Impact Study for Transmission Service Request #112543 6/1/99 – 10/1/99 Entergy to Western Resources

Southwest Power Pool
Transmission Reliability Assessment
June, 1999

Description of Request

This Impact Study is in response to OASIS request #112543 by Western Resources. This request is for a transfer of up to 50 MW of Firm Point-to-Point Transmission Service to be supplied by SPP from Entergy to Western Resources. The request is for service from 6/1/99 to 10/1/99. The Fort Smith 500/161 kV transformer has been identified as a constraint upon the outage of the 500/345 kV transformer. These facilities are owned by OG+E who has put its facilities under the SPP Regional Tariff. The Impact Study identifies switching, redispatch, or firm reservations that, if curtailed, would affect or relieve the transmission constraint.

Summary

Southwest Power Pool (SPP) studied multiple system reconfigurations as an option to relieve overloading of the Fort Smith 500/161 kV transformer upon the outage of the 500/345 kV transformer and determined that a system reconfiguration did exist which would relieve the overload. This was reviewed by OG+E and was not accepted as a viable solution to the overload because of several negative repercussions.

Redispatch options for this overload were evaluated to determine which units, if redispatched, could unload the facilities. SPP determined that a redispatch solution did exist within the SPP Region. This solution required increased generation at the OG+E's Muskogee plant and a corresponding decrease in generation at OG+E's Sooner plant. OG+E determined that they were not in a position to offer redispatch because of reduced capacity caused by tornado damage.

No existing transmission reservations were found which could be curtailed to relieve the constraint pursuant to the SPP Tariff guidelines.

SPP denies the request based on the study information.

Procedures

A. System Reconfiguration

The 1999 Southwest Power Pool (SPP) Summer Peak model completed in January of 1999, was used for the study. This model was updated to reflect current circumstances. The initial studies were performed prior to the extended outage of the Sooner – Northwest 345 kV line on May 5, 1999. Later studies included the outage with negligible impact in the Fort Smith area.

The reservation request modeled with the Fort Smith 500/345 kV transformer outage was shown to overload the 500/161 kV transformer. The 161 kV bus at Fort

Smith is served by step-down transformers at the 500 and 345 kV levels with four 161 kV lines attached to a ring bus. SPP has examined a number of switching scenarios to determine if the overload could be eliminated by system reconfiguration.

B. Redispatch

The SPP used the NERC Generator Sensitivity Factor (GSF) Viewer to obtain possible unit pairings which would relieve the constraint. The GSF viewer calculates unit impacts on monitored facilities for all units above 20 MW in the Eastern Interconnection. The Fort Smith transformer 500/161 kV is included in this list as a monitored facility. Unit pairings were formed based on generation shift factors which would unload the transformer. These pairings were placed in the base model and tested for effectiveness as possible redispatch options.

C. Transaction Curtailment

SPP reviewed the existing firm reservations under the SPP Tariff and tariffs of transmission providers that signed the Agency Agreement. No existing firm reservations existed which could be curtailed to relieve the transmission constraint.

Study Results

A. System Reconfiguration

SPP reviewed system reconfigurations in the Fort Smith area. With reconfiguration limited to switching of only single transmission elements, the only options available for relief of the transformer were within the Fort Smith substation. Several system reconfiguration switching options were studied for the Fort Smith 161 kV ring bus. (See attachment for various scenarios and loading.) Segmentation of the 161 kV bus at Fort Smith into two sections was analyzed. The 161 kV lines connected from the Fort Smith 161 kV bus to Arkoma and Colony carry the majority of the flow out of the bus in the base case (244 and 250 MW's respectively). The 161 kV lines connected to Quanex and Bonanza Tap have significantly less load on them (69 and -29 MW's).

After assessing reconfigurations of the 161 kV bus, one option was settled on as being the most feasible: Segmentation of the bus by opening breakers 182 and 186 during outage of the 500/345 kV transformer, closure of the Quanex Tap to Barling line, and opening of the Barling to Messard 161 kV line. This configuration serves the Colony and Quanex Tap load from the 500/161 kV transformer. The Bonanza Tap and Arkoma lines are connected to the 345/161 kV transformer.

The segmentation of the bus adds loss of load risk to the Fort Smith area. The 161 kV bus section served by the 500 kV transformer has increased risk caused by a single breaker lock-out at 185 separating the transformer from the two transmission lines. The bus section served by the 345 kV transformer does not have the same configuration which allows both transmission lines to be separated by a single breaker action. Sectionalizing of the ring bus would only be done during the loss of the 500/345 kV transformer reducing loss of load risk exposure.

This configuration reduced flows on the 500/161 kV transformer below the normal ratings with no other overloads. Consultation was made with OG+E to determine if any operational issues unknown to SPP would render this system configuration unacceptable in an emergency situation upon the loss of the 500/345 kV transformers. OG+E informed SPP that an arrangement within the Fort Smith station that sectionalizes the 161 kV bus has three repercussions. 1.) The loss of load expectation increases significantly due to compromised protective relaying systems. 2.) This also creates a potential for an extended period where normal maintenance of protective relay and substation equipment is negatively impacted. 3.) A major customer in Fort Smith requires a low impedance source for arc furnace operation and the change in configuration will reduce the customer's service to an unacceptable level.

B. Redispatch

NERC already calculates shift factors on specified facilities for all generation units over 20 MW in the Eastern Interconnection. These generation shift factors were reviewed for impacts on the Fort Smith transformer as a starting point for redispatch assessment. Numerous SPP generators were available with significant negative impacts which would reduce transformer flows when unit output is increased. However, none of the units with a positive impact (increasing flows when unit output is increased or reducing flow when unit output is reduced) were in the SPP area. Only units east of Fort Smith (outside of SPP) have positive impact factors. Consequently, the only redispatch options within the SPP are between units with relatively different negative impacts on the constraint. Such a pairing has less redispatch leverage than a pairing of units having positive impacts with units having negative impacts.

Table 1. NERC Generator Shift Factor Viewer Results.

UNIT	GSF
Muskogee 3	-24.3%
Muskogee 4	-23.7%
Muskogee 5	-23.7%
Muskogee 6	-23.7%
Sooner 1	-16.6%
Sooner 2	-16.7%

The tabulated DC analysis shows an increase in generation at Muskogee 3 and a corresponding reduction in generation at Sooner 2 providing a net change of 7.6%. AC verification indicates a response factor of 7.3% on the 500/161 kV transformer with the 500/345 kV transformer out of service. The distribution factor on the Fort Smith transformer for an Entergy to Western Resources response on the Fort Smith transformer is 12.9%.

By decreasing generation on a unit with a smaller negative impact, compared to the unit on which generation is increased, the net effect of redispatch is a reduction in flows on a monitored facility. Both Sooner units have approximately the same impact and are normally shown loaded near their rating (514 MW), allowing for the reduction in generation output. This would be in addition to any reduction in output caused by the loss of the Sooner to Northwest transmission line. By redispatching these two units 88 MW's under emergency conditions, the relief on the overloaded 500/161 kV transformer was shown to be the opposite of a 50 MW schedule from Entergy to Western Resources. This conclusion has been verified with AC solutions.

The redispatch solution selected, as meeting the criteria of providing effective impact relief and probable availability, is an increase of Muskogee unit 3 and a decrease of the Sooner Plant (either unit) by 88 MW. All of the units at Muskogee had approximately the same impact; however, the Muskogee unit 3 is a gas-fired steam unit rated at 165 MW and is normally shown as not running in the summer peak models. Muskogee 3 was selected as the unit to be increased since it would have the highest probability of not being needed to serve OG+E load.

Redispatch would only occur during heavy loading on the 500/161 kV transformer and with the loss of the Fort Smith 500/345 kV transformer. The loss of the 500/345 kV transformer by itself does not necessarily require redispatch. The ultimate decision for redispatch would be made by OG+E with consultation with SPP.

OG+E was contacted to determine availability and costs for redispatching these two units. The Muskogee plant was recently damaged by a tornado. Unit #6 coal handling system was severally damaged and portions of the Unit #4 cooling towers were destroyed. Muskogee Unit #3 has been periodically required to run because of OG+E unit deratings. OG+E has placed a temporary conveyor system in place on unit #4 that while functional, reduces the reliability until permanent repairs are made. Repairs at the Muskogee plant are expected to extend approximately 15 weeks.