Affected System Study SPP-ASA-2013-001

7/5/2013

SPP Engineering, SPP Transmission Service Studies

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Executive Summary

NRG Energy has requested an affected system study to determine the impacts on SPP facilities due to the transfer of 51 MW from LAGN to CLEC. The period of the service requested is from 1/1/2014 to 1/1/2026.

The principal objective of this study is to identify system problems and potential system modifications necessary to facilitate the deliverability of the 51 MW request while maintaining system reliability. The LAGN to CLEC 51 MW request was studied using two System Scenarios. The service was modeled by a transfer from LAGN to CLEC. The two scenarios were studied to capture worst case system limitations dependent on the bias of the transmission system. Analysis was conducted on the planning horizon from 1/1/2014 to 1/1/2026.

The service was modeled from the LAGN to CLEC. The transfer causes new facility overloads on the SPP transmission system. Tables 1 and 2 summarize the results of the system impact analyses for the transfer for the scenarios listed in the table. Table 1 lists SPP thermal transfer limitations identified. Table 2 lists SPP voltage violations identified. No SPP voltage transfer limitations were identified; therefore, Table 2 is empty and is not included in this report.

Introduction

NRG Energy has requested a system impact study to determine the impacts on SPP facilities with the transfer of a 51 MW from LAGN to CLEC. The principal objective of this study is to identify the restraints on the SPP Regional Tariff System that may limit the Transmission Service Request (TSR) and determine the least cost solutions required to alleviate the limiting facilities.

This study includes steady-state contingency analyses (PSS/E function ACCC). The steady-state analyses considers the impact of the request on transmission line and transformer loadings, and bus voltages for outages of single transmission lines, transformers, and generating units, and selected multiple transmission lines and transformers on the SPP system.

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Study Methodology

Description

The facility study analysis was conducted to determine the steady-state impact of the requested service on the SPP and first tier non-SPP control area systems. The steady-state analysis was performed to ensure current SPP Criteria and NERC Reliability Standards requirements are fulfilled. SPP conforms to NERC Reliability Standards, which provide strict requirements related to voltage violations and thermal overloads during normal conditions and during a contingency. NERC Standards require all facilities to be within normal operating ratings for normal system conditions and within emergency ratings after a contingency.

Normal operating ratings and emergency operating ratings monitored are Rate A and B in the SPP Model Development Working Group (MDWG) models, respectively. The upper bound and lower bound of the normal voltage range monitored is 105% and 95%. The upper bound and lower bound of the emergency voltage range monitored is 105% and 90%. Transmission Owner voltage monitoring criteria is used if more restrictive. The SPS Tuco 230 kV bus voltage is monitored at 92.5% due to pre-determined system stability limitations. The WERE Wolf Creek 345 kV bus voltage is monitored at 103.5% and 98.5% due to transmission operating procedure.

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 control areas with SPP reserve share program redispatch. The monitor 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 115 kV and above. Voltage monitoring was performed for SPP control area buses 69 kV and above.

A 3 % transfer distribution factor (TDF) cutoff was applied to all SPP control area facilities. For first tier non-SPP control area facilities, a 3 % TDF cutoff was applied to AECI, AMRN (Ameren), and ENTR (Entergy) control areas. A 2 % TDF cutoff was applied to WAPA. For voltage monitoring, a 0.02 per unit change in voltage must occur due to the transfer or modeling upgrades to be considered a valid limit to the transfer.

Model Development

SPP used five seasonal models to study the LAGN to CLEC 51 MW request for the requested service period. The following SPP Transmission Expansion Plan 2012 Build 1 Cases were used to study the impact of the requested service on the transmission system:

2013/14 Winter Peak (13WP)
2014 Summer Peak (14SP)
2014/15 Winter Peak (14WP)
2018 Summer Peak (18SP)
2018/19 Winter Peak (18WP)
2013 Summer Peak (23SP)

2023/24 Winter Peak (23WP)

The Summer Peak models apply to June through September and the Winter Peak models apply to December through March.

The chosen base case models were modified to reflect the current modeling information. From the five seasonal models, two system scenarios were developed. Scenario 0 includes projected usage of transmission included in the SPP 2012 Series Cases. Scenario 5 includes transmission service not already included in the SPP 2012 Series Cases.

Transmission Request Modeling

Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation transfers. Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation because the requested Network Integration Transmission Service is a request to serve network load with the new designated network resource, and the impacts on Transmission System are determined accordingly. Point-To-Point Transmission Service requests are modeled as Generation to Generation transfers. Generation to Generation transfers are accomplished by developing a post-transfer case for comparison by dispatching the request source and redispatching the request sink.

Transfer Analysis

Using the selected cases both with and without the requested transfers modeled, the PSS/E Activity ACCC was run on the cases and compared to determine the facility overloads caused or impacted by the transfer. Transfer distribution factor cutoffs (SPP and 1st-Tier) and voltage threshold (0.02 change) were applied to determine the impacted facilities. The PSS/E options chosen to conduct the analysis can be found in Appendix A.

Study Results

Study Analysis Results

Tables 1 and 2 contain the initial steady-state analysis results of the System Impact Study. The Tables are in the attached workbook SPP-ASA-2013-001 Tables. The tables identify the seasonal case in which the event occurred, the transfer amount studied, the facility control area location, applicable ratings of the thermal transfer limitations and SPP voltage transfer limitations, and the loading percentage and voltage violation.

Table 1 lists the SPP thermal transfer limitations caused by the 51 MW transfer for applicable scenarios. Solutions with engineering and construction costs are provided in the tables.

Table 2 lists the SPP voltage transfer limitations caused by the 51 MW transfer for applicable scenarios. Solutions with engineering and construction costs are provided in the tables.

Conclusion

The results of the Affected System Study show that the transfer of the full 51 MW from LAGN to CLEC causes no steady-state violations on the SPP regional transmission system.

Appendix A

PSS/E CHOICES IN RUNNING LOAD FLOW PROGRAM AND ACCC

BASE CASE SETTINGS:

• Solutions:	Fixed slope decoupled Newton-Raphson solution (FDNS)
• Tap adjustment:	Stepping
• Area Interchange Control:	Tie lines and loads
• Var limits:	Apply immediately
• Solution Options:	X Phase shift adjustment __ Flat start __ Lock DC taps __ Lock switched shunts

ACCC CASE SETTINGS:

• Solutions:	AC contingency checking (ACCC)
• MW mismatch tolerance:	0.5
• System intact rating:	Rate A
• Contingency case rating:	Rate B
• Percent of rating:	100
• Output code:	Summary
• Min flow change in overload report:	3mw
• Excld cases w/ no overloads from report:	YES
• Exclude interfaces from report:	NO
• Perform voltage limit check:	YES
• Elements in available capacity table:	60000
• Cutoff threshold for available capacity table:	99999.0
• Min. contng. Case Vltg chng for report:	0.02
• Sorted output:	None
• Newton Solution:	
• Tap adjustment:	Stepping
• Area interchange control:	Tie lines and loads (Disabled for generator outages)
• Var limits:	Apply immediately
• Solution options:	X Phase shift adjustment __ Flat start __ Lock DC taps __ Lock switched shunts

Scenario	Season	From Area	To Area	Monitored Branch Over 100% Rate B	Pre-Transfer Case % Loading	Transfer Case % Loading	TDF (%)	Outaged Branch Causing Overload	Upgrade Name	Solution
				No Thermal Limitation						

Table 2- SPP Facility Voltage Transfer Limitations

Scenario	Season	Area	Monitored Bus with Violation	Transfer Case Voltage (PU)	Outaged Branch Causing Overload	Upgrade Name	Solution
			No Voltage Limitation				

Table 3 - Upgrade Requirements and Solutions Needed

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
	No Directly Assigned Projects				

Construction Pending Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
	No Construction Pending Projects				

Expansion Plan Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
	No Expansion Plan Projects			

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
	No Reliability Plan Projects			