Allegheny Power

Allegheny Power Interconnection Feasibility Study

for

Harrison 500kV - 35 MW Injection

Harrison County, West Virginia

(#73)

July 2002

Prepared by Allegheny Power's System Planning section of the System Planning and Operations Group
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1. Introduction and Background

The developer has requested Allegheny Power (AP) to perform a Feasibility Study to determine the interconnection facilities and local system reinforcements required for a 35 MW injection in Harrison County, West Virginia.

It should be noted that, although this analysis examined the AP transmission system and the required reinforcements assuming a 35 MW injection into the AP transmission system, this study does not guarantee that Transmission Transfer Capability to all possible destinations will exist when the generation is placed in service.

2. Summary of Costs

AP has determined that it will require no system changes to accommodate a 35 MW injection at the Harrison 500 kV substation. In addition, no protective-relaying or metering changes are necessary.

It should be noted that stability or transient analysis studies are not a part of the Feasibility Study process, and no studies of this type have been performed. No corrective actions to problems that may be identified in such studies, or resulting financial obligations, have been identified at this time.

Additional considerations include cumulative effect of adding multiple non-utility generating units to the AP system. If all of the NUGs in the AP queue are installed, the increase in fault duty will result in the need for facility replacements throughout the AP system. Evaluations concerning the distribution of financial obligations for this scenario will be done when Facility Study agreements are received.

3. Assumptions

All studies that look into the future require assumptions concerning the load, facility additions and transmission sales within and external to the AP control area. This analysis is no exception.

The 2007 summer base case was selected to model the 35 MW injection. The AP control area load in the model was 8692 MW.

As in all studies, some type of generation dispatch needs to be used. For the purposes of the base study, a single economic-type dispatch was used. Study results which appeared to be somewhat generation dispatch sensitive, had alternative dispatches considered.

AP facility additions were assumed to be those as planned in the present series of cases that followed the present AP Planning Guide. The Bulk Power facility additions modeled for other utilities used in this study are those that have been included in the MMG (Multi-regional Modeling Group) base case by the other utilities. Transmission sales modeled for the study year are those sales that were known at the time the base case was created and include only confirmed, firm transmission service reservations.

Generation output was assumed to stay within the AP control area.

4. Results - Summary

Results of the power flow studies indicate that the 35 MW can be accommodated without system capacity reinforcements.

Two base cases were run for this study. They include a case with and without the 35 MW injection. All single and credible double contingency cases were simulated to evaluate the impact of the 35 MW injection on the AP system.

Further discussion can be found in the *Study Methodology and Analysis* section of this report.

5. Study Methodology and Analysis

Methodology

Based on a December 2003 in-service date, a 2007 summer base model was selected with loads in the study area adjusted to represent 2007 summer conditions. A summer base case was chosen because line capacity in the summer months is more critical than that in winter. The assumptions previously stated in the section titled *Assumptions* regarding forecasted control area loads, maintenance schedules, confirmed Firm Point-to-Point Transmission reservations and generation dispatch were all used in the Feasibility Study.

Power flow cases were created and contingency tests were evaluated based upon the AP planning criteria reported in FERC Form 715, Part 4 which is available to the general public for a nominal fee. These criteria were applied to studies using the 2007 summer model to evaluate the effect the 35 MW injection might have on AP transmission facilities.

Analysis

Two base cases were run for this study. The first was run to evaluate the system as it currently is planned and is expected to perform. The second was run to evaluate the system with the 35 MW injection.

6. Short Circuit Study Results

Shown below are the maximum three phase and single line-to-ground fault currents at those stations most affected by the 35 MW injection.

Bus Faults

Fault Location	Harrison 500kV – 35 MW injection			
	Three Phase *Symmetrical Fault*		Line to Ground *Fault*	
	Amps	Angle	Amps	Angle
Belmont 500 kV	27481	-88	26505	-87
Ft. Martin 500 kV	33288	-88	30657	-86
Harrison 500 kV	33125	-88	31689	-86
Pruntytown 500 kV	29907	-88	24030	-83
Wylie Ridge 500 kV	22121	-88	17418	-83
Harrison #1 20 kV	193405	-89	---	----
Harrison #2 20 kV	200660	-89	---	---
Harrison #3 20 kV	195258	-89	---	---

The existing circuit breakers at the Belmont, Fort Martin, Harrison, Pruntytown, and Wylie Ridge substations were evaluated Since none of the breakers evaluated exceeded their maximum interrupting capacity, no further investigation concerning symmetrical or asymmetrical values was necessary, and breaker replacements are not likely to be required on the AP system.

7. Issues Beyond the Scope of this Study

The developer has not indicated how the power output from the generators will be sold. Since the developer could not commit to a direction or market for the power output, no tests were made modeling the power as though it were sold off system. The developer should also be aware that the tests performed with this analysis assumed that the new installations were control-area capacity resources. The developer, by not providing a direction or market, has assumed the risk that Transmission Transfer Capability may not be available when the project comes on line. Any firm transmission reservations made by other marketers or developers prior to an agreement with the developer would not only alter these study results, but could force limitations on generation output.

Additionally, the developer needs to be aware that in the event that there is congestion on the Eastern Interconnection, generation dispatch might be restricted. In that case, PJM, as the operator of the AP transmission system, could invoke their congestion management system, or follow the North American Electric Reliability Council's (NERC) Transmission Line Loading Relief Procedure (TLR) and the guidelines set forth within that procedure. A copy of these procedures can be downloaded via the Internet from the PJM website at http://www.pjm.com/. Additionally, the developer may choose to implement the NERC Market Re-dispatch or the Lake Erie Emergency Re-dispatch (LEER) procedures. Involvement in either procedure is voluntary. More information on the NERC market re-dispatch procedure can be obtained from the NERC website at http://www.nerc.com/. Information on the LEER can be obtained from the FERC-filed LEER procedure.