Allegheny Power

Allegheny Power Interconnection Feasibility Study

Bluestone Dam - 41 MW Generation Project

Summers County, West Virginia

Queue #69

May 2002

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

(Edited July 1, 2002 to remove confidential developer information prior to PJM web posting.)

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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 to interconnect 41 MW of generation at their Bluestone Dam site. The developer plans to have the generation in service and producing power by September 2004.

It should be noted that this analysis examined the AP 46 kV subtransmission system and the required reinforcements assuming a 41 MW injection into the AP subtransmission system, this study does not guarantee that Transmission Transfer Capability to all possible destinations will exist when the developer's generation is placed in service.

2. Description of Project

The location for the developer's proposed generation project is Summers County, West Virginia near the city of Hinton.

AP will construct approximately 2.5 miles of 46 kV line from Hinton substation to a new switching station. AP will install a 46 kV breaker, a 46 kV meter and other necessary facilities at the new switching station to provide an interconnection point.

Other system reinforcements identified during this study that will be necessary prior to interconnection to the AP system include installing a 46 kV breaker at Hinton substation and replacing the #5 Hinton transformer with a 50 MVA 138 – 46 kV transformer. AEP has been notified of the developer's plans to construct a 41 MW generating station. Costs and reinforcements noted in this study to not include potential problems on the AEP system. Reinforcements on the AEP system may be 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.

3. Summary of Costs

The total estimated cost to install all of the facilities described individually below is **$1,915,000 in 2004 dollars**. Scope of work and estimated cost by project segment are listed under the following bullets:

- The estimated cost to install a new metered, 46kV breaker terminal (for the proposed NUG interconnection) and to replace the existing No. 5, 138-46kV, 8.4/10.5 MVA power transformer with a 138-46kV, 48/64/80 MVA, LTC power transformer (to accommodate need for increased capacity) at Hinton Substation is **$1,200,000 in 2004 dollars**. This figure includes all protective relaying, metering and communications equipment required to accommodate addition of the new metered breaker terminal and replacement of the power transformer.

- The estimated cost to overbuild 2.5 miles of 12kV from Hinton Substation to Bluestone Dam with 556 kcmil ACSR at 46kV to provide an electrical path for connecting the proposed new generation to the AP grid at Hinton Substation is **$690,000 in 2004 dollars**.

While AP cannot mandate that our personnel install protective relaying and communications equipment at the generator site, AP does have responsibility for designing the protection scheme and providing specifications for all relays to be employed on the interconnection breaker terminal at the generation site to assure that the protective relaying equipment will be compatible with that installed on the interconnection breaker terminal at the new switching station. The relaying package will likely include both primary and backup protection. Further, AP also has responsibility for testing and calibrating all relays and performing all tests to make sure that protective relaying at the generation site is properly installed and functional. The estimated total cost of this engineering and field test effort is **$20,000 in 2004 dollars**.

Note: Purchase and installation of protective relaying and associated equipment at the generation site is not included in this scope of work. This phase of work is the responsibility of the customer.

- Adding the proposed generation will require that protective relaying coordination in the entire area be reviewed and changes will likely be required at one or more area substations. AP estimates the total cost for coordination review, new settings, and implementation to be approximately **$5,000 in 2004 dollars**.

4. Assumptions

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

The 2007 summer base case was selected to model the developer's generation project.

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 are known at the time the base case was created and include only confirmed, firm transmission service reservations.

The generation output from the developer's project was assumed to stay within the AP system.

The developer provided generator data for the proposed installation. The developer did not provide generator step-up transformer data. The Impedance was assumed to be 10% on a 50 MVA base.

5. Results - Summary

Two base cases were run for this study. They include a case with and a case without the developer's Bluestone Dam generating plant. Credible single and double contingency cases were simulated to evaluate the impact of the generating facility on the AP system.

Results of the power flow studies indicate that the installation of 41 MW of generation at Bluestone Dam cannot be accommodated without system reinforcements.

System reinforcements identified during this study that will be necessary prior to interconnection to the AP transmission system include:

- Construction of a new 46 kV switching station
- Construction of new 46 kV line with 556 ACSR
- Installation of new 30/40/50 MVA 138 – 46 kV transformer at Hinton Substation

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

6. Study Methodology and Analysis

Methodology

The in-service date for the proposed generator installation is projected to be September 2004. Based on this 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 power output 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, without the inclusion of any new generating plants. The second was run to evaluate the system with the inclusion of the developer's generation.

7. Short Circuit Study Results

Results of the short circuit evaluations for the developer's generation are tabulated below.

The study focused on determining the maximum short circuit currents at Hinton, Ronceverte, Bluestone Dam and Greenbrier Substations.

Shown below are the maximum three-phase and single line-to-ground fault currents at those stations most affected by the inclusion of the developer's generation.

Bus Faults

Fault Location	Bluestone Dam In-Service				Bluestone Dam Not In-Service			
	Three Phase		Line to Ground		Three Phase		Line to Ground	
	Symmetrical Fault		*Fault*		*Symmetrical Fault*		*Fault*	
	Amps	Angle	Amps	Angle	Amps	Angle	Amps	Angle
Greenbrier 138 kV	4432	-72	3848	-75	4421	-72	3842	-75
Hinton 138 kV	12201	-79	8421	-78	11737	-78	8270	-78
Ronceverte 138 kV	4584	-72	4592	-75	4548	-72	4568	-75
Hinton 46 kV	941	-87	1253	-87	940	-87	1252	-87
Bluestone Dam 46 kV	6329	-86	6939	-86	4364	-84	3376	-84
Bluestone Dam 13.8 kV	18156	-88	0	0	- - -	- - -	- - -	- - -

Existing circuit breakers at the stations listed above were not significantly impacted by the addition of the Bluestone Dam generation. Further evaluation will be performed in the System Impact Study. The short circuit positive and zero sequence source equivalent impedance representing the AP system at the new Bluestone Dam switching station 46 kV bus not including the Bluestone Dam generation is as follows:

Positive Sequence **R+jX**	Zero Sequence **R+jX**
(0.03136+j0.28588)	(0.05752+j0.53713)

These values are in per unit on a 100 MVA base.

8. 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 agreement with the developer would not only alter these study results, but could force limitations on the developer's generation output.

Additionally, the developer needs to be aware that in the event that there is congestion on the Eastern Interconnection, generation dispatch out of Bluestone Dam at times 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.