION AND MITIGATION

Table 8 summarizes system intact and contingency thermal constraints identified during the NRIS analysis.

Table 8 : NRIS Thermal Constraints and Mitigation

<table>
<tr><th>Monitored Facility</th><th>Mitigation</th></tr>
<tr><td>Maryville to Midway 161 kV</td><td>Rebuild Maryville to Midway 161 kV</td></tr>
<tr><td>Midway to Avenue City 161 kV</td><td>Rebuild Midway to Avenue City 161 kV</td></tr>
<tr><td>Avenue City to St Joseph 161 kV</td><td>Rebuild Avenue City to St Joseph 161 kV</td></tr>
<tr><td>Nashua 345/161 kV Transformer</td><td>Add 2nd Nashua 345/161 kV Transformer</td></tr>
<tr><td>Nashua to Roanridge 161 kV</td><td>Rebuild Nashua to Roanridge 161 kV</td></tr>
<tr><td>Council Bluffs to S3456 345 kV</td><td rowspan="2">Constraints only occur in 19WP and SPP determined that these upgrades are not required under the study circumstances as load changes in later cases mitigate the overloads.</td></tr>
<tr><td>Warrenburg to WAFBW 161 kV</td></tr>
</table>

NRIS VOLTAGE CONSTRAINT IDENTIFICATION AND MITIGATION

No NRIS voltage constraints met mitigation criteria.

POWER FLOW ANALYSIS

The results of the power flow analysis for interconnection requests under study are embedded in

Table 9.

Table 9: Power Flow Analysis Results

Results	
Thermal Constraints	ERIS Thermal Results.xlsx NRIS Thermal Results.xlsx
Voltage Constraints	N/A

LIMITED OPERATION AVAILABILITY

SPP will coordinate with Associated Electric Cooperative, Inc. (AECI) to determine the appropriate level of Limited Operation in accordance with the AECI's Open Access Transmission Tariff, Joint Operating Agreement Among and Between SPP and AECI, and the customer's Generation Interconnection Agreement.

COST ALLOCATION

Preliminary cost estimates provided in this analysis are subject to change, pending the Transmission Owner Facilities Studies.

SPP utilizes the one-year-out spring seasonal model for Variable Energy Resources (VERs). The five-year-out summer peak seasonal model is used for conventional fuel type generators. If both fuel types are being studied, both sets of models are utilized. Project distribution factors on the identified upgrades, under system intact conditions, are used to determine cost allocation. The impact each generation interconnection request has on each upgrade project is weighted by the size of each request. Finally, the costs due by each request for a particular project are then determined by allocating the portion of each request's impact over the impact of all affecting requests.

For example, assume that there are three Generation Interconnection requests, X, Y, and Z that are responsible for the costs of Upgrade Project '1'. Given that their respective power transfer distribution factors (PTDF) for the project have been determined, the cost allocation for Generation Interconnection request 'X' for Upgrade Project 1 is found by the following set of steps and formulas:

- Request X, Upgrade Project 1 = PTDF (%)(X) * MW(X) = X1
- Request Y, Upgrade Project 1 = PTDF (%)(Y) * MW(Y) = Y1
- Request Z, Upgrade Project 1 = PTDF (%)(Z) * MW(Z) = Z1

Allocation of Cost for a particular project:

$$\text{Request X's Project 1 Cost Allocation (\$)} = \frac{\text{Network Upgrade Project 1 Cost (\$)} * X1}{X1 + Y1 + Z1}$$

Repeat previous for each responsible GI request for each Project.

It should be noted that network upgrades associated with higher-queued projects are also considered as contingent upgrades. These facilities have been included in the models for this study and are assumed to be in service. This list may not be all-inclusive. While current study interconnection customers do not have cost responsibility for contingent upgrades, they may later be assigned cost if higher-queued customers withdraw their interconnection request or terminate their interconnection agreement. The network upgrades associated with higher-queued projects are listed in Appendix C**.**

Table 10: ERIS and NRIS Upgrades Required for Interconnection Service

Upgrade Type	Upgrade	Length	Rate Cost
ERIS	Reconductor Maryville to Creston 161 kV	62.34	$ 14,900,000
ERIS	Rebuild Maryville to Braddyville 161 kV	16.74	$ 18,652,900
NRIS	Rebuild Maryville to Midway 161 kV	19.45	$ 21,500,000
NRIS	Rebuild Midway to Avenue City 161 kV	20.35	$ 21,500,000
NRIS	Rebuild Avenue City to St Joseph 161 kV	3.5	$ 4,900,000
NRIS	Add 2nd Nashua 345/161 kV Transformer	0	$ 8,500,000
NRIS	Rebuild Nashua to Roanridge 161 kV	6.1	$ 9,150,000

ERIS	$ 33,552,900
NRIS	$ 65,550,000
Total	$ 99,102,900

CONCLUSION

A power flow analysis was performed to determine the impact of GIA-61 on the SPP transmission system. The results of the power flow analysis identified several constraints that require mitigation. Please refer to **Table 10** for and cost allocation of assigned network upgrades.

In no way does this study guarantee operation for all periods. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to **0 MW** under certain system conditions to allow system operators to maintain the reliability of the transmission network.

APPENDICES

APPENDIX A

Table 11: Current Study Interconnection Request

Generation Interconnection Number	Group	Type	G PMAX	SP PMAX	WP PMAX	Service	GEN Area	Point of Interconnection
GIA-61	13	Wind	242	242	242	ER/NR	AECI	Maryville 161 kV

APPENDIX B

Higher Queued Projects.xlsx

APPENDIX C

Higher Queued Network Upgrades.›

APPENDIX D

MISO Projects Inadvertently Exclud

EXHIBIT 20:

SPP Presentation

SPP Southwest Power Pool

DISIS-2016-002 AND DISIS-2017-001 UPDATE

GIUF 4/28/2021

OBJECTIVE

- OATT 8.8 Restudy
- Describe SPP's sensitivity/restudy approach for withdrawals
- Provide results, schedule for 2016-002
- Provide plan, schedule for 2017-001 and 2017-002

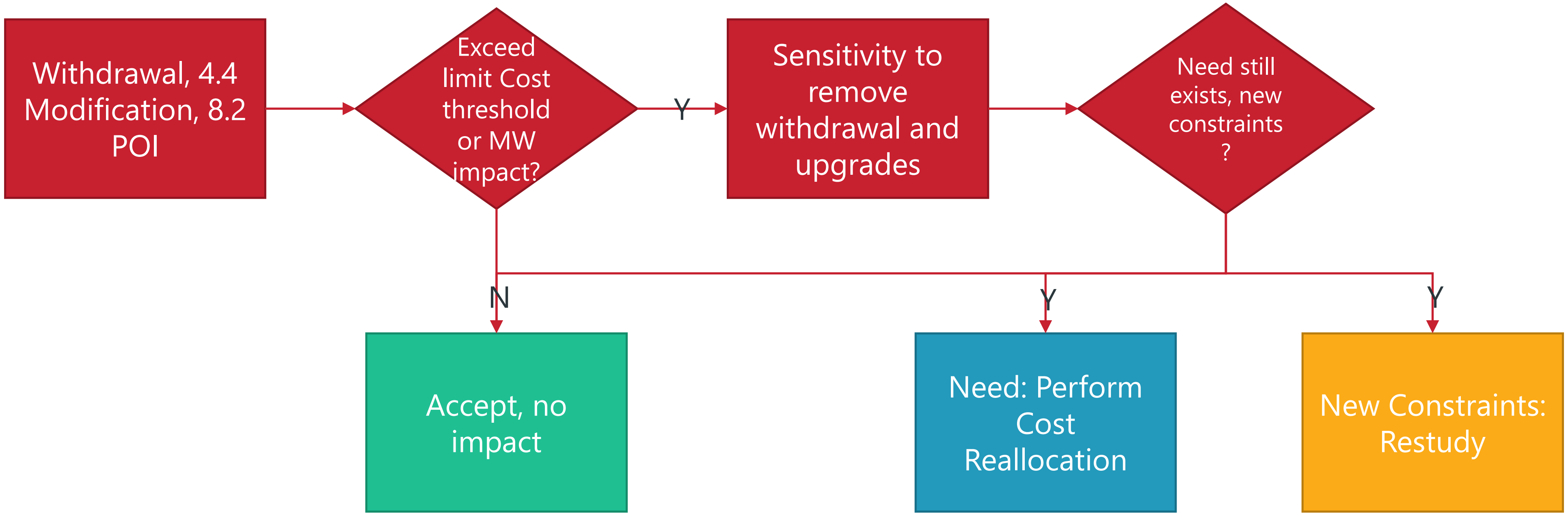
OATT 8.8 RESTUDY

- If Re-Study of the Definitive Interconnection System Impact Study is required due to a higher queued or equal priority queued project dropping out of the queue, or a modification of a higher queued project subject to Section 4.4 of the GIP, or redesignation of the Point of Interconnection pursuant to Section 8.2 of the GIP, the Transmission Provider shall notify Interconnection Customer in writing. Such ReStudy shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study, as reduced by deposit amounts retained for other Interconnection Customer(s) under Section 13.3 of the GIP, shall be borne by the Interconnection Customer(s) being re-studied.

- After the completion of the Restudy, an Interconnection Customer that is being restudied may elect to remain in the Interconnection Facilities Study Queue, or withdraw its Interconnection Request and receive a refund of its security deposit in accordance with Sections 8.14 and 13.3 of the GIP.

Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment V Generator Interconnection Procedures (GIP)

SPP'S SENSITIVITY / RESTUDY APPROACH



Also if no shared upgrades

DISIS-2016-002-3

- Generator Interconnection (GI) received 2016-002 withdrawals
  - Group 8 – 795 MW (1st 500 MW), (2nd 295 MW)
  - Group 4 – 755 MW
  - Group 9 – 552 MW
  - Group 13 – 151.2 MW *no shared upgrades
  - Group 15 – 175 MW (TBD G16)
- GI performed sensitivities; the results:
  - 1st Group 8 sensitivity reposted on 01/06/2021
  - Groups 4, 9, 15 and 16 sensitivities reposted on 4/23/2021
  - GI determined a need to Restudy DISIS-2016-002-3 for Group 8. The restudy will commence on April 23, 2021 and complete June 24, 2021 (60-calendar days). power flow will be performed and TBD if stability will be needed.

DISIS-2016-002 SENSITIVITY RESULTS GROUPS 4, 9, 15, 16

- **Group 4:** All Network Upgrades went away, except the addition of Buckeye Transformer Rebuild allocated to one customer.
- **Group 9:** All Network Upgrades went away. Still dependent on the R Plan.
- **Group 15:** All Network Upgrades went away. Still dependent on the R Plan.
- **Group 16:** Leland Olds Substation Reconfiguration still remains. Still dependent on the R plan.

DISIS-2017-001-1 RESTUDY

- GI has determined a need to Refresh/Restudy DISIS-2017-001-1 during Phase 3 due to withdrawals from DISIS-2016-002 Groups 4, 9, 8, 15 and 16, as well as TBD DISIS-2017-001 withdrawals/changes from Decision Point 2 due **May 13, 2021**.
- The Refresh/Restudy DISIS-2017-001-1 is expected to commence **May 14, 2021** and complete **July 21, 2021** (66 calendar days). Both power flow and stability analyses will be performed.

DISIS-2016-002-3, DISIS-2017-001-1 PHASE 3, DISIS-2017-002 PHASE 1 AND PHASE 2

Study Name	Start	Complete	Comments
DISIS-2016-002-2 Reposting Groups 4, 9, 15 and 16	4/23/2021	4/23/2021	COMPLETE
DISIS-2016-002-3 Restudy Group 8	4/23/2021	6/24/2021	Notification 4/23; completion meets 60-calendar day Tariff deadline
DISIS-2017-001 Phase 2 Reposting	4/27/2021	4/27/2021	COMPLETE
DISIS-2017-001-1 Refresh/Restudy Groups 4, 8, 9, 15 possibly more/most from 1701 DP2	5/14/2021	7/21/2021	Notification 5/13 with close of DP2; does not meet Tariff completion 60-calendar days of 7/15/2021, but we will need more time for so many groups
DISIS-2017-001 Phase 3 Facility Study - requests not being restudied can proceed	5/14/2021	9/26/2021	Meets Tariff 135 days for non-restudied requests
DISIS-2017-001 Phase 3 Facility Study - requests being restudied must wait	7/22/2021	12/4/2021	Meets Tariff 135 days for restudied requests
DISIS-2017-002 Phase 1	6/1/2021	8/30/2021	Meets Tariff 90 days for Phase 1; Phase 1 start not dependent on previous restudies; however, GI will make best assumptions about withdrawals/contingent upgrades available at brightline
DISIS-2017-002 Phase 2	9/27/2021	1/25/2022	1702 Phase 2 start is dependent on 1702 DP1, 1602-3 and 2017-001-1 restudies completions, so far OK; however, Phase 2 start of 9/27/2021 is at risk if additional withdrawals from 1602 or 1701 cause more restudies

JENNIFER SWIERCZEK
HANNAH JONES

Please feel free to contact us at jswierczek@spp.org or hjones@spp.org if you have any questions related to GI Studies schedules.

For further reading:

http://opsportal.spp.org/documents/studies/sppgistudyupdate_weekly.pdf

ATTACHMENT 2

Testimony of Judah L. Rose and Himali Parmar on behalf of Tenaska Clear Creek Wind, LLC

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tenaska Clear Creek Wind, LLC	)	
Complainant,	)	
	)	
v.	)	**Docket Nos. EL21-___-000**
	)	
Southwest Power Pool, Inc.	)	
Respondent.	)	

TESTIMONY OF JUDAH L. ROSE AND HIMALI PARMAR ON BEHALF OF TENASKA CLEAR CREEK WIND, LLC

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Tenaska Clear Creek Wind, LLC	)	
Complainant,	)	
	)	
v.	)	**Docket Nos. EL21-___-000**
	)	
Southwest Power Pool, Inc.	)	
Respondent.	)	

TESTIMONY OF JUDAH L. ROSE AND HIMALI PARMAR ON BEHALF OF TENASKA CLEAR CREEK WIND, LLC

I. INTRODUCTION

Q1: Please state your name and business address.

A1: Our names are Judah L. Rose and Himali Parmar. Our business address is ICF, 9300 Lee Highway, Fairfax, Virginia 22031.

Q2: On whose behalf are you testifying?

A2: We are testifying on behalf of Tenaska Clear Creek Wind, LLC ("Tenaska Clear Creek").

Q3: Please describe your educational backgrounds.

A3: Judah L. Rose has a Bachelor of Science in Economics from the Massachusetts Institute of Technology and a Master of Public Policy from Harvard University. Himali Parmar has a Master of Science in Electrical Engineering from University of Wisconsin, Milwaukee.

Q4: Please provide your current positions and describe the duties and responsibilities of your current positions.

A4: Judah L. Rose is an Executive Director of ICF and the Chair of ICF's Energy Advisory division. Himali Parmar leads the transmission practice within the Energy Advisory division. ICF is a recognized consulting firm that provides professional services and technology solutions across a range of industries. Of approximately 7,000 employees, roughly 1,200 work in the energy sector.

Q5: Please summarize your professional experience.

A5: Judah L. Rose has extensive experience in wholesale electric power markets, including market design, generation (renewable/non-renewable), and transmission in Southwest Power Pool, Inc. ("SPP") and the Midcontinent Independent System Operator ("MISO"). Mr. Rose has worked over 40 years in the field, including nearly 39 years at ICF. Himali Parmar has 21 years of experience including 19 years working on transmission issues at ICF. We have multiple transmission related-projects ongoing at any time. We have worked for a broad range of clients, including electric utilities, grid operators, government regulators/agencies, consumers, environmental groups, fuel providers, Independent Power Producers, marketers, financial institutions, and law firms.

Q6: Have you previously testified in any legal proceedings before the Federal Energy Regulatory Commission ("FERC")?

A6: Yes. Judah L. Rose has testified before or made presentations to the Federal Energy Regulatory Commission ("FERC"), international arbitration tribunals, numerous courts, arbitration panels, and state regulators and legislators in 24 U.S. states and Canadian provinces. Judah L. Rose has testified as an expert over 140 times, in approximately 45 venues, including on SPP-related matters. Mr. Rose has also authored numerous articles on the subject of wholesale power market design, and has spoken at numerous industry conferences. Himali Parmar has 21 years of transmission experience. The resumes of both affiants are attached as Exhibits 2-1 and 2-2.

Q7: Please describe your experience with affected system studies.

A7: We regularly evaluate affected system studies on behalf of our clients, including system models, associated assumptions, and methodologies. We also have submitted comments on interconnection issues before FERC and other regulatory agencies. Among other things, Mr. Rose participated in the FERC technical conference on affected system studies involving SPP, MISO, and PJM, and filed multiple rounds of comments in 2018.[1] Himali Parmar assisted in that effort.

Q8: What is the purpose of your testimony in this proceeding?

A8: The purpose of this testimony is to support the complaint filed by Tenaska Clear Creek in this docket against SPP related to SPP's affected system studies of Tenaska Clear Creek's wind-powered generator located in Maryville, Missouri ("Clear Creek Project" or "Project"). This testimony summarizes ICF's analysis of SPP's affected system study of the Clear Creek Project.

Q9: Please describe the Clear Creek Project.

A9: The Clear Creek Project is a 242 MW wind plant that is physically interconnected to the transmission system owned and operated by Associated Electric Cooperative Inc. ("AECI"). The Project is interconnected to an area of the AECI system that is adjacent to the seams of both MISO and SPP.

Q10: Please summarize your testimony.

A10: Our testimony documents our evaluation of the affected system studies prepared by SPP for the Clear Creek Project, including the recent restudy of the Clear Creek Project that has

[1] Reform of Affected System Coordination in the Generator Interconnection Process, Docket No. AD18-8-000; *EDF Renewable Energy v. Midcontinent Independent System Operator. Inc, Southwest Power Pool, Inc. and PJM Interconnection, LLC*, Docket No EL18-26-000; *see also* "Response to Post-Technical Conference Comments of Judah L. Rose on Behalf of EDF Renewable Energy, Inc.," June 18, 2018.

resulted in the Project being assigned approximately $66 million in costs due to the application of Network Resource Interconnection Service ("NRIS") modeling standards that were not identified in the initial studies of the Project conducted over 2018 and 2019. As detailed further below, our analysis of these studies documents a series of serious errors and irregularities that were made in connection with SPP's affected system study of the Clear Creek Project. These errors and irregularities are reflected in close to a dozen separate iterations of the studies for the Clear Creek Project over a period spanning nearly three years. The errors and irregularities include:

(1) the addition of thousands of MWs of generation resources in the restudy of the Clear Creek Project that was not included in the initial studies;

(2) fundamental changes to the study model, modeling assumptions, and methodologies including changes in dispatch, years, and other key assumptions not related to queue withdrawals; and

(3) significant base case overloads resulting in the Clear Creek Project being unfairly assigned $66 million in costs associated with resolving pre-existing thermal overloads caused by other powerplants and a planning process not addressing base case overloads.

Our analysis indicates that the impact of these errors has been exacerbated by unrealistic assumptions employed by SPP in connection with affected system studies that result in customers on adjacent systems being assigned the cost of funding affected system upgrades from which they derive little benefits. Specifically, SPP fails to treat interconnections in affected systems as Energy Resource Interconnection Service ("ERIS"), as MISO does, and SPP now indicates it believes it should. Were SPP to apply this approach, one strongly recommended for years, the Clear Creek Project would not be assigned the cost of *any* of the additional upgrades that SPP has allocated to the Project as a result of the recent restudy. We also note that that MISO and now SPP believe they can operate their systems reliably treating even NRIS service requests in other host systems as ERIS requests. Therefore, the Clear Creek dispute is not primarily one impacting reliability, but rather cost allocation, and ensuring that the interconnection process is just and reasonable and not discriminatory in the context of a particularly egregious set of circumstances.

II. SPP'S AFFECTED SYSTEM STUDY PROCESS

Q11: Please briefly describe the SPP affected system study process.

A11: Affected system studies seek to determine if the interconnection of a new generator to a particular transmission provider (i.e., the "Host System") will adversely impact an adjacent transmission provider's system (the "Affected System"). Affected system studies determine the extent to which network upgrades are required on the Affected System in order to ensure that the interconnection of a generator will not impair the ability of the Affected System to operate in a safe and reliable manner.

Q12: Please briefly describe how SPP, as an Affected System, models and studies new generator interconnections.

A12: SPP's affected system study process utilizes the Definitive Interconnection System Impact Study ("DISIS") approach and mitigation criteria. SPP compares the system conditions under Base Case and Transfer Case conditions to identify incremental overloads and solutions.

Q13: Please describe the Base Case and Transfer Case overloads and how costs are allocated to new projects.

A13: In order to assess the impact of any new generator(s) on the grid and estimate its share of upgrade costs, system operators typically rely on two scenarios. First, the transmission provider constructs and identifies a Base Case to use as the basis of the study of the interconnection customer. As a general matter, the Base Case will take into account all higher-queued interconnection customers, the results of the transmission planning process, and other factors. However, the Base Case will exclude the generation resource that is under study. For the purpose of evaluating the impact of the interconnection customer at issue, the system operator then adds the new generator to the study. The results of the study when the interconnection customer that is being evaluated is included is referred to as the Transfer Case. The transmission provider will then evaluate the impact that the addition of the capacity associated with the interconnection customer will have on transmission facilities within the Affected System.

Q14: Please describe the powerflow models utilized by SPP in its interconnection process.

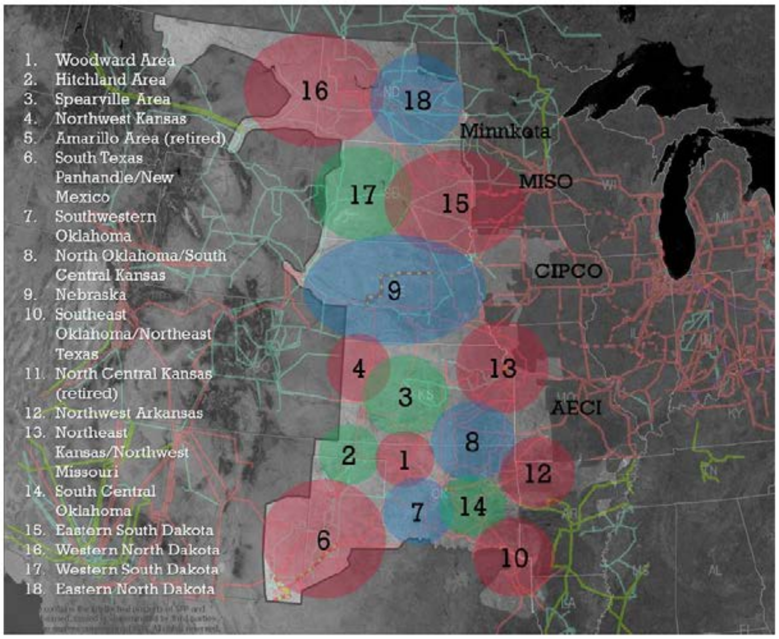
A14: The SPP Integrated Transmission Plan ("ITP") powerflow models serve as the starting point for all interconnection studies. These models typically include four years and different system conditions as shown in Figure 1. This information serves as the baseline for the state of the transmission system prior to the interconnection of a new generator. The affected system study then seeks to analyze how the generator's interconnection affects this baseline data.

Figure 1: DISIS Power Model Run Year and Conditions

Year	Season/Condition
Year 1	Spring
Year 1	Summer
Year 1	Winter
Year 2	Spring
Year 2	Summer
Year 2	Winter
Year 5	Light Load
Year 5	Summer
Year 5	Winter
Year 10	Summer
Source: SPP DISIS Manual	

Further, the SPP DISIS is disaggregated into 16 active cluster groups in order to evaluate particular geographic regions of its transmission system, as depicted in **Figure 2**. The Clear Creek Project was evaluated using 2016-DISIS-002 powerflow models for Cluster Group 13. Depending on the type of study request, SPP deploys specific dispatch assumptions for the study units as shown below in Figure 3. Within the DISIS-2016-002 study cycle, the interconnection studies for each cluster differ in terms of the different dispatch levels modelled for generators within and outside the cluster as shown in Figure 3.

Figure 2: SPP Cluster Map



Source: SPP DISIS Manual

Figure 3: SPP DISIS Dispatch Assumptions

Dispatch Type	Season	Service Type	Variable Energy		Conventional	
			In Group	Out Group	In Group	Out Group
ERIS HVER	All	All	100%	20%	N/A	N/A
ERIS LVER	Peak	All	20%		100%	
NRIS	Spring and Light Load	ERIS	80%	20%	N/A	N/A
		NRIS	100%	20%	100%	20%
	Peak	ERIS	20% (Solar: 80% in summer)		80%	
		NRIS	100%		100%	

Source: SPP DISIS Manual

Note:
In its powerflow models for a study cluster, SPP uses three dispatch scenarios which are developed using regional grouping. The three dispatch scenarios modelled are (1) High-Variable Energy Resource ("HVER"); (2) Low-Variable Energy Resource ("LVER"); and (3) Network Resource ("NRIS"), which are assessed for various seasons and the dispatch assumptions for In Group and Out Group renewable and conventional generators.

Q15: Please briefly describe how SPP uses affected system studies to identify overloads and allocate network upgrade costs to new generator interconnections.

A15: As noted above, SPP evaluates the impact of the interconnection customer through the simulation of a Transfer Case. For the purpose of determining whether to assign an interconnection customer responsibility for the cost of constructing network upgrades necessary to mitigate overloads in the Transfer Case, SPP utilizes a threshold criteria based on Distribution Factors ("DFAX") under system impact and n-1 contingency conditions[2]. A DFAX is a measure of the impact that the injection of electricity at the generator's point of interconnection will have on the SPP transmission system. In SPP, unlike neighboring MISO, the modeling practices and thresholds that are applied to determine whether the interconnection customer should be required to fund Network Upgrades differs based on whether the customer is requesting ERIS or NRIS on the Host System.

Q16: How does SPP's affected system study approach compare with that of MISO, which was also an affected system for the Clear Creek Project?

A16: The approach of SPP and MISO are very different. As noted above, the studies performed and the DFAX thresholds that are applied by SPP differ depending on whether the customer is requesting ERIS or NRIS on the Host System. This stands in stark contrast to the approach employed by MISO, which applies only the ERIS studies and thresholds when evaluating whether a customer on an adjacent system should be required to fund Network Upgrades.

[2] System intact assumes all transmission facilities are in operation (or no outages). Planners would typically design the system such that system will continue to operate reliably even if one major transmission element is out of service. To ensure reliable operations, planning studies are performed under n-1 contingency conditions.

This difference in approach was reflected in the way that SPP and MISO evaluated the Clear Creek Project. Under SPP's approach, because the Clear Creek Project sought both a 242 MW NRIS and ERIS interconnection with AECI, SPP assessed Clear Creek both as a 242 MW NRIS and a 242 MW ERIS interconnection request. MISO, in contrast, evaluated the Clear Creek Project using only ERIS studies and thresholds. Figure 4 outlines the affected system approach used by SPP and MISO for ERIS and NRIS requests and applicable cost thresholds. As discussed, MISO only performs ERIS study irrespective of ERIS/NRIS interconnection in host system. SPP performs the requisite studies based on the interconnection type in host system and SPP's criteria requires NRIS projects to clear a 3% DFAX threshold while requiring ERIS projects to clear a 20% DFAX threshold under n-1 contingency. This results in cost allocation of network upgrades being done only for projects which have DFAX above the threshold values. MISO applies a 5% DFAX threshold under system intact conditions, as compared to SPP's 3%.

Both markets apply comparable DFAX thresholds under n-1 contingency conditions. Overall, SPP has a stricter affected system criterion compared to MISO, and does not account for the modification to dispatch that occurs if there are violations of the affected systems interface and other limits. In actual operation, the affected system would not dispatch its plants in a manner that violates transmission limits on its system or on the affected system. In addition, where generation resources on an adjacent system are contributing to a constraint on the system of the transmission provider, the transmission provider will coordinate with the reliability coordinator and the operator of the adjacent system to curtail generators having an effect on the constraint in accordance with applicable transmission priorities. Importantly, the transmission provider will do so regardless of whether the generation resource on the adjacent system has been granted ERIS or NRIS. Therefore, MISO studies NRIS service requests made in other systems as if they are ERIS requests. Figure 4 sets out the thresholds that SPP and MISO apply to affected system studies.

Figure 4: SPP and MISO Approach and Cost Thresholds for Affected System Studies

System Conditions	SPP		MISO	
	ERIS	NRIS	ERIS	NRIS
System Intact (N-0)	3%	3%	5%	Not performed [1]
Contingency (N-1)	20%	3%	20%	

Source: SPP DISIS Manual; MISO Business Practice Manual Generator Interconnection (BPM-015)
Notes:
[1] Only ERIS study performed irrespective of ERIS/NRIS interconnection in host system

Q17: Has SPP been consistent in its application of NRIS modeling practices and thresholds when evaluating the impact of customers on affected systems?

A17: No. As part of a Joint Targeted Interconnection Queue Study being conducted by SPP and MISO to identify projects required for the interconnection of low cost resources that provide economic benefits to both the MISO and SPP seams, SPP has proposed to apply ERIS study practices and thresholds when evaluating generation on the MISO system. In the scope of work for the study, SPP and MISO acknowledge that the addition of renewable resources and transmission system upgrades along the seam of SPP and MISO would benefit the market. The Joint Targeted Interconnection Queue Study scope notes, however, that current mechanisms do not provide sufficient cost sharing to facilitate new generator interconnection.[3] SPP also acknowledges very large challenges at the seams and the need for improvements in the planning process.[3] As part of the study scope, SPP explains that "[a]s MISO will not be evaluating Network Resource Interconnection Service (NRIS) for SPP, the SPP GI study will not evaluate NRIS for MISO. MISO and SPP interconnection requests will be evaluated for ERIS only. As such, SPP will only develop HVER and LVER dispatch scenarios."

SPP's acknowledgement of the inadequacies of current planning processes and willingness to adopt ERIS practices is notable given SPP's treatment of the Clear Creek Project.

Q18: Why is this significant?

A18: SPP's adopting MISO's approach of applying ERIS standards to affected system studies demonstrates that applying only ERIS standards to the Clear Creek Project would not be inequitable or interfere with the reliable operation of the SPP system. This demonstrates that SPP can, and should, adopt this approach when evaluating the Clear Creek Project's effect on SPP's transmission system. If the approach that SPP articulated in the Joint Interconnection Queue Study scope were applied to Tenaska Clear Creek, all of the additional costs that SPP has proposed to assign to the Project as a result of the restudy would be eliminated.

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[3] SPP-MISO 2021 Joint Interconnection Queue Study, February 19, 2021, https://spp.org/documents/64101/spp-miso%20jtiq%20detailed%20scope%2002192021%20final.pdf, page 1.

III. SPP's AFFECTED SYSTEM STUDIES OF THE CLEAR CREEK PROJECT

Q19: How many times did SPP perform affected system studies of the Clear Creek Project?

A19: SPP performed eleven affected system studies of the Clear Creek Project. These studies can be divided into two categories: (1) the initial six studies that were issued between October 5, 2018 and April 8, 2019 (the "Initial Studies")[4]; and (2) a restudy process that occurred over the course of 2020 and early 2021. We classify these studies as 2020/2021 Restudies.[5]

Q20: Please briefly describe the six Initial Studies and their results.

A20: Following Tenaska's request that SPP conduct an affected system study of the Clear Creek Project in August 2018, SPP issued the results of the First Initial Study, an Affected System Impact Study, on October 5, 2018. The study allocated costs of $31.2 million to the Project for two network upgrades to be made to the Maryville (KCPL) – Maryville (AECI) and Creston (WAPA) – Maryville (AECI) 161 kV Circuits. One month later on November 5, 2018, SPP issued its Second Initial Study, a revised version of the First Initial Study intended to account for SPP's omission of J476, a higher-queued generator. Tenaska's cost responsibility did not change as a result of the Second Initial Study.

On February 12, 2019, SPP issued an Affected System Interconnection Facilities Study, the Third Initial Study, which purported to allocate only $16.3 million in costs to the Project, rather than $31.2 million. This decrease in costs reflected the Western Area Power

[4] SPP's initial study issued on April 8, 2019 is referenced as Original Study

[5] The first restudy issued on November 2, 2020 is referenced as the 2020 Restudy in our discussion. The latest restudy issued on March 25, 2021 is referenced as the 2021 Restudy.

Administration's ("WAPA") determination that the costs associated with re-conductoring the Creston-Maryville 161 kV line had decreased significantly to $14.9 million. On March 13, 2019, SPP issued a revised Affected System Impact Study, the Fourth Initial Study, which accounted for the Project's change in capacity from 230 MW to 242 MW. Eight days later on March 21, 2019, SPP issued its Fifth Initial Study, an Affected System Impact Study that increased the Clear Creek Project's total costs to $33 million by allocating an additional network upgrade to the Project: the Braddyville (J611) –Maryville 161 kV Circuit 1. On April 8, 2019, SPP issued a revised Affected System Interconnection Facilities Study, the Sixth Initial Study, that increased the Project's total cost of upgrades to $33.5 million. Each of the Initial Studies were conducted using the same study model that was employed for the DISIS-2016-002 study cluster, which incorporated SPP's 2017 ITP models.

Q21: Please briefly describe the 2020/2021 Restudies.

A21: On November 1, 2019, SPP informed Tenaska of its intention to restudy the Clear Creek Project following the withdrawal of a higher-queued MISO generator, J570.

SPP issued the results of the First Restudy (the "2020 Restudy") approximately one year later. More specifically, on October 22, 2020, SPP provided Tenaska Clear Creek with preliminary study results, followed by subsequent issuance of a restudy report on November 2, 2020. The First Restudy results allocated $762 million in upgrade costs to the Clear Creek Project. The First Restudy also incorporated 7,000 MW of generation apparently omitted from all Initial Studies. On December 18, 2020, SPP issued a revised restudy, the Second Restudy, allocating $106.8 million in costs to the Clear Creek Project. On January 8, 2021, SPP issued a Third Restudy, which revised the findings of the Second

Restudy to remove upgrades on the 161 kV Archie – Adrian line. This decreased the Project's total network upgrade costs to $93 million. On February 26, 2021, SPP issued a Fourth Restudy, which decreased the Clear Creek Project's total network upgrade costs to $91 million as a result of revision to MISO's "partial" NR units, which were dispatched at reduced NR designation as opposed to their full nameplate.

Finally, on March 25, 2021, SPP issued a draft Affected System Study Report, the Fifth Restudy (the "2021 Restudy"), in which costs were adjusted upwards for all five NRIS upgrades leading to $8 million increase (to $99 million) in total network upgrade costs to the Clear Creek Project. Figure 5 below provides an overview of all study results.

Unlike the Initial Studies, the 2020/2021 Restudies were based on models that had been constructed for the SPP DISIS-2017-001 study cluster—the study cluster that is immediately behind the Clear Creek Project in the SPP queue—and incorporates the 2019 ITP models.

Figure 5 - Timeline of the SPP's Affected System Study Process and Cost Summary

Date	Study Number	SPP's Network Cost Allocated ($ MM)		
		ERIS	NRIS	Total
INITIAL STUDIES				
10/5/2018	1	31.2	0	31.2
11/5/2018	2	31.2	0	31.2
2/12/2019	3	16.3	0	16.3
3/13/2019	4	16.3	0	16.3
3/21/2019	5	33	0	33
4/8/2019	6	33.5	0	33.5
RESTUDIES				
11/2/2020	7	33.9	728.9	762.7
12/18/2020	8	33.6	73.3	106.8
1/8/2021	9	33.6	59.1	92.7
2/26/2021	10	33.9	57.1	91
3/25/2021	11	33.6	65.6	99.1

Q22: What is your reaction to the changes that SPP made as part of the 2020/2021 Restudies?

A22: They were extensive and effectively completely reset the baseline used to evaluate the Clear Creek Project's responsibility for network upgrades. Because the study model and assumptions used as the basis for a study will necessarily have a significant impact on the costs assigned to a customer, the Base Case and associated assumptions used in the initial studies of an interconnection customer should remain in place for subsequent restudies. The 2020/2021 Restudies are akin to a complete redo of the studies of the Clear Creek Project.

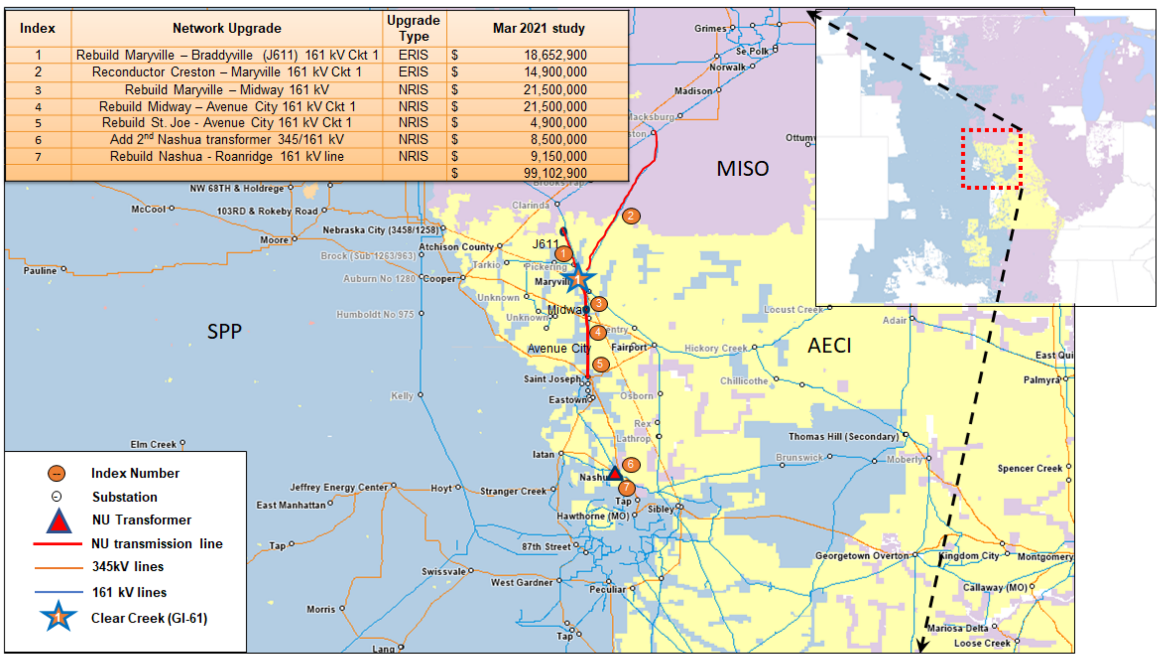
Q23: Please describe the differences between the results of the Initial Studies and the 2020/2021 Restudies.

A23: The primary difference is that the 2020/2021 Restudies resulted in a significant increase in the costs assigned to the Clear Creek Project. Both the Initial Studies and the 2020/2021 Restudies assigned Tenaska Clear Creek responsibility for two upgrades that were determined to be necessary to accommodate ERIS for the Clear Creek Project: Rebuild the Maryville – Braddyville 161 kV Line; and Reconducting of the Creston – Maryville 161 kV Line. The total cost of these upgrades is approximately $33.6 million. The 2020/2021 Restudies, however, assigned approximately $66 million in additional costs related to the construction of five additional network upgrades associated with the application of SPP's NRIS Criteria. Figure 6 provides an overview of the network upgrades that have been assigned to the Clear Creek Project, and Figure 7 depicts the location of the upgrades relative to the Clear Creek Project.

Figure 6- ERIS and NRIS Upgrades Assigned to Clear Creek Project

Upgrade Type	Upgrade	Cost (Million $)
ERIS	Reconducter Maryville to Crestone 161 kV	14.9
ERIS	Rebuild Maryville to Braddyville 161 kV	18.6
NRIS	Rebuild Maryville to Midway 161 kV	21.5
NRIS	Rebuild Midway to Avenue City 161 kV	21.5
NRIS	Rebuild Avenue City to St. Joseph 161 kV	4.9
NRIS	Add 2nd Nashua 345/161 kV Transformer	8.5
NRIS	Rebuild Nashua to Roanridge 161 kV	9.15

Figure 7: Project Location Map



Source: Created by ICF using Velocity Suite

IV. ADDITION OF MISO GENERATION IN SPP RESTUDY

Q24: Please explain your understanding of the omission that SPP has identified from the initial studies of the Clear Creek Project.

A24: In response to questions from Tenaska Clear Creek following the receipt of the 2020 Restudy from SPP, SPP provided Tenaska with a list of approximately 7 GW of generation resources on the MISO system that SPP claims were omitted from the Initial Studies of the Clear Creek Project as well as the SPP DISIS-2016-002 study cluster. Unsurprisingly, the introduction of these higher-queued generation resources resulted in a significant increase in loading on facilities in the Base Case study models of the 2020/2021 Restudies in comparison to the Initial Studies.

We note that there are discrepancies between the list of generation resources that SPP provided and the generation resources that were actually included in the Initial Studies of the Clear Creek Project. After being engaged by Tenaska Clear Creek, we reviewed the full list of units that were identified as "missing" by SPP. In our review, we observed that only 4.5 GW of rated capacity was not included in SPP's original models. The remaining 2.6 GW of rated capacity had been included in the Initial Studies of the Clear Creek Project. To arrive at the improperly modeled MW amount, ICF reviewed the missing generator list shared by SPP and identified that 2.6 GW was already modelled by SPP in the Initial Studies, and this capacity was in fact modelled at 3.7 GW rated capacity and at cumulative dispatch level of 3.5 GW in both the Original Study and 2021 Restudy. All of the missing 4.5 GW were located in MISO's footprint. We also observed that two other MISO queue positions—J718 and J748—were not identified by SPP as having been excluded from the Initial Studies, but did not appear in the models. Figure 8 summarizes our evaluation of missing generators in SPP's Original Study based on the Omitted Generation List shared by SPP. Appendix A provides a detailed list of the missing generators shared by SPP and ICF's comments on the status of the generators in the Original Study model.

Figure 8 - ICF's assessment of Omitted Generation

Status in Initial Studies	Number of Units	SPP Omitted Generation List	2021 Restudy (2019 ITP)		Original Study (2017 ITP)	
		Pmax	Pgen	Pmax	Pgen	Pmax
Missing	41	4,542	3,048	5,386	--	--
Existing	21	2,593	3,471	3,671	3,475	3,685

Notes:
Pmax is the summer peak rated capacity of the unit in SPP's Omitted Generation list shared with Tenaska Clear Creek
Pmax and Pgen are the unit's rated capacity and actual dispatch respectively in the 2019/2017 ITP models. 2019 ITP model shows 2024 summer peak conditions and 2017 ITP model shows 2026 summer peak conditions

Q25: What is your reaction to this change?

A25: This is a highly irregular and improper change that should apply prospectively to future entrants into the interconnection queue, and, if necessary, should be dealt with via other planning processes provided for by SPP's tariff.

Q26: Please describe how SPP's decision to add in approximately 4.5 GW of additional generation affected the Initial Studies and Restudies.

A26: ICF began its analysis of the impact of the omitted generation by first simulating the Initial Studies and adding in the approximately 4.5 GW of excluded generation. ICF also accounted for withdrawal of J570 and the addition of two higher-queued MISO projects: J718 and J748. After adjusting the original models for these capacities, we performed a detailed contingency analysis of the SPP system.

The result of this analysis shows significant Base Case overloads in the NRIS study model. In fact, four of the five NRIS upgrades that have been assigned to the Clear Creek Project in the 2021 Restudy are overloaded in the Original Study Base Case when the omitted generation is included.[6]

Further, J611 (Braddyville) – Maryville 161 kV, one of the two ERIS upgrades that has been assigned to the Project, does not appear to be overloaded in the transfer case. Our analysis suggests that if the ERIS analysis had been run using the 2017 ITP models that formed the basis for the Initial Studies of the Project, the Network Upgrades assigned to the Clear Creek Project for ERIS dispatch scenarios would be approximately $18 million lower.

Figure 9 below provides an overview of the results of ICF's Assessment. We also provide base case and transfer case loading on all seven upgrades assigned to the Clear Creek Project in the October/November 2020 (i.e., the 2020 Restudy) restudy results that SPP provided and the restudy results provided by SPP in 2021 (i.e., the 2021 Restudy).

ICF relied on the same models which were used by SPP to prepare the 2020/2021 Restudy Cases and ran a contingency analysis and documented all overloads where Clear Creek adds to the flows. ICF expects SPP to have used the same process to evaluate Clear Creek's impact on their grid. Please note, ICF did not make any assumption changes to SPP's powerflow models. As a result, the overloads identified by ICF align with the study information that SPP has shared with Tenaska Clear Creek.

[6] The fifth NRIS upgrade assigned to the Clear Creek Project, the rebuild of 161 kV Nashua – Roanridge, is attributed to overloads caused by a SPP's proposed solutions to overloads on the Nashua 345/161 kV transformer. Nashua – Roanridge is not observed to be overloaded directly in the Transfer Case for the Clear Creek Project.

The presence of significant Base Case overloads on these facilities prior to the introduction of the Clear Creek Project demonstrates that Project did not trigger the need for these upgrades. The results of the 2020 Restudy similarly included overloads in the Base Case prior to the introduction of the Clear Creek Project. Based on the 2020 Restudy results provided to Tenaska Clear Creek in November 2020, we observe that each of the NRIS upgrades that SPP has proposed to assign to the Project were overloaded in the Base Case. However, in the 2021 Restudy, further changes in dispatch assumptions for neighboring MISO units resulted in only one of the five facilities as overloaded while all others are approaching their limit in the Base Case.

Figure 9: Line loading in ICF's assessment of Original Study Versus 2020/2021 Restudies

Apr 2019 /March 2021Vintage	Type of Constraint	ICF Assessment [1]		2020 Restudy		2021 Restudy	
		Base Case	Transfer Case	Base Case	Transfer Case	Base Case	Transfer Case
Creston-Maryville 161 kV for the loss of Maryville- Maryville Tap 161 kV							
21 SP/24 SP	ER	69.1%	103.0%	77.8%	110.0%	77.6%	110.0%
26 SP/29 SP	ER	74.8%	109.0%	77.1%	109.2%	76.8%	109.2%
J611(Braddyville)- Maryville 161 kV for the loss of Creston-Maryville 161 kV							
21 SP/24 SP	ER	<50%	90 .8%	79.5%	115.8%	76.0%	113.9%
26 SP/29 SP	ER	57.2%	98.1%	78.1%	114.5%	74.7%	112.7%
Maryville- Midway 161 kV for the loss of Gentry-Fairport 161 kV [4]							
21 SP/24 SP	NR	117.4%	154.1%	140.8%	183.7%	104.6%	146.1%
21 WP/24 WP	NR	66.3%	100.1%	107.9%	NConv [2]	78.4%	110.8%
26 SP/29 SP	NR	117.5%	167.6%	140.7%	184.6%	105.9%	147.5%
Midway-Avenue City 161 kV for the loss of Gentry-Fairport 161 kV							
21 SP/24 SP	NR	106.9%	143.4%	133.3%	175.7%	97.5%	138.9%
21 WP/24 WP	NR	54.7%	88.2%	101.6%	NConv[2]	72.4%	104.6%
26 SP/29 SP	NR	107.6%	157.2%	133.2%	176.7%	99.0%	140.3%
Avenue City 161- St Joe 161 kV for the loss of Gentry-Fairport 161 kV							
21 SP/24 SP	NR	105.2%	141.6%	131.8%	174.1%	96.0%	137.3%
21 WP/24 WP	NR	53.4%	86.8%	100.0%	NConv[2]	71.0%	103.1%
26 SP/29 SP	NR	105.9%	155.4%	131.6%	175.0%	97.4%	138.7%
Nashua transformer 345/161 kV for the loss of Hawthorn – Nashua 345 kV							
21 SP/24 SP	NR	107.3%	107.3%	126.7%	126.7%	96.1%	<100%

21 WP/24 WP	NR	94.6%	96.9%	127.0%	NConv[2]	99.7%	102.2%
26 SP/29 SP	NR	104.4%	108.7%	125.0%	125.1%	<100%	<100%
Nashua - Roanridge 161 kV line for the loss of Hawthorn – Nashua 345 kV							
21 SP/24 SP	NR	99.0%	98.3%	116.0%	117.5%	<100%	<100%
21 WP/24 WP	NR	75.4%	77.3%	112.7%	NConv[2]	<90%	101.8%
26 SP/29 SP	NR	95.8%	100.5%	115.3%	116.3%	<100%	<100%

Notes:
[1] Original Study after adjusting for omitted MISO capacity, withdrawal of J 570 and inclusion of MISO customers J718 and J748.
[2] Non- Convergence in power flows typically indicates extreme thermal violations or voltage stability issues. Non-Convergence may be caused by poor initial system conditions. Observation of significant overloads in the Base Case indicates the system may be at the tipping point especially under specific contingency conditions.

Q27: Please explain how the withdrawal of J570 contributed to the increase in costs observed in the 2020 Restudy.

A27: It did not. The withdrawal of J570 did not have any impact on the cost responsibility of the Clear Creek Project as shown in Figure 10. We did not observe any major changes on loadings on any of the seven overloads assigned to the Clear Creek Project. Notably, results of the Initial Studies of the Clear Creek Project did not depend on the construction of any network upgrades that had been assigned to J570. Instead, the dramatic increase in the costs assigned to the Clear Creek Project appear to be the result of a combination of factors, including the addition of 4.5 GW of generation resources in the 2020/2021 Restudy, the presence of base case overloads that predate the interconnection of the Clear Creek Project and SPP’s decision to shift to the use of the 2019 ITP model as the basis for the evaluation of the Clear Creek Project.

Figure 10 - Impact of J570 withdrawal

Apr 2019 /March 2021Vintage	Type of Constraint	ICF Assessment (with J570) [1]		ICF Assessment (without J570) [2]	
		Base Case	Transfer Case	Base Case	Transfer Case
Creston-Maryville 161 kV for the loss of Maryville- Maryville Tap 161 kV					
21 SP/24 SP	ER	69.5%	103.4%	69.1%	103.0%
26 SP/29 SP	ER	75.2%	109.4%	74.8%	109.0%
J611(Braddyville)- Maryville 161 kV for the loss of Creston-Maryville 161 kV					
21 SP/24 SP	ER	50.1%	91.3%	<50%	90.8%
26 SP/29 SP	ER	57.5%	98.5%	57.2%	98.1%
Maryville- Midway 161 kV for the loss of Gentry-Fairport 161 kV					
21 SP/24 SP	NR	117.3%	153.8%	117.4%	154.1%
21 WP/24 WP	NR	66.1%	99.9%	66.3%	100.1%
26 SP/29 SP	NR	117.3%	167.3%	117.5%	167.6%
Midway-Avenue City 161 kV for the loss of Gentry-Fairport 161 kV					
21 SP/24 SP	NR	106.7%	143.1%	106.9%	143.4%
21 WP/24 WP	NR	54.4%	87.9%	54.7%	88.2%
26 SP/29 SP	NR	107.4%	156.9%	107.6%	157.2%
Avenue City 161- St Joe 161 kV for the loss of Gentry-Fairport 161 kV					
21 SP/24 SP	NR	105.1%	141.4%	105.2%	141.6%
21 WP/24 WP	NR	53.1%	86.6%	53.4%	86.8%
26 SP/29 SP	NR	105.7%	155.2%	105.9%	155.4%
Nashua transformer 345/161 kV for the loss of Hawthorn – Nashua 345 kV					
21 SP/24 SP	NR	108.2%	108.2%	107.3%	107.3%
21 WP/24 WP	NR	95.7%	98.1%	94.6%	96.9%
26 SP/29 SP	NR	105.5%	109.6%	104.4%	108.7%
Nashua - Roanridge 161 kV line for the loss of Hawthorn – Nashua 345 kV [2]					
21 SP/24 SP	NR	100.0%	99.4%	99.0%	98.3%
21 WP/24 WP	NR	76.3%	78.3%	75.4%	77.3%
26 SP/29 SP	NR	96.8%	101.4%	95.8%	100.5%

[1] Original Study after adjusting for omitted MISO capacity and inclusion of MISO customers J718 and J748. The case includes J570
[2] Original Study after adjusting for omitted MISO capacity and inclusion of MISO customers J718 and J748 and excluding J570

Q28: Absent being explicitly notified by SPP of the missing 4.5 GW of generation, could Tenaska Clear Creek reasonably been expected to have identified the missing generation in reviewing SPP's study results and materials?

A28: No, not without unreasonable efforts. SPP, as the system operator, is obligated to maintain accurate databases which represent their current and future grid conditions such as demand, dispatch of all generators, and transmission facilities. In addition, while SPP is the lead in its affected system studies, the Host System must also proactively coordinate and review the studies. In practice, particularly in the affected system study context, SPP and other RTOs tend to exercise a significant amount of discretion in determining how to study projects. Given this complexity, claiming that this generation should be added in as part of a restudy is unjust and unreasonable. It is not unusual for a project sponsor to rely exclusively on the system operator for interconnection assessments, especially given that grid data is protected as critical energy infrastructure information (CEII). Further, even with the necessary CEII clearance, to make sense of the large volume of datapoints in these databases, one needs expensive powerflow modeling tools and subject matter expertise.

In addition, interconnection customers generally have little visibility into the information that is shared between SPP and other RTOs (e.g., MISO). Even if this was an inadvertent omission, there was no reasonable way for Tenaska to know that (1) SPP was not modeling relevant MISO units properly; or (2) changes in those assumptions would lead to significantly higher costs for the Clear Creek Project. The interconnection customer pays tens of thousands of dollars to the system operators to perform these studies. Specifically, for affected system studies by SPP, the costs could range between $40,000 to $80,000. It is unjust to require interconnection customers to front these costs when they are unable to rely on the accuracy of the results.

It is unclear whether SPP's decisions throughout its various studies of the Clear Creek Project were errors or intentional choices. Regardless, there changes should have been made prospectively for customers queued with lower priority than the Clear Creek Project and these changes should have been applied in a non-discriminatory manner.

V. BASE CASE VIOLATIONS

Q29: Have you evaluated the cause of the Base Case overloads?

A29: We understand that SPP has taken the position that the overloads are the cumulative result of higher-queued projects that individually did not have an impact significant enough on the upgrades at issue to trigger an allocation of costs based on the application of SPP's DFAX criteria. After being engaged by Clear Creek, we evaluated the Initial Studies and 2020/2021 Restudies to determine whether SPP's explanation was accurate.

Q30: Does SPP's explanation align with your evaluation?

A30: No. Based on our evaluation, it appears that the overloads are associated with identifiable, higher-queued generation resources that have a significant enough impact on the constraints at issue that if the assumptions relied on for assessing network upgrade costs, most notably the omitted MISO capacity was accounted for, they should have been assigned responsibility for constructing the upgrades that SPP is now attempting to assign to the Clear Creek Project. These overloads may not have been flagged at the time the facilities studies were being performed for the higher-queued projects due to decisions made by SPP during the study process, such as the omission of higher-queued generation resources.

We came to this conclusion based on our evaluation of the results of the Initial Studies (with the omitted generation included) and the results of the 2020/2021 Restudies. For the purpose of both analyses, we developed a comprehensive list of all modeled units for the 2017 ITP model used as the basis for the Initial Studies and the 2019 ITP used as the basis for the 2020/2021 Restudies. The contribution of existing and queued capacity from various SPP, MISO, and AECI study cycles on each of the seven identified constraints was estimated. Relative order of the projects with the 'Higher-Queued' stack was assessed based on ICF's review of SPP's interconnection/affected system studies for customers interconnecting to the SPP, MISO, and AECI systems.

The outcome of our analyses differs based on whether the 2017 ITP model or the 2019 ITP model is used as the starting point for the analysis. When the 2017 ITP model is used, the project that first triggered overloads is GI-53, an interconnection customer located on the AECI system in close proximity to the Clear Creek Project and that is receiving NRIS from AECI. The result of this analysis for the Maryville – Midway 161 kV upgrade is shown in Figure 11. From the column '*Cumulative Loading (%)*,' we observed that loading on the line exceeds 100% due the contribution of GI-53. AECI GI-53 also meets SPP's DFAX threshold of >=3% under contingency conditions. Another NRIS project in the queue between AECI GI-53 and the Clear Creek Project—MISO interconnection queue position J611—further exacerbated overloads on the line. Like GI-53, J611 meets SPP's DFAX threshold. Neither of these projects have been assigned any costs by SPP.

A similar analysis was conducted to identify the triggers for the other overloads currently assigned to the Clear Creek Project. As depicted in Appendix B, when the 2017 ITP model is used, AECI GI-53 is the initial trigger for overloads on the Midway – Avenue City 161 kV line in addition to the Maryville – Midway 161 kV line. In both cases, MISO J611 further exacerbated the overload on the line. MISO J611 also is the initial trigger for overloads on the Avenue City – St Joe 161 kV line and Nashua 345/161 kV transformer. Again, both GI-53 and J611 meet SPP's DFAX thresholds under contingency conditions. Through this analysis, we conclude that the overloads on the NRIS upgrades assigned to the Clear Creek Project pre-date the Project's entering the queue. To conclude, based on our assessment of the triggers for overloads after adjusting the powerflow models used in the Initial Studies for missing capacity in MISO, we believe SPP has improperly assigned network upgrades to the Clear Creek Project.

Figure 11: Trigger analysis - Maryville – Midway 161 kV Line for the loss of Fairport to Gentry -2026 Summer Peak / ICF's Assessment of the Original Study [1]

Priority Order	MVA Contribution	Cumulative Loading (%)
Existing	95	55.6%
Higher Queued	20	67.1%
SPP 2016 DISIS 001	*2.6*	*57.1%*
MISO 2016 DPP Feb West	*17*	*67.1%*
AECI GI-53	74	**110.6%[Trigger]**
MISO 2016 DPP August West	*29.0*	127.6%
Rest of MISO 2016 DPP August West except J611	*3*	112.6%
MISO J611	*26*	*127.6%*
SPP 2016 DISIS 002	-9	122.3%
MISO 2017 Feb West	2	123.3%
AECI GI-61	75.7	167.6%
Total	**287**	**167.6%**

GI 53 DFAX on Maryville- Midway line is 31.1%

[1] Original Study after adjusting for omitted MISO capacity, withdrawal of J570 and inclusion of MISO customers J718 and J748.

Note: Trigger analysis for all other overloads is summarized in Appendix B.

Q31: What did your evaluation of the 2020/2021 Restudies conclude?

A31: We observed severe Base Case violations on all NRIS upgrades assigned to the Clear Creek Project in the 2020 Restudy. However, as highlighted in our response to Q26, we observed changes in dispatch assumptions in MISO that led to reduction in Base Case overloads in the results that were provided to Tenaska Clear Creek in 2021. In the 2021 Restudy results, SPP observed Base Case violations for only one of the five NRIS upgrades. It is important to note, however, that all other NRIS upgrades were at or approaching their limit in the Base Case. Similar to our approach in identifying the likely triggers of overloads in the Base Case of the Initial Studies, we conducted a trigger analysis using the 2021 Restudy powerflow models to evaluate if a higher-queued project that meets SPP's DFAX criteria was the likely trigger for this overload. In conducting the trigger analysis for the 2021 Restudy, we developed a comprehensive list of all modeled units that have an impact on the identified overloads. The impact assessment was done through DFAX of each existing unit. As shown in the column '*Cumulative Loading (%)*,' we observed that loading on the line exceeds 100% due the contribution of MISO's J611. J611 also meets SPP's DFAX threshold of >=3% under contingency conditions.

Figure 12: Trigger analysis - Maryville – Midway 161 kV Line for the loss of Fairport to Gentry -2029 Summer Peak / 2021 Restudy

	Priority Order	MVA contribution	Cumulative Loading (%)
	Existing	43	25.4%
	Higher Queued	28	41.7%
	SPP 2016 DISIS 001	-0.1	25.3%
	MISO 2016 DPP Feb West	27.9	41.7%
	AECI GI-53	72.9	84.3%
	MISO 2016 DPP August West	37.2	**106.1%[Trigger]**
	Rest of MISO 2016 DPP August West except J611	12	91.0%
	MISO J611	26	**106.1%**
	SPP 2016 DISIS 002	-5	103.1%
	MISO 2017 Feb West	2	104.1%
	AECI GI-61	74.1	147.5%
	Total	252	147.5%

J 611 DFAX on Maryville-Midway line is 23.5%

Q32: Would these impacts have triggered responsibility to fund upgrades in order to resolve these constraints?

A32: Yes, both GI-53 and J611 meet SPP's DFAX criteria for cost allocation. For example, GI-53 has a 31% DFAX on Maryville – Midway 161 kV line for the loss of Fairport – Gentry and J611 has a 24% DFAX on Avenue City 161- St Joe 161 kV line. Figure 13 below shows the DFAX of the projects that trigger the overloads on the NRIS upgrades assigned to the Clear Creek Project.

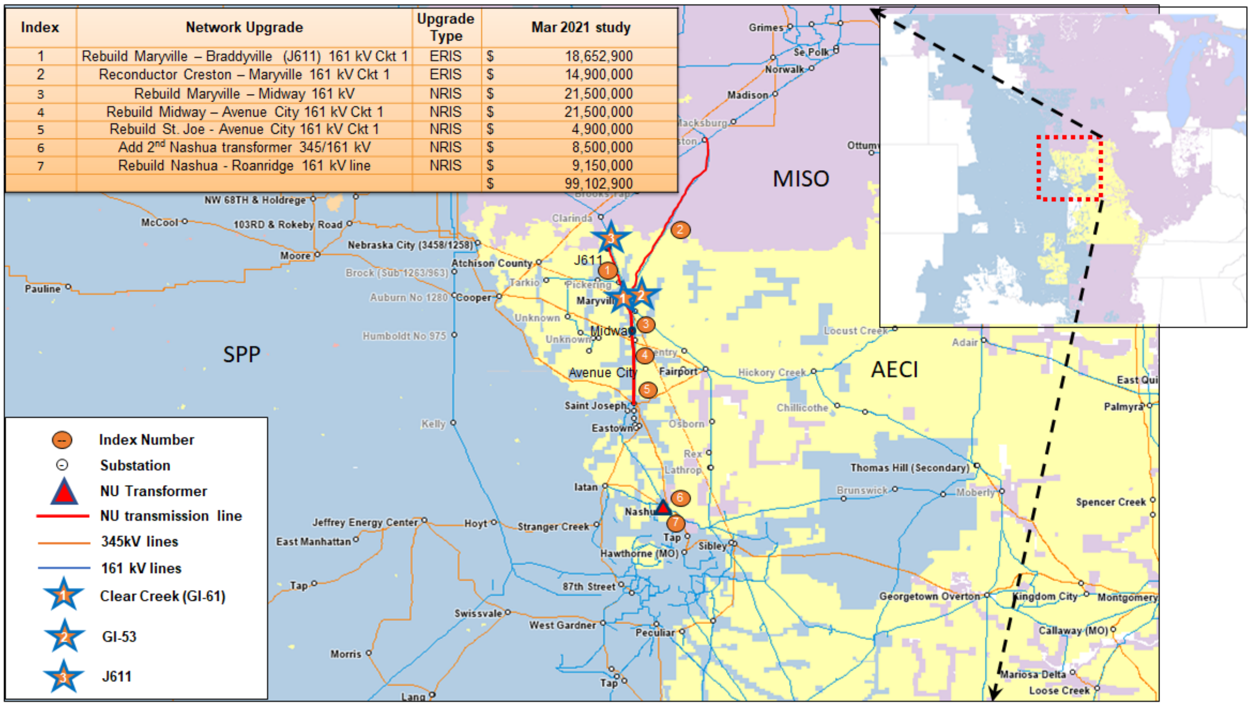
Figure 13 : DFAX contribution of projects on constraints

Type	Upgrade	DFAX -Original Study [1]		DFAX -2021 Restudy [2]
		GI-53	J611	J611
NR	Maryville- Midway 161 kV for the loss of Gentry-Fairport 161 kV	31.3%	NA	23.5%
NR	Midway-Avenue City 161 kV for the loss of Gentry-Fairport 161 kV	31.3%	NA	NA
NR	Avenue City 161- St Joe 161 kV for the loss of Gentry-Fairport 161 kV	NA	23.6%	NA
NR	Nashua transformer 345/161 kV for the loss of Hawthorn – Nashua 345 kV	NA	5.3%	NA
NR	Nashua - Roanridge 161 kV line for the loss of Hawthorn – Nashua 345 kV [3]	NA	NA	NA

[1] DFAX for 26 Summer Peak of Original Study
[2] DFAX for 24 Summer Peak for 2021 Restudy
[3] Loadings on Nashua-Roanridge in SPP's2020/2021 Restudies is observed due to inclusion of the 2nd Nashua 345/161 kV transformer upgrade

Both GI-53 and J611 are in close electrical proximity to Clear Creek as depicted in the map below.

Figure 14: Location of higher-queued projects (GI-53 and J611) relative to Clear Creek



Source: Created by ICF using Velocity Suite

Q33: If SPP had properly allocated the network upgrades costs to a higher-queued project, would Tenaska Clear Creek's cost responsibility change significantly?

A33: Yes. Based on the DFAX of the units triggering the overloads, we believe they should have been responsible for all or the vast majority of the five NRIS upgrades assigned to the Clear Creek Project.

Q34: Have you conducted this analysis using the study models that were originally used as the basis for the evaluation of GI-53 or J611?

A34: No. We have not been able to obtain these models. We have requested access, but SPP has thus far denied our request.

Q35: Have you identified any other factors that have contributed to the base case overloads?

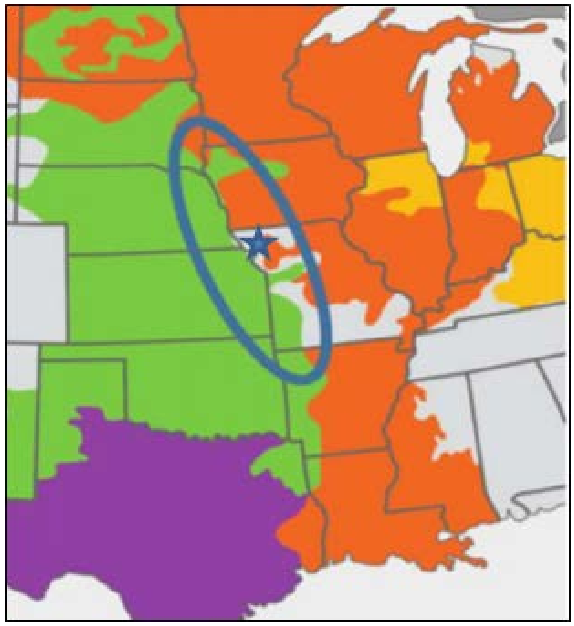
A35: As noted above, the primary triggers appear to be GI-53 and J611. That being said, it is worth noting that the SPP-MISO-AECI seam has been identified as one of the most constrained regions within SPP. Notably, SPP and MISO recently commenced the joint interconnection study referenced earlier in this testimony in recognition that greater interregional collaboration and planning is necessary to address reliability issues at the SPP and MISO seams. In their recent 2021 Joint Targeted Interconnection Queue Study, SPP and MISO acknowledge:

> "The transmission system is at its capacity and the next iteration of network upgrades are too costly for interconnection projects to proceed. While the additional of renewable resources and transmission along the seam benefit the market, current mechanisms do not provide sufficient cost sharing to facilitate new generator interconnection. Process, criteria, and schedule differences between the RTO's contribute to study delays and introduce questions on study results"[7]

Figure 15 below depicts the area that is being evaluated by the MISO and SPP joint study as well as the position of the Clear Creek Project.

[7] SPP-MISO 2021 Joint Targeted Interconnection Queue Study, Scope Of Work at 1 (Mar. 24, 2021).

Figure 15: Seams Region of Interest [showing the Clear Creek Project]



Q36: Can you please provide evidence of transmission being at capacity at the seams?

A36: Transmission facilities at the seams of MISO, SPP, and AECI have been observed to be bottlenecked in both generation interconnection and planning studies, and also in actual market operations. All seven upgrades currently assigned to the Clear Creek Project are located at the seams between these three systems. We observe that units located in all three systems contribute to flows on these seven transmission facilities. Beyond the seven upgrades assigned to the Clear Creek Project, there are several other transmission facilities along the seams that have been observed to be overloaded in SPP's affected system studies, which further corroborates the transmission issues along the seams. These bottlenecks require large-scale mitigation solutions close to a billion dollars, as shown in Figure 16, making it extremely unviable for renewable development along the seams, resulting in project withdrawals and several restudies which further adds to significant delays in the interconnection process. Upgrades identified for some of most notable constraints observed along the SPP, MISO, and AECI seams are shown in Figure 16.

Figure 16: Identified Upgrades for Congestion Along Seams

Identified Upgrade	Estimated Cost ($ Million)
Cooper - Stranger Creek 345 kV circuit 1 (New Line) [1]	625
Rebuild of Cooper – St. Joseph 345 kV circuit 1 [1]	
Rebuild of Cooper – Fairport - St. Joseph 345 kV circuit 1 [1]	
Dekalb & Nemaha County – 345 kV substations [1]	
Build a new line Sibley – Nashua 345 kV	130
Rebuild Stranger Creek – Craig 345 kV	81
Rebuild 87th – Craig 345 kV	13.6

Source: Several SPP Affected System Studies performed between 2018-2021.
Notes:
[1] Collectively called Cooper South Interface Upgrades. MISO's 2017 Feb West cycle was the most recent study cycle to trigger Cooper South Interface upgrades. However, after withdrawal of approximately 2.5 GW from the MISO queue and several others opting for reduced NRIS capacity, the overload was mitigated in the final affected system study released by SPP in April 2021. . Subsequently, in the 2017 DISIS 001 study results shared in April 2021, an alternate upgrade which includes a new 345 kV transmission line from Cooper to Hoyt with estimated cost of $146 million has been identified. This upgrade is expected to provide some mitigation to the Cooper South interface issues.

Further, we observe significant congestion along the seams, especially for the transmission facilities assigned to the Clear Creek Project in actual market operations. Congestion on the Maryville corridor and Nashua during 2016 to 2020 (January through April), clearly shows that these issues existed even before the Clear Creek Project started commercial operations and corroborates ICF's observations of Base Case violations. Figure 17 shows the number of hours of congestion on 161 kV Maryville – Midway and Nashua 345/161 kV transformer in both Day Ahead and Real Time markets. Congestion is often a harbinger or secondary measure of reliability overloads, and hence, reinforce the conclusion that the grid is at capacity.

Figure 17: Historical Congestion on Transmission Facilities assigned to Clear Creek

Constraint	Day Ahead							Real Time						
	2016	2017	2018	2019	2020 (Jan	2020 (May	2021	2016	2017	2018	2019	2020 (Jan	2020 (May	2021

					to April)	to Dec)						to April)	to Dec)	
161 kV Maryville to Midway under contingency			-	62	92	836	197			-	1	58	211	56
Nashua 345/161 kV transformer under contingency	713	314	1002	109	4	22	150	265	107	551	44	-	-	47
Source: Velocity Suite based on actual SPP's operations data														

Q37: What is the significance of the documented seams issues?

A37: It is another instance of planning failure that requires a remedy. This issue was identified and documented in the previously mentioned technical conference and was effectively left to interconnection customers to fix on their own. The lack of actions taken to resolve these issues is evidenced by the lack of interregional projects and the broad extent of Base Case overloads.

VI. SPP's USE OF 2017 VS. 2019 ITP MODELS

Q38: Please explain the significance of SPP's decision to conduct the 2020/2021 Restudies using a new study model.

A38: As noted earlier, SPP's decision to shift to a new study model for the 2020/2021 Restudies effectively resets the baseline used to evaluate the impact of the Clear Creek Project on the SPP system. For instance, ICF's analysis identified considerable changes between the two ITP models. The supply, dispatch, demand, and transmission assumptions and year/seasonal combinations analyzed were different in the 2017 ITP and 2019 ITP models. In the responses below, we summarize assumptions differences between Original Study, based on 2017 ITP models and 2021 Restudy, based on 2019 ITP models.

Q39: What is your reaction to this change?

A39: This is improper. Such changes should be made prospectively for analysis of later queued projects only.

Q40: Can you provide an example of some of the key differences?

A40: As a starting point, the "run" years evaluated in each of the studies differed significantly. The 2017 ITP model evaluated 2017, 2018, 2021, and 2026. In contrast, the 2019 ITP model evaluated 2019, 2020, 2024, and 2029. Figure 18 below compares the run years for both the 2017 ITP and 2019 ITP models.

Figure 18: Run Years – 2017 ITP vs. 2019 ITP models

Run years	2017 ITP	2019 ITP
Year 1	2017	2019
Year 2	2018	2020
Year 5	2021	2024
Year 10	2026	2029

Supply and Dispatch:

There also are significant differences in the dispatch levels for individual units included within the models. Below we summarize some of our observations:

- SPP assumed different Pgen[8] assumptions for several generators in SPP which contribute significantly to the loading on the identified upgrades. Figure 19 below shows the dispatch differences for select units in Cluster Group 13, i.e. the study group whose Base Case was used as a starting point to develop the Transfer Case for the Clear Creek Project. We observe that while overall Group 13 dispatch is comparable across

[8] Pgen represents the actual dispatch level of the generator assumed while Pmax represents its rated capacity.

both models, dispatch of select generators in SPP with positive DFAX on overloads assigned to the Clear Creek Project was higher. For example, we observed higher dispatch for several units with positive DFAX on the Nashua 345/161 kV transformer. The increase in dispatch of these units may have contributed to higher flows on the Nashua transformer relative to the results of the Initial Studies.

Figure 19: Dispatch Assumptions of Select Thermal Units - 2017 ITP vs. 2019 ITP

Generator Name	P_{Max}	Dfax for Nashua Transformer [1]	P_{Gen} in 2019 ITP based model (MW) [2]	P_{Gen} in 2017 ITP based model (MW) [3]
IAT G2 1	904.5	10.10%	779.9	550.1
IAT G1 1	754.4	10.10%	650.6	432.7
COOPER1G	874.4	6.00%	850.9	454.8
1WINSLOWG1	168	8.10%	60.5	51.6
1CLYDEG1	50.4	7.40%	18.2	17.4
Notes: *[1] for the loss of 345 kV Nashua -Hawthorn; [2] 2024 winter peak; [3] 2021 winter peak*				

- In the 2019 ITP, SPP also adjusted the dispatch of several MISO generators. Figure 20 shows dispatch of select generators in MISO with positive DFAX on Nashua 345/161 kV transformer. Similar to our observations for SPP units, we note that the increase in dispatch of these units may have led to higher flows on the Nashua transformer relative to the results of the Initial Studies.

Figure 20: Dispatch Assumptions of Select MISO Units - 2017 ITP vs. 2019 ITP

Generator Name	P_{Max}	Dfax for Nashua Transformer [1]	P_{Gen} in 2019 ITP based model (MW) [2]	P_{Gen} in 2017 ITP based model (MW) [3]
J091	266	1.70%	266	53
J249	180	2.10%	180	72
J262	100	2.00%	100	49
J263	100	2.00%	100	49
J274	120	3.60%	120	26
J289	120	3.60%	120	26
R15	80	2.50%	80	18
R23	100	2.90%	100	22

R35	92	2.50%	80	18
R42	114	2.60%	114	25
R22	97.5	2.50%	98	22

Notes:
[1] for the loss of 345 kV Nashua -Hawthorn; [2] 2024 summer peak;[3] 2026 summer peak

Q41: Could the differences in the models create different results for Tenaska Clear Creek's cost responsibility for network upgrades?

A41: Yes, the differences in the models and assumptions used by SPP for the Initial Studies and the 2020/2021 Restudies have had an impact on the results. As noted herein, changes in dispatch assumptions for the thermal fleet located close to Nashua led to increased flows on the Nashua transformer and subsequent overloading in the transfer case when the 2019 ITP model is used. We also observe that adjustments made to account for missing capacity in MISO led to significant increase in Base Case flows. As we have noted above, if those changes were made to the 2017 ITP based powerflow models, SPP would have observed severe Base Case violations for all NRIS upgrades assigned to the Clear Creek Project. At the same time, our analysis indicates that certain ERIS upgrades currently assigned to the Clear Creek Project would no longer be overloaded.

Q42: Please explain transmission issues along the Nashua Corridor in greater detail.

A42: SPP's 2020/2021 Restudies identified overloads in the Nashua corridor. In contrast, SPP's Initial Studies did not report any violations along the Nashua Corridor. In the 2020/2021 Restudies using the 2019 ITP model, we observe that Nashua 345/161 kV transformer is overloaded only in one of three future snapshots evaluated by SPP. Specifically, the transformer is overloaded at 102.2% in the 2024 winter peak cases. The loading is below 100% in both the 2024 and 2029 summer peak cases.

It is worth noting that SPP's addition of the Nashua transformer to the model, in turn, results in the 161 kV Nashua-Roanridge becoming overloaded. In other words, it is mitigation of the overload on the Nashua transformer and not the interconnection of the Clear Creek Project is the cause of overloads on the Nashua – Roanridge 161 kV line.

Q43: Did you find any other solutions that might mitigate the need for the Nashua Transformer network upgrades?

A43: Yes, given the modest overloading (2.2% or 15 MVA) of the 345/161 kV transformer and especially in light of overloads caused by the mitigation plan, we recommend a redispatch solution for the overloads. In establishing the redispatch solution, we followed the overall dispatch assumptions outlined by SPP in their DISIS studies. Specifically, we identified a pool of thermal units in SPP that have a high DFAX on the Nashua transformer and can be dispatched (up or down depending on the DFAX) to relieve the overloads on the Nashua transformer. The units that provided counterflows (or relieved the loading) on the Nashua transformer were dispatched up by small amounts while units that added to flows on the Nashua transformer were dispatched down. In doing this, we ensured that all units that were dispatched down were operating at greater than 80% level as stipulated in SPP's DISIS manuals. Our proposed mitigating solution for 2024 winter peak case is shown in below Figure 21.

By making small changes to the dispatch of select units consistent with SPP manuals, we were able to mitigate the overload on the Nashua transformer. Because the need for the rebuild of the 161 kV Nashua – Roanridge Line is caused by the upgrade of the Nashua transformer, these changes in dispatch assumptions also mitigate the need for the rebuild of the 161 kV Nashua – Roanridge 1ine. In other words, small changes in the manner in which certain generators are dispatched would eliminate approximately $18 million of the additional $66 million in costs associated with NRIS upgrades that SPP has proposed to assign to the Project.

Figure 21: ICF Re-Dispatch Solution for Nashua Transformer Overloads in 2024 Winter Peak/ 2021 Restudy

	Unit Name	Fuel Type	Pmax (MW)	DFAX on Nashua Transformer	Pgen/ Pmax (%)	Pgen/ Pmax after Redispatch (%)
Dispatch Up	Nearman Creek	Coal	257	-12.1%	57%	75%
	Quindaro 1	Gas	83	-11.7%	17%	85%
Dispatch Down	Iatan Generator 1	Coal	754	10%	86%	81%
	Iatan Generator 2	Coal	905	10%	86%	81%
	Whelan Energy Center 1	Coal	84	3%	94%	83%
	Nebraska City 1	Coal	691	4%	86%	86%

We believe the proposed dispatch assumptions for both "up" and "down" are very reasonable and in-line with actual market operations. The most notable dispatch down is recommended for Iatan 1 and 2 coal plants. These two units with a combined capacity of approximately 1,700 MW have a significant impact as measured by DFAX on the Nashua transformer. Our recommended dispatch of 81% is shown compared to SPP's 2017 and 2019 ITP dispatch assumption in Figure 22.

Figure 22: Proposed Re-Dispatch Assumptions compared to 2017 and 2019 ITP

Unit Name	Proposed Dispatch	2019 ITP based model			2017 ITP based model		
		2024 Summer Peak	2024 Winter Peak	2029 Summer Peak	2021 Summer Peak	2021 Winter Peak	2026 Summer Peak

Iatan 1	81%	88.7%	86.2%	89.7%	64.1%	57.4%	66.6%
Iatan 2	81%	88.8%	86.2%	89.7%	68.5%	64.7%	71.2%

Further, we note that the "dispatch up" option is maximizing the revenue potential for existing resources which would be incentivized to dispatch up in real-time market operations if the Nashua transformer is a binding constraint. In that regard, these assumptions are likely to better align with actual system operations.

VII. NRIS v. ERIS TREATMENT FOR NEIGHBORING SYSTEM UNITS

Q44: Do the various studies of the Clear Creek Project demonstrate that the Clear Creek Project is responsible for reliability issues solved by the network upgrades allocated to the Project?

A44: No. As ICF has noted herein, the reliability issues SPP is asking the Project to mitigate by paying for network upgrades appear to be caused by higher-queued generators and congestion on the seams of MISO, SPP, and AECI. We have demonstrated this through (1) evaluation of the base case violations that appear when the additional 4.5 GW of generation is added into the study models; (2) evidence of historical congestion on Midway corridor and Nashua transformer that pre-dates Clear Creek; and finally (3) SPP and MISO's acknowledgement of the seams issues in the materials released in connection with the 2021 Joint Targeted Interconnection Queue Study.

Q45: Why is the Clear Creek Project being allocated costs for transmission bottlenecks not caused by its interconnection?

A45: SPP's standards for affected system studies are much more restrictive than neighboring MISO. As ICF has explained, SPP and MISO evaluate affected systems differently. MISO applies ERIS study scenarios and thresholds to all customers interconnecting to adjacent systems, regardless of whether that customer is seeking ERIS or NRIS service on its Host System. However, SPP applies both ERIS and NRIS study scenarios and thresholds to interconnection customers seeking NRIS service on adjacent systems. SPP only requires NRIS projects to clear a 3% DFAX threshold in order to be allocated network upgrade costs, resulting in the Clear Creek Project being allocated costs for significant upgrades to remedy reliability issues its interconnection did not cause.

Q46: Why is this a problem?

A46: SPP's unrealistic standards in connection with affected system studies result in customers on adjacent systems being assigned the cost of funding affected system upgrades from which they derive little benefit. SPP fails to reasonably account for the modification to dispatch that occurs if there are violations of the affected systems interface and other limits. In actual operation, the affected system would not dispatch its plants in a manner that violates transmission limits on its system or on the affected system. If SPP had applied the ERIS only standards to any of the neighboring systems including AECI, the NRIS network upgrades assigned to Clear Creek would not be applicable, remedying this problem (see Figure 23 and Figure 24).

Figure 23: ERIS and NRIS Upgrades Assigned to Clear Creek Project and Associated Costs

Upgrade Type	Upgrade	Cost (Million $)
ERIS	Reconduct Maryville to Crestone 161 kV	14.9
ERIS	Rebuild Maryville to Braddyville 161 kV	18.6
NRIS	Rebuild Maryville to Midway 161 kV	21.5
NRIS	Rebuild Midway to Avenue City 161 kV	21.5
NRIS	Rebuild Avenue City to St. Joseph 161 kV	4.9

NRIS	Add 2nd Nashua 345/161 kV Transformer	8.5
NRIS	Rebuild Nashua to Roanridge 161 kV	9.15
Total	**NA**	**99.05**

Figure 24: ERIS and NRIS Upgrades Assigned to Clear Creek Project if SPP Treats Affected System Studies the Same as MISO Does

Upgrade Type	Upgrade	Cost (Million $)
ERIS	Reconduct Maryville to Crestone 161 kV	14.9
ERIS	Rebuild Maryville to Braddyville 161 kV	18.6
NRIS	Rebuild Maryville to Midway 161 kV	0
NRIS	Rebuild Midway to Avenue City 161 kV	0
NRIS	Rebuild Avenue City to St. Joseph 161 kV	0
NRIS	Add 2nd Nashua 345/161 kV Transformer	0
NRIS	Rebuild Nashua to Roanridge 161 kV	0
Total	**NA**	**33.5**

Q47: Does SPP have the ability to remedy this problem?

A47: Yes, and SPP has considered doing so as evidenced by its ongoing 2021 Joint Targeted Interconnection Queue Study with MISO. SPP has recently considered adopting a methodology to bring itself in line with MISO. By considering evaluation of affected system customers as ERIS only, SPP seems to be acknowledging that this shift will not impact the reliability of its grid.

Appendix - A

Figure 25: Detailed List of ICF's assessment of missing generators in SPP's Original Study model

Study	GEN Bus Num	GEN ID	# Queue	Gen Name	GEN Area	G PMAX	SP PMAX	Service	Group	Type	Status in Original Study model
DIS-14-2-PQ	635415	W	J285	J285_W2	MEC	94	94	ER/NR	15 E-SD	Wind	Exists
DIS-14-2-PQ	635414	W	J285	J285_W1	MEC	94	94	ER/NR	15 E-SD	Wind	Exists
DIS-14-2-PQ	661986	W	J316	J316_W	MDU	113	113	ER/NR	18 E-ND	Wind	Exists
DIS-14-2-PQ	635059	W	J343	J343_W	MEC	113	113	ER/NR	09 NEB	Wind	Exists
DIS-14-2-PQ	600065	Y	J320	J320_Y	XEL	0	0	ER	18 E-ND	Gas	Missing
DIS-15-1-PQ	620101	W	G736	G736_W	OTP	150	150	ER/NR	15 E-SD	Wind	Exists
DIS-15-1-PQ	600170	PV	J385	J385_PV	XEL	75	75	ER/NR	15 E-SD	Solar	Exists
DIS-15-1-PQ	600169	PV	J400	J400_PV	XEL	47	47	ER/NR	15 E-SD	Solar	Exists
DIS-15-1-PQ	661104	Y	J405	J405_Y	MDU	16	16	ER/NR	16 W-ND	Gas	Missing
DIS-15-1-PQ	661104	1	J405	J405_1	MDU	7	7	ER/NR	16 W-ND	Gas	Missing
DIS-15-1-PQ	661104	2	J405	J405_2	MDU	7	7	ER/NR	16 W-ND	Gas	Missing
DIS-15-1-PQ	627034	1	J407	J407_1	ALTW	75	75	ER/NR	15 E-SD	Wind	Exists
DIS-15-1-PQ	627035	1	J407	J407_2	ALTW	75	75	ER/NR	15 E-SD	Wind	Exists
DIS-15-1-PQ	635216	W	J411	J411_W2	MEC	94	94	ER/NR	09 NEB	Wind	Exists
DIS-15-1-PQ	635216	W1	J411	J411_W3	MEC	19	19	ER/NR	09 NEB	Wind	Exists
DIS-15-1-PQ	635215	W	J411	J411_W1	MEC	113	113	ER/NR	09 NEB	Wind	Exists
DIS-15-1-PQ	600167	W	J426	J426_W	XEL	75	75	ER/NR	15 E-SD	Wind	Exists
DIS-15-1-PQ	600046	Y2	J299	J299_Y2	XEL	0	0	ER	15 E-SD	Combined Cycle	Missing
DIS-15-2-PQ	631249	Y1	J455	J455_Y3	ALTW	1	1	ER	09 NEB	Wind	Missing
DIS-15-2-PQ	631248	1	J455	J455_1	ALTW	88	88	ER	09 NEB	Wind	Missing
DIS-15-2-PQ	631249	Y2	J455	J455_Y4	ALTW	1	1	ER	09 NEB	Wind	Missing
DIS-15-2-PQ	631248	2	J455	J455_2	ALTW	22	22	ER	09 NEB	Wind	Missing
DIS-15-2-PQ	631249	1	J455	J455_3	ALTW	88	88	ER	09 NEB	Wind	Missing
DIS-15-2-PQ	631249	2	J455	J455_4	ALTW	22	22	ER	09 NEB	Wind	Missing
DIS-15-2-PQ	631248	Y1	J455	J455_Y1	ALTW	1	1	ER	09 NEB	Wind	Missing
DIS-15-2-PQ	631248	Y2	J455	J455_Y2	ALTW	1	1	ER	09 NEB	Wind	Missing
DIS-15-2-PQ	620102	W	J436	J436_W	OTP	113	113	ER	15 E-SD	Wind	Missing
DIS-15-2-PQ	620995	W	J437	J437_W	OTP	113	113	ER	15 E-SD	Wind	Missing
DIS-15-2-PQ	657745	Y	MPC02100	MPC02100_Y	OTP	1	1	ER	16 W-ND	Wind	Missing
DIS-15-2-PQ	635258	W	J412	J412_W1	MEC	75	75	ER/NR	09 NEB	Wind	Exists
DIS-15-2-PQ	635259	W	J412	J412_W2	MEC	75	75	ER/NR	09 NEB	Wind	Exists
DIS-15-2-PQ	620100	W	J442	J442_W	OTP	150	150	ER/NR	15 E-SD	Wind	Exists
DIS-15-2-PQ	615124	Y	MPC00500	MPC00500_Y	OTP	10	10	ER/NR	18 E-ND	Wind	Missing
DIS-12-1-PQ	615148	W	G830	G830_W	GRE	74	74	ER/NR	16 W-ND	Wind	Missing

Study	GEN Bus Num	GEN ID	# Queue	Gen Name	GEN Area	G PMAX	SP PMAX	Service	Group	Type	Status in Original Study model
DIS-12-2-PQ	603185	Y	J171	J171_Y	XEL	5	5	ER/NR	18 E-ND	Biom ass	Missing
DIS-12-2-PQ	600149	Y	J183	J183_Y	XEL	0	0	ER/NR	15 E-SD	Wind	Exists
DIS-12-2-PQ	661102	Y	J200	J200_Y	MDU	18	0	ER/NR	18 E-ND	Gas	Missing
DIS-12-2-PQ	661999	Y	J249	J249_Y	MDU	135	135	ER/NR	18 E-ND	Wind	Missing
DIS-12-2-PQ	600166	W	H081	H081_W	XEL	151	151	ER	15 E-SD	Wind	Missing
DIS-13-2-PQ	635214	Y	J279	J279_Y	MEC	23	23	ER/NR	09 NEB	Coal	Missing
DIS-13-2-PQ	635648	Y	J289	J289_Y	MEC	15	15	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	60421	1	J488	J488_1	OTP	114	114	ER	15 E-SD	Wind	Missing
DIS-16-1-PQ	61033	G1	J432	J432_G1	XEL	74	74	ER/NR	15 E-SD	Wind	Missing
DIS-16-1-PQ	61045	1	J460	J460_2	XEL	75	75	ER/NR	15 E-SD	Wind	Missing
DIS-16-1-PQ	61044	1	J460	J460_1	XEL	75	75	ER/NR	15 E-SD	Wind	Missing
DIS-16-1-PQ	621020	W	J493	J493_W	XEL	113	113	ER/NR	15 E-SD	Wind	Missing
DIS-16-1-PQ	61531	1	J495	J495_1	ALTW	75	75	ER/NR	15 E-SD	Wind	Missing
DIS-16-1-PQ	61534	1	J495	J495_2	ALTW	75	75	ER/NR	15 E-SD	Wind	Missing
DIS-16-1-PQ	636009	W	J498	J498_W2	MEC	128	128	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	636008	W	J498	J498_W1	MEC	128	128	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	635585	W	J499	J499_W1	MEC	128	128	ER/NR	09 NEB	Wind	Exists
DIS-16-1-PQ	635586	W	J499	J499_W2	MEC	128	128	ER/NR	09 NEB	Wind	Exists
DIS-16-1-PQ	635577	W1	J500	J500_W1	MEC	126	126	ER/NR	09 NEB	Wind	Exists
DIS-16-1-PQ	635578	W2	J500	J500_W2	MEC	125	125	ER/NR	09 NEB	Wind	Exists
DIS-16-1-PQ	635579	W3	J500	J500_W3	MEC	125	125	ER/NR	09 NEB	Wind	Exists
DIS-16-1-PQ	15040	1	J506	J506_1	MEC	75	75	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	16040	1	J506	J506_2	MEC	75	75	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	71033	1	J510	J510_1	OTP	213	200	ER/NR	15 E-SD	Gas	Missing
DIS-16-1-PQ	96999	W	J524	J524_W	MEC	75	75	ER/NR	09 NEB	Solar	Missing
DIS-16-1-PQ	72036	1	J526	J526_2	OTP	113	113	ER/NR	15 E-SD	Wind	Missing
DIS-16-1-PQ	72034	1	J526	J526_1	OTP	113	113	ER/NR	15 E-SD	Wind	Missing
DIS-16-1-PQ	637042	W	J527	J527_W2	MEC	94	94	ER/NR	09 NEB	Wind	Exists
DIS-16-1-PQ	637041	W	J527	J527_W1	MEC	94	94	ER/NR	09 NEB	Wind	Exists
DIS-16-1-PQ	635426	W	J529	J529_W1	MEC	94	94	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	635427	W	J529	J529_W2	MEC	94	94	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	637061	W	J530	J530_W1	MEC	94	94	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	637062	W	J530	J530_W2	MEC	94	94	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	66005	1	J534	J534_2	MEC	94	94	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	66003	1	J534	J534_1	MEC	94	94	ER/NR	09 NEB	Wind	Missing
DIS-16-1-PQ	66204	1	J535	J535_1	MEC	158	158	ER/NR	09 NEB	Wind	Missing
DIS-16-2-PQ	83023	1	J302	J302_1	MDU	76	76	ER/NR	18 E-ND	Wind	Missing

Study	GEN Bus Num	GEN ID	# Queue	Gen Name	GEN Area	G PMAX	SP PMAX	Service	Group	Type	Status in Original Study model
DIS-16-2-PQ	84764	1	J476	J476_1	MEC	185	185	ER/NR	13 NE-KS & NW-MO	Wind	Exists
DIS-16-2-PQ	85033	1	J503	J503_1	MDU	74	74	ER/NR	18 E-ND	Wind	Missing
DIS-16-2-PQ	85126	1	J512	J512_1	XEL	15	15	ER/NR	15 E-SD	Wind	Missing
DIS-16-2-PQ	85127	1	J512	J512_2	XEL	173	173	ER/NR	15 E-SD	Wind	Missing
DIS-16-2-PQ	85415	1	J541	J541	AMMO	300	300	ER/NR	13 NE-KS & NW-MO	Wind	Missing
DIS-16-2-PQ	85693	1	J569	J569_1	XEL	75	75	ER/NR	15 E-SD	Wind	Missing
DIS-16-2-PQ	85834	1	J583	J583_1	MEC	150	150	ER/NR	09 NEB	Wind	Exists
DIS-16-2-PQ	858741	1	J587	J587_1	XEL	74	74	ER/NR	15 E-SD	Wind	Missing
DIS-16-2-PQ	858742	1	J587	J587_2	XEL	76	76	ER/NR	15 E-SD	Wind	Missing
DIS-16-2-PQ	85902	1	J590	J590_2	ALTW	34	34	ER/NR	15 E-SD	Wind	Missing
DIS-16-2-PQ	85901	1	J590	J590_1	ALTW	34	34	ER/NR	15 E-SD	Wind	Missing
DIS-16-2-PQ	86115	1	J611	J611_1	MEC	83	83	ER/NR	13 NE-KS & NW-MO	Wind	Exists
PQ	600147	Y	G602	G602_Y	XEL	1	1	ER/NR	15 E-SD	Wind	Exists
PQ	600153	Y	G621	G621_Y	XEL	7	7	ER/NR	15 E-SD	Wind	Exists
PQ	629994	Y	G741	G741_Y	ALTW	1	1	ER/NR	15 E-SD	Waste Heat Recovery	Exists
PQ	600001	Y2	G930	G930_Y2	XEL	23	23	ER/NR	15 E-SD	Coal	Missing
PQ	600000	Y1	G930	G930_Y1	XEL	23	23	ER/NR	15 E-SD	Coal	Missing
PQ	635020	Y	R26	R26_Y	MEC	191	191	ER	13 NE-KS & NW-MO	Wind	Missing
PQ	620115	Y	G380	G380_Y	OTP	1	1	ER	16 W-ND	Wind	Missing
PQ	608775	Y	H092	H092_Y	MP	45	45	ER/NR	18 E-ND	Coal	Missing
PQ	600045	Y	G370	G370_Y	XEL	43	43	ER	15 E-SD	Gas	Missing
PQ	600134	Y	G514	G514_Y	XEL	1	1	ER	15 E-SD	Wind	Missing
PQ	635102	Y	R34	R34_Y	MEC	60	60	ER/NR	09 NEB	Wind	Missing
PQ	636035	Y	R49	R49_Y	MEC	9	9	ER/NR	09 NEB	Wind	Missing

Appendix - B

Figure 26: Trigger Analysis- Midway - Avenue City 161 kV line for the loss of Gentry-Fairport 161 kV (NRIS) - 2026 Summer Peak / ICF's Assessment of the Original Study [1]

Priority Order	MVA Contribution	Cumulative Loading (%)
Existing	77	45.3%
Higher Queued	20	56.7%
SPP 2016 DISIS 001	*2.6*	*46.7%*
MISO 2016 DPP Feb West	*17*	*56.7%*
AECI GI-53	74	**100.3%[Trigger]**
MISO 2016 DPP August West	*29*	117.2%
Rest of MISO 2016 DPP August West except J611	*3*	102.2%
MISO J611	*26*	*117.2%*
SPP 2016 DISIS 002	-9	111.9%
MISO 2017 Feb West	2	112.9%
AECI GI-61	75.7	157.2%
Total	**269**	**157.2%**

[1] Original Study after adjusting for omitted MISO capacity, withdrawal of J 570 and inclusion of MISO customers J718 and J748.

GI 53 DFAX on Midway-Avenue City 161 kV line is 31.1%

Figure 27: Trigger Analysis- Avenue City – St Joe 161 kV line for the loss of Gentry-Fairport 161 kV (NRIS)- 2026 Summer Peak / ICF's Assessment of the Original Study [1]

Priority Order	MVA Contribution	Cumulative Loading (%)
Existing	74	43.5%
Higher Queued	20	55.0%
SPP 2016 DISIS 001	2.6	45.0%
MISO 2016 DPP Feb West	17	55.0%
AECI GI-53	74	98.5%
MISO 2016 DPP August West	29	**115.5%[Trigger]**
Rest of MISO 2016 DPP August West except J611	3	100.4%
MISO J611	26	115.5%
SPP 2016 DISIS 002	-9	110.1%
MISO 2017 Feb West	2	111.2%
AECI GI-61	75.7	155.4%
Total	266	155.4%

[1] Original Study after adjusting for omitted MISO capacity, withdrawal of J 570 and inclusion of MISO customers J718 and J748.

J611 DFAX on Avenue City – St Joe 161 kV line is 23.6%

Figure 28: Trigger Analysis- Nashua 345/161 kV transformer for the loss of Hawthorn – Nashua 345 kV (NRIS)- 2026 Summer Peak / ICF's Assessment of the Original Study [1]

Priority Order	MVA Contribution	Cumulative Loading (%)
Existing	646	90.3%
Higher Queued	48	97.1%
SPP 2016 DISIS 001	0.4	90.4%
MISO 2016 DPP Feb West	48	97.1%
AECI GI-53	19	99.8%
MISO 2016 DPP August West	32	**104.2%[Trigger]**
Rest of MISO 2016 DPP August West except J611	13	101.6%
MISO J611	19	104.2%
SPP 2016 DISIS 002	7	105.2%
MISO 2017 Feb West	5	105.9%
AECI GI-61	20	108.7%
Total	777	108.7%

[1] Original Study after adjusting for omitted MISO capacity, withdrawal of J 570 and inclusion of MISO customers J718 and J748.

J611 DFAX on Nashua transformer 345/161 kV 5.3%

VERIFICATION OF JUDAH L. ROSE

Pursuant to 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing testimony is true and correct to the best of my knowledge, information, and belief.

Executed this 21st day of May, 2021

Judah L. Rose

____

Judah L. Rose
ICF
Chair, Energy Advisory Practice

Docket No. ER21-___-000
Attachment No. 2

VERIFICATION OF HIMALI PARMAR

Pursuant to 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing testimony is true and correct to the best of my knowledge, information, and belief.

Executed this 21st day of May, 2021

Himali Parmar

Himali Parmar
ICF
Vice President, Energy Advisory Practice

EXHIBIT 2-1:

Resume of Judah L. Rose

Judah L. Rose

ICF

Executive Director, Chair, Energy Advisory

Education

- M.P.P., John F. Kennedy School of Government, Harvard University, 1982
- S.B., Economics, Massachusetts Institute of Technology, 1979

Awards and Recognition

- One of ICF's Distinguished Consultants, an honorary title given to only three of ICF's 7,000 employees

Experience Overview

Judah L. Rose joined ICF in 1982 and currently serves as an Executive Director of ICF and Chair of its Energy Advisory practice.

Accomplishment Highlights

- 40 years of experience in the energy industry
- 140 Testimonies in 45 venues including 24 states and provinces, FERC, federal, international, and other legal proceedings
- Frequent counselor on restructuring and financing of new and existing power plants

Mr. Rose has 40 years of experience in the energy industry including in electricity market design, power generation, coal, natural gas, renewables, environmental compliance, planning, market monitoring, finance, forecasting, and transmission. His clients include electric utilities, financial institutions, law firms, government agencies, fuel companies, consumers and Independent Power Producers. Mr. Rose is one of ICF's Distinguished Consultants, an honorary title given to three of ICF's 7,000 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative. Approximately 1,200 ICF employees work in energy.

Mr. Rose has supported the financing of tens of billion dollars of new and existing power plants and is a frequent counselor to the financial community in restructuring and financing.

Mr. Rose has also addressed approximately 100 major energy conferences, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies. He has also appeared in TV interviews.

Selected Press Interviews

Television

- "The Most With Allison Stewart," MSNBC, "Blackouts in NY and St. Louis & ongoing Energy Challenges in the Nation," July 25, 2006
- CNBC Wake-Up Call, August 15, 2003
- Wall Street Journal Report, July 25, 1999
- Back to Business, CNBC, September 7, 1999

Journals:

- Electricity Journal

- Energy Buyer Magazine
- Public Utilities Fortnightly
- Power Markets Week

Magazines:
- Business Week
- Power Economics
- Costco Connection

Newspapers:
- Denver Post
- Rocky Mountain News
- Financial Times Energy
- LA Times
- Arkansas Democratic Gazette
- Galveston Daily News
- The Times-Picayune
- Pittsburgh Post-Gazette
- Power Markets Week

Wires:
- Associated Press
- Bridge News
- Dow Jones Newswires

Testimony

140. Testimony, Wind Powerplant Contract Dispute, on Behalf of Southern California Edison, Arbitration, November, 2020.

139. Expert Declaration, Case No. 18-50757, On behalf of Energy Harbor LLC, Chapter 11, May, 2020.

138. Supplemental Testimony and Exhibits, Docket 19-014-U, on behalf of Oklahoma Gas and Electric, Before the Arkansas Public Service Commission, May 30, 2019.

137. Rebuttal Testimony, Case No. PUD 201800159, on behalf of Oklahoma Gas and Electric, Preapproval Pursuant to 17 O.S. Section 286 (C) For Acquisition of Capacity Through Asset Purchase, March 1, 2019

136. Direct Testimony, Case No. PUD 201800159, on behalf of Oklahoma Gas and Electric, Preapproval Pursuant to 17 O.S. Section 286 (C) For Acquisition of Capacity Through Asset Purchase, December 28, 2018.

135. Supplemental Testimony, Case No. 17-872-EL-RDR, On behalf of Duke Energy Ohio, June 6, 2018.

134. Expert Declaration, Case No. 18-50757, On behalf of FirstEnergy Solutions Corp., Chapter 11, April 1, 2018.

133. Application of Eight Point Wind Center for a Certificate under Article 10 of the Public Service Law, Case No. 16-F0062, New York State Board on Electric Generation Siting and the Environment, November 28, 2017

132. Direct Testimony, Case No. 17-872-EL-RDR, On behalf of Duke Energy Ohio, March 31, 2017.

131. Affidavit, In Answer to Complaint of Next Era and PSEG Companies, FERC Docket No. EL16-93-000, Testimony on New Gas Pipelines, and Wholesale Gas and Power Market Design, July 28, 2016. On behalf of Eversource.

130. Rebuttal Testimony, Support for an Electric Security Plan Filing, on behalf of Ohio Edison Company, The Cleveland Electric illuminating Company, The Toledo Edison Company, Case No. 14-1297-EL-SSO, October 20, 2015.

129. Demand Resource Pricing Testimony on behalf of P3, Docket ER15-852-000, February, 13, 2016

128. Damages Testimony on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, January 5, 2015.

127. Responsive Testimony of Judah L. Rose on Behalf of Oklahoma Energy Results, LLC December 16, 2014, CAUSE NO. PUD 201400229

126. Rebuttal Testimony on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, November 26, 2014.

125. Statement of Opinions on behalf of Duke Energy Indiana, Inc. Plaintiff v. Cause No. 1:13-cv-1984-SEB/TAB, Benton County Wind Farm LLC, October 30, 2014.

124. Direct Testimony, CO_2 price forecasts provided to IPL for use in their compliance analysis, as well as, support for the probabilities assigned to the Coal Combustion Residuals ("CCR"), 316 (b) and Effluent Limitation Guidelines ("ELG") regulations for use in IPL analysis in support of their Compliance Project, Indianapolis Power & Light Company, IURC Cause No. 44540, October 14, 2014.

123. Direct Testimony, Support for an Electric Security Plan Filing, Ohio Edison Company (FirstEnergy), August 4, 2014.

122. Rebuttal Testimony, Valuation of Mad River Power Plant, FirstEnergy, February 27, 2014.

121. Expert Report, Computation of Future Damages, Breach of Wolf Run Coal Sales Agreement, prepared for Meyer, Unkovic, and Scott, LLP, filed February 12, 2014.

120. Supplemental Direct Testimony of Judah Rose on behalf of National Grid and Northeast Utilities, Petition of New England Power Company d/b/a/ National Grid for Approval to Construct and Operate a New 345 kV Transmission Line and to Modify an Existing Switching Station Pursuant to G.L. c. 164, § 69J, August 8, 2013.

119. Rebuttal Testimony of Judah Rose on Behalf of Monongahela Power Company, The Potomac Edison Company, Petition for Approval of a Generation Resource Transaction and Related Relief, Case No. 12-1571 – E – PC, May 17, 2013.

118. Direct Testimony of Judah Rose on behalf of New England Power Company d/b/a National Grid before the Commonwealth Of Massachusetts Energy Facilities Siting Board and Department Of Public Utilities, Petition of New England Power Company d/b/a National Grid for Approval to Construct and Operate a New 345kV Transmission Line and to Modify an Existing Switching Station Pursuant to G.L. c. 164, § 69, Docket EFSB 12-1/D.P.U. 12-46/47, November 21, 2012.

117. Direct Testimony for the Narragansett Electric Company d/b/a National Grid (Interstate Reliability Project), Before the State of Rhode Island Public Utilities Commission, Energy Facility Siting Board ("Siting Board") Notice of Designation to Public Utilities Commission ("PUC") to Render an Advisory Opinion on need and cost-justification for Narragansett Electric d/b/a National Grid's proposal to construct and alter major energy facilities in RI, the "Interstate Reliability Project", RIPUC Docket No. 4360, November 21, 2012

116. Sur-Surrebuttal Testimony, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, September 21, 2012.

115. Rebuttal Testimony, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, July 30, 2012.

114. Direct Testimony, The Connecticut Light & Power Company, Application for a Certificate of Environmental Compatibility and Public Need for the Connecticut Portion of the Interstate Reliability Project that traverses the municipalities of Lebanon, Columbia, Coventry, Mansfield, Chaplin, Hampton, Brooklyn, Pomfret, Killingly, Putnam, Thompson, and Windham, which consists of (a) new overhead 345-kV electric transmission lines and associated facilities extending between CL&P's Card Street Substation in the Town of Lebanon, Lake Road Switching Station in the Town of Killingly, and the Connecticut/Rhode Island border in the Town of Thompson; and (b) related additions at CL&P's existing Card Street Substation, Lake Road Switching Station, and Killingly Substation, Docket No. 424, July 17, 2012.

113. Direct Testimony, Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding That Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Docket No. 12-008-U, February 9, 2012.

112. Rebuttal Testimony, Otter Tail Power Company, Before the Office of administrative Hearings, for the Minnesota Public Utilities Commission, In The Matter of Otter Tail Power Company's Petition for an Advance Determination of Prudence for its Big Stone Air Quality Control System Project, September 7, 2011.

111. Rebuttal Testimony, on behalf of Arizona Public Service, In the Matter of the Application of Arizona Public Service Company for Authorization for the Purchase of Generating Assets from Southern California Edison, and for an Accounting Order, Docket No. E-01345A-10-0474, June 22, 2011.

110. Direct Testimony, Duke Energy Ohio, Inc., Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service, Case No. 11-XXXX-EL-SSO. Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20. Case No. 11-XXXX-EL-ATA. Application of Duke Energy Ohio for Authority to Amend its Corporate Separation Plan. Case No. 11-XXXX-EL-UNC, June 20, 2011.

109. Direct Testimony, Manitoba Hydro Power Sales Contracting Strategy, U.S. Power Markets, Manitoba Hydro Drought Risks, Modeling, Forecasting and Planning, Selected Risk and Financial Issues, Governance, Trading and Risk Related Comments Before the Public Utilities Board of Manitoba, February 22, 2011.

108. Surrebuttal Testimony – Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2010-0356, January 12, 2011.

107. Rebuttal Report Concerning Coal Price Forecast for the Harrison Generation Facility, Meyer, Unkovic and Scott, LLP, filed December 6, 2010.

106. Direct Testimony of Judah Rose on behalf of Duke Energy Ohio In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service, Case No. 10-2586-EL-SSO, filed November 15, 2010.

105. Updated Forecast, Coal Price Report for the Harrison Generation Facility, Meyer, Unkovic and Scott, LLP, filed October 18, 2010.

104. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 29, 2010.

103. Declaration of Judah Rose in re: Boston Generating LLC, et al., Chapter 11, Case No. 10-14419 (SCC) Jointly Administered, September 16, 2010.

102. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line Oklahoma LLC to conduct Business as an Electric Utility in the State of Oklahoma, Cause No.PUD 201000075, July 16, 2010.

101. Direct Testimony of Judah Rose on behalf of Plains and Eastern Clean Line LLC, in the Matter of the Application of Plains and Eastern Clean Line LLC for a Certificate of Public Convenience and Necessity to Operate as an Electric Transmission Public Utility in the State of Arkansas, Docket No. 10-041-U, June 4, 2010.

100. Supplemental Testimony on Behalf of Entergy Arkansas, Inc., In the Matter of Entergy Arkansas, Inc., Request for a Declaratory Order Approving the Addition of the Environmental Controls Project at the White Bluff Steam Electric Station Near Redfield, Arkansas, Docket No. 09-024-U, July 6, 2009.

99. Rebuttal Testimony on Behalf of TransEnergie, Canada, Province of Quebec, District of Montreal, No.: R-3669-2008-Phase 2, FERC Order 890 and Transmission Planning, July 3, 2009.

98. Surrebuttal Testimony – Revenue Requirement of Judah Rose on Behalf of Dogwood Energy, LLC, before the Missouri Public Service Commission, In the Matter of the Application of KCP&L GMO, Inc. d/b/a KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes to its Charges for Electric Service, Case No. ER-2009-0090, April 9, 2009.

97. Hawaii Structural Ironworkers Pension Trust Fund v. Calpine Corporation, Case No. 1-04-CV-021465, Assessment of Calpine's April 2002 Earnings Projections, March 25, 2009.

96. Coal Price Report for Harrison Coal Plant, Allegheny Energy Supply Company, LLS and Monongahela Power Company versus Wolf Run Mining Company, Anker Coal Group, etc., Civil Action. No. GD-06-30514, In the Court of Common Pleas, Allegheny County, Pennsylvania, February 6, 2009.

95. Supplemental Direct Testimony of Judah Rose, on behalf of Southwestern Electric Power Company, In the Matter of the Application of Southwestern Electric Power Company for Authority to Construct a Natural-Gas Fired Combined Cycle Intermediate Generating Facility in the State of Louisiana, Docket No. 06-120-U, December 9, 2008.

94. Rebuttal Testimony of Judah Rose on behalf of Kelson Transmission Company, LLC re: Application of Kelson Transmission Company, LLC For A Certificate of Convenience and Necessity For the Amended Proposed Canal To Deweyville 345 kV Transmission Line Within Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, And Orange Counties, SOAH Docket No. 473-08-3341, PUCT Docket No. 34611, October 27, 2008.

93. Testimony of Judah Rose, on behalf of Redbud Energy, LP, in Support of Joint Stipulation and Settlement Agreement, In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Granting Pre-Approval of the Purchase of the Redbud Generating Facility and Authorizing a Recovery Rider, Cause No. PUD 200800086, September 3, 2008.

92. Direct Testimony of Judah L. Rose on behalf of Duke Energy Carolinas, In the Matter of Advance Notice by Duke Energy Carolinas, LLC, of its Intent to Grant Native Load Priority to the City of Orangeburg, South Carolina, and Petition of Duke Energy Carolinas, LLC and City of Orangeburg, South Carolina for Declaratory Ruling With Respect to Rate Treatment of Wholesale Sales of Electric Power at Native Load Priority, Docket No. E-7, SUB 858, August 15, 2008.

91. Affidavit filed on behalf of Public Service of New Mexico pertaining to the Fuel Costs of Southwest Public Service for Cost-of-Service and Market-Based Customers, August 11, 2008.

90. Direct Testimony of Judah L. Rose on behalf of Duke Energy Ohio, Inc., Before the Public Utilities Commission of Ohio, In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of an Electric Security Plan, July 31, 2008.

89. Rebuttal Testimony, Judah L. Rose on Behalf of Duke Energy Carolinas, in re: Application of Duke Energy Carolinas, LLC for Approval of Save-A-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs, Docket No. E-7, Sub 831, July 21, 2008.

88. Updated Analysis of SWEPCO Capacity Expansion Options as Requested by Public Utility Commission of Texas, on behalf of SWEPCO, June 27, 2008.

87. Direct Testimony of Judah L. Rose on Behalf of Nevada Power/Sierra Pacific Electric Power Company, Docket No. 1, Public Utilities Commission of Nevada, Application of Nevada Power/Sierra Pacific for Certificate of Convenience and Necessity Authorization for a Gas-Fired Power Plant in Nevada, May 16, 2008.

86. Rebuttal Testimony of Judah L. Rose on Behalf of the Advanced Power, Commonwealth of Massachusetts, Before the Energy Facilities Siting Board, Petition of Brockton Power Company, LLC, EFSB 07-7, D.P.U. 07-58 & 07-59, May 16, 2008.

85. Supplemental Rebuttal Testimony on Commissioner's Issues of Judah L. Rose for Southwestern Electric Power Company, on behalf of Southwestern Electric Power Company, PUC Docket No. 33891, Public Utilities Commission of Texas, May 2008.

84. Supplemental Direct Testimony on Commissioners' Issues of Judah Rose for Southwestern Electric Power Company, for the Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization for a Coal-Fired Power Plant in Arkansas, SOAH Docket No. 473-07-1929, PUC Docket No. 33891, Public Utility Commission of Texas, April 22, 2008.

83. Rebuttal Testimony of Judah Rose, In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, April 1, 2008.

82. Rebuttal Report of Judah Rose, Ohio Power Company and AEP Power Marketing Inc. vs. Tractebel Energy Marketing, Inc. and Tractebel S.A. Case No. 03 CIV 6770, 03 CIV 6731 (S.D.N.Y.), January 28, 2008.

81. Proposed New Gas-Fired Plant, on behalf of AEP SWEPCO, 2007.

80. Rebuttal Report, Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 21, 2007.

79. Expert Report. Calpine Cash Flows, on behalf of Unsecured Creditor's Committee, November 19, 2007.

78. Application of Duke Energy Carolina, LLC for Approval of Energy Efficiency Plan Including an Energy Efficiency Rider and Portfolio of Energy, Docket No. 2007-358-E, Public Service Commission of South Carolina, December 10, 2007.

77. Independent Transmission Cause No. PUD200700298, Application of ITC, Public Service of Oklahoma, December 7, 2007.

76. Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code š8-1-2.5-1, et. Seq. for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance With Ind. Code šš8-1-2.5-1 et seq. and 8-1-2-42(a); Authority

to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the PowerShare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Cause Earnings and Expense Tests, Indiana Utility Regulatory Commission, Cause No. 43374, October 19, 2007.

75. Rebuttal Testimony, Docket No. U-30192, Application of Entergy Louisiana, LLC For Approval to Repower the Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery, October 4, 2007.

74. Direct Testimony of Judah Rose on Behalf of Tucson Electric Power Company, In the matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona, Estimation of Market Value of Fleet of Utility Coal Plants, July 2, 2007.

73. Supplemental Testimony on behalf of Southwestern Electric Power Company before the Arkansas Public Service Commission, In the Matter of Application of Southwestern Electric Power Company for a Certificate of Environmental Compatibility and Public Need for the Construction, Ownership, Operation, and Maintenance of a Coal-Fired Base Load Generating Facility in the Hempstead County, Arkansas, dated June 15, 2007, Docket No. 06-154-U.

72. Rebuttal Testimony, Causes No. PUD 200500516, 200600030, and 20070001 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, June 2007.

71. Rebuttal Testimony on behalf of Duke Energy Indiana, IGCC Coal Plant CPCN, Cause No. 43114 before the Indiana Utility Regulatory Commission, May 31, 2007.

70. Responsive Testimony, Causes No. PUD 200500516, 200600030, and 200700012 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, May 2007.

69. Rebuttal Testimony on behalf of Florida Power & Light Company In Re: Florida Power & Light Company's Petition to Determine Need for FPL Glades Power Park Units 1 and 2 Electrical Power Plant, Docket No. 070098-EL, March 30, 2007.

68. Rebuttal Testimony, Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, May 2007.

67. Direct Testimony for Southwestern Electric Power Company, Before the Louisiana Public Service Commission, Docket No. U-29702, in re: Application of Southwestern Electric Power Company for the Certification of Contracts for the Purchase of Capacity for 2007, 2008, and 2009 and to Purchase, Operate, Own, and Install Peaking, Intermediate and Base Load Coal-Fired Generating Facilities in Accordance with the Commission's General Order Dated September 20, 1983. Consolidated with Docket No. U-28766 Sub Docket B in re: Application of Southwestern Electric Power Company for Certification of Contracts for the Purchase of Capacity in Accordance with the Commission's 'General Order of September 20, 1983, February 2007.

66. Second Supplemental Testimony on Behalf of Duke Energy Ohio Before the Public Utility Commission of Ohio, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA, February 28, 2007.

65. Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, February 2007.

64. Supplemental Testimony on behalf of Duke Energy Carolinas before the North Carolina Utilities Commission in the Matter of Application of Duke Energy Carolinas, LLC for Approval for an Electric Generation Certificate of Public Convenience and Necessity to Construct Two 800 MW State of Art Coal Units for Cliffside Project, Docket No. E7, SUB790, December 2006.

63. Expert Report, Chapter 11, Case No. 01-16034 (AJG) and Adv. Proc. No. 04-2933 (AJG), November 6, 2006.

62. IGCC Coal Plant, Testimony on behalf of Duke Energy Indiana, Cause No. 43114, October 2006.

61. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106 OAL Docket No. PUC-1874-05, Supplemental Testimony March 20, 2006.

60. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, Surrebuttal Testimony December 27, 2005.

59. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, November 14, 2005.

58. Brazilian Power Purchase Agreement, confidential international arbitration, October 2005.

57. Cost of Service and Fuel Clause Issues, Rebuttal Testimony on behalf of Public Service of New Mexico, Docket No. EL05-151, November 2005.

56. Cost of Service and Peak Demand, FERC, Testimony on behalf of Public Service of New Mexico, September 19, 2005, Docket No. EL05-19.

55. Cost of Service and Fuel Clause Issues, Testimony on behalf of Public Service of New Mexico, FERC Docket No. EL05-151-000, September 15, 2005.

54. Cost of Service and Peak Demand, FERC, Responsive Testimony on behalf of Public Service of New Mexico, August 23, 2005, Docket No. EL05-19.

53. Prudence of Acquisition of Power Plant, Testimony on behalf of Redbud, September 12, 2005, No. PUD 200500151.

52. Proposed Fuel Cost Adjustment Clause, FERC, Docket Nos. EL05-19-002 and ER05-168-001 (Consolidated), August 22, 2005.

51. Market Power and the PSEG Exelon Merger on Behalf of the NJBPU, FERC, Docket EC05-43-000, May 27, 2005.

50. New Air Emission Regulations and Investment in Coal Power Plants, rebuttal testimony on behalf of PSI, April 18, 2005, Causes 42622 and 42718.

49. Rebuttal Report: Damages due to Rejection of Tolling Agreement Including Discounting, February 9, 2005, CONFIDENTIAL.

48. New Air Emission Regulations and Investment in Coal Power Plants, supplemental testimony on behalf of PSI, January 21, 2005, Causes 42622 and 42718.

47. Damages Due to Rejection of Tolling Agreement Including Discounting, January 10, 2005, CONFIDENTIAL.

46. Discount rates that should be used in estimating the damages to GTN of Mirant's bankruptcy and subsequent abrogation of the gas transportation agreements Mirant had entered into with GTN, December 15, 2004. CONFIDENTIAL

45. New Air Emission Regulations and Investment in Coal Power Plants, testimony on behalf of PSI, November 2004, Causes 42622 and 42718.

44. Rebuttal Testimony of Judah Rose on behalf of PSI, "Certificate of Purchase as of yet Undetermined Generation Facility" Cause No. 42469, August 23, 2004.

43. Rebuttal Testimony of Judah Rose on behalf of the Hopi Tribe, Case No. A.02-05-046, Mohave Coal Plant Economics, June 4, 2004.

42. Supplemental Testimony "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, May 20, 2004.

41. "Application of Southern California Edison Company (U338-E) Regarding the Future Disposition of the Mohave Coal-Fired Generating Station," May 14, 2004.

40. "Appropriate Rate of Return on Equity (ROE) TransAlta Should be Authorized For its Capital Investment Related to VAR Support From the Centralia Coal-Fired Power Plant", for TransAlta, April 30, 2004, FERC Docket No. ER04-810-000.

39. "Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, April 15, 2004.

38. "Valuation of Selected MIRMA Coal Plants, Acceptance and Rejection of Leases and Potential Prejudice to Leasors" Federal Bankruptcy Court, Dallas, TX, March 24, 2004 CONFIDENTIAL.

37. "Certificate of Purchase as of yet Undetermined Generation Facility", Cause No. 42469 for PSI, March 23, 2004.

36. "Ohio Edison's Sammis Power Plant BACT Remedy Case", In the United States District Court of Ohio, Southern Division, March 8, 2004.

35. "Valuation of Power Contract," January 2004, confidential arbitration.

34. "In the matter of the Application of the Union Light Heat & Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources, etc.", before the Kentucky Public Service Commission, Coal-Fired and Gas-Fired Market Values, July 21, 2003.

33. "In the Supreme Court of British Columbia", July 8, 2003. CONFIDENTIAL

32. "The Future of the Mohave Coal-Fired Power Plant – Rebuttal Testimony", California P.U.C., May 20, 2003.

31. "Affidavit in Support of the Debtors' Motion", NRG Bankruptcy, Revenues of a Fleet of Plants, May 14, 2003. CONFIDENTIAL

30. "IPP Power Purchase Agreement," confidential arbitration, April 2003.

29. "The Future of the Mohave Coal-Fired Power Plant", California P.U.C., March 2003.

28. "Power Supply in the Pacific Northwest," contract arbitration, December 5, 2002. CONFIDENTIAL

27. "Power Purchase Agreement Valuation", Confidential Arbitration, October 2002.

26. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants, rebuttal testimony on behalf of PSI. Filed on 8/23/02."

25. "Cause No. 42200 - in support of PSI's petition for authority to recover through retail rates on a timely basis. Filed on 7/30/02."

24. "Cause No. 42196 - in support of PSI's petition for interim purchased power contract. Filed on 4/26/02."

23. "Cause No. 42145 - In support of PSI's petition for authority to acquire the Madison and Henry County plants. Filed on 3/1/2002."

22. "Analysis of an IGCC Coal Power Plant", Minnesota state senate committees, January 22, 2002.

21. "Analysis of an IGCC Coal Power Plant", Minnesota state house of representative committees, January 15, 2002

20. "Interim Pricing Report on New York State's Independent System Operator", New York State Public Service Commission (NYSPSC), January 5, 2001

19. "The need for new capacity in Indiana and the IRP process", Indiana Utility Regulatory Commission, October 26, 2000

18. "Damage estimates for power curtailment for a Cogen power plant in Nevada", August 2000. CONFIDENTIAL

17. "Valuation of a power plant in Arizona", arbitration, July 2000. CONFIDENTIAL

16. Application of FirstEnergy Corporation for approval of an electric Transition Plan and for authorization to recover transition revenues, Stranded Cost and Market Value of a Fleet of Coal, Nuclear, and Other Plants, Before PUCO, Case No. 99-1212-EL-ETP, October 4, 1999 and April 2000.

15. “Issues Related to Acquisition of an Oil/Gas Steam Power plant in New York”, September 1999 Affidavit to Hennepin County District Court, Minnesota

14. “Wholesale Power Prices, A Cost Plus All Requirements Contract and Damages”, Cajun Bankruptcy, July 1999. Testimony to U.S. Bankruptcy Court.

13. “Power Prices.” Testimony in confidential contract arbitration, July 1998.

12. “Horizontal Market Power in Generation.” Testimony to New Jersey Board of Public Utilities, May 22, 1998.

11. “Basic Generation Services and Determining Market Prices.” Testimony to the New Jersey Board of Public Utilities, May 12, 1998.

10. “Generation Reliability.” Testimony to New Jersey Board of Public Utilities, May 4, 1998.

9. “Future Rate Paths and Financial Feasibility of Project Financing.” Cajun Bankruptcy, Testimony to U.S. Bankruptcy Court, April 1998.

8. “Stranded Costs of PSE&G.” Market Valuation of a Fleet of Coal, Nuclear, Gas, and Oil-Fired Power Plants, Testimony to New Jersey Board of Public Utilities, February 1998.

7. “Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code.” Market Value of Fleet of Nuclear, Coal, Gas, and Oil Power Plants, Rebuttal Testimony filed July 1997.

6. “Future Wholesale Electricity Prices, Fuel Markets, Coal Transportation and the Cajun Bankruptcy.” Testimony to Louisiana Public Service Commission, December 1996.

5. “Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets.” Testimony on a contract arbitration, Las Vegas, Nevada, June 1996.

4. “Future Rate Paths and the Cajun Bankruptcy.” Testimony to the U.S. Bankruptcy Court, June 1997.

3. “Fuel Prices and Coal Transportation.” Testimony to the U.S. Bankruptcy Court, June 1997.

2. “Demand for Gas Pipeline Capacity in Florida from Electric Utilities.” Testimony to Florida Public Service Commission, May 1993.

1. “The Case for Fuel Flexibility in the Florida Electric Generation Industry.” Testimony to the Florida Department of Environmental Regulation (Der), Hearings on Fuel Diversity and Environmental Protection, December 1992.

Selected Speaking Engagements

115. Rose, J.L., The Polar Vortex, System Reliability and Recent PJM Developments, American Municipal Power Conference, October 28, 2014.

114. Rose, J.L., Wholesale power Market Price Projection in California, Infocast, California Energy Summit, San Francisco, CA, May 28, 2014.

113. Rose, J.L., The Polar Vortex and Future Power system Trends, National Coal Council, 2014 Annual Spring Meeting, May 14, 2014.

112. Rose, J.L., The Polar Vortex and System Reliability, The Energy Authority (TEA), Jacksonville, FL, April 30, 2014.

111. Rose, J.L., Utility and Transco Plans and Transmission Projects to Deal with the Changing Generation Resource Mix, Panel Moderator, Transmission Summit Panel Discussion, March 14, 2014.

110. Rose, J.L., Examining Natural Gas and Power Price Dynamics During the Polar Vortex, APPA, March 10, 2014.

109. Rose, J.L., Polar Vortex – Skating too Close to the Edge, First Friday Club, March 7, 2014.

108. Rose, J.L., New Developments in the California Power Market, Infocast California Energy Summit, San Francisco, CA, December 3, 2013.

107. Rose, J.L., Financial Issues in Determining the Disposition of Fossil Power Plants, Managing the Power Plant Decommissioning, Decontamination, and Demolition Process, November 7, 2013.

106. Rose, J.L, Reality and Impacts of Plant Retirements, Reading Tea Leaves – The Future of America's Installed Power Plants, July 25, 2013.

105. Rose, J.L., Financial issues in Determining the Disposition of Fossil Power Plants, Plant Decommissioning, Decontamination, and Demolition, May 9, 2013.

104. Rose, J.L., Financial Issues in Determining the Disposition of Plant Decommissioning, Decontamination & Demolition Summit, Infocast, May 1, 2013.

103. Rose, J.L., Implications of Current Low Natural Gas Price Environment on Wholesale Power, Edison Electric Institute, May 3, 2012.

102. Rose, J.L., Anticipating the Next Turn in a Gas-Rich Environment, Key Pricing Drivers, and Outlook, Houlihan and Lokey Merchant Energy Conference, April, 24, 2012.

101. Rose, J.L., CREPC/SPSC Natural Gas – Electricity in West Panel, San Diego, April 3, 2012

100. Rose, J.L., EUCI Financing Transmission Expansion, San Diego, CA, March 8-9, 2011.

99. Rose, J.L., Vinson & Elkins Conference, Houston, TX, November 11, 2010.

98. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Crystal City, Arlington, VA, June 29-30, 2010.

97. Rose, J.L., Economics of PC Refurbishment, Improving the Efficiency of Coal-Fired Power Generation in the U.S., DOE-NETL, February 24, 2010.

96. Rose, J.L., Fundamentals of Electricity Transmission, EUCI, Orlando, FL, January 25-26, 2010.

95. Rose, J.L., CO_2 Control, "Cap & Trade", & Selected Energy Issues, Multi-Housing Laundry Association, October 26, 2009.

94. Rose, J.L., Financing for the Future – Can We Afford It?, 2009 Bonbright Conference, October 9, 2009.

93. Rose, J.L., EEI's Transmission and Market Design School, Washington, D.C., June 2009.

92. Rose, J.L., ICF's New York City Energy Forum - Market Recovery in Merchant Generation Assets, June 10, 2008.

91. Rose, J.L., Southeastern Electric Exchange – Integrated Resource Planning Task Force Meeting, Carbon Tax Outlook Discussion, February 21-22, 2008.

90. Rose, J.L., AESP, NEEC Conference, Rising Prices and Failing Infrastructure: A Bleak or Optimistic Future, Marlborough, MA, October 23, 2006.

89. Rose, J.L., Infocast Gas Storage Conference, "Estimating the Growth Potential for Gas-Fired Electric Generation," Houston, TX, March 22, 2006.

88. Rose, J.L., "Power Market Trends Impacting the Value of Power Assets," Infocast Conference, Powering Up for a New Era of Power Generation M&A, February 23, 2006.

87. Rose, J.L., "The Challenge Posed by Rising Fuel and Power Costs", Lehman Brothers, November 2, 2005.

86. Rose, J.L., "Modeling the Vulnerability of the Power Sector", EUCI – Securing the Nation's Energy Infrastructure, September 19, 2005

85. Rose, J.L., "Fuel Diversity in the Northeast, Energy Bar Association, Northeast Chapter Meeting, New York, NY, June 9, 2005.

84. Rose, J.L., "2005 Macquarie Utility Sector Conference", Macquarie Utility Sector Conference, Vail, CO, February 28, 2005.

83. Rose, J.L., "The Outlook for North American Natural Gas and Power Markets", The Institute for Energy Law, Program on Oil and Gas Law, Houston, TX, February 18, 2005.

82. Rose, J.L. "Assessing the Salability of Merchant Assets – What's on the Horizon?" Infocast – The Market for Power Assets, Phoenix, AZ, February 10, 2005.

81. Rose, J.L. "Market Based Approaches to Transmission – Longer-Term Role", National Group of Municipal Bond Investors, New York, NY, December 10, 2004.

80. Rose, J.L. "Supply & Demand Fundamentals – What is Short-Term Outlook and the Long-Term Demand? Platt's Power Marketing Conference, Houston, TX, October 11, 2004.

79. Rose, J.L. "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.

78. Rose, J. L. "After the Blackout – Questions That Every Regulator Should be Asking," NARUC Webinar Conference, Fairfax, VA, November 6, 2003.

77. Rose, J. L., "Supply and Demand in U.S. Wholesale Power Markets," Lehman Brothers Global Credit Conference, New York, NY, November 5, 2003.

76. Rose, J.L., “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?”, Infocast’s Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.

75. Rose, J.L., “Asset Valuation in Today’s Market”, Infocast’s Project Finance Tutorial, New York, NY, October 8, 2003.

74. Rose, J.L., “Forensic Evaluation of Problem Projects”, Infocast’s Project Finance Workouts: Dealing With Distressed Energy Projects, September 17, 2003.

73. Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.

72. Rose, J.L., “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?”, Infocast’s Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.

71. Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New York, NY, “Spark Spread Outlook”, July 17, 2003.

70. Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., “Trends in U.S. Energy and Economy”, June 24, 2003.

69. Rose, J.L., “Power Markets: Prices, SMD, Transmission Access, and Trading”, Bechtel Management Seminar, Frederick, MD, June 10, 2003.

68. Rose, J.L., Platt’s Global Power Market Conference, New Orleans, LA, “The Outlook for Recovery,” March 31, 2003.

67. Rose, J.L., “Electricity Transmission and Grid Security”, Energy Security Conference, Crystal City, VA, March 25, 2003.

66. Rose, J.L., “Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast’s Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.

65. Rose, J.L., Panel Discussion, “Forensic Evaluation of Problem Projects”, Infocast Conference, NY, February 24, 2003.

64. Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).

63. Rose, J.L., “The Merchant Power Market—Where Do We Go From Here?” Center for Business Intelligence’s Financing U.S. Power Projects, November 18-19, 2002.

62. Rose, J.L., “Assessing U.S. Regional and the Potential for Additional Coal-Fired Generation in Each Region,” Infocast’s Building New Coal-Fired Generation Conference, October 8, 2002.

61. Rose, J.L., “Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, ”Infocast’s Product Structuring in the Real World Conference, September 25, 2002.

60. Rose, J.L., “PJM Price Outlook,” Platt’s Annual PJM Regional Conference, September 24, 2002.

59. Rose, J.L., “Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies,” New York Venture Group’s Investing in the Power Industry—Targeting The Newest Trends Conference, July 31, 2002.

58. Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.

57. Rose, J.L., "Locational Market Price (LMP) Forecasting in Plant Financing Decisions," Structured Finance Institute, April 8-9, 2002.

56. Rose, J.L., "PJM Transmission and Generation Forecast", Financial Times Energy Conference, November 6, 2001.

55. Rose, J.L., "U.S. Power Sector Trends", Credit Suisse First Boston's Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.

54. Rose, J.L., "Dealing with Inter-Regional Power Transmission Issues", Infocast's Ohio Power Game Conference, September 6, 2001

53. Rose, J.L., "Where's the Next California", Credit Suisse First Boston's Global Project Finance Capital Markets Conference, New York NY, June 27 2001

52. Rose, J.L, "U.S. Energy Issues: What MLA Members Need to Know," Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001

51. Rose, J.L., "How the California Meltdown Affects Power Development", Infocast's Power Development and Finance Conference 2001, Washington D.C., June 12, 2001

50. Rose, J.L., "Forecasting 2001 Electricity Prices" presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001

49. Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California, February 12, 2001

48. Rose, J.L., "An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000" Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.

47. Rose, J. L., "An Analysis of the Power Markets, summer 2000" Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000.

46. Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000

45. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

44. Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

43. Rose, J.L., "Understanding Generation" Pre-Conference Workshop, Powermart, Houston, Texas, October 26-28, 1999.

42. Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.

41. Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power Conference, New York, New York, September 24, 1999.

40. Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, Transmission The Future of Electric Transmission Conference, Washington, DC, September 13, 1999.

39. Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.

38. Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.

37. Rose, J.L., "Transmission Solutions to Market Power" presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.

36. Rose, J.L., "Repowering Existing Power Plants and Its Impact on Market Prices" presentation, Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.

35. Rose, J.L., "Transmission and Retail Issues in the Electric Industry" Session Speaker, Gas Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.

34. Rose, J.L., "Peak Price Volatility in the Rockies and Southwest" presentation at Repowering the Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.

33. Rose, J.L., "Understanding Generation" presentation and Program Chairman at Buying & Selling Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.

32. Rose, J.L., "Buying Generation Assets in PJM" presentation at Mid-Atlantic Power Summit, Philadelphia, Pennsylvania, April 12, 1999.

31. Rose, J.L., "Evaluating Your Generation Options in Situations With Insufficient Transmission," presentation at Congestion Management Conference, Washington, D.C., March 25, 1999.

30. Rose, J.L., "Will Capacity Prices Drive Future Power Prices?" presentation at Merchant Plant Development Conference, Chicago, Illinois, March 23, 1999.

29. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting Conference, Atlanta, Georgia, February 25, 1999

28. Rose, J.L., "Developing Reasonable Expectations About Financing New Merchant Plants That Have Less Competitive Advantage Than Current Projects," presentation at Project Finance International's Financing Power Projects in the USA conference, New York, New York, February 11, 1999.

27. Rose, J.L., "Transmission and Capacity Pricing and Constraints," presentation at Power Fair 99, Houston, Texas, February 4, 1999.

26. Rose, J.L., "Peak Price Volatility: Comparing ERCOT With Other Regions," presentation at Megawatt Daily's Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.

25. Rose, J.L., "The Outlook for Midwest Power Markets," presentation to The Institute for Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.

24. Rose, J.L., "Developing Pricing Strategies for Generation Assets," presentation at Wholesale Power in the West conference, Las Vegas, Nevada, November 12, 1998.

23. Rose, J.L., "Understanding Electricity Generation and Deregulated Wholesale Power Prices," a full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.

22. Rose, J.L., "The Impact of Power Generation Upgrades, Merchant Plant Developments, New Transmission Projects and Upgrades on Power Prices," presentation at Profiting in the New York Power Market conference, New York, NY, October 22, 1998.

21. Rose, J.L., "Capacity Value – Pricing Firmness," presentation to Edison Electric Institute Economics Committee, Charlotte, NC, October 8, 1998.

20. Rose, J.L., "Locational Marginal Pricing and Futures Trading," presentation at Megawatt Daily's Electricity Regulation conference, Washington, D.C., October 7, 1998.

19. Rose, J.L., Chairman's opening speech and "The Move Toward a Decentralized Approach: How Will Nodal Pricing Impact Power Markets?" at Congestion Pricing and Tariffs conference, Washington, D.C., September 25, 1998.

18. Rose, J.L., "The Generation Market in MAPP/MAIN: An Overview," presentation at Megawatt Daily's MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16, 1998.

17. Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Baltimore, Maryland, August 24, 1998.

16. Rose, J.L., "ICF Kaiser's Wholesale Power Market Model," presentation at Market Price Forecasting conference, New York, New York, August 6, 1998.

15. Rose, J.L., Campbell, R., Kathan, David, "Valuing Assets and Companies in M&A Transactions," full-day workshop at Utility Mergers & Acquisitions conference, Washington, D.C., July 15, 1998.

14. Rose, J.L., "Must-Run Nuclear Generation's Impact on Price Forecasting and Operations," presentation at The Energy Institute's conference entitled "Buying and Selling Electricity in the Wholesale Power Market," Las Vegas, Nevada, June 25, 1998.

13. Rose, J.L., "The Generation Market in PJM," presentation at Megawatt Daily's PJM Power Markets conference, Philadelphia, Pennsylvania, June 17, 1998.

12. Rose, J.L., "Market Evaluation of Electric Generating Assets in the Northeast," presentation at McGraw-Hill's conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15, 1998.

11. Rose, J.L., "Overview of SERC Power," opening speech presented at Megawatt Daily's SERC Power Markets conference, Atlanta, Georgia, May 20, 1998.

10. Rose, J.L., "Future Price Forecasting," presentation at The Southeast Energy Buyers Summit, Atlanta, Georgia, May 7, 1998.

9. Rose, J.L., "Practical Risk Management in the Power Industry," presentation at Power Fair, Toronto, Canada, April 16, 1998.

8. Rose, J.L., "The Wholesale Power Market in ERCOT: Transmission Issues," presentation at Megawatt Daily's ERCOT Power Markets conference, Houston, Texas, April 1, 1998.
7. Rose, J.L., "New Generation Projects and Merchant Capacity Coming On-Line," presentation at Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.
6. Rose, J.L., "Projecting Market Prices in a Deregulated Electricity Market," presentation at conference: Market Price Forecasting, San Francisco, California, March 9, 1998.
5. Rose, J.L., "Handling of Transmission Rights," presentation at conference: Congestion Pricing & Tariffs, Washington, D.C., January 23, 1998.
4. Rose, J.L., "Understanding Wholesale Markets and Power Marketing," presentation at The Power Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.
3. Rose, J.L., "Determining the Electricity Forward Curve," presentation at seminar: Pricing, Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October 23, 1997.
2. Rose, J.L., "Market Price Forecasting In A Deregulated Market," presentation at conference: Market Price Forecasting, Washington, D.C., October 23, 1997,
1. Rose, J.L., "Credit Risk Versus Commodity Risk," presentation at conference: Developing & Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16, 1997.

Selected Publications and Presentations

Rose, J.L., "Return of the RTO: Auction Results Portend Recovery," White Paper, June 14, 2014.

Rose, J. L., "The Next Polar Vortex: How Long Will Grid Emergencies and Price Volatility Continue?" Public Utilities Fortnightly, June 2014.

Rose, J.L., "Wind Curtailment, Assessing and Mitigating Risks," White Paper, December 2012.

Rose, J.L. and Henning, B. "Partners in Reliability: Gas and Electricity," PowerNews, September 1, 2012.

Rose, J.L. and Surana, S. "Using Yield Curves and Energy Prices to Forecast Recessions – An Update." World Generation, March/April 2011, V.23 #2.

Rose, J.L. and Surana, S. "Oil Price Increases, Yield Curve Inversion may be Indicators of Economic Recession." Oil and Gas Financial Journal, Volume 7, Issue 6, June 2010

Rose, J.L. and Surana, S. "Forecasting Recessions and Investment Strategies." World-Generation, June/July 2010, V.22, #3.

Rose, J.L., "Should Environmental Restrictions be Eased to Allow for the Construction of More Power Plants? The Costco Connection, April 2001.

Rose, J.L., “Deregulation in the US Generation Sector: A Mid-Course Appraisal”, Power Economics, October 2000.

Rose, J. L., “Price Spike Reality: Debunking the Myth of Failed Markets”, *Public Utilities Fortnightly,* November 1, 2000.

Rose, J.L., “Missed Opportunity: What’s Right and Wrong in the FERC Staff Report on the Midwest Price Spikes,” *Public Utilities Fortnightly,* November 15, 1998.

Rose, J.L., “Why the June Price Spike Was Not a Fluke,” *The Electricity Journal*, November 1998.

Rose, J.L., S. Muthiah, and J. Spencer, “Will Wall Street Rescue the Competitive Wholesale Power Market?” *Project Finance International*, May 1998.

Rose, J.L., “Last Summer’s “Pure” Capacity Prices – A Harbinger of Things to Come*,” Public Utilities Fortnightly,* December 1, 1997.

Rose, J.L., D. Kathan, and J. Spencer “Electricity Deregulation in the New England States,” *Energy Buyer*, Volume 1, Issue 10, June-July 1997.

Rose, J.L., S. Muthiah, and M. Fusco, “Financial Engineering in the Power Sector,” *The Electricity Journal,* Jan/Feb 1997.

Rose, J.L, S. Muthiah, and M. Fusco, “Is Competition Lacking in Generation? (And Why it Should Not Matter)*,” Public Utilities Fortnightly,* January 1, 1997.

Mann, C. and J.L. Rose, “Price Risk Management: Electric Power vs. Natural Gas,” *Public Utilities Fortnightly,* February 1996.

Rose, J.L. and C. Mann, “Unbundling the Electric Capacity Price in a Deregulated Commodity Market,” *Public Utilities Fortnightly,* December 1995.

Booth, William and J.L. Rose, “FERC's Hourly System Lambda Data as Interim Bulk Power Price Information,” *Public Utilities Fortnightly,* May 1, 1995.

Rose, J.L. and M. Frevert, “Natural Gas: The Power Generation Fuel for the 1990s.” Published by Enron.

Employment History

ICF International	Executive Director	2015-Present
ICF International	Managing Director	1999-2015
ICF International	Vice President	1996-1999
ICF International	Project Manager	1993-1996
ICF International	Senior Associate	1986-1993
ICF International	Associate	1982-1986

EXHIBIT 2-2:

Resume of Himali Parmar

HIMALI PARMAR

Vice President

Himali Parmar joined ICF in 2002 and is a Vice President in the Energy Advisory group. Ms. Parmar leads the Transmission & Interconnection practice and has expertise in renewable integration, interconnection assessments, production cost modeling, forecasting transmission congestion and losses and their effect on locational power prices and asset valuation. Ms. Parmar and her team have provided market and transmission due diligence support for approximately 30 GW of renewable projects, over the last two years. ICF assessments are relied on by financing/ lending agencies for an independent and unbiased view of the future market and grid conditions and the economic viability of the individual assets. Her team closely follows interconnection and transmission issues and proposed transmission plans across various power markets and also perform independent assessments of reliability issues on the grid and identify mitigation plans to alleviate those issues.

Ms. Parmar is very proficient in load flow simulation tools such as Power World, GE PSLF, PowerGem and production cost modeling tools such as GE's MAPS and ABB's PROMOD models.

Experience

- Professional start date: 1999
- ICF start date: 2002

Education

- MS, Electrical Engineering, University of Wisconsin, 2001
- BS, Electrical Engineering, Punjab Technical University, India, 1999

Before joining ICF, Ms. Parmar worked as a planning engineer at American Transmission Company, WI and developed short and long-term transmission system plans for the company.

Select Recent Project Experience

Basis and Curtailment Assessments- Ms. Parmar routinely supports renewable developers with generation-weighted price forecasts and transmission assessments for basis, congestion, and curtailment. ICF is currently supporting financing related markets and transmission diligence for upwards of 5 GW of renewables across several markets across US including approximately 500 MW of wind projects in SPP and 1.5 GW in the MISO market footprint.

Greenfield Renewable Development- Site Screening (US-wide)- Ms. Parmar has supported several large renewable developers with renewable siting strategies which rely on a combination of factors including existing and future transmission availability, strong nodal premiums, existing and future supply assumptions, resource potential, environmental and permitting restrictions, land ownership criteria. ICF's assessments are relied on to secure land parcels and interconnection queue positions, estimating land and interconnection costs in responding to RFPs and acquisition support of early-stage renewable development platforms. Markets of recent and ongoing assessments are ERCOT, PJM, SPP, MISO, PacifiCorp, PNM, Salt River and Arizona Public Service

Assessment of Consumer Benefits from Interconnection Customer Funded Network Upgrades- Ms Parmar is currently leading a detailed study for American Council of Renewable Energy (ACORE) to assess benefits to the consumers from transmission upgrades sponsored by interconnection customers. ICF is analyzing the impact of several dozen major network upgrades identified by MISO and SPP which are exclusively cost allocated to the interconnection customers for their impact on overall production cost, congestion and renewable production. ICF will also assess benefit/cost ratios of each of the network upgrades and compare with the respective ISO's threshold for market efficiency projects.

Assessment of Transmission Bottlenecks impacting Renewable Development- Ms Parmar led a detailed study for American Wind Energy Association (AWEA) to assess congestion pricing in the MISO, SPP, and ERCOT organized power markets with a focus on impact to wind generators. ICF's scope included a review of historical congestion patterns and causes, a forward-looking congestion analysis using SCED modeling, and a high-level evaluation of indicative transmission upgrades in each market to relieve projected congestion. ICF analysis and report was relied upon by AWEA for their stakeholder outreach in three markets and also with federal entities including Department of Energy (DOE)

Assessment of SPPs Affected System Costs for a Wind Project in MISO's DPP 2017 August West Cycle- Ms Parmar is currently supporting a private developer assess SPP's affected system costs for a 200 MW wind project located in Iowa in Midwest ISO.

Annual-Energy Resource Interconnection Service (AERIS) and Quarterly Operating Limit (QOL) Study in MISO – Ms. Parmar led a study for a major renewable developer to assess the potential restrictions on the output of their wind project under MISO's AERIS and QOL studies. ICF's analysis mirrored MISO's AERIS study approach and provided a view on the amount of the Project's MW that would be subject to MISO's QOL process. ICF simulated several scenarios to provide a range that could potentially limit the outcome of the Project on an annual basis.

Generator Interconnection System Impact Study (SIS) Assessment in MISO – Private Developer- Ms. Parmar is currently leading a study for a major renewable developer to assess the impact of the proposed SOO Green HVDC transmission project on their projects in a future MISO DPP cycle. ICF followed MISO's Business Practice Manual for Generator Interconnection to identify system constraints and determine the impact and the potential cost allocation for network upgrades that would help deliver the developer's requested capacity to the grid.

Transmission Security Assessment of the Withdrawal of Frontera from ERCOT South to CFE, Mexico - Ms Parmar led a team that assisted Blackstone assess the impact of the withdrawal of Frontera on the reliability of the ERCOT grid. ICF performed power flow and contingency analysis using to identify conditions that could result in violations with the withdrawal of supply from the load pocket. Further, ICF supported the client in identifying mitigation measures for the most severe violations. ICF's support included frequent discussion with ERCOT planners on behalf of the client.

Transmission Security Assessment for Cogeneration Facility Located in LA Basin (CAISO)- Ms Parmar performed detailed power flow assessment to assess the reliability value of the power generated by the cogeneration facility to the CAISO grid. ICF simulated various scenarios including alternate solar output (from both FTM and BTM), delayed transmission, retirements that could pose a reliability threat to the grid especially with the cogeneration facility assumed off-line. ICF shared their finding with the project stakeholders, Southern California Edison and CAISO.

Renewable Integration Study along US Northeastern corridor (NYISO, ISO New England and PJM)- Ms Parmar and her team performed a broad site screening of the US northeastern corridor to assess viable landing sites for off-shore wind. Ms Parmar identified maximum possible injection at each POI site without any upgrades. In addition, Ms Parmar simulated the power flow with stepwise injection ranging between maximum possible injection at each POI site without any upgrades and with upgrades. Identified upgrades included reinforcements to the existing grid, identification of least cost transmission solution and likely non-wires alternatives such as demand response and storage. The assessment covered three different US power markets- ISO New England, NYISO and PJM

Thought Leadership

Ms. Parmar is very actively publishing white papers and hosting webinars related to the topic of renewable and storage integration. Some of her recent publications include:

Whitepaper- "Wind in southwest power pool (SPP) is not so simple"

https://www.icf.com/insights/energy/wind-in-spp-is-not-so-simple

Whitepaper- "Navigating the PJM interconnection process for wind and solar projects."

https://www.icf.com/insights/energy/pjm-interconnection-process

Webinar- "Developing No-Regret Approaches to Battery Storage Financing"

https://go.icf.com/Energy-Storage-101-2019-05-22-OnDemand.html

Blog- "Is the Grid Ready for the Next 100 GW of Renewables"

https://www.icf.com/blog/energy/renewable-energy-next-generation

Blog- "Using powerflow studies to push PTC projects across the finish line"

https://www.icf.com/insights/energy/wind-power-flow-analysis

Document Content(s)