

PSE&G

# Artificial Island Proposal Window

Questions and Comments for the December 9<sup>th</sup> TEAC

PSE&G would like to thank PJM for this opportunity. PSE&G believes its proposal was originally selected by PJM staff and will be selected again due to the clear advantages PSE&G has enumerated in both its original and supplemental proposals.

For PJM's consideration, PSE&G submits the following questions and comments to these presentations, based on PSE&G's multi-decade construction, maintenance and operational history at Artificial Island in an attempt to assist PJM in making the most informed judgment possible.

## 1.0 Dominion

### Slide 4

1. PJM required in their technical evaluation of projects a 650 MVAR SVC, on what basis does Dominion expect to reduce the size to a 500MVAR SVC?
2. Can Dominion specify which size SVC is used when determining total project costs?

### Slide 5

1. Dominion states:
  - **Partnership with PHI**
    - MOU with PHI provides 50/50 Partnership should PJM approve 1-1C
    - Provides Dominion access to LDV via PHI – *reduces project costs and schedule risks for right of way acquisition*
  - a) How does PHI intend to convey its LDV rights to a third party or use its LDV rights in connection with the project?
  - b) Does such a conveyance or use of LDV rights by PHI for purposes of the project require the consent of the other LDV owners?
  - c) If consent of the other owners is required, has PHI secured such consent?
  - d) Is PHI required under the LDV Agreement to compensate the other LDV owners for its use of the LDV system for this purpose? If so, has Dominion taken such costs into account in its proposal?
2. Can Dominion elaborate as to the basis with which they derived a requirement of 60 permits for their proposal?

### Slide 8

1. Dominion has proposed a single 750 MVAR SVC which could be the largest SVC in the world. Please elaborate on your operational experience in recommending this solution.
2. For reference in Attachment A, two depictions of the requisite expansion of New Freedom and Hope Creek Switching Stations have been provided.
  - a. What basis of design did Dominion use to ascertain that additional 500kv Breakers could be inserted into an existing bay at New Freedom and Hope Creek Switching Stations?

- b. How can the \$17 million that Dominion estimated for these breaker upgrades include the required expansion of both New Freedom and Hope Creek buses to accommodate this equipment and associated relocation of existing circuit terminations?

## Slide 9

1. Dominion uses a graphic to indicate the proposed new station utilizes the incorrect representation of 5023 and 5024 circuits being adjacent. In PSE&G's presentation slide 4 it is indicated that 5023 and 5024 circuits are in fact separated by the 5039. What level of confidence can Dominion have in the siting and design for proposal 1A when it is apparent the fact the 5039 separates the 5023 and 5024 circuits was omitted?
2. Has Dominion included for the siting of the new station and transmission line rearrangements the requisite NJDEP wetlands permits, applicable ROW permitting and NJ Pinelands permitting?
  - a. What are the inherent benefits to the NJ Pinelands that Dominion has considered when siting the new station within 3 miles of New Freedom Switching Station?
  - b. What duration does Dominion include in its schedule for this permitting?
  - c. What consideration did Dominion make regarding the permitting of 200ft+ 500kV towers required to cross the 5039 and achieve the 5023 & 5024 being adjacent in their design?
3. What has Dominion included as necessary work and agreements required by Artificial Island due to the proposed changes in system topology and its effect to off-site power as required by the Nuclear Regulatory Commission?

## Slide 10

1. SSR for 'fault occurs' has been addressed, but no other conditions were mentioned. Has this been fully vetted by Dominion?
2. The TCSC controllers will sense the change in power flow and reinsert the capacitor. What if the sensor for the power flow rate on the TCSC controller fails?
3. In the boosted mode, what is the assurance of having no sub-synchronous interactions among devices such as exciters, PSS, TSCS, SVC, AVRs and prime movers?
4. There are the possibilities of exposing shafts to transient torques. Has Dominion looked at stress-time curves and the low cycle fatigue associated with the sequence of events, including potential additive effects of sub-synchronous and 60 Hz currents.

## Slide 11

1. Regarding Dominion's statement that TCSC eliminates the risk of SSR: Was SSR vetted for the entire sequence of events?
2. In PJM's territory the sole SVC installation older than three years is Larrabee, an installation which has been prone to operational issues. Can Dominion elaborate on the experience with SVCs and the confidence in their proposal in this critical location?
3. What specific example does Dominion have where TSCS are being used for Transient Stability in the United States?

## Slide 12

1. Dominion references multiple TCSC installations at several locations as proof of deployment:

“Figure 5 – 500kV, 400 MVAR SVC...”

“Figure 6 – 420kV, +/- 160 MVAR SVC...”

The example given in Slide 12 showing a California installation illustrates thyristor switched capacitors (TSC) which are different than TCSC. TSC can be thought of as fast switched capacitors and they are shunt connected, not series connected.

How does Dominion believe these SVC's can be used as examples to promote TCSC's despite the significant differences including differentiation between a series and shunt component?

## 2.0 LS Power

### Slide 3&4

1. If LS Power is unable to permit or utilize the proposed Jet Plow methodology, will their cost cap include the costs for utilizing other techniques such as HDD and Cofferdams?
2. In order for PJM to compare the total costs of each proposal, what is the estimated cost of the Transmission Owner upgrades not included in the \$146M estimate LS Power provided?
3. LS Power characterizes its costs cap as “binding” and inclusive of all of the costs associated with the items listed on slide 3 of the Presentation. On slide 4 of the Presentation, LS Power states that it is “taking on the most significant commercial risks” which it then identifies as the “risks associated with real estate costs, environmental mitigation costs, overhead/submarine river crossing costs, and routing costs.”
  - a. Referring to LS Power’s proposed contract language as set forth in its September 12, 2014, Artificial Island Proposal (“LS Power Contract Proposal”), under the LS Power Contract Proposal, LS Power’s “Construction Cost Cap Amount” is subject to increases for “Excluded Costs.” In this regard, costs for any “addition or modification to the Scope of Work” are excluded. LS Power identifies its “November 4, 2013, Detailed Constructability Submittal” as the contractually defined “Scope of Work” (See p. 2, footnote 1).

Based upon the foregoing, it would appear that any change to LS Power’s submittal, including those due to LS Power’s own errors and/or omissions, would be an “Excluded Cost.” LS Power’s Contract Proposal would, accordingly, have the effect of shifting the risk of project design and/or construction costs overruns to PJM. Such a result would be inconsistent with the statements made by LS Power in the Presentation regarding its cost cap.

Please reconcile the apparent inconsistency between LS Power’s Contract Proposal and the Presentation concerning the all-inclusive nature of LS Power’s cost cap and the risks that LS Power is taking on in its cost cap proposal.

- b. It would also appear that if LS Power’s original construction plan is determined to be non-feasible, that LS Power reserves the right to submit unlimited claims.

Please explain how such a reservation of rights is consistent with the statements made by LS Power in the Presentation regarding the all-inclusive nature of LS Power’s cost cap proposal and the risks that LS Power is taking on in its cost cap proposal.

- c. Referring to Section 1.1 of the LS Power Contract Proposal, LS Power promises to limit its demand for recovery of costs associated with subsection (a) or (b).

Does LS Power intend to have the ability to choose between the two proposed limits? If so, how is this consistent with the statements made by LS Power in its Presentation regarding its cost cap?

## Slide 6

1. How can LS power reconcile the difference between theirs and Transource's proposal of categorically the same scope at significantly increased cost?
2. Which resource in submarine installation expertise does LS Power have which supports the constructability of their design method in light of the opposing perspective of industry leaders?

## Slide 7

1. What 500kV outages has LS Power identified are required in the modifications of Salem and the interconnection of the new 500/230kV Station LS Power is proposing at Artificial Island?
2. Given the presence of numerous known federally and state protected aquatic species, how does LS Power propose to permit the use of invasive technologies such as jet-plowing?
3. With respect to the proposed location in Delaware for the 230kV Switching Station, what is the proposed mitigation to the Historic Scenic Highway and impacts at that location?

## 3.0 Transource

### Slide 2

1. The proposed project by Transource will have significant cable charging generated due to the underground/submarine nature of the installation. What mitigation is being proposed by Transource and is this included in the estimate?

### Slide 4

1. Transource states that Transource and PHI have executed a Memorandum of Understanding pursuant to which, upon the satisfaction of certain conditions, the parties would jointly develop, construct, operate and maintain the project if it is awarded to Transource.
  - a. How does PHI intend to convey its LDV rights to a third party or use its LDV rights in connection with the project?
  - b. Does such a conveyance or use of LDV rights by PHI for purposes of the project require the consent of the other LDV owners?
  - c. If consent of the other owners is required, has PHI secured such consent?
  - d. Is PHI required under the LDV Agreement to compensate the other LDV owners for its use of the LDV system for this purpose? If so, has Transource taken such costs into account in its proposal?

### Slide 9

1. The Transource proposal will have the greatest environmental and navigation impacts from the cable installation methods they currently proposed in terms of extensive multiple suspended sediment /turbidity events, water quality, fisheries resources (Sturgeon habitat), benthic resources and general navigation in the federal channel. The extent of these impacts could very well require a NEPA EIS level process which would delay the project for 2-3 years and increase project costs. CH2M Hill has also reinforced this notion in their independent review. What has Transource done to identify and mitigate these impacts?

### Slide 10

1. Transource states their contingency includes “two specific scope changes that may be required for permitting”. Given their potential impact on PJM’s consideration, what are these two changes Transource has included but believes others have not as there may be implications beyond cost (e.g., regulatory requirements, schedule delays etc)?
2. What level of engineering has Transource completed that would offer them the confidence to state “We stand behind our \$46M estimate of the ‘Salem Work’...”?



- a. In this engineering has Transource deployed the incumbent transmission owners design basis standards?
- b. In this preliminary design can Transource elaborate on the level of operability to the grid afforded by their design (Relocation of existing circuits such as 5024)?

## Slide 15

1. When referencing the MAPP project, what is the relevance between 40mi of Chesapeake Bay submarine crossing and the proposed Delaware River submarine crossing in regards to Federal and State endangered aquatic species and environmental concerns?
2. Was any submarine cable actually permitted or installed as part of MAPP?

## Slide 16

1. How is the Transource project schedule duration influenced by time of year restrictions for all in water activities?
2. Given the presence of numerous known federally and state protected aquatic species, how does Transource propose to permit the use of invasive technologies such as jet-plow and dredging?
3. Can Transource elaborate on the USACE requirements for suitable backfill material to be used in bringing the elevation equal to the existing adjoining river bottom?
  - a. Given a backfill requirement by USACE, what has Transource included in its proposal to account for the associated longer construction duration in the channel, greater marine navigational impacts, more significant environmental impacts such as turbidity and endangered aquatic species impacts, and not least importantly an increased potential for an agency to request an EIS?

On November 14, 2014, PJM scheduled a Transmission Expansion Advisory Committee (TEAC) meeting for December 9<sup>th</sup> to provide Stakeholders and state commission representatives the opportunity to offer final comments and input for PJM staff's consideration, in developing its recommendation to the PJM Board of Managers on the updated final five proposals as part of PJM's Artificial Island solicitation.

PJM provided the Bidders' presentations to Stakeholders on December 3, 2014. PSE&G has reviewed these presentations and offers the following questions and comments for PJM's consideration.

A significant benefit of the PSE&G proposal compared the other bidders is the margin provided by fiber optic ground wire (FOG) and optimization of the generator step-up transformers (GSUs) at Artificial Island.

All of the PSE&G proposals include FOG wire and optimization of the GSUs at Artificial Island. Both features act to significant increase the stability margin afforded Artificial Island with little to no additional cost. These allow the PSE&G proposal to operate with much higher stability margin than all other competing proposals.

## Comparison with the Other Projects

TO	Project ID	Project	SVC Size (MVAR)	AI 500kV Bus Voltage	AI MVAR Output	Critical Outage	Critical Contingency	Maximum Angle Swing (Degrees)	Analysis Performed by
LS Power	P2013_1-5A-SVC	230 kV+SVC	650	1.041	721	5015 <sup>(1)</sup>	14b <sup>(2)</sup>	112	PJM
	P2013_1-5B-SVC	500 kV+SVC	650	1.04	667	5015	14b2 <sup>(3)</sup>	102	PJM
Transource (AEP)	P2013_1-2B-SVC	230 kV+SVC	650	1.042	662	5015	14b	109	PJM
	P2013_1-2A-SVC	230 kV+SVC	650	1.042	658	5015	14b	112	PJM
	P2013_1-2C-SVC	500 kV+SVC	650	1.041	670	5015	14b2	101	PJM
DVP	P2013_1-1B-SVC	500 kV+SVC	650	1.041	674	5015	14b	110	PJM
	P2013_1-1C-SVC	500 kV+SVC	650	1.041	675	50151 <sup>(4)</sup>	2b2 <sup>(5)</sup>	99	PJM
PHI/Exelon	P2013_1-4A-SVC	500 kV+SVC	650	1.041	669	5015	14b2	102	PJM
<b>DVP</b>	<b>P2013_1-1A-SVC (TCSC/SVC Solution)</b>	<b>Potential of Damaging AI Units and leading to blackouts</b>							
DVP	P2013_1-1C-SVC	500 kV+SVC	650	1.039	688	5021	5b <sup>(7)</sup>	98	PSE&G
PSE&G	P2013_1-7K- New Hope Creek - Red Lion (FOG <sup>(8)</sup> , GSU tap <sup>(9)</sup> )	<b>500 kV No SVC</b>	<b>Not Required</b>	1.039	600	5021	5b <sup>(7)</sup>	91	

(1) 5015: Hope Creek – Red Lion 500kV line

(2) 14b: Single-line-to-ground (SLG) fault on the new line from Salem w/ delayed clearing due to stuck breaker

(3) 14b2: SLG fault on the new Salem-Red Lion 500kV line at Salem w/delayed clearing due to stuck breaker

(4) 50151: Proposed new Hope Creek – Red Lion 500 kV line

(5) 2b2: SLG fault on 5015 w/ delayed clearing due to stuck breaker resulting the loss of 5015 and New Salem-Hope Creek 500kV line (second tie)

(6) 2b: SLG fault on Hope Creek-Red Lion 500kV line w/ delayed clearing due to stuck breaker

(7) 5b: SLG fault on Hope Creek-Salem 500kV line (Existing 5037) w/ delayed clearing due to stuck breaker

(8) FOG wire installation

(9) GSU tap adjustment (Salem unit 1 GSU: 512500 V; Salem unit 2 GSU: 500130 V; Hope Creek GSU: 500130 V)

Note: FOG wire installation and GSU tap adjustment are part of the PSE&G proposed solution

# Modeling Data Assumptions

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Following modeling data provided by PJM was used for the study:

1. Base power flow case (based on the NERC MMWG 2011 Series 2017 Summer Light Load case)
2. Dynamic Case (based on the NERC SSDWG 2011 Series 2017 Summer Light Load case)
3. Short Circuit Case (2017 short circuit model)
4. Machine Capability Curves (“D Curves”)

Input assumptions have been discussed below:

- **AI Units Step Up Transformer Taps** – The following fixed tap setting were used:  
Salem unit 1 GSU: Tap 4: 512500 V  
Salem unit 2 GSU: Tap 4: 500130 V  
Hope Creek GSU: Tap 4: 500130 V
- **AI Units Power System Stabilizers (PSS)** – Study considered simultaneous outage of Power System Stabilizers (PSS) of Artificial Island units Hope Creek and Salem-2. The Salem-1 PSS is assumed to be on for all scenarios.
- **Fault configurations & impedances** – The study looked at all possible faults single line to ground (SLG) faults and three phase faults. Per NERC criteria, breaker failures and relay failures were considered with SLG faults. All three phase faults were assumed to be zero impedance faults.
- **Fault clearing times** – Clearing times for buses at/near the Artificial Island are provided in Table2, which provides Fault clearing times considering the installation of Fiber Optic Ground (FOG) wire on PJM 500kV network near Artificial Island. There is no transfer trip delay in case FOG wire is installed.

# Modeling Data Assumptions

Fault Clearing Times

Station	Faulted Line / Transformer	Fault Clearing Times (cycles)			
		Three phase or SLG fault on Line/Transformer with Normal Clearing	Delayed Clearing Due to Stuck Breaker		Three phase or SLG fault on Bus with Normal Clearing
			Local Station Clearing	Remote Station Clearing	
Hope Creek	5037	2.9	9.06 <sup>a</sup>	9.56	4.26
	5015, 5023	2.9	9.06	9.56	
Salem	5024, 5021	2.9	9.06	9.56	4.26
Orchard	5039, 230kV Transformer	2.9	11.76 <sup>b</sup>	9.56	4
Red Lion	5015, 230kV Transformer	2.9	9.06 <sup>c</sup>	9.56	4
East Windsor	5022	2.9	11.76	9.56	4
	5038	2.9	11.76	9.56	4
New Freedom	5038	2.9	11.76	9.56	4

a- Clearing time at station with Generation

b- Clearing time at station with no Generation

c- Critical Line Clearing time at station with no Generation

- **Contingency list** – PJM provided list of faults for existing 500kV system. The list was modified, depending upon the proposed option. For each of the proposed solutions, the list of faults has been provided in the corresponding Attachment B.
- **System voltages** – The stability limit is proportional to the product of system voltage and machine internal induced EMF. To study the performance of each option at same AI voltage levels, in some cases, the system voltages was adjusted.
- **System load** – System load was not modified.

PSE&G maintains that this inclusion of FOG wire and step up transformer fixed tap settings changes are scope included in the original PSE&G 7K proposal, not omitted by PJM during the modifications period, and therefore not suggested as an addition or modification to the proposed scope.

FOG wire in the *Artificial Island Project Proposal* report is covered in the following sections:

Executive Summary, ii, iii

## Sections

2.2, pp. 5- 6

3.4.1.1, p. 17 (Attachment A)

4.1, p. 46, 54, 56

4.2, p. 66, 69, 71

4.3, p. 88, 93, 94

4.4, p. 112, 115, 117

4.5, p. 130, 133, 135

4.6, p. 173, 183

Optimization of the three units' step up transformers fixed tap settings in the *Artificial Island Project Proposal* report is covered in Section 3.4.1.1 (p. 17) and included in the scope for all alternatives (see Attachment B).

**Figure 1: Hope Creek Switching Station Additional Breaker Expansion. Photo Sourced from Google Earth.**

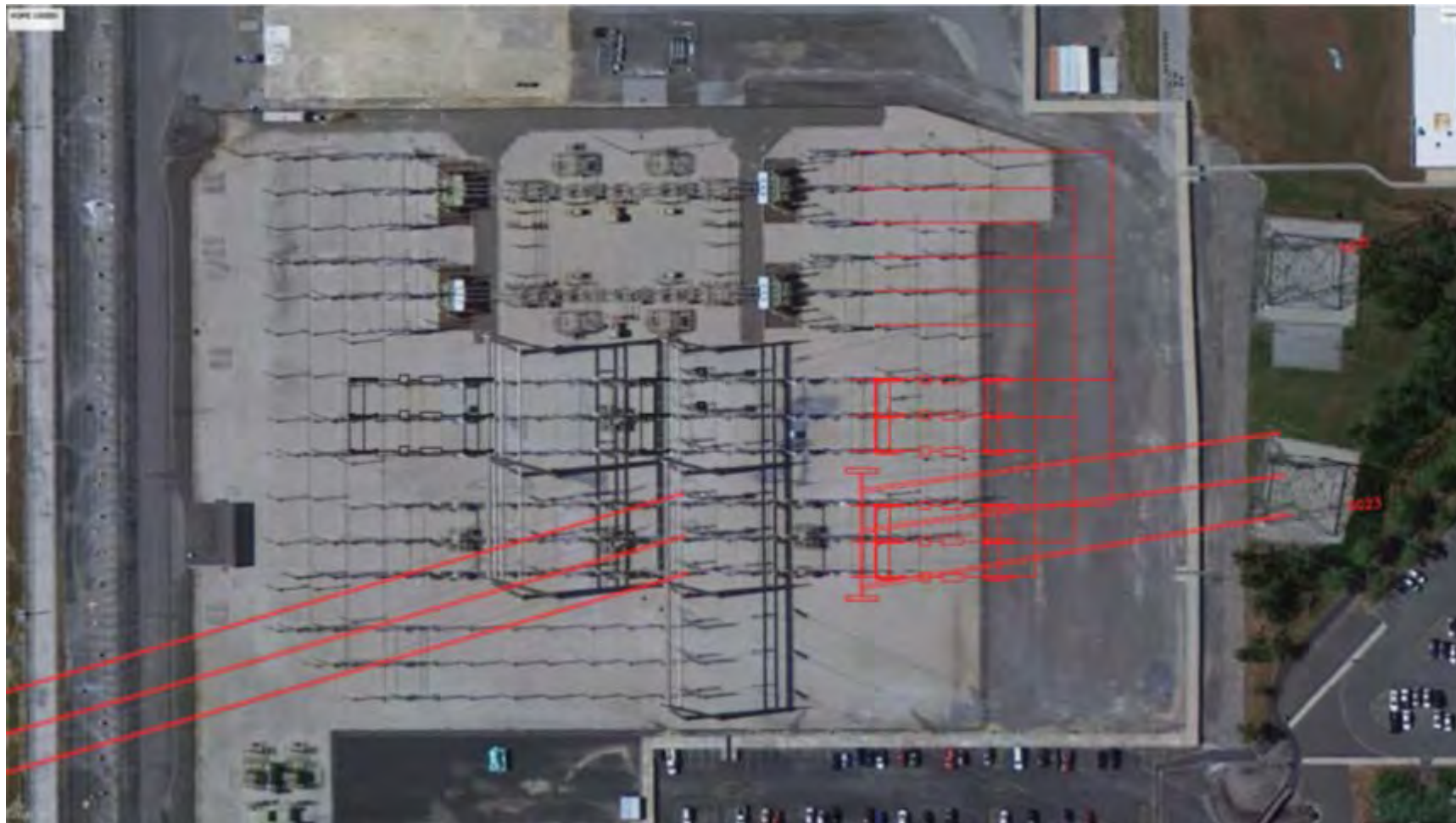
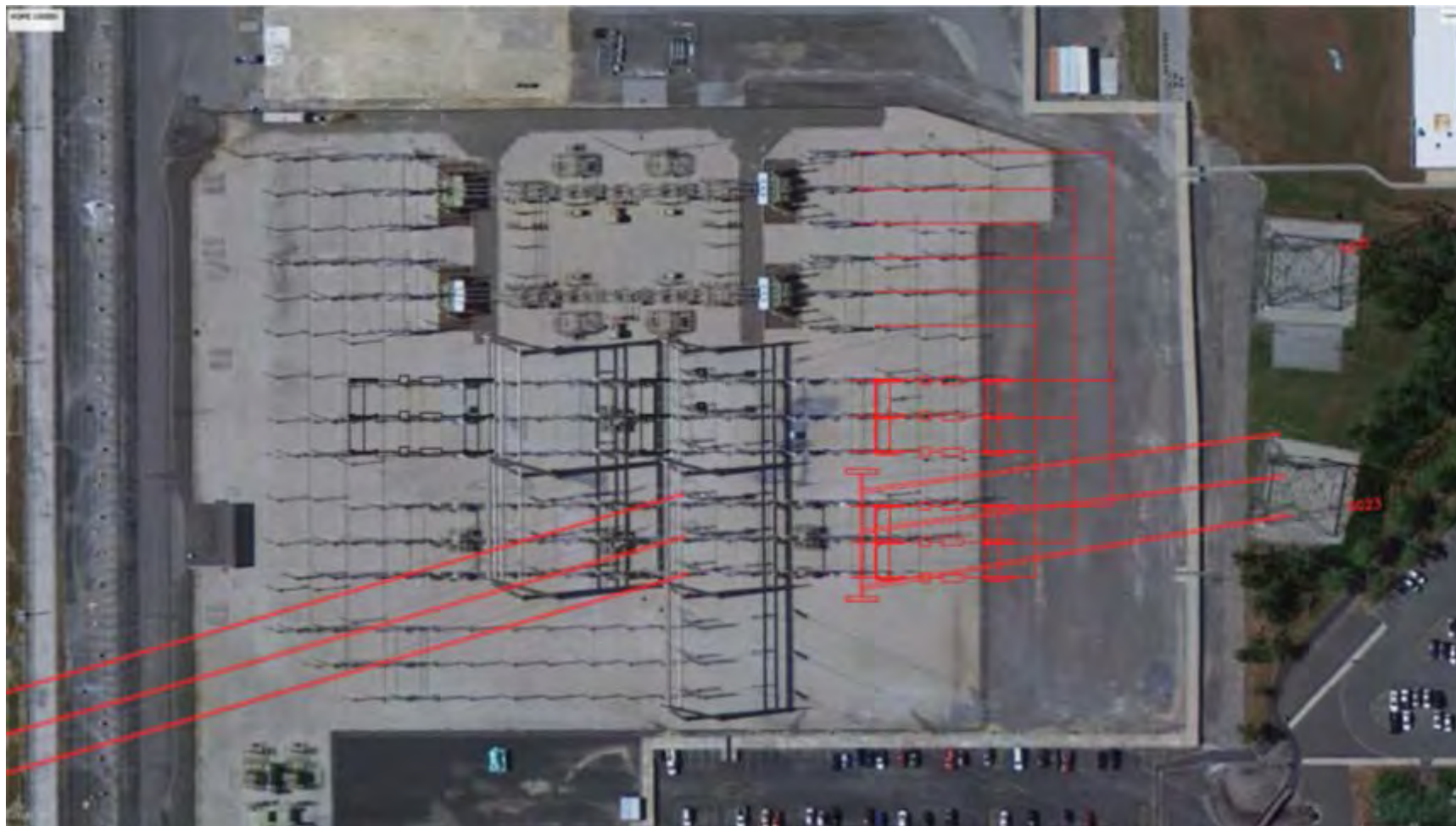


Figure 2: New Freedom Switching Station Additional Breaker Expansion. Photo Sourced from Google Earth



**3.4.1.1. Enhancements to Proposed Options**

To improve the stability margin and to meet PJM RFP requirements PSE&G for each alternative, is proposing to include the following as a part of each potential option:

1. A second Hope Creek to Salem 500kV circuit.
  - a) The Salem and Hope creek 500kV stations are in the same location. The two stations are connected by one 500kV circuit (5037) that is 0.5 miles long. The outage of the 5037 circuit puts the Hope Creek and the Salem stations about 100 electrical miles apart. The two stations become connected via Salem to New Freedom and New Freedom back to Hope creek circuits. With the second Hope Creek to Salem circuit, the two stations become the same bus.
  - b) The Hope Creek bus is a two bay breaker and a half design, which functions as a ring bus. During breaker maintenance/outage, a line or bus fault at hope creek would cause the bus to split, which increases the severity of the fault. The second line would require a third bay at Hope creek, which would return the bus to a true breaker and a half design.
  - c) The connection is 0.5 miles long and the total cost of the line and the additional bay is not a significant cost as compared to the total project cost. This project assumed using gas insulated bus (GIB) based on available construction space.
  - d) Project cost is

Base	\$18M
R&C	\$4.5M
Total	\$22.5M
  
2. FOG wire installation
  - a) FOG wire will facilitate faster clearing times, which will enhance the stability response/margin. See Table 1 in the Solutions Proposals section.
  - b) FOG wire will Minimize the risk for overtrip condition that could be caused by relay failure
  - c) the incremental cost of FOG wire installation versus regular shield wire is negligible.
  - d) Project cost is included in the base project costs.
  
3. Installation of a 500kV breaker on the Hope Creek and Salem unit generator leads to the 500kV bus sections.

Currently, anytime the Salem No. 1 or No. 2 units are shut down, the station operators have to physically open two 500kV generator bus section breakers to isolate the unit from the 500kV bus then remove the 500kV line drops to disconnect the unit from the 500kV system, then reclose the 500kV bus breakers and return the Salem 500kV bus to normal. This process takes about 24 hours to complete. The same process is used to return the unit to service. Due to the length of time the 500kV unit section bus breakers are open, the existing AIOG has specific tables and associated unit operating curves to cover this condition. Similar process is used for the Hope Creek unit. However the time to complete the process is shorter since the Hope Creek unit has a disconnect switch in place of the line drops.



The new breakers on the generator leads will eliminate the need to open the 500kV generator bus section breakers and therefore, provide higher system reliability and eliminate the need for the specific AIOG operating instructions.

4. Optimization of the three units step up transformers fixed tap settings.

With the new system topology and the new real and reactive AI unit limit requirements associated with the proposed upgrades, voltage and stability evaluations were performed to determine optimum fixed tap setting for the unit transformers to maintain the generator terminal design voltage range and to optimize stability performance.