Generation Interconnection Facilities Study Report

For

PJM Generation Interconnection Request Queue Positions AA2-173 and AB1-112 (Combined)

Hatfield 500 kV

March 2017

Queue #AA2-173 / AB1-112 (Combined)
Hatfield 500 kV
Facilities Study Report

Description of the Project

Hill Top Energy Center LLC (hereinafter referred to as "Interconnection Customer") has proposed the addition of 535.0 MW of natural gas generation with 535.0 MW capacity to the Hatfield
500 kV substation, west of Masontown, PA. This study combines PJM Queue projects AA2-173 (515.0 MW) and AB1-112 (20.0 MW) into this Facility Study analysis. This project is located in Greene County, in southwestern Pennsylvania (Ref: Figure 5).

The generation facility will interconnect with **West Penn Power Company** (West Penn), a FirstEnergy Company (FirstEnergy), (hereinafter referred to as "Transmission Owner") at a new 500 kV cross-bus at Hatfield 500 kV Substation.

Amendments to the System Impact Study Data / Results

- Interconnection Customer has proposed alignment of a new 500 kV Lead Line from Interconnection Customer generator site in Nemacolin, PA, approximately 2.75 miles to Hatfield 500 kV substation.
- AB1-112 increased total capacity of AA2-173 to combined 535 MW.

Schedule

Interconnection Customer's requested Commercial Operation Date (COD) for the generation facility is **January 1, 2019**. Transmission Owner's proposed schedule does not match Interconnection Customer's requested Milestone Schedule. A Project Kickoff meeting must occur by **March 1, 2017** to meet the Milestone Schedule listed below.

Interconnection Customer's Requested Milestone Schedule:

03/01/2018 Initial Back-feed through Project Substation Date
01/01/2019 Project Commercial Operation Date

Direct Connection and Non-Direct Connection Schedule: Transmission Owner proposes a **twenty** (**20**)-month schedule following a fully executed Interconnection Construction Service Agreement and Construction Kick-Off Meeting in order to complete the engineering and construction associated with activities, as detailed in the "Direct Connection" and "Non-Direct Connection" sections below.

Transmission Owner's Proposed Milestone Schedule:

11/01/2018 Initial Back-feed through Project Substation Date
06/01/2019 Project Commercial Operation Date

Recommended New Operational Procedures

The system stability study for both projects AA2-1173/AB1-112 combined revealed that there are several criteria not met during outages of the 500 kV lines. New operational procedures are recommended to alleviate instabilities of maintenance outages. Please refer to Attachment B for Dynamic Simulation Analysis report.

Scope of Interconnection Customer's Work

Direct Connection Facilities

Interconnection Customer will construct facilities, including the natural gas collection system, generation step-up (GSU) transformer, new 500 kV generator Lead Line (2.75 miles), and connect to the Transmission Owner's new two (2)-breaker, 500 kV cross-bus at Hatfield substation.

Point of Interconnection (POI): the point where Interconnection Customer's 500 kV generator Lead Line crosses the Transmission Owner substation fence at Hatfield Substation (Ref: Figure 1B).

Interconnection Customer is required to own, install, and maintain a fully-rated, fault-interrupting circuit breaker on the high-side of each GSU transformer, revenue meter, and also a main breaker between the collector bus and the incoming line disconnect switch, located in the generator substation yard.

The direct connection facilities also includes line terminal equipment on Transmission Owner's side of the point of interconnection. This typically includes operational metering, dead-end structure, and a three-phase, gang-operated disconnect switch. These facilities are considered radial equipment from the terminal to the point of interconnection.

Project Scope

It is proposed that the combined AA2-173/AB1-112 project expand the existing Hatfield substation and construct a new two (2)-breaker, 500 kV cross-bus for interconnection of the generator 500 kV Lead Line. Interconnection Customer is responsible for constructing all of the facilities on its side of the POI, as shown in the attached one-line diagram (Ref: Figure 3), including obtaining all property rights and required permits for installing 2.75 mile, 500 kV generator Lead Line from the generator site, near Nemacolin, PA to the POI at Hatfield substation.

Description of Facilities Work:

Direct Connection

Facilities Work to be constructed by Transmission Owner (Ref: Figure 2):

1. **Transmission Owner Interconnection Substation – HATFIELD SUBSTATION**

Transmission Owner will design, furnish and construct the following for the new two (2)-breaker 500 kV cross-bus at Hatfield substation:

Network Upgrade Number: n4942

- modify Hatfield 500 kV substation fence as required for new facilities;
- construct new 500 kV cross-bus structure and transmission line termination (dead-end) structures;
- two (2) 500 kV, 3000 ampere, 50 kA interrupting power circuit breakers;
- five (5) 500 kV, 3000 ampere, three-pole, motor-operated, disconnect switches;
- three (3) surge arresters for application on a 500 kV system;
- three (3) 500 kV capacitor voltage transformers (CVT's) for relaying;
- 500 kV bus and conductor with associated steel structures;
- foundations for the structures and equipment listed above;
- substation fencing, cable trench & conduit system, ground grid and stoning.
- Supervisory scada control and data acquisition (SCADA) remote terminal unit (RTU) monitoring for new equipment;
- relocate (i.e. remove/scrap) the existing storage building and foundation and install a new 36' x 80' storage building;
- relocate one (1) spare 500 kV breaker and one (1) 138-4 kV start-up transformer, includes removing existing foundations and installing new foundations with monitoring;
- install and upgrade relaying and controls equipment; and
- install fiber interface at Hatfield POI with Interconnection Customer's optical ground wire and fiber for communication and relaying with Interconnection Customer's generator substation 500 kV breaker.

Assumptions / Notes:

- Transmission Owner has adequate land to accommodate the yard expansion at Hatfield Substation, provided there are no additional requirements for on-site storm water management measures.
- Assume working clearance is adequate and minimal outages will be required to erect new 500 kV structures and two (2) breaker cross-bus at Hatfield substation. Interconnection of both existing main busses to the new breaker string will require extended bus outages for cut-in, testing, and commissioning of new equipment, relays, and protection schemes.
- In order to meet the proposed back-feed date of **11/01/2018**, Interconnection Customer must confirm final alignment of the last transmission structure, on the generator Lead Line, to the proposed 500 kV dead-end structure at Hatfield Substation **by June 1, 2017** (Ref: Figures 4A & 4B). Delays in this provision will delay final substation design details and affect the project schedule.
- Schedule can be affected by availability of 500 kV system outages in spring and fall 2018 for construction and cut-in of new 500 kV cross-bus at Hatfield substation.

2. Generator Lead Line (2.75 miles from POI to Project Site) – Interconnection Customer owned

General Assumptions / Notes:

- Interconnection Customer will coordinate design and alignment of proposed 500 kV Lead Line with the Transmission Owner for review of any clearance or right-of-way encroachment issues with existing Transmission Owner owned 500 kV facilities.
- Interconnection Customer will coordinate design and construction of proposed 500 kV Lead Line with the Transmission Owner on any transmission line crossings or adjacent corridors for review of proper conductor clearances to Transmission Owner owned facilities. For these areas, the Interconnection Customer shall provide Transmission Owner with proposed transmission plan & profile or PLS-CAD drawings file prior to construction and as-built drawings, confirmed by as-built survey data post-construction.
- Transmission Owner preference would be to maintain 140 foot separation between centerlines of proposed new 500 kV Lead Line and existing Transmission Owner 500 kV centerline. As a minimum, Interconnection Customer's right-of-way should not encroach within 100 feet of Transmission Owner centerline at blowout conditions. If Interconnection Customer's line design does not comply with this requirement Transmission Owner would need to review this area as a special exception.
- Additional costs will be incurred by the Interconnection Customer, if final alignment of 500 kV Lead Line causes encroachments, changes, or modifications to any existing Transmission Owner facilities.

Right-of-Way (ROW) Assumptions:

- Interconnection Customer will acquire all necessary line and access road right-of-ways for generator 500 kV Lead line.
- Interconnection Customer will provide a perpetual easement to Transmission Owner allowing permanent access to POI.

Forestry/Vegetation Management Assumptions:

- The only vegetation clearing work on the project is associated with the generator 500 kV Lead Line.
- Interconnection Customer is responsible for Erosion and Sediment Control (E&S) installation, access road construction and rehabilitation along the length of the generator 500 kV Lead Line.
- Logs, debris, and brush shall not be placed within the Transmission Owner owned right-of-way corridor.

Non-Direct Connection

Transmission Owner Facilities:

Adjust remote end relaying and metering settings at Hatfield Substation. (Network Upgrade Number: n4943).

Total Estimated Costs of Transmission Owner Facilities for Direct and Non-Direct Connection:

Transmission Owner facilities and network upgrades required to support AA2-173/AB1-112 projects are:

(a) Attachment Facilities: $ 0.0

(b) Non-Direct Connection Network Upgrades:

Adjust remote end relaying and metering settings.
Network Upgrade Number: n4943.

Estimated cost: $ 12,700.

(c) Direct Connection Network Upgrades:

Hatfield Substation – Install two (2) 500 kV breakers and construct new 500 kV cross-bus for new AA2-173 line terminal.
Network Upgrade Number: n4942.

Estimated cost: $6,608,800.

(d) Non-Direct Connection Local Upgrades: $ 0.0

(e) Non-Direct Connection Network Upgrades: $ 0.0

(f) Option to Build Upgrades: $ 0.0

Estimated Total Costs (a) to (f): ....***$ 6,621,500***

NOTE: Above net amounts are in 2016 Dollars. Contribution in Aid of Construction (CIAC) Federal Income Tax Gross Up charge will be added to above amounts if this project does not meet the eligibility requirements of IRS Notice 88-129.

Schedule:

A proposed **twenty** (**20**)-month **Direct Connection** and **Non-Direct Connection** schedule is estimated to complete the engineering, construction and the associated activities, from the date of a fully executed Interconnection Construction Service Agreement and Construction Kick-Off Meeting. This schedule assumes that all issues covered by the "Environmental, Real Estate and Permitting Issues" section of this document are resolved, and outages will occur as planned. Construction cannot begin until after all applicable permits and/or easements have been obtained.

Activity	Start Month	End Month
Preliminary Engineering	1	2
Permits	3	8
Detailed Engineering	3	16
Equipment Procurement - Delivery	6	12
Below Grade Construction	N/A	N/A
Above Grade Construction	13	18
Testing & Commissioning**	15	20

**** Note:** Schedule allows for testing and commissioning in both spring 2018 for interconnection of new 500 kV ring bus and then final connection of 500 kV Lead Line in fall 2018.

Generation Connection Requirements

The proposed interconnection facilities must be designed in accordance with the Transmission Owner's *Requirements for Transmission Connected Facilities* document located at either of the following links:

www.firstenergycorp.com/feconnect

www.pjm.com/planning/design-engineering/to-tech-standards.aspx

The following is an excerpt taken from Transmission Owner's *Requirements for Transmission Connected Facilities* document:

> *For all generation facilities, other than wind-powered and other non-synchronous generating facilities, the minimum requirement shall be the provision of a reactive power capability sufficient to maintain a composite power delivery at continuous rated power output at a power factor as defined in the table below. This requirement will be measured at either the POI or generator terminals as specified in the table below. These reactive requirements apply to both the initial installation as well as to any incremental change in unit MW capability. FirstEnergy will coordinate with the Connecting Party to identify the optimal generator step-up transformer tap to make such a capability available when demanded.*
>
> *For all wind-powered or other non-synchronous generating facilities the minimum requirement shall be the provision of a reactive power capability sufficient to maintain a composite power delivery at a power factor as defined in the table. This requirement will be measured at either the POI or generator's terminals as specified in the table below. These reactive requirements apply to both the initial installation as well as to any incremental change in unit MW capability. FirstEnergy will coordinate with the Connecting Party to identify the optimal generator step-up transformer tap to make such a capability available when needed.*

Generation Type	New / Increase	Size	Power Factor Requirement	Measurement Location
Synchronous	New	> 20 MW	0.95 leading to 0.90 lagging	Generator's Terminals
Synchronous	New	<= 20 MW	0.95 leading to 0.90 lagging	Point of Interconnection
Wind or Non-Synchronous	New	All	0.95 leading to 0.95 lagging	Generator's Terminals[1]
Synchronous	Increase	> 20 MW	1.0 (unity) to 0.90 lagging	Generator's Terminals
Synchronous	Increase	<= 20 MW	1.0 (unity) to 0.90 lagging	Point of Interconnection
Wind or Non-Synchronous	Increase	All	0.95 leading to 0.95 lagging[2]	Generator's Terminals

Any different reactive power requirements that FirstEnergy and/or PJM determines to be appropriate for wind-powered or other non-synchronous generation facilities will be stated in the applicable interconnection agreement(s).

Induction generators and other generators with no inherent VAR (reactive power) control capability, or those that have a restricted VAR capability less than the defined requirements, must provide dynamic supplementary reactive support located at the generation facility with electrical characteristics equivalent to that provided by a similar-sized synchronous generator.

Design Requirements

Interconnection Customer is responsible for specifying appropriate equipment and facilities such that the parallel generation is compatible with Transmission Owner's Transmission System. Interconnection Customer is also responsible for meeting any applicable federal, state, and local codes.

Design Criteria

Facilities owned and operated by Transmission Owner shall comply with the applicable Transmission Owner technical requirements and standards posted on the PJM website per the PJM Tariff, and the following criteria. Where there are different requirements for the same criterion, the more restrictive shall apply. Interconnection Customer must abide by any PJM, RFC or NERC criteria imposed that is more restrictive than those of Transmission Owner.

General Design Requirements

- System phasing (counter clockwise) 1-2-3
- System frequency: 60 hertz
- Elevation, Above Mean Seal Level (AMSL): Less than 1000 meters
- Isokeraunic level: 40
- Maximum ambient temperature: 40 degrees C
- Minimum ambient temperature: -40 degrees C
- Maximum conductor operating temperature: Contact Transmission Owner

[1] For projects that entered PJM's New Service Queue prior to May 1, 2015, the power factor requirement will be measured at the Point of Interconnection.
[2] For projects that entered PJM's New Service Queue prior to May 1, 2015, the power factor requirement is 1.0 (unity) to 0.95 lagging.

• Wind Loading (round shapes):	Per ASCE 10, per Fig. 250-2B depending on location
• Ice loading – Substations (no wind):	25 mm
• Seismic zone:	Per ASCE Manual 113 Substation Structure Design Manual. Equipment qualification per IEEE 693-2005 and IEE 1527-2006

Voltage and Current Ratings

• Nominal phase-to-phase:	500 kV
• Maximum phase-to-phase:	550 kV
• Basic impulse level (BIL):	1800 kV
• Maximum continuous current carrying capacity:	4000 A
• Design fault current:	40 kA
• Single Contingency (breaker failure) clearing time:	30 cycles

Clearances and Spacing

• Recommended rigid bus center-to-center phase spacing:	300”
• Minimum phase-to-phase, metal-to-metal distance:	222”
• Recommended phase-to-ground:	152”
• Minimum phase-to-ground:	144”
• Low bus height above top of foundations (match existing):	30’-0”
• High bus height above top of foundations (match existing):	55’-0”
• Minimum vertical clearance from live parts to grade:	20’-6”
• Minimum horizontal clearance from live parts:	15’-0”
• Minimum conductor clearance above roads in switchyard:	42’-0”
• Minimum bottom of insulator to top of foundation:	8’-6”

Back-up Retail Service

Interconnection Customer will execute a back-up retail service agreement with West Penn Power to service the customer load supplied from the Interconnection Customer’s interconnection point when the units are out-of-service.

Metering, SCADA and Communications

Interconnection Customer shall install, own, operate, test and maintain the necessary revenue metering equipment. Interconnection Customer shall provide Transmission Owner with dial-up communication to the revenue meter.

Transmission Owner’s Revenue Metering Requirements may be found in the *Requirements for Transmission Connected Facilities* document located at the following links:

www.firstenergycorp.com/feconnect

www.pjm.com/planning/design-engineering/to-tech-standards.aspx

These requirements are in addition to any metering required by PJM.

Transmission Owner will provide the telecommunication circuits for the SCADA RTU and the telephone in the Transmission Owner interconnection substation at Hatfield substation.
Transmission Owner will obtain real-time, site-specific, generation data from PJM, via the required communication link from Interconnection Customer to PJM. Transmission Owner will work with PJM and Interconnection Customer to ensure the generation data provided to PJM meets Transmission Owner's requirements.

Communications for transmission line protection between Hatfield substation and Interconnection Customer's generation (collector) substation, will be via fiber optics (see "Fiber-Optic Communication Channels" section below).

Fiber-Optic Communication Channels

Transmission Owner Responsibilities:

Transmission Owner will provide fiber interface for Interconnection Customer Optical Ground Wire fiber terminations at Hatfield substation and into existing control house.

Interconnection Customer Responsibilities:

Per the attached Protection Requirements (Ref: Attachment A), Interconnection Customer will design, provide, install, own and maintain a fiber-optic communications cable between Hatfield substation and Interconnection Customer's AA2-173 **generation** (collector) substation. Two (2) fiber-optic channels are required for protection schemes to obtain high-speed tripping capability for any fault within the zone of protection. These channels may reside in the same cable, provided that this line does not require completely redundant protection for system stability reasons. Should subsequent/additional PJM studies indicate that stability issues exist, therefore requiring dual, high-speed tripping schemes, the primary and backup relay fiber-optic communication channels must be in separately-routed cable paths, and additional fiber-optic connection costs would apply (not included herein). Interconnection Customer is responsible for obtaining and maintaining all associated Rights-of-Way (ROW), Easements, and Permits for its fiber-optic cable.

General Assumptions/Qualifiers

The accomplishment of the work on the Transmission Owner system to support the estimated costs and proposed schedule is dependent on the following:

- Obtaining the necessary line outages. Transmission line outages are typically not granted from June to September and are discouraged during extreme winter conditions.
- No equipment delivery, environmental, permitting, regulatory or real estate delays.
- No extreme weather.
- No force majeure.

- Estimates assume no significant rock encountered during construction, and suitable soil conditions exist to accommodate a standard ground-grid and foundation installation.
- Interconnection Customer will develop, and secure regulatory approval for, all necessary Erosion and Sediment Control (E&SC) plans and National Pollutant Discharge Elimination System (NPDES) permits.
- Interconnection Customer will obtain all necessary permits.
- Interconnection Customer will develop all necessary access roads for project sites.
- Interconnection Customer will conduct all necessary wetlands and waterways studies and permits.

ATTACHMENTS

ATTACHMENT A
Queue #AA2-173 / AB1-112 (combined)
Detailed Protection Requirements
(NOT to be used for Construction)

Short Circuit Analysis

Short Circuit Values (Existing Conditions)

HATFIELD SUBSTATION (PERCENT ON 100 MVA BASE) current system conditions w/out new Hill Top Energy Natural Gas Generation

SHORT CIRCUIT DATA (Symmetrical Values Only)		3 PHASE	L-GR
500kV			
Z1 =	(0.016 + j 0.431) %	26.8 kA	22.1 kA
Z0 =	(0.125 + j 0.693) %		

Short Circuit Values (Including AA2-173 option 1 generation direct connect to Hatfield 500kV)

HATFIELD SUBSTATION (PERCENT ON 100 MVA BASE) current system conditions with new Hill Top Energy Natural Gas Generation

SHORT CIRCUIT DATA (Symmetrical Values Only)		3 PHASE	L-GR
500kV			
Z1 =	(0.009 + j 0.311) %	37.1 kA	36.7 kA
Z0 =	(0.03 + j 0.319) %		

The faults provided are bolted, symmetrical values for normal system conditions with a flat 1.0 p.u. voltage profile. Future increases in fault currents are possible and it is the customer's responsibility to upgrade their equipment and/or protective equipment coordination when necessary.

General Connection Requirements

All proposed generation interconnection points and load-serving delivery points must comply with the technical requirements detailed in FirstEnergy's "Requirements for Transmission Connected Facilities" document.

The customer is solely responsible for protecting its own equipment in such a manner that electrical faults or other disturbances on the FirstEnergy system do not damage its equipment.

Hatfield Substation – AA2-173/AB1-112 500kV Interconnection Requirements

The attached relay sketch (Ref: Figure 1A) provides detail on the installation of the new AA2-173 500kV interconnection at Hatfield Substation. Two new 550kV rated, 3000A continuous, 50kA interrupting (minimum), nominal 500kV breakers are required to create a new breaker and a half configuration line exit between the No. 1 and No. 2 busses at Hatfield Substation. Each of the (2) 500kV breakers will be equipped with 4 sets per phase (2 per bushing) of CTs – 3000/5 MR, C800 @ 3000:5, thermal factor equal to 2.0.

One set of (3) CVTs, one per phase, are required for installation on the AA2-173 line exit. The CVTs shall have dual secondary windings with each winding capable of being connected at either a 4500:1 or a 2500:1 ratio.

AA2-173 500kV Interconnection Tie Line Protection

The zone of protection for this scheme consists of the protected interconnection tie line between the CTs supplying the relays at Hatfield Substation and the CTs on the high side circuit breaker at the Hill Top Energy substation. The AA2-173 interconnection tie line primary protection shall be an SEL-411L current differential scheme communicating over a dedicated fiber-optic channel via a direct, relay to relay fiber cable, with direct tripping, non-pilot step distance and directional ground overcurrent elements. The AA2-173 interconnection tie line backup protection shall be an SEL-411L current differential scheme utilizing a second dedicated fiber-optic channel over a direct, relay-to-relay fiber cable, with direct tripping, non-pilot, step distance and directional ground overcurrent elements. Direct Transfer Trip (DTT) for breaker failure to trip will also utilize both SEL-411L relays and their respective fiber optic communication channels between Hatfield Substation and the AA2-173 Hill Top Energy Substation. Redundancy for primary and backup line protection schemes is required including independent DC supply on separate breakers from a DC panelboard, separate tripping paths energizing separate trip coils in the breakers, independent current transformers, and independent voltage transformers or independent secondary windings of the same voltage transformer for primary and backup relaying. Should additional PJM studies indicate that stability issues exist, therefore requiring dual high speed tripping schemes, the primary and backup relay fiber optic communication channels must be in separately routed cable paths. The Interconnection Customer may propose additional schemes or relays to protect his facility such as DTT transmitters/receivers, etc. FirstEnergy must review and agree to any additional protection. No automatic reclosing will be applied at the Hatfield Substation for faults on the 500kV interconnection tie line.

Breaker Failure Relaying

A breaker failure SEL-501 relay shall be utilized on each of the 500kV circuit breakers on the AA2-173 interconnection tie line exit. The source for the breaker failure relay shall be CTs on either side of the 500kV circuit breaker. Any protective trip of this breaker shall initiate the breaker failure to trip scheme. The re-trip feature of each SEL-501 breaker failure relay shall be utilized to re-trip the associated 500kV circuit breaker. DC supplied to power the breaker failure schemes shall be DC breakers independent from either the primary or backup relaying scheme DC. The 500kV breaker failure scheme shall trip and block close each electrically adjacent breaker. Tripping shall be done via a self-reset auxiliary tripping relay. Block close will be via an electrically reset LOR. Additionally, the breaker failure scheme will key direct transfer trip to the remote substation terminal.

DC Power

The relaying system shall have a reliable source of DC power, independent from the AC system, that is immune to AC system disturbance or loss (for example - DC battery and charger) to assure proper operation of the protection scheme. Primary and backup relaying schemes shall be powered from different DC distribution panel circuit breakers.

Operational Metering Requirements

Meter accuracy operational metering is required by PJM for the interconnect tie line and will be provided using a Satec meter, and meter accuracy CTs and CVTs at the interconnect tie line exit at Hill Top Energy on the generator side of their breaker.

AA2-173/AB1-112 HILL TOP ENERGY SUBSTATION PROTECTION REQUIREMENTS

It is the responsibility of the Interconnect Owner to assure protection, coordination and equipment adequacy within their facility for conditions including but not limited to:

- Single phasing of supply
- System faults
- Equipment failures
- Deviations from nominal voltage or frequency
- Lightning and switching surges
- Harmonic voltages
- Negative sequence voltages
- Separation from FirstEnergy supply
- Synchronizing generation
- Synchronizing facilities between independent transmission system and FE
- Transmission System

The Interconnect Owner is to design their protective system to clear any faults within their zones of protection with one or more of their local circuit breakers. Each zone of protection covering the 500kV portion of the interconnection system, including the transformer, is to be protected by two independent relay schemes that each provide high speed fault clearing. The terminal breaker at the interconnect end of the direct connection line is to be included in the 500kV over-lapping zones of protection. The CTs used for the zones of protection covering the 500kV portion of the system shall use C800 relay accuracy CTs and the CTs should not saturate for the maximum through-fault current that can be experienced by the relay system for the tap ratio in use. Each 500kV breaker is to have breaker failure to trip protection. The transformer windings shall be wye grounded high side and have a delta connected winding on the low (generation) side. The Hill Top Energy Substation shall not close into the interconnection tie line if it is dead, so that all synchronizing is performed at the Hill Top Energy Substation. All communications between Hatfield and the Hill Top Energy Substation, including relay trip signals, shall utilize fiber optic communications paths so that no copper cables shall be run between these substations for the purpose of carrying currents, trip signals, or communications of any sort.

Hatfield 500kV Interconnection Tie Line Protection

Two SEL-411L relays with separate fiber optic communication channels shall be used for the interconnection tie line protection to match the line relays schemes as described for Hatfield Substation. Two fiber optic channels are required for these schemes to obtain high-speed tripping capability for any fault within the tie line zone of protection. Should additional PJM studies indicate that stability issues exist, therefore requiring dual high speed tripping schemes for stability, the two fiber optic channels must be in separately routed paths. At least one of the two current differential protective relays shall also provide direct tripping non-pilot phase distance and ground time overcurrent protection to cover for a loss of communication. The use of any other relays for interconnection tie line protection will require written approval from FirstEnergy. The 500kV interconnection tie line protection circuit breaker CTs shall be 3000:5 A MR C800 current transformers. A 500kV three phase potential source (CVT or equivalent) is required for line terminal relaying.

Breaker Failure Relaying

The interconnection tie line breaker on the high side of the Hill Top Energy Substation is to have breaker failure to trip protection. The breaker failure to trip protection must include current sensing Or'd with the breaker status to identify a closed breaker. The breaker failure to trip protection shall trip all breakers electrically adjacent to the failed breaker at the Hill Top Energy Substation and shall send DTT utilizing the SEL-411L line protection relays through both fiber channels to the FirstEnergy Hatfield Substation.

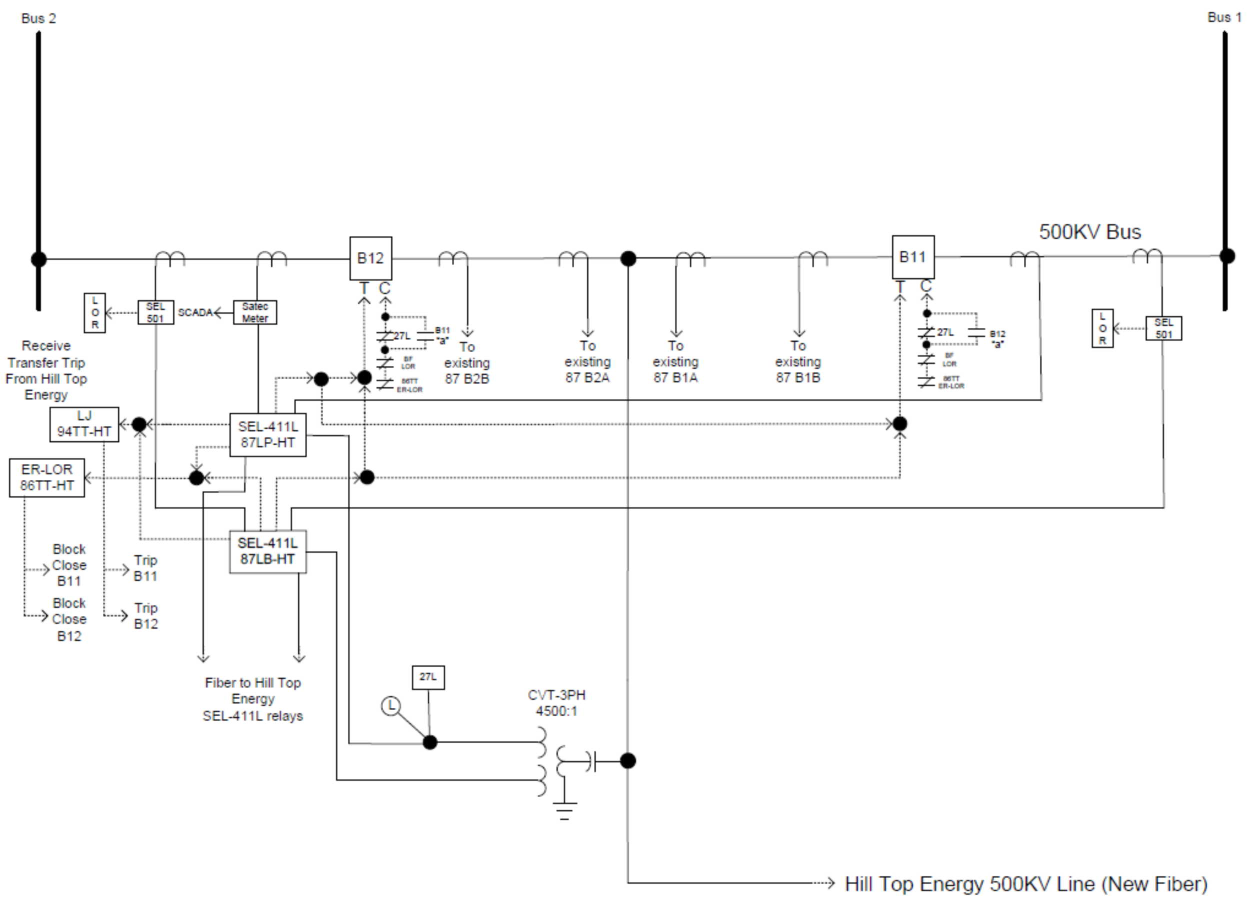
DC Power

The relaying system shall have a reliable source of DC power independent from the AC system or immune to AC system disturbance or loss (for example - DC battery and charger) to assure proper operation of the protection scheme.

Approvals

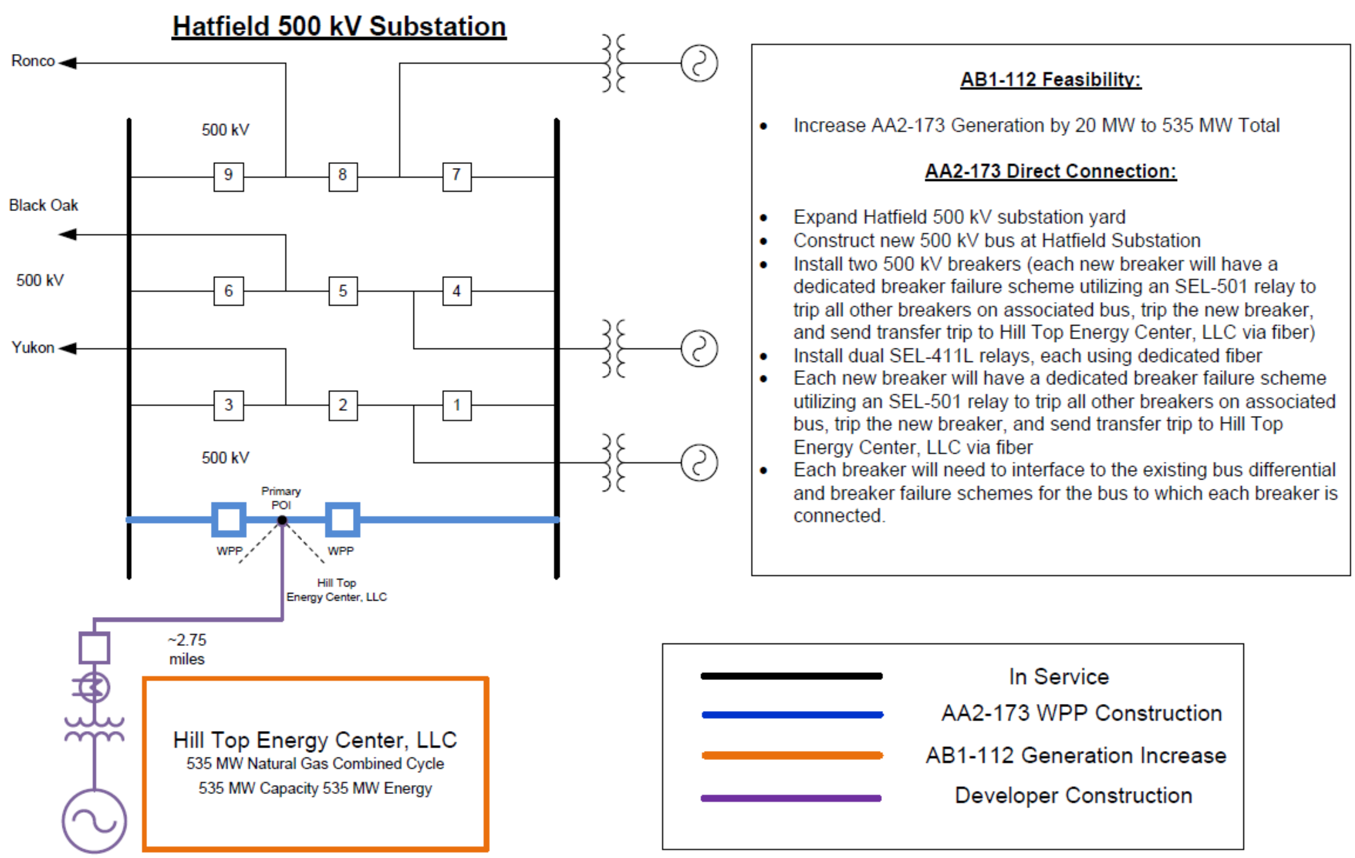
All relays, relay schemes and relay settings that include 500kV voltages or currents, or trip any 500kV circuit breakers shall require the review and approval of FirstEnergy. FirstEnergy will complete detailed relay coordination studies to identify off-site relay setting changes required due to this Hill Top Energy interconnection. This may result in additional individual relay replacements being required. The cost of these relay replacements will be borne by the Interconnection Customer.

FIGURE 1
Queue #AA2-173 / AB1-112 (Combined)
Relay Sketch*



* Note: Diagram does not represent a physical layout. Not to be used for construction.

FIGURE 2
Queue #AA2-173 / AB1-112 (Combined)
Planning One Line Diagram*



* Note: Diagram does not represent a physical layout. Not to be used for construction.

FIGURE 3
Queue #AA2-173 / AB1-112 (Combined)
Point of Interconnection Diagram*

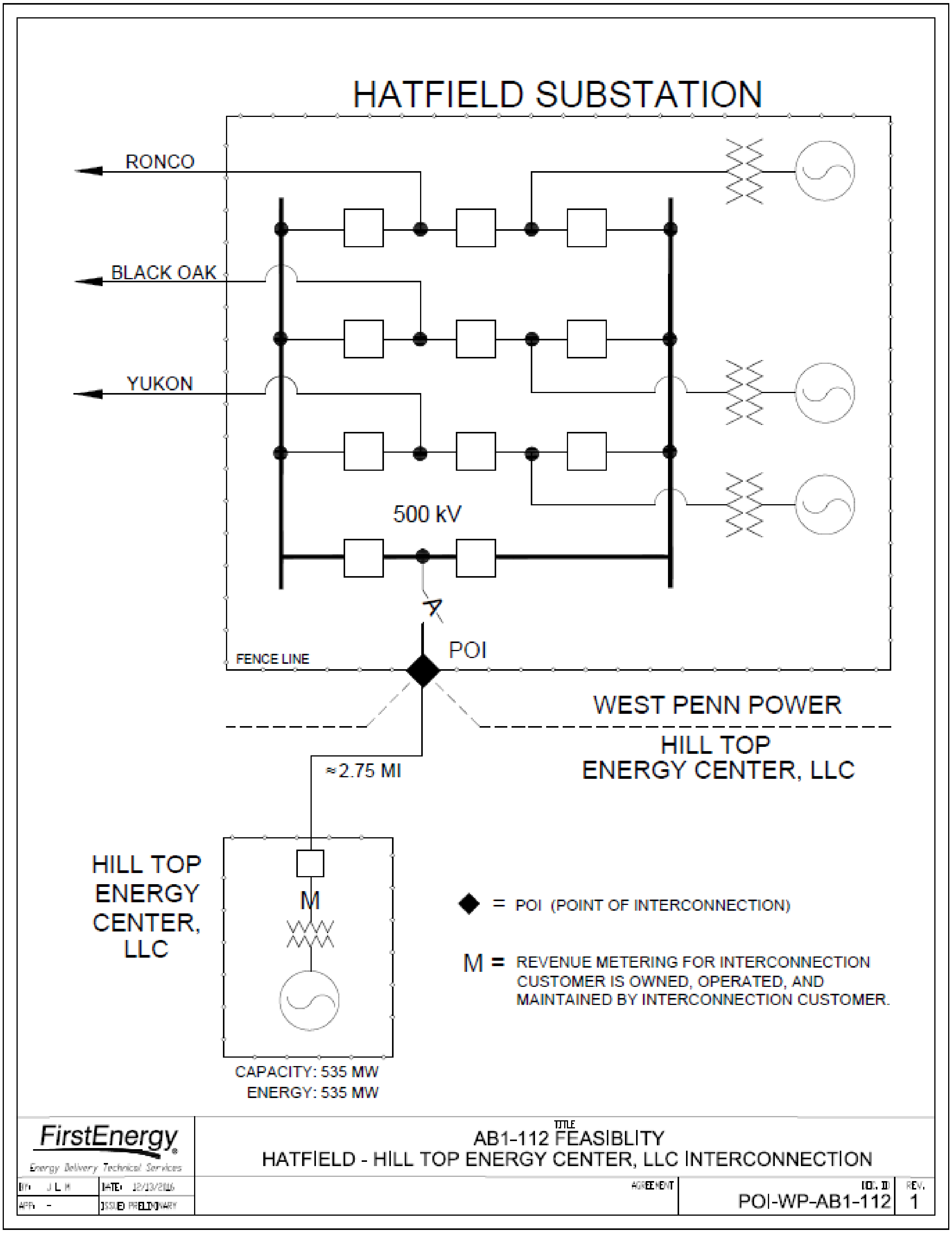
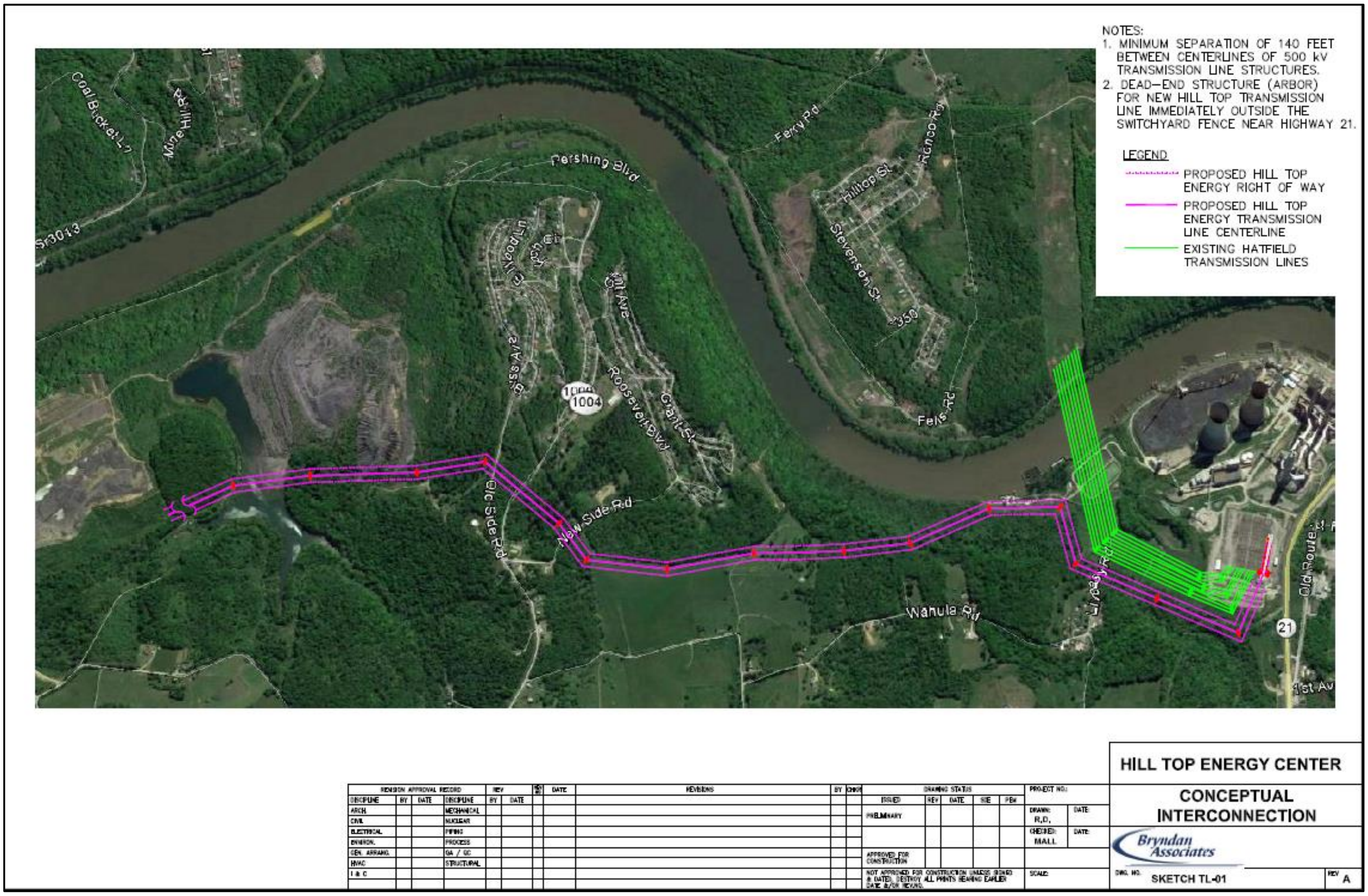


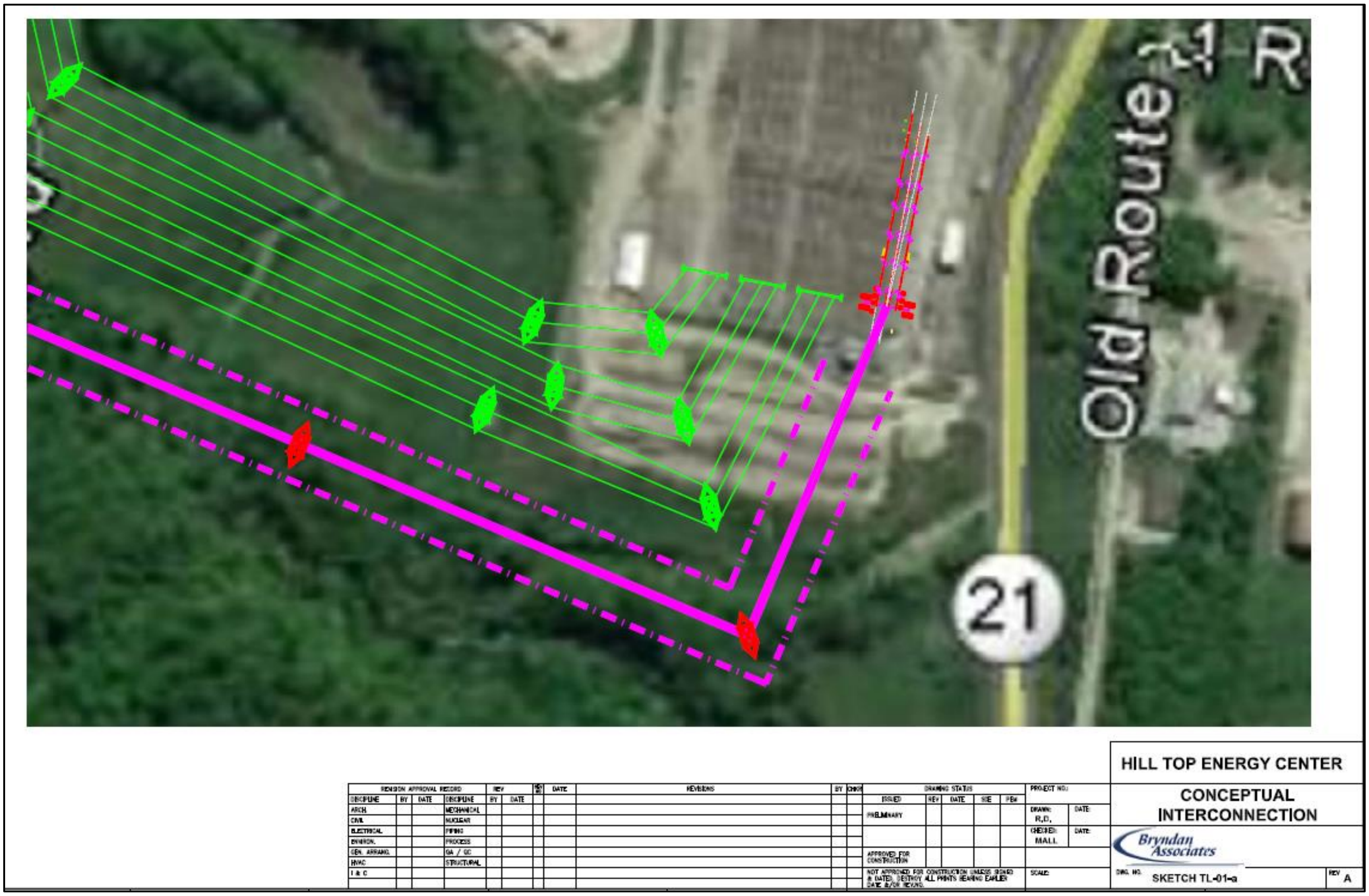
FIGURE 4A
Queue #AA2-173 / AB1-112 (Combined)
Conceptual 500 kV Generator Lead Line*
By Interconnection Customer



* Notes:

- Interconnection Customer will coordinate design and alignment of proposed 500 kV Lead Line with the Transmission Owner for review of any clearance or right-of-way encroachment issues with existing Transmission Owner owned
  500 kV facilities.
- This report assumes that the he Interconnection Customer's 500 kV generator Lead Line right-of-way and the structures will align with Transmission Owner's proposed 500 kV cross-bus configuration at Hatfield substation.

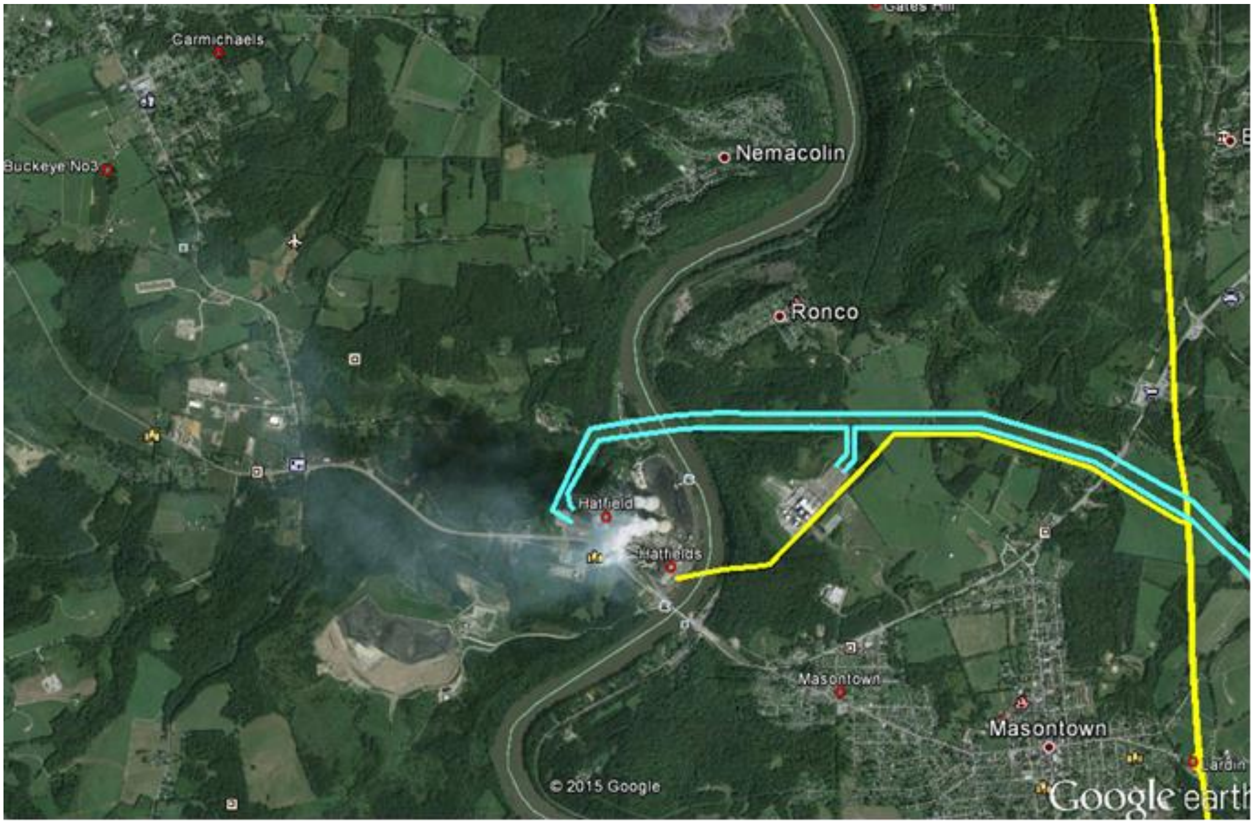
FIGURE 4B
Queue #AA2-173 / AB1-112 (combined)
Conceptual 500 kV Generator Lead Line*
By Interconnection Customer



* Notes:

- Interconnection Customer will coordinate design and alignment of proposed 500 kV Lead Line with the Transmission Owner for review of any clearance or right-of-way encroachment issues with existing Transmission Owner owned
  500 kV facilities.
- This report assumes that the he Interconnection Customer's 500 kV generator Lead Line right-of-way and the structures will align with Transmission Owner's proposed 500 kV cross-bus configuration at Hatfield substation.

FIGURE 5
Queue #AA2-173 / AB1-112 (combined)
Project Location



ATTACHMENT B

Queue #AA2-173 / AB1-112 (combined)

Dynamic Simulation Analysis

(Page 1 of 11)

1. Introduction

Generator Interconnection Request AB1-112 is a 20 MW increase to the output of the STG in AA2-173. The uprate increases the Maximum Facility Output (MFO) of the STG from 178.2 MW to 198.2 MW. AB1-112 will have a Point of Interconnection (POI) at the Hatfield 500 kV Substation, in the Allegheny Power (APS) system, Greene County, Pennsylvania.

This analysis is effectively a screening study to determine whether the addition of AB1-112 will meet the dynamic requirements of the NERC, PJM and Transmission Owner reliability standards.

In this report the AB1-112 project and how it is proposed to be connected to the grid are first described, followed by a description of how the project is modeled in this study. The fault cases are then described and analyzed, and lastly a discussion of the results is provided.

Queue #AA2-173 / AB1-112 (combined)
Dynamic Simulation Analysis

2. Description of Project

AB1-112 consists of one 413 MVA combustion turbine generators and one 253 MVA steam turbine with a Point of Interconnection (POI) at Hatfield 500 kV substation. AB1-112 is connected to the POI via 500 kV / 20 kV generator step-up transformer with a rating of 261/348/435 MVA (OA/F1/F2) to CT1 and 500 kV / 21 kV generator step-up transformer with a rating of 159/212/265 MVA (OA/F1/F2) to ST1.

Figure 1 shows the simplified one-line diagram of the AB1-112 loadflow model. Table 1 lists the parameters given in the impact study data and the corresponding parameters of the AB1-112 loadflow models.

The dynamic models for the AB1-112 plant are based on standard PSS/E models, with parameters supplied by the Developer.

Additional project details are provided in Attachments 1 through 4:

- Attachment 1 contains the Impact Study Data which details the proposed AB1-112 project.
- Attachment 2 shows the one line diagram of the APS network in the vicinity of AB1-112.
- Attachment 3 provides a diagram of the PSS/E model in the vicinity of AB1-112.
- Attachment 4 gives the AB1-112 PSS/E loadflow and dynamic models of the AB1-112 plant.

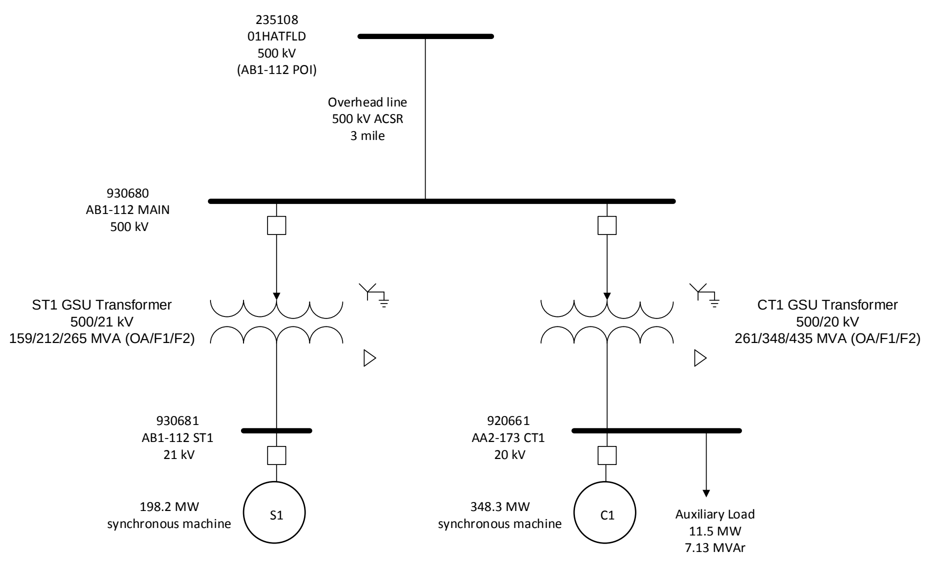


Figure 1: AB1-112 Plant Model

Queue #AA2-173 / AB1-112 (combined)
Dynamic Simulation Analysis
(Page 3 of 11)

Table 1: AB1-112 Plant Model

	Impact Study Data	**Model**
Steam Turbine Generator ST1	1 x 198.2 MW Steam Turbine generator. MVA base = 253 MVA Vt = 21 kV Unsaturated sub-transient reactance = 0.169 pu at MVA base	1 x 198.2 MW Steam Turbine generator. Pgen 198.2 MW Pmax 198.2 MW Pmin 0.0 MW Qgen 9.4 MVAr Qmax 142 MVAr Qmin -80 MVAr Mbase 253 MVA Zsorce j0.169 pu @ Mbase
GSU Transformer ST1	525/21 kV YNd Rating = 159/212/265 MVA (OA/F1/F2) Transformer base = 159 MVA Impedance = 0.0015 + j 0.09 pu @ 159 MVA Number of taps = 5 Tap step size = 2.5%	525/21 kV YNd Rating = 159/212/265 MVA (OA/F1/F2) Transformer base = 159 MVA Impedance = 0.0015 + j 0.09 pu @ 159 MVA Number of taps = 5 Tap step size = 2.5%
Auxiliary Load	11.5 MW + 7.13 MVAr Connected to CT1 generator bus	11.5 MW + 7.13 MVAr Connected to CT1 generator bus
Transmission line	3 miles at 500 kV Total positive sequence series impedance: 0.00004 + j0.00074 pu @ 100 MVA Total positive sequence charging susceptance : 0.0526 pu @ 100 MVA	3 miles at 500 kV Total positive sequence series impedance: 0.00004 + j0.00074 pu @ 100 MVA Total positive sequence charging susceptance : 0.0526 pu @ 100 MVA

Queue #AA2-173 / AB1-112 (combined)
Dynamic Simulation Analysis
(Page 4 of 11)

3. Loadflow and Dynamics Case Setup

The dynamics simulation analysis was carried out using PSS/E Version 32.2.4.

The load flow scenario and fault cases for this study are based on PJM's Regional Transmission Planning Process[1].

The selected load flow scenario is the RTEP 2019 light load case with the following modifications:

a) Addition of all applicable queue projects prior to AB1-112.

b) Addition of AB1-112 queue project.

c) Removal of withdrawn and subsequent queue projects in the vicinity of AB1-112.

d) Dispatch of units in the PJM system to maintain slack generators within limits.

The AB1-112 initial conditions are listed in Table 2, indicating maximum power output, with leading power factor and less than 1.0 pu voltage at the generator bus.

Table 2: AB1-112 machine initial conditions

Bus	Name	Unit	PGEN	QGEN	ETERM	POI Voltage
9200681	AB1-112 ST1	1	198.2	-46.8421 MVAr	0.95 pu	1.032 pu

Generation within the PJM500 system (area 225 in the PSS/E case) and within the vicinity of AB1-112 has been dispatched online at maximum output (PMAX). The dispatch of generation in the vicinity of AB1-112 is given in Attachment 5.

4. Fault Cases

Tables 3 to 10 list the contingencies that were studied, with representative worst case total clearing times provided by PJM. Each contingency was studied over a 10 second simulation time interval.

The studied contingencies include:

a) Steady state operation (20 second simulation);

b) Three phase faults with normal clearing time;

c) Single-phase faults with stuck breaker;

d) Single-phase faults placed at 80% of the line with delayed (Zone 2) clearing at line end remote from fault due to primary communications/relay failure.

e) Three phase faults with normal clearing time with maintenance outages of Fort Martin – Ronco 500 kV line;

f) Three phase faults with normal clearing time with maintenance outages of AB1-112 – Yukon 500 kV line;

g) Single phase faults with stuck breaker with maintenance outages of AB1-112 – Yukon 500 kV line; and

h) Three phase faults with stuck breaker with maintenance outages of AB1-112 – Yukon 500 kV line.

No relevant Bus, Tower or High Speed Reclosing (HSR) contingencies were identified.

Buses at which the faults listed above will be applied are

- Hatfield 500 kV (AB1-112 POI)
- AB1-106 POI 500 kV
- Black Oak 500 kV
- Ronco 500 kV
- Fort Martin 500 kV
- Yukon 500 kV

Additional delayed (Zone 2) clearing at remote and faults will be applied on lines from Bedington 500 kV, North Longview 500 kV, Pruntytown 500 kV and South Bend 500 kV circuit towards the queue project.

Clearing times listed in Tables 4 to 10 are as per Revision 18 of "*2016 Revised Clearing times for each PJM company*" spreadsheet.

Attachment 2 contains the one-line diagrams of the APS network in the vicinity of AB1-112, showing where faults were applied.

The positive sequence fault impedances for single line to ground faults were derived from a separate short circuit case, modified to ensure that connected generators in the vicinity of AB1-112 have not withdrawn from the PJM queue, and are not greater than the queue position under study.

5. Evaluation Criteria

This study is focused on AB1-112, along with the rest of the PJM system, maintaining synchronism and having all states return to an acceptable new condition following the disturbance. The recovery criteria applicable to this study are as per PJM's Regional Transmission Planning Process and Transmission Owner criteria:

a) The system with AB1-112 included is transiently stable and post-contingency oscillations should be positively damped with a damping margin of at least 3%.

b) The AB1-112 is able to ride through faults (except for faults where protective action trips a generator(s)).

c) Following fault clearing, all bus voltages recover to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).

d) No transmission element trips, other than those either directly connected or designed to trip as a consequence of that fault.

6. Summary of Results

Plots from the dynamic simulations are provided in Attachment 6, with results summarized in Table 3 through Table 10.

The stability criteria was not met for any of the four maintenance outage contingencies tested on the RTEP 2019 light load case, with results showing,

- unanticipated tripping of AB1-106 units and Ronco Units for the three-phase fault contingencies, MA.3N01 and MB.3N01; and
- unanticipated tripping of AB1-106 units, Ronco Units and Fort Martin units for the stuck breaker contingencies, MB.3B01 and MB.1B01.

New operational mitigation for these outages has been proposed which is to reduce T174 generation dispatch to 360 MW and open Ft.Martin-FL-8 breaker. Additinally, AA2-173/AB1-112 generation dispatch needs to be reduced to 276 MW.

It is recommended that the operating guide detailing the measures required to ensure stability for these maintenance outages be reviewed before the queue project is brought online.

For the remaining 56 fault contingencies tested on the 2019 light load case:

a) Post-contingency oscillations were positively damped with a damping margin of at least 3%.

b) The AB1-112 generator was able to ride through all faults (except for faults where protective action trips a generator(s)).

c) Following fault clearing, all bus voltages recover to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).

d) No transmission element trips, other than those either directly connected or designed to trip as a consequence of that fault.

Damping margin of oscillations for the Keystone station generator G1 angle plot was confirmed to be greater than 3%.

No mitigations were found to be required.

Queue #AA2-173 / AB1-112 (combined)

Dynamic Simulation Analysis

7. Mitigations

Following new operational mitigation has been proposed to alleviate the instabilities due to maintenance outages listed in Table 4, 5, 6 and 7.

Scenario 1: Maintenance outage of T174 – Yukon 500 kV Line

1. Reduce T174 Generation Dispatch to 360 MW and reduce AA2-173/AB1-112 generation dispatch to 276 MW
2. Open the Ft. Martin FL-8 Breaker

Scenario 2: Maintenance outage of Fort Martin – Ronco 500 kV Line

1. Reduce T174 Generation Dispatch to 360 MW and reduce AA2-173/AB1-112 generation dispatch to 276 MW

*Note: Opening the FL-8 breaker is not required. This is due to the generation retirement of Hatfield.

Queue #AA2-173 / AB1-112 (combined)
Dynamic Simulation Analysis
(Page 8 of 11)

Table 3: Steady State Operation

Fault ID	Duration	AB1-112 No Mitigation
SS.01	Steady state 20 sec	Stable

Table 4: Three-phase Faults With Normal Clearing

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	AB1-112 No Mitigation
3N.01	Fault at Hatfield 500 kV POI on AB1-112 circuit (Trips AB1-112).	3	Stable
3N.02	Fault at Hatfield 500 kV on AB1-106 circuit HAT-YUK_518.	3	Stable
3N.03	Fault at Hatfield 500 kV on Ronco circuit HF-RC_538.	3	Stable
3N.04	Fault at Hatfield 500 kV on Black Oak circuit HAT-BO_542.	3	Stable
3N.05	Fault at AB1-106 500 kV on AB1-106 circuit (Trips AB1-106).	3	Stable
3N.06	Fault at AB1-106 500 kV on Hatfield circuit.	3	Stable
3N.07	Fault at AB1-106 500 kV on Yukon circuit.	3	Stable
3N.08	Fault at Black Oak 500 kV on Hatfield circuit circuit HAT-BO_542.	3	Stable
3N.09	Fault at Black Oak 500 kV on Bedington circuit BO-BD_544.	3	Stable
3N.10	Fault at Black Oak 500 kV on 500/138 kV Transformer T3.	3	Stable
3N.11	Fault at Ronco 500 kV on Hatfield circuit HF-RC_538.	3	Stable
3N.12	Fault at Ronco 500 kV on Fort Martin circuit FTM-RC_516.	3	Stable
3N.13	Fault at Ronco 500 kV on Fayette circuit (Trips Fayette units 1-3).	3	Stable
3N.14	Fault at Fort Martin 500 kV on Ronco circuit FTM-RC_516.	3	Stable
3N.15	Fault at Fort Martin 500 kV on North Longview circuit FTM-NLVW_523.	3	Stable
3N.16	Fault at Fort Martin 500 kV on Pruntytown circuit PYT-FTM_508.	3	Stable
3N.17	Fault at Fort Martin 500 kV on Fort Martin unit 1 circuit (Trips Fort Martin unit 1).	3	Stable
3N.18	Fault at Fort Martin 500 kV on Fort Martin unit 2 circuit (Trips Fort Martin unit 2).	3	Stable
3N.19	Fault at Yukon 500 kV on AB1-106 circuit HAT-YUK_518.	3	Stable
3N.20	Fault at Yukon 500 kV on South Bend circuit SBE-YU_507.	3	Stable
3N.21	Fault at Yukon 500 kV on 500/138 kV T1 circuit.	3	Stable
3N.22	Fault at Yukon 500 kV on 500/138 kV T2 circuit.	3	Stable

Queue #AA2-173 / AB1-112 (combined)
Dynamic Simulation Analysis
(Page 9 of 11)

Table 5: Single-phase Faults With Stuck Breaker

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	AB1-112 No Mitigation
1B.01	Fault at Hatfield 500 kV POI on AB1-112 circuit. Breaker stuck to AB1-112*. Fault cleared with no additional losses. (Trips AB1-112).	3 / 12	Stable
1B.02	Fault at Hatfield 500 kV on AB1-106 circuit HAT-YUK_518. Breaker 2 stuck*. Fault cleared with no additional losses.	3 / 12	Stable
1B.03	Fault at Hatfield 500 kV on Black Oak circuit HAT-BO_542. Breaker 5 stuck*. Fault cleared with no additional losses.	3 / 12	Stable
1B.04	Fault at Hatfield 500 kV on Ronco circuit HF-RC_538 circuit. Breaker 8 stuck*. Fault cleared with no additional losses.	3 / 12	Stable
1B.05	Fault at AB1-106 500 kV on AB1-106 circuit. Breaker stuck to AB1-106 circuit. Fault cleared with loss of Yukon circuit and Hatfield circuit (Trips AB1-106)	3 / 12	Stable
1B.06	Fault at AB1-106 500 kV on Hatfield circuit. Breaker stuck to Hatfield circuit. Fault cleared with loss of AB1-106 circuit and Yukon circuit HAT-YUK_518 (Trips AB1-106)	3 / 12	Stable
1B.07	Fault at AB1-106 500 kV on Yukon circuit. Breaker stuck to Yukon circuit. Fault cleared with loss of AB1-106 circuit and Hatfield circuit HAT-YUK_518 (Trips AB1-106)	3 / 12	Stable
1B.08	Fault at Black Oak 500 kV on Bedington circuit BO-BD_544. Breaker L2 stuck. Cleared with loss of Hatfield circuit HAT-BO_542.	3 / 12	Stable
1B.09	Fault at Black Oak 500 kV on Hatfield circuit HAT-BO_542. Breaker L2 stuck. Cleared with loss of Bedington circuit BO-BD_544.	3 / 12	Stable
1B.10	Fault at Black Oak 500 kV on Hatfield circuit HAT-BO_542. Breaker L1 stuck. Fault cleared with loss of Bedington circuit BO-BD_544 , Black Oak 500/138 kV Transformer T3, Black Oak SVC, and Black Oak 216 MVAr capacitor.	3 / 12	Stable
1B.11	Fault at Black Oak 500 kV on 500/138 kV Transformer T3. Breaker L3 stuck. Fault cleared with loss of Bedington circuit BO-BD_544.	3 / 12	Stable
1B.12	Fault at Black Oak 500 kV on Bedington circuit BO-BD_544. Breaker L3 stuck. Fault cleared with loss of Hatfield circuit BO-HAT_542, Black Oak 500/138 kV Transformer T3, Black Oak SVC, and Black Oak 216 MVAr capacitor.	3 / 12	Stable
1B.13	Fault at Ronco 500 kV on Hatfield circuit HF-RC_538. Breaker 1 stuck. Fault cleared with loss of Fort Martin circuit FTM-RC_516 (Trips Fayette units 1,2 and 3).	3 / 12	Stable
1B.14	Fault at Ronco 500 kV on Fort Martin circuit FTM-RC_516. Breaker 1 stuck. Fault cleared with loss of Hatfield circuit HF-RC_538 (trips Fayette units 1,2 and 3).	3 / 12	Stable
1B.15	Fault at Ronco 500 kV on Fayette circuit. Breaker 2 stuck. Fault cleared with loss of Hatfield circuit HF-RC_538 and Fort Martin circuit FTM-RC_516 (trips Fayette units 1,2 and 3)	3 / 12	Stable
1B.16	Fault at Fort Martin 500 kV on Ronco circuit FTM-RC_516. Breaker 3 stuck. Fault cleared with loss of Fort Martin unit 2	3 / 12	Stable
1B.17	Fault at Fort Martin 500 kV on North Longview circuit FTM-NLVW_523. Breaker 8 stuck. Fault cleared with loss of Pruntytown circuit PYT-FTM_508.	3 / 12	Stable
1B.18	Fault at Fort Martin 500 kV on Pruntytown circuit PYT-FTM_508. Breaker 8 stuck. Fault cleared with loss of North Longview circuit FTM-NLVW_523.	3 / 12	Stable
1B.19	Fault at Fort Martin 500 kV on Fort Martin unit 1. Circuit Breaker 2 stuck. Fault cleared with no additional losses (Trips Fort Martin unit 1).	3 / 12	Stable
1B.20	Fault at Fort Martin 500 kV on Fort Martin unit 2. Circuit Breaker 5 stuck. Fault cleared with no additional losses (Trips Fort Martin unit 2).	3 / 12	Stable
1B.21	Fault at Yukon 500 kV on AB1-106 circuit HAT-YUK_518. Breaker YL1 stuck. Cleared with loss of Yukon 500/138 kV T1 and T3 circuit.	3 / 12	Stable
1B.22	Fault at Yukon 500 kV on South Bend circuit SBE-YU_507. Breaker YL6 stuck. Cleared with loss of Yukon 500/138 kV T2 and Yukon 500/138 kV T4.	3 / 12	Stable
1B.23	Fault at at Yukon 500 kV on Yukon 500/138 kV Transformer T1. Breaker YL1 stuck. Fault cleared with loss of AB1-106 circuit HAT-YUK 518.	3 / 12	Stable
1B.24	Fault at at Yukon 500 kV on Yukon 500/138 kV Transformer T1. Breaker YL4 stuck. Fault cleared with loss of South Bend circuit SBE-YU 507 circuit.	3 / 12	Stable

* Hatfield units 1,2 and 3 not modeled (deactivated)

Queue #AA2-173 / AB1-112 (combined)
Dynamic Simulation Analysis
(Page 10 of 11)

Table 6: Single-phase Faults With Delayed (Zone 2) Clearing at line end closest to AB1-112 POI

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	AB1-112 No Mitigation
1D.01	Fault at 80% of line from Hatfield 500 kV to AB1-106 circuit HAT-YUK_518. Delayed clearing at Hatfield.	3 / 21	Stable
1D.02	Fault at 80% of line from Hatfield 500 kV to Black Oak circuit HAT-BO_542. Delayed clearing at Hatfield.	3 / 21	Stable
1D.03	Fault at 80% of line from Hatfield 500 kV to Ronco circuit HF-RC_538. Delayed clearing at Hatfield.	3 / 21	Stable
1D.04	Fault at 80% of line from AB1-106 500 kV to Yukon circuit HAT-YUK_518. Delayed clearing at AB1-106.	3 / 21	Stable
1D.05	Fault at 80% of line from Black Oak 500 kV to Bedington circuit BO-BD_544. Delayed Clearing at Black Oak.	3 / 21	Stable
1D.06	Fault at 80% of line from Ronco 500 kV to Fort Martin circuit FTM-RC_516. Delayed clearing at Ronco.	3 / 21	Stable
1D.07	Fault at 80% of line from Fort Martin 500 kV to North Longview circuit FTM-NLVW_523. Delayed clearing at Fort Martin.	3 / 21	Stable
1D.08	Fault at 80% of line from Fort Martin 500 kV to Pruntytown circuit PYT-FTM_508. Delayed clearing at Fort Martin.	3 / 21	Stable
1D.09	Fault at 80% of line from Yukon 500 kV to South Bend circuit SBE-YU_507. Delayed clearing at Yukon.	3 / 21	Stable

Table 7: Three-phase Faults With Normal Clearing – Prior outage of Fort Martin–Ronco 500 kV line

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	AB1-112 No Mitigation	AB1-112 with Operating Procedure
MA.3N01	Fault at AB1-112 500 kV on AB1-112 – Yukon 500 kV line (with AA2-139 Unit 1 offline*)	3	Unstable - Unanticipated trip of AB1-106 units, AA2-139 units, AA2-173 unit and AB1-112 unit.	Stable

Table 8: Three-phase Faults With Normal Clearing – Prior outage of AB1-112 –Yukon 500 kV line

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	AB1-112 No Mitigation	AB1-112 with Operating Procedure
MB.3N01	Fault at Fort Martin 500 kV on Fort Martin – Ronco 500 kV line (with AA2-139 Unit 1 offline*)	3	Unstable - Unanticipated trip of AB1-106 units, AA2-139 units, AA2-173 unit and AB1-112 unit.	Stable

* As specified in Section 5: Index and Operating Procedures for PJM RTO Operation by the document "PJM Manual 03: Transmission Operations.pdf", dated April 1, 2013.

Queue #AA2-173 / AB1-112 (combined)
Dynamic Simulation Analysis
(Page 11 of 11)

Table 9: Three-phase Faults With Stuck Breaker – Prior outage of AB1-112 –Yukon 500 kV line

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	AB1-112 No Mitigation	AB1-112 with Operating Procedure
MB.3B01	Fault at Fort Martin 500 kV on North Longview circuit FTM-NLVW_523. Breaker 8 stuck. Fault cleared with loss of Pruntytown circuit PR-FM_508 (with AA2-139 Unit 1 offline*)	3 / 7.5	Unstable - Unanticipated trip of AB1-106 units, AA2-139 units, AA2-173 unit and AB1-112 unit.	Stable

Table 10: Single-phase Faults With Stuck Breaker – Prior outage of AB1-112 –Yukon 500 kV line

Fault ID	Fault description	Clearing Time Near & Remote (Cycles)	AB1-112 No Mitigation	AB1-112 with Operating Procedure
MB.1B01	Fault at Fort Martin 500 kV on North Longview circuit FTM-NLVW_523. Breaker 8 stuck. Fault cleared with loss of Pruntytown circuit PR-FM_508 (with AA2-139 Unit 1 offline*)	3 / 12.5	Unstable - Unanticipated trip of AB1-106 units, AA2-139 units, AA2-173 unit, AB1-112 unit and Fort Martin units.	Stable

* As specified in Section 5: Index and Operating Procedures for PJM RTO Operation by the document "PJM Manual 03: Transmission Operations.pdf", dated December 1, 2015.