



**PERSPECTIVES**

Reliability  
Economy  
Environment

**> 62,500 MILES**  
of transmission lines

Collaboration  
with over  
**925**  
members



**15-YEAR**  **HORIZON**  
LONG-TERM



**IMPACTS**  
61+ million people



**13 STATES**

**ARTIFICIAL  
ISLAND PROJECT  
RECOMMENDATION  
WHITE PAPER**





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# Section 1 – Executive Summary

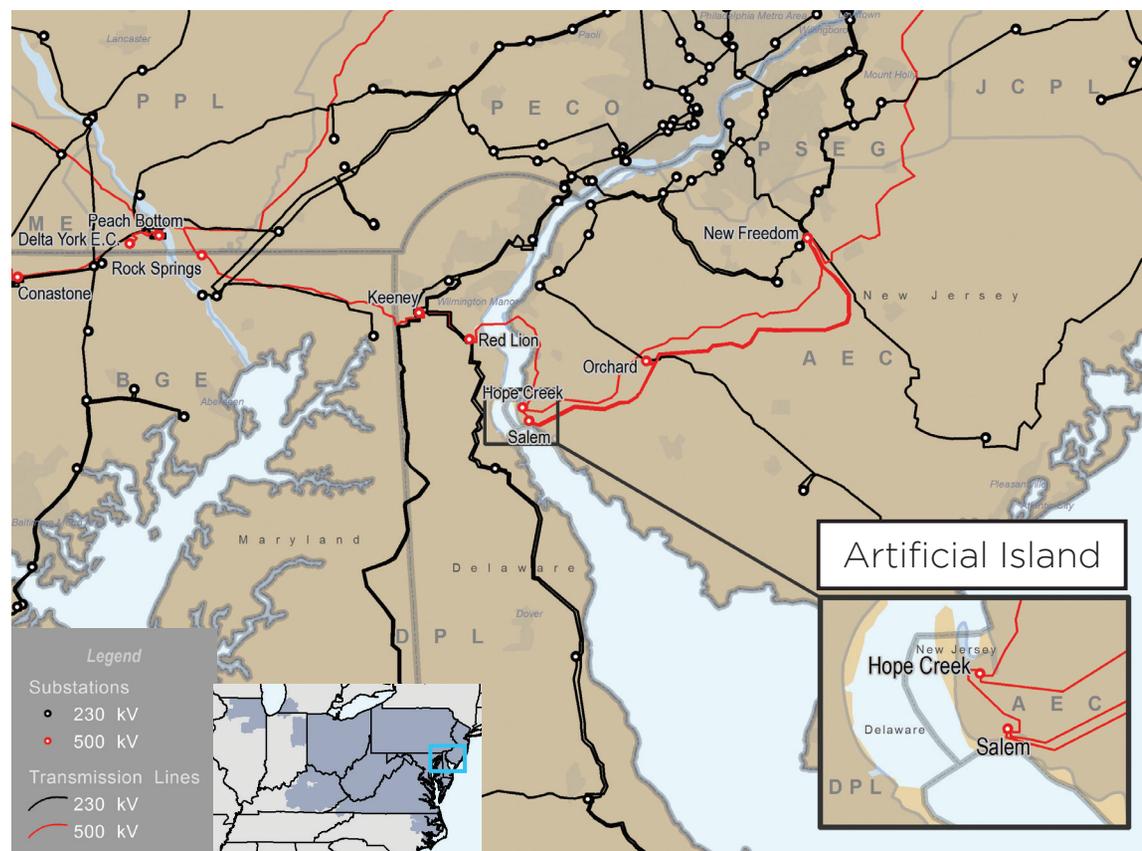
## 1.0: Executive Summary

### 1.0.1 — Overview

PJM opened an RTEP process window on April 29, 2013, seeking proposals to improve operational performance on bulk electric system facilities in the southern New Jersey, Artificial Island area, site of PSE&G's Salem 1 and 2 and Hope Creek 1 nuclear generating plants, shown on **Map 1.1**. PJM specified that solution proposals must improve stability margins, reduce Artificial Island MVAR output requirements and address high voltage reliability issues.

Seven different sponsors submitted 26 separate proposals, the various elements of which are shown on **Map 1.2**, with original cost estimates (as submitted) ranging from \$100 million to \$1.55 billion. A number of proposals included identical or similar elements. Proposals reflected a diverse range of technologies: new overhead and underground/underwater 230 kV lines, new overhead 500 kV lines, HVDC lines, new transformers, new or upgraded substations and related equipment, circuit breakers, system reconfiguration, dynamic reactive devices, dynamic series compensation and DC technology. Proposals spanned a range of project risk exposure levels and lead-time requirements.

**Map 1.1: Artificial Island - New Jersey Area**



### Note:

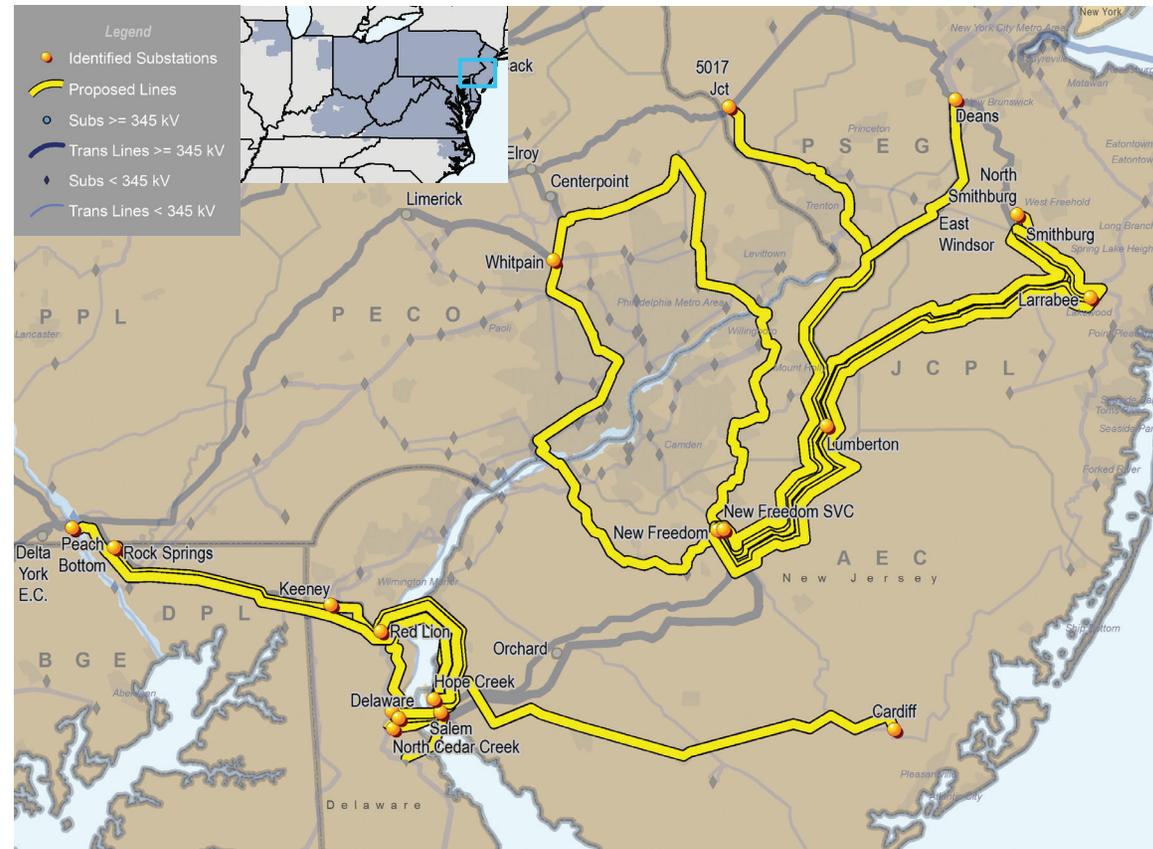
PJM notes that it sought solutions to Artificial Island operational performance issues prior to implementation of its Order 1000 competitive solicitation tariff. As a result, those tariff procedures did not govern this

process, a point recently affirmed by the FERC. Nevertheless, PJM utilized those procedures to the extent feasible as a trial run of Order 1000 tariff provisions.

Once the Artificial Island window closed on June 28, 2013, PJM began evaluation of the 26 proposals along three dimensions – system performance, constructability and cost. Initial analytical studies tested proposals in terms of transient stability, voltage, thermal and short-circuit performance against established NERC and regional reliability planning criteria. In parallel, engineering consultant expertise enlisted by PJM evaluated constructability risks to project cost and schedule, such as siting and permitting, rights-of-way and land acquisition, project complexity and operational impact among others. Ultimately, results of system performance, constructability and cost evaluations allowed PJM to identify all or part of five proposals that would be the basis for further consideration and solution development:

- A portion of Proposal PSE&G-7K, which included a 17-mile 500 kV line from Hope Creek to Red Lion, paralleling the existing Red Lion to Hope Creek 500 kV line (designation 5015) and the expansion of the existing Hope Creek and Red Lion substations.
- A portion of Proposal DVP-1C submitted by Dominion Virginia Power, which included an expansion of the existing Hope Creek 500 kV substation and the construction of a 17-mile 500 kV line from Hope Creek to Red Lion, paralleling the existing Red Lion to Hope Creek 500 kV line (designation 5015), as well as a Red Lion substation reconfiguration into a breaker-and-a-half scheme.

Map P.1.2: Artificial Island Window Proposals



#### Note:

A **Static VAR Compensation (SVC)** device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system performance.

A **Thyristor Controlled Series Compensation (TCSC)** device comprises a series capacitor bank shunted by a bidirectional thyristor valve in series with an inductor. This combination of devices is used to lower the apparent line impedance, resulting in increased power transfer capability. A TCSC device makes a long transmission line act like a much shorter one.

- Proposal LS Power-5A, which included expansion of the existing Salem substation to include a new 500/230 kV autotransformer and the construction of a new 230 kV line from that point, under or over the Delaware River to a new substation in Delaware that would tap the existing Red Lion - Carranza and Red Lion - Cedar Creek 230 kV lines.
- Proposal Transource-2B, which included an expansion of the Salem 500 kV substation and the construction of a new substation near Artificial Island with two 500/230 kV autotransformers. The proposal would also include a new 230 kV line from that substation, under the Delaware River, to a new substation in Delaware that would tap the existing Red Lion - Carranza and Red Lion - Cedar Creek 230 kV lines.
- Proposal DVP-1A, submitted by Dominion Virginia Power, which included a new switching station, cutting the Hope Creek - New Freedom 500 kV line (operational designation 5023) and the Salem - New Freedom 500 kV line (operational designation 5024), near New Freedom. The new substation would include 500 kV SVC devices and thyristor controlled series compensation devices in each line.

Additional analytical work, constructability evaluation and stakeholder discussions provided PJM many insights as it developed a solution for recommendation to the PJM Board. These efforts included interviews with the finalists to clarify various items in their proposals with the oversight of a FERC Administrative Law Judge. The judge noted that “PJM treated each bidder equally” and “PJM afforded all four bidders equal opportunity to present their supplemental proposals during the information gathering sessions...”

### 1.0.2 — Recommendation to the PJM Board

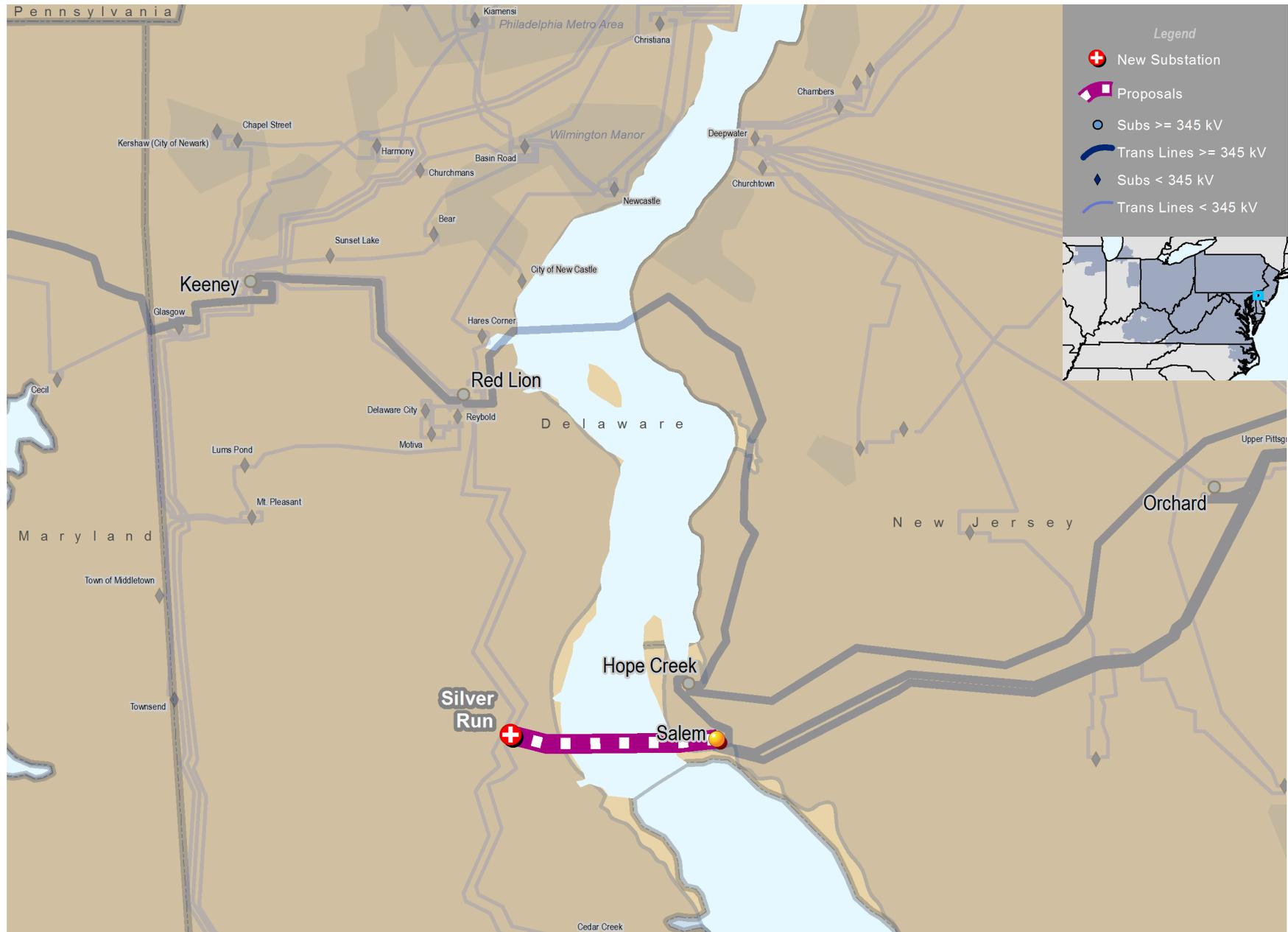
Each project offers certain advantages and risks with regard to performance, cost commitment, and constructability. However, based on the technical analysis and constructability assessments, PJM staff is recommending the following projects to the Board because they represent the best balanced solution that both satisfies the technical performance requirements and provides a constructible solution with reasonable cost commitment.

#### ***New 230 kV Transmission Line Delaware River Crossing***

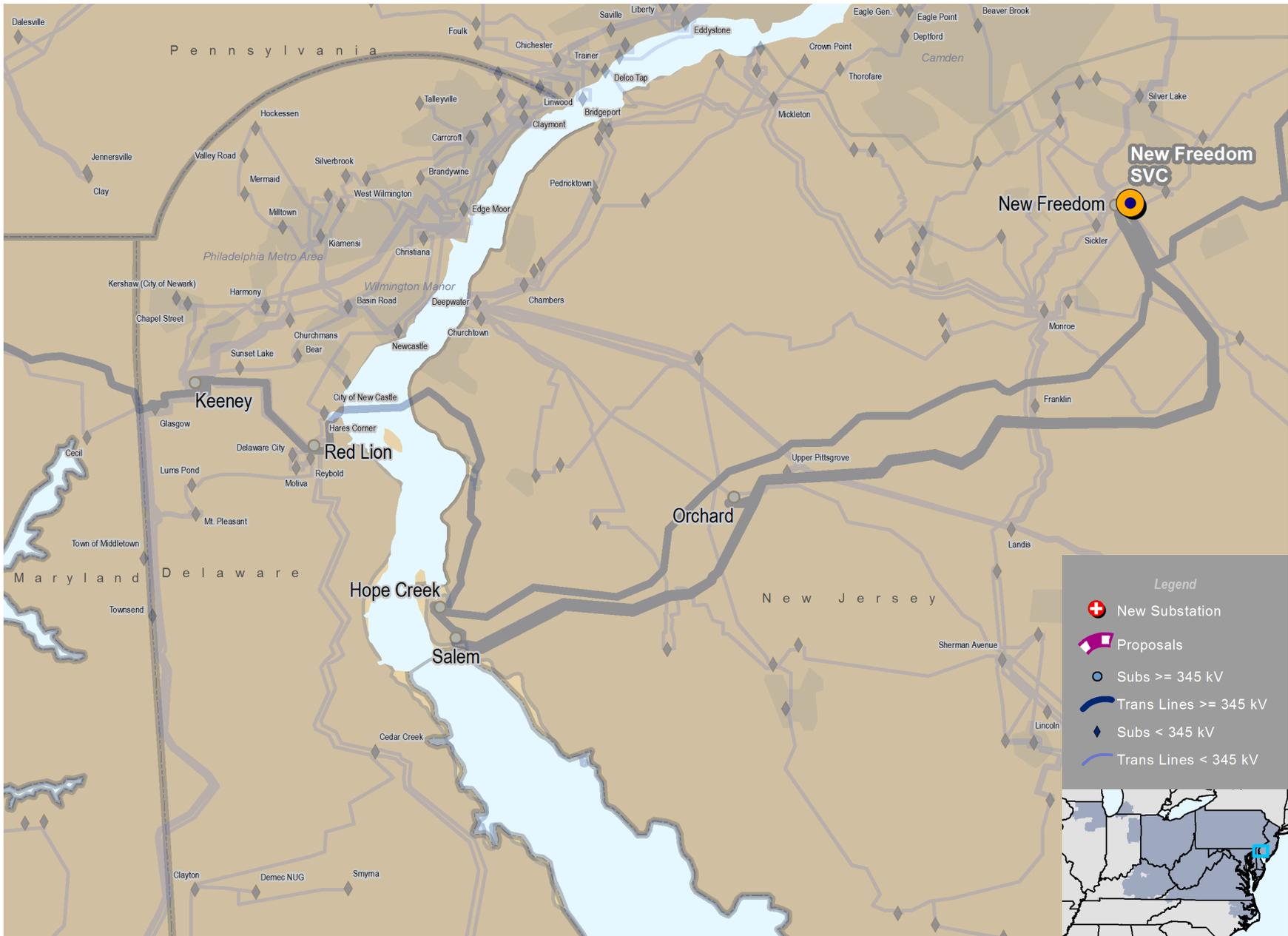
A new 230 kV transmission line to be designated to LS Power should be constructed under the Delaware River from Salem to a new substation in Delaware that would tap the existing Red Lion - Carranza and Red Lion - Cedar Creek 230 kV lines, as shown on **Map 1.3**. Associated substation work at Salem, including existing 500 kV substation expansion and installation of a new 500/230 kV auto-transformer, would be designated to PSE&G. Associated work on the 230 kV right-of-way in Delaware to tap into existing 230 kV lines would be designated to Pepco Holdings, Inc. (PHI).

Among a number of factors, LS Power’s proposed construction technique and cost containment provide notable advantages. From a constructability perspective, utilizing horizontal directional drilling techniques could mitigate permitting risks associated with crossing the Delaware River. Additionally, the LS Power proposal provides greater cost certainty with fewer exclusions to cost commitment compared to the other proposals.

Map 1.3: New 230 kV Transmission Line Delaware River Crossing



Map 1.4: New Freedom 300 MVAR SVC Device



***New Freedom 300 MVAR SVC Device***

A new 300 MVAR SVC device should be constructed at the New Freedom 500 kV substation, shown on **Map 1.4**, and designated to PSE&G. When compared to the simulations without an SVC device, proposals with SVC devices provided better voltage and machine MVAR response at Artificial Island, correlating to better post-fault system stability operational performance as sought in PJM's request for proposal.

***High Speed Optical Grounding Wire Communications***

High speed relaying utilizing fiber optic communications installed in optical ground wire should be added to the protection systems of a number of critical 500 kV circuits in the vicinity of Artificial Island, listed below and shown on **Map 1.5**, to provide faster fault clearing times and additional stability margin:

- Hope Creek - Red Lion (operational designation 5015)
- Salem - Orchard (5021)
- East Windsor - Deans (5022)
- Hope Creek - New Freedom (5023)
- Salem - New Freedom (5024)
- Salem - Hope Creek Line (5037)
- New Freedom - East Windsor (5038)
- New Freedom - Orchard (5039)

Doing so will improve the operational performance sought by PJM's request for proposal. Optical ground wire (OPGW) upgrades to these facilities would be designated to PSE&G, PHI and FirstEnergy accordingly.

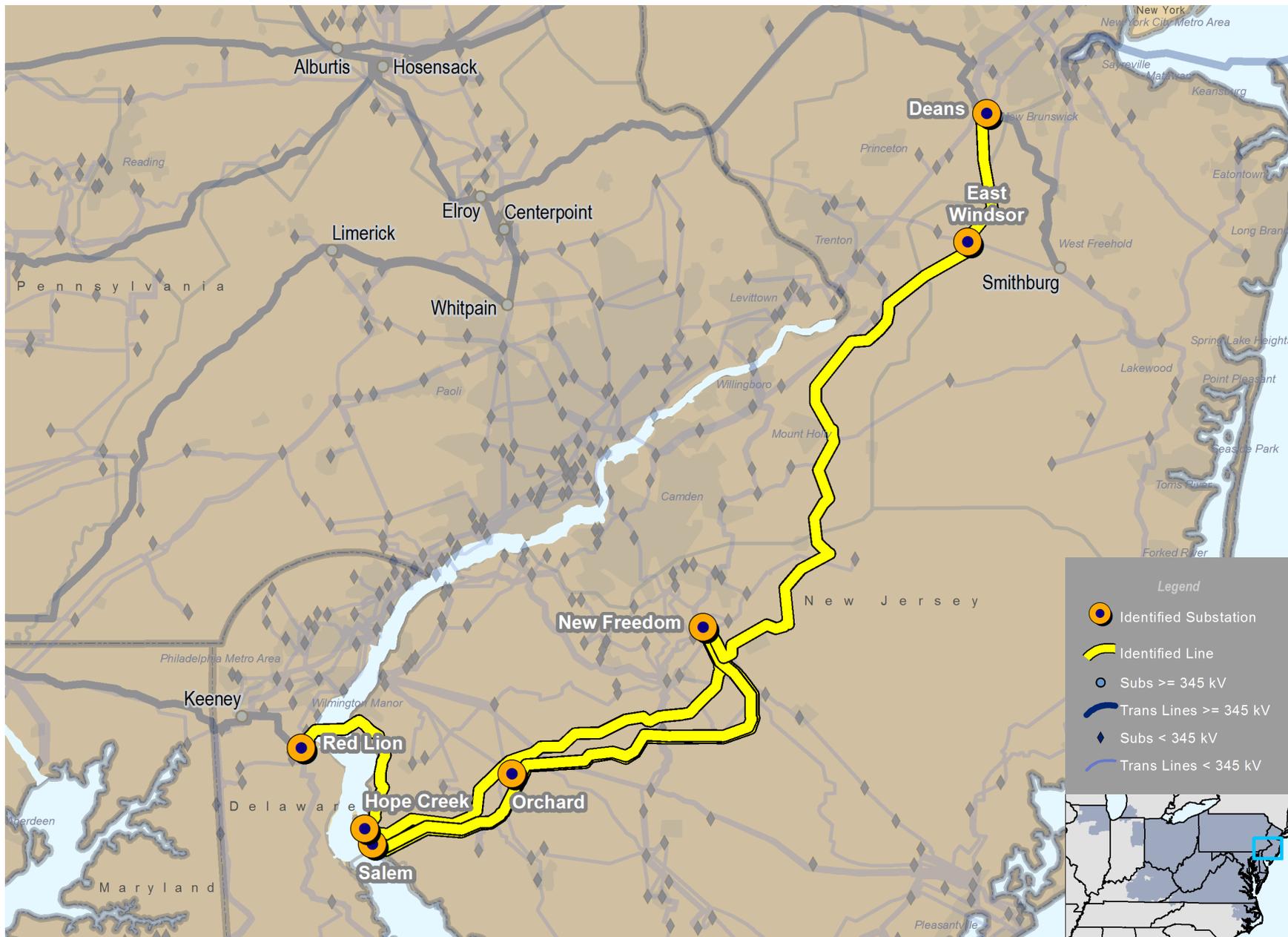
***Artificial Island Generator Step-Up Transformer Tap Settings***

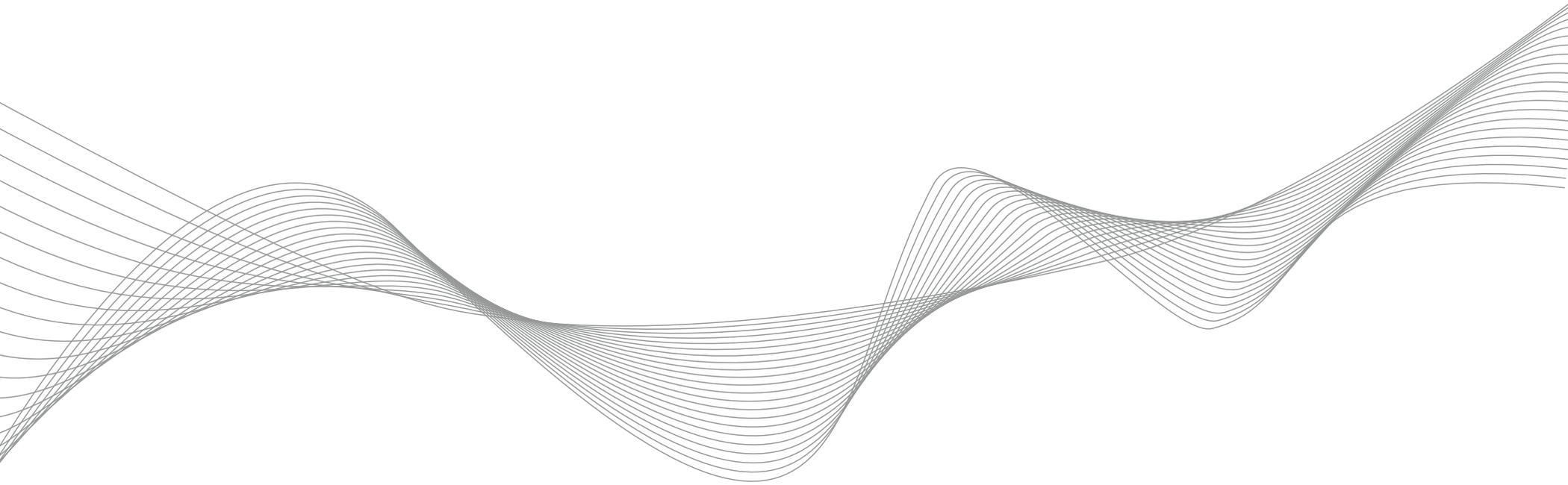
Tap settings for the generator step-up transformers at the three Artificial Island units – Salem 1, Salem 2 and Hope Creek – to improve the voltage control operational performance. This solution element will be assigned to PSE&G.

**1.0.3 — Next Steps**

If the PJM Board elects to approve the recommended solution, PJM staff will then notify LS Power that it has been assigned as the Designated Entity for the 230 kV transmission line portion of the solution. PJM will also draft the Designated Entity Agreement and Interconnection Coordination Agreements, which will detail the duties, accountabilities, obligations and responsibilities of each party. The terms of the Designated Entity Agreement will incorporate those presented by LS Power in documents posted publicly on PJM's website and shared with PJM stakeholders. Existing Transmission Owners with responsibility for portions of the recommended solution will also be notified of their respective Designated Entity assignments as well.

Map 1.5: 500 kV Lines for Optical Ground Wire Communications







## Section 2 – Artificial Island Window

### 2.0: Artificial Island Window

#### 2.0.1 — Stating the Issue

PJM conducted its first RTEP proposal window between April 29, 2013, and June 28, 2013 seeking proposals to improve operational performance on bulk electric system facilities in the area of Artificial Island in southern New Jersey, site of the Salem 1 and 2 and Hope Creek 1 nuclear generating plants, shown on **Map 1.1**. Opening the Artificial Island window included publication of a formal problem statement and requirements document comprising PJM's official request for proposals. Specifically, the request sought proposals to eliminate Artificial Island Operating Guide complexity regarding stability limitations and minimum unit MVAR output requirements, as well as to address previously identified high voltage reliability issues. PJM asked that proposals achieve the following objectives:

1. Generate maximum power (3,818 MW total) from all Artificial Island units without a minimum MVAR requirement. Full maximum power must be maintained under both baseline and all N-1 500 kV line outage conditions in the Artificial Island area. Voltages must be maintained within established operating limits and stable for all NERC Category B and C contingencies. N-1-1 contingencies do not need to be applied in addition to the N-1 500 kV outage condition in the Artificial Island area
2. Ensure maximum Artificial Island MW output is not affected by the simultaneous outage of power system stabilizers of Salem Unit 2 and Hope Creek. The Salem Unit 1 power system stabilizer is assumed to be on for all scenarios
3. Reduce operational complexity
4. Improve Artificial Island stability
5. Maintain PJM System Operating Limits (SOLs)

#### 2.0.2 — Artificial Island Area Transient Stability

PJM performs multi-tiered transient stability analyses for system contingencies of reasonable probability as part of its annual RTEP cycle in compliance with NERC TPL standards. These studies examine the grid's ability to return to a stable operating point following a system fault or similar disturbance. Such contingencies can cause

a nearby generator's rotor's position to change in relation to the stator's magnetic field, affecting the generator's ability to maintain synchronism with the grid. Power system engineers measure this stability in terms of generator bus voltage and maximum observed angular displacement between a generator's rotor axis and the stator magnetic field – also known as “maximum angle swing.” If this swing is in excess of 120 degrees then the generator's ability to remain synchronized may be compromised, requiring additional testing. Generally speaking, lesser angle swing correlates to greater stability margin. Transient stability behavior in actual operations is affected by machine megawatts, system voltage, machine voltage, duration of the disturbance and by system impedance.

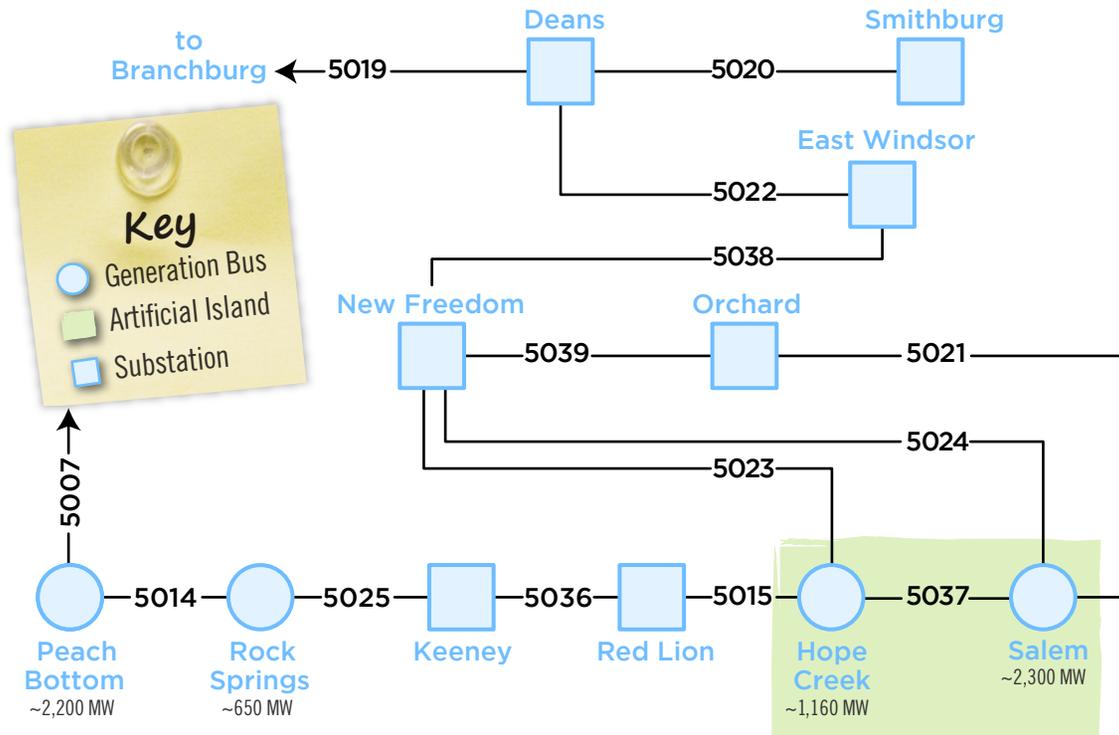
#### ***Artificial Island Operating Guide***

Historically, Salem and Hope Creek generation output has been constrained by dynamic and transient stability limitations, particularly under transmission line outage scenarios. These constraints have been aggravated by high voltage conditions that have also emerged in actual operations. As a result PSE&G has implemented a special protection system scheme to address these operational issues.

The Artificial Island Operating Guide – included in PJM’s manuals – describes the procedures for managing stability limitations. The guide specifies minimum reactive output requirements for each machine at Artificial Island for various operating conditions. The guide has become increasingly complex since 1987 when the special protection system was originally implemented. Many system topology changes – new transmission lines and other facilities as well as generation additions and retirements, for example – have altered operating conditions in southern New Jersey. Over time, the aggregate effects have made the minimum reactive output requirements of the Artificial Island Operating Guide particularly difficult to implement while maintaining system voltages within limits, presenting PJM and PSE&G system operators with limited solutions for remaining within prescribed operating limits to maintain reliability.

As **Figure 2.1** shows, when either the 5015 or 5038 transmission line is out of service, generation output from Artificial Island has limited paths to the remainder of PJM. For example, when 5015 is out of service, the 5038 line becomes the sole 500 kV tie to the rest of the system, and likewise for the 5015 line when 5038 is out of service. Given this topology, the Artificial Island complex is currently subject to both dynamic stability and transient stability restrictions. Power system stabilizers installed on each unit improve dynamic stability. However, if any stabilizers are out of service during three-unit operation, unit reductions and/or increases in MVAR output become necessary.

**Figure 2.1: Artificial Island Area 500 kV Single Line Schematic**



### 2.0.3 — The Need for an RTEP Proposal Window

PJM's decision to open an RTEP proposal window has its roots in 2012 RTEP process studies that identified near-term and long-term solutions to improve PJM Artificial Island operational performance. These were reviewed and discussed with TEAC during 2012:

Potential near-term solutions

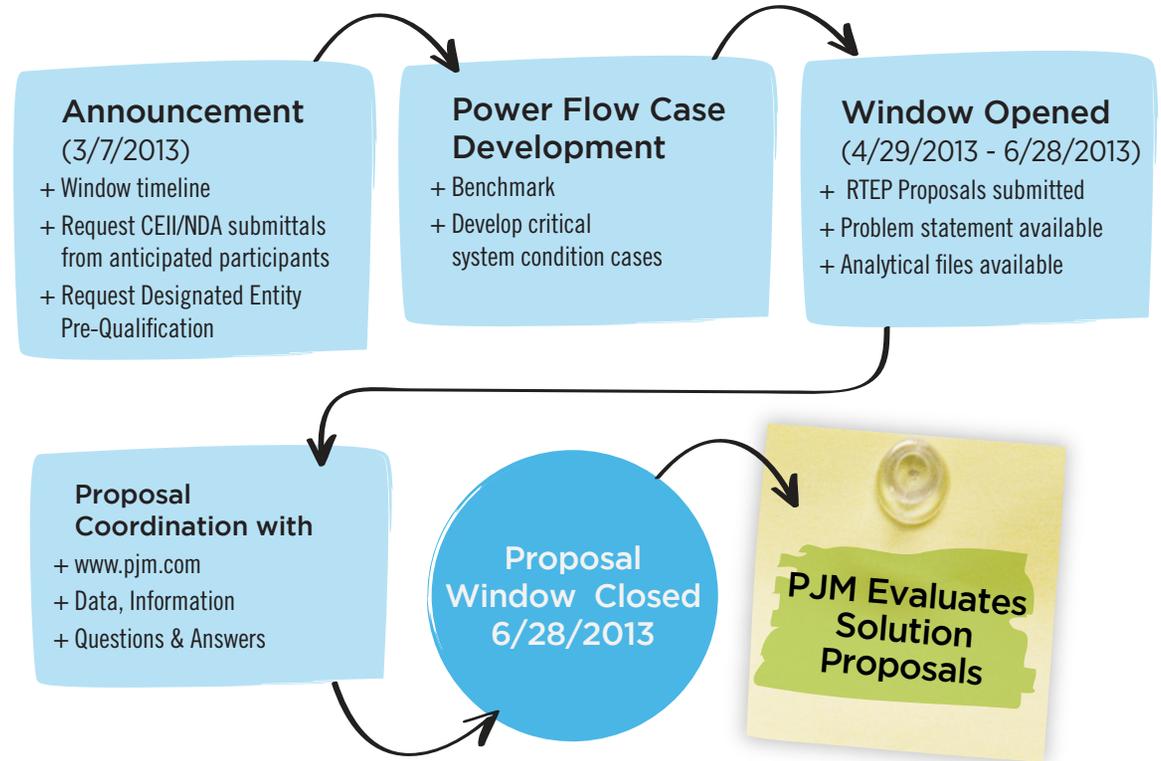
- Consider voltage as an operating guide instead of reactive output
- Fixed or variable reactor at New Freedom, Salem/Hope Creek
- Substation reconfiguration at New Freedom
- Series reactor on line 5037 Hope Creek - Salem
- Braking resistor
- SVC device on 5039 New Freedom - East Windsor 500 kV line

Potential long-term solution

- New 500 kV transmission out of Artificial Island

Ultimately, these TEAC discussions gave rise to the RTEP proposal window announced on March 7, 2013, and opened from April 29, 2013, through June 28, 2013, as shown in **Figure 2.2**.

**Figure 2.2: Artificial Island Proposal Window**



### 2.0.4 — Scope of Proposals Submitted

Seven different sponsors submitted 26 separate proposal packages during the RTEP process Artificial Island window. Summarized in **Table 2.1** and shown earlier on **Map 3.2**, cost estimates ranged from approximately \$100 million to \$1.55 billion and reflected a diverse range of technologies: new transformation, substations and associated equipment, additional circuit breakers, system reconfiguration, dynamic reactive devices, dynamic series compensation and DC technology. Proposals spanned a range of risk exposure and

lead-time requirements. PJM conducted both analytical and constructability evaluations to assess the proposals submitted and develop a solution for PJM Board consideration, as discussed next.

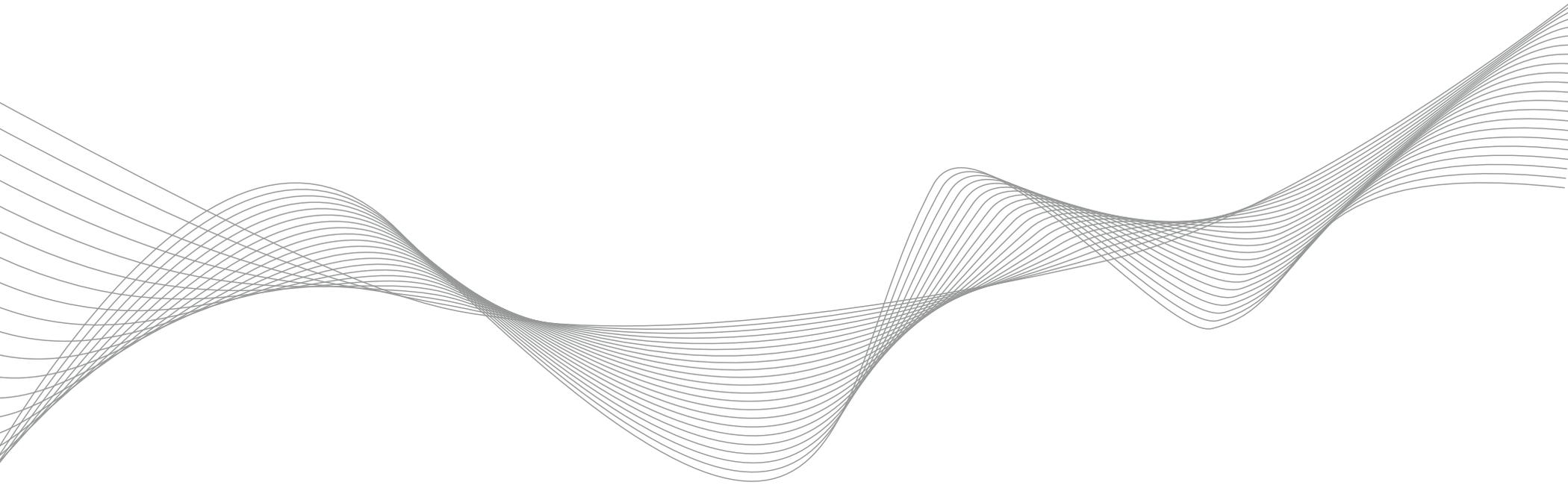
Table 2.1: Summary of Artificial Island Window Proposals

Project ID	Proposal Sponsor	Proposal Sponsor Estimated Cost (\$M)	Major Components	Supporting Information
P2013_1-1A	Virginia Electric and Power Company	\$133	500 MVAR SVC near New Freedom	Two (2) Thyristor Controlled Series Compensation (TCSC) Devices near New Freedom
P2013_1-1B	Virginia Electric and Power Company	\$126	New 500 kV from Salem – a new station in Delaware	New 500/230 kV station in Delaware that taps existing Cedar Creek - Red Lion 230 kV and Catanza - Red Lion 230 kV
P2013_1-1C	Virginia Electric and Power Company	\$202	New 500 kV from Hope Creek – a new Station in Delaware	Install a new 500 kV line from Hope Creek - Red Lion; New Salem - Hope Creek 500 kV line
P2013_1-2A	Transource	\$213 - \$269	Salem - Cedar Creek 230 kV	Two (2) 500/230 Transformers near Salem; Loop in Red Lion - Cartanza 230 to Cedar Creek
P2013_1-2B	Transource	\$165 - \$208	Salem - North Cedar Creek (new) 230 kV	Two (2) 500/230 transformers near Salem and loop in Red Lion - Cartanza 230 and Red Lion - Cedar Creek 230 kV
P2013_1-2C	Transource	\$123 - \$156	Salem - Red Lion 500 kV	
P2013_1-2D	Transource	\$788 - \$994	New Freedom - Lumberton - North Smithburg (New) 500 kV line	New Salem - Hope Creek 500 kV line and new 500/230 station east of Lumberton
P2013_1-3A	First Energy	\$410.7 (Only FirstEnergy portion)	New Freedom - Smithburg 500 kV line with a loop into Larrabee	Hope Creek - Red Lion 500 kV line
P2013_1-4A	PHI Exelon	\$475	Peach Bottom - Keeney - Red Lion - Salem 500 kV	Remove Keeney - Red Lion 230 kV; Reconfigure 230 around Hay Road; Reconnector Harmony - Chapel St 138 kV
P2013_1-5A	LS Power	\$116.3 - \$148.3	Salem - Silver Run (new) 230 kV; Salem 500/230 kV Transformer	New 230 kV station that taps existing Cedar Creek - Red Lion 230 kV and Catanza - Red Lion 230 kV
P2013_1-5B	LS Power	\$170	Salem - Red Lion 500 kV	
P2013_1-6A	Atlantic Wind	\$1,012	320 kV HVDC Salem/Hope Creek - Cardiff	SVC at Salem/Hope Creek; New HVDC Stations at Cardiff and Salem
P2013_1-7A	PSE&G	\$1,371	Salem-Hope Creek to Peach Bottom 500 kV	Existing ROW
P2013_1-7B	PSE&G	\$1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with Loop into Keeney
P2013_1-7C	PSE&G	\$1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with Loop into Red Lion
P2013_1-7D	PSE&G	\$831	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with New ROW
P2013_1-7E	PSE&G	\$692	New Freedom - Deans 500 and Salem - Hope Creek 500 kV lines	
P2013_1-7F	PSE&G	\$879	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Existing ROW

**Table 2.1: Summary of Artificial Island Window Proposals (Continued)**

Project ID	Proposal Sponsor	Proposal Sponsor Estimated Cost (\$M)	Major Components	Supporting Information
P2013_1-7G	PSE&G	\$1,034	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Same as 7F with a Loop into a new Larrabee 500 kV station
P2013_1-7H	PSE&G	\$1,177	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Northern Route
P2013_1-7I	PSE&G	\$1,353	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Same as 7H with the Southern Route
P2013_1-7J	PSE&G	\$915	New Freedom - New Station on Branchburg-Elroy 500 kV line (5017 Junction) and Salem - Hope Creek 500 kV line	Existing ROW
P2013_1-7K	PSE&G	\$1,066	New Freedom - Deans and Salem - Hope Creek - Red Lion 500 kV lines with Hope Creek - Red Lion (new)	Same as 7E with Hope Creek - Red Lion
P2013_1-7L	PSE&G	\$1,250	New Freedom - Smithburg and Salem - Hope Creek - Red Lion 500 kV lines with Hope Creek - Red Lion (new)	Same as 7F with Hope Creek - Red Lion
P2013_1-7M	PSE&G	\$1,548	New Freedom - Whitpain (North) and Salem - Hope Creek - Red Lion 500 kV lines with Hope Creek - Red Lion (new)	Same as 7H with Hope Creek - Red Lion
P2013_1-7N	PSE&G	\$1,289	New Freedom - a new Station on the Branchburg-Elroy - 500 kV line (5017 Junction) and Salem - Hope Creek - Red Lion 500 kV lines with Hope Creek - Red Lion (new)	

**ROW** – right-of-way



## Section 3 – Analytical Evaluation

### 3.0: Analytical Evaluation

#### 3.0.1 — Reviewing the 26 Proposals

PJM's initial review found that only two of the 26 projects as proposed satisfied the operational performance criteria specified in the posted requirements document. Consistent with established RTEP practice, PJM undertook additional engineering review to identify the most effective solution to stated needs, taking into consideration the elements of submitted proposals. Substation configuration changes, device changes such as increasing the size of a Static VAR Compensator (SVC) device, and adding or removing substation components such as circuit breakers and SVC devices improved the performance of several proposals. After subsequent additional analysis, PJM was able to categorize proposals into four groupings based on estimated cost, voltage level, technology and scope, as shown in **Table 3.1**:

- Proposals for southern Delaware River crossings – both overhead and submarine – that terminated at the existing 230 kV system in Delaware
- Proposals for new 500 kV lines from either Hope Creek or Salem substations to the Red Lion 500 kV substation in northern Delaware

- A proposal comprising thyristor controlled series compensation devices near New Freedom
- Proposals with cost estimates more than twice that of the others

#### *Evaluating the Four Proposal Groups*

Having identified the four study groups shown in **Table 3.1**, PJM initiated analyses to compare proposals in terms of transient stability, voltage, thermal and short circuit system performance. NERC TPL Standards require that following single contingencies all facilities be within their applicable facility ratings; transient, dynamic and voltage stability are maintained; and, cascading outages or uncontrolled separation do not occur. Analysis of the proposals in each group did not identify any steady-state voltage, thermal or short circuit system reliability criteria violations. Consequently, transient stability – including the need for system oscillations to display positive damping – emerged as a key performance metric as solution development continued.

PJM created over 200 transient stability cases and conducted over 1,000 simulations. Consistent with established practice, stability studies tested system response to three-phase-faults with normal clearing and single-line-to-ground faults with delayed clearing. Where proposal stability studies failed, they did so because simulations encountered transient rotor angle instability for critical contingencies under critical system conditions. Importantly, no stability

failure cases were encountered in which damping violations or voltage criteria violations were more critical than transient stability criteria violations.

#### *Delaware River Crossings*

PJM conducted additional stability, voltage and thermal performance, short circuit and NERC Category D studies for the Delaware River crossing elements of various proposals. Results of all those tests met required NERC reliability criteria. Additionally, market efficiency production cost simulations revealed economic benefits for river crossings on the order of several million dollars per year, but well below the market efficiency criteria for justification on economics alone.

#### *Initial SVC Device Analysis*

PJM staff studies showed the effectiveness of a number of the proposals could be improved with the addition of a dynamic reactive device. PJM evaluated SVC device effectiveness at Artificial Island, Orchard and New Freedom 500 kV substations shown earlier on **Map 1.4** by observing Artificial Island MVAR output and maximum angle swing. Study results revealed that the closer the SVC device location was to Artificial Island, the better the voltage response and the smaller the machine angle swing. When compared to the simulations without an SVC device, proposals with SVC devices provided better voltage and machine MVAR response at Artificial Island, correlating to better post-fault system stability.

**Table 3.1: Artificial Island Project Proposals Grouped by Scope and Cost**

Analytical Study Group	Group 1				Group 2					Group 3	Group 4
	Artificial Island to Delmarva 230 kV System between Cedar Creek and Red Lion				Artificial Island to Red Lion 500 kV					TCSC Near New Freedom 500 kV	Higher Cost Solutions
Project ID	P2013_1-1B	P2013_1-2A	P2013_1-2B	P2013_1-5A	P2013_1-1C	P2013_1-2C	P2013_1-4A	P2013_1-5B	Various	P2013_1-1A	P2013_1-2D, P2013_1-3A, P2013_1-6A, P2013_1-7A, P2013_1-7B, P2013_1-7C, P2013_1-7D, P2013_1-7E, P2013_1-7F, P2013_1-7G, P2013_1-7H, P2013_1-7I, P2013_1-7J, P2013_1-7K, P2013_1-7L, P2013_1-7M, P2013_1-7N
Project Sponsor	Virginia Electric and Power Company	Transource	Transource	LS Power	Virginia Electric and Power Company	Transource	PHI Exelon	LS Power	PSE&G	Virginia Electric and Power Company	
Approximate Cost Range	\$115 M - \$275 M				\$125 - \$300 M					\$133	\$692 - \$1,548 M

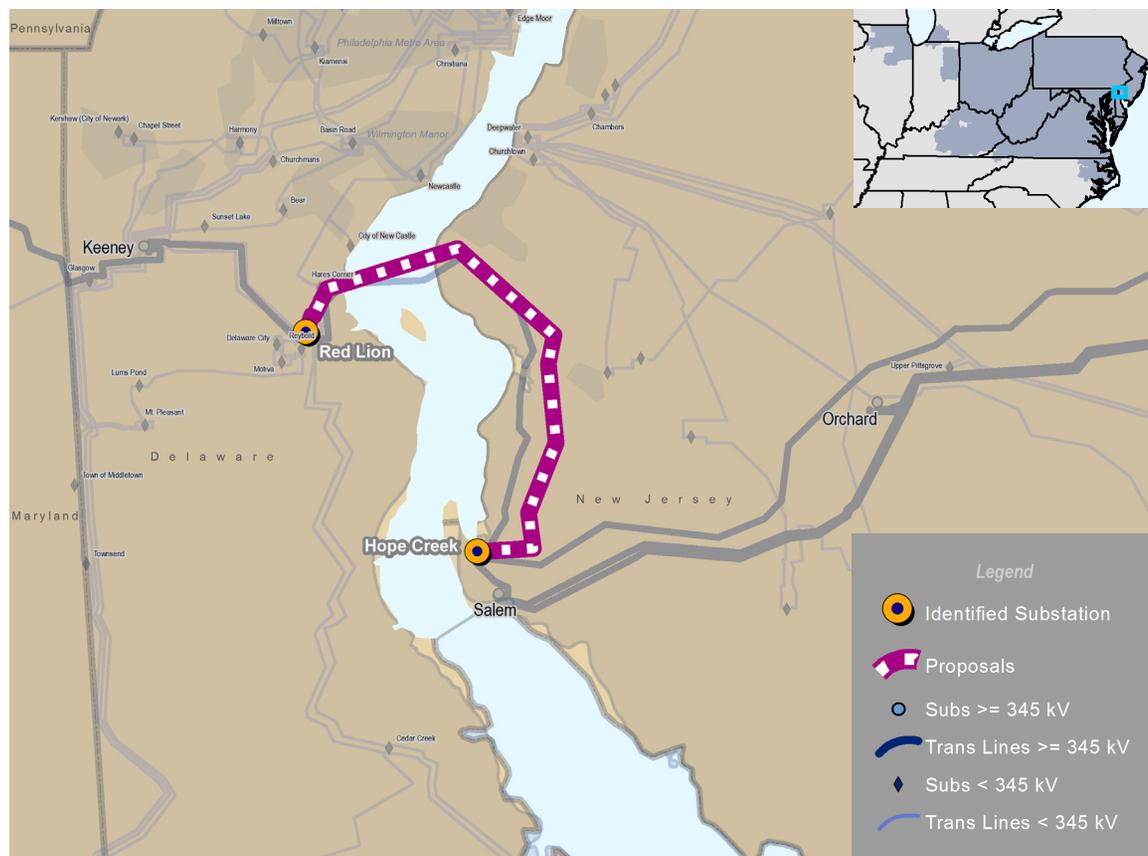
TCSC – Thyristor Controlled Series Device

### 3.0.2 — Further Analytical Evaluation of the Five Finalists

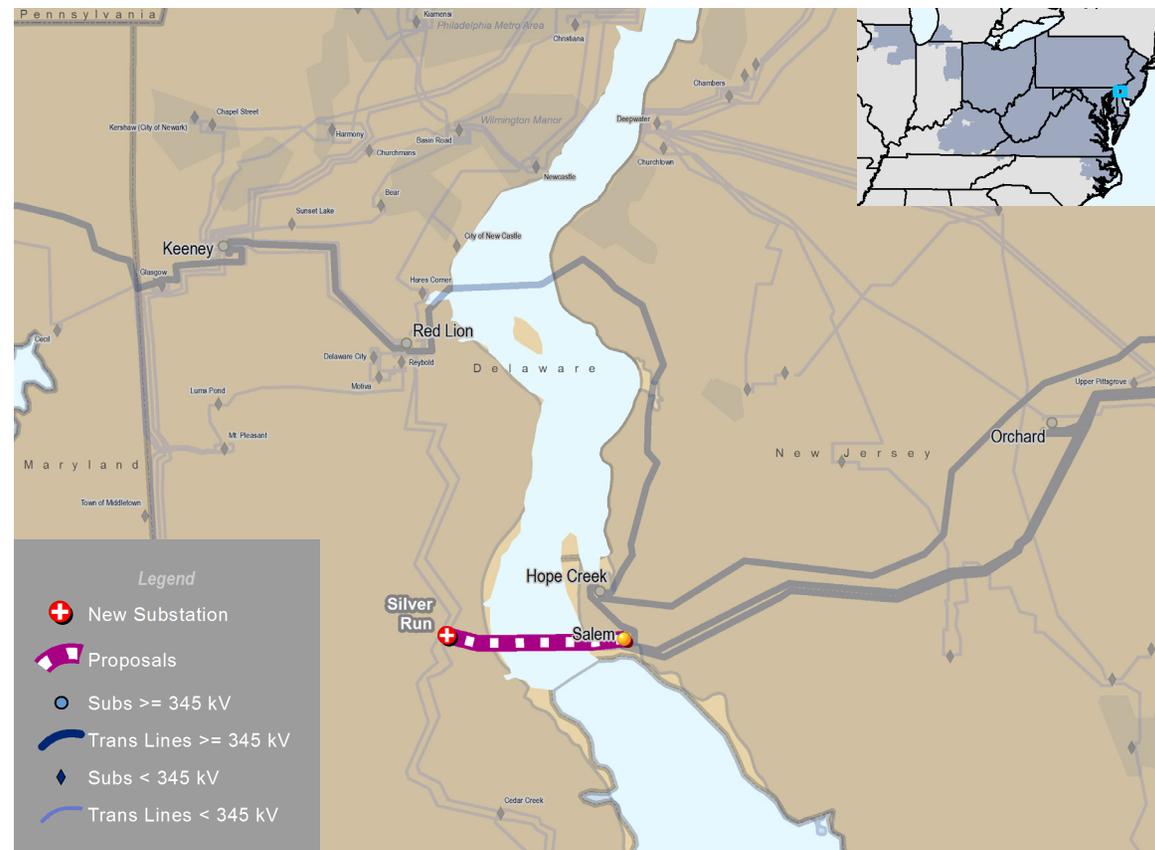
As analytical, constructability and cost evaluations proceeded – as discussed in **Sections 4 and 5** – PJM was able to narrow the list of viable solution options from 26 to five:

- Proposal PSE&G-7K, shown on **Map 3.1**, included a 17-mile 500 kV line from Hope Creek to Red Lion, paralleling the existing Red Lion to Hope Creek 500 kV line (designation 5015), and the expansion of the existing Hope Creek and Red Lion substations.
- Proposal DVP-1C, also shown on **Map 3.1**, submitted by Dominion Virginia Power, included an expansion of the existing Hope Creek 500 kV substation and the construction of a 17-mile 500 kV line from Hope Creek to Red Lion, paralleling the existing Red Lion to Hope Creek 500 kV line (designation 5015) and also included Red Lion substation reconfiguration into a breaker-and-a-half scheme.

**Map 3.1: Proposal PSE&G-7K and Proposal DVP-1C**

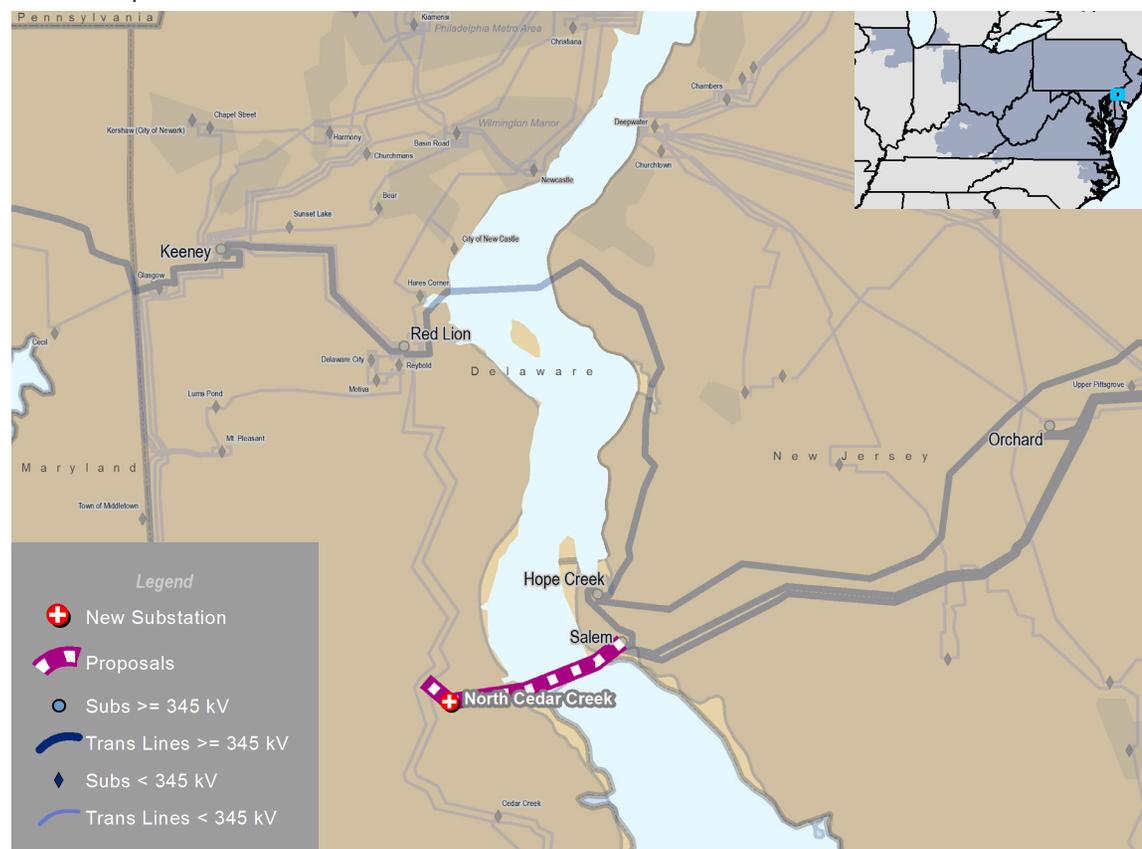


- Proposal LS Power-5A, shown on **Map 3.2**, included existing Salem substation expansion for a new 500/230 kV autotransformer and construction of a new 230 kV line from that point, under or over the Delaware River, to a new substation on the Delmarva Peninsula that would tap the existing Red Lion - Carranza and Red Lion-Cedar Creek 230 kV lines.

**Map 3.2: Proposal LS Power-5A**

- Proposal Transource-2B, shown on **Map 3.3**, included an expansion of the Salem 500 kV substation and the construction of a new substation near Artificial Island with two 500/230 kV autotransformers. The proposal would also include a new 230 kV line from that substation, under the Delaware River, to a new substation on the Delmarva Peninsula that would tap the existing Red Lion - Carranza and Red Lion-Cedar Creek 230 kV lines

**Map 3.3: Proposal Transource-2B**



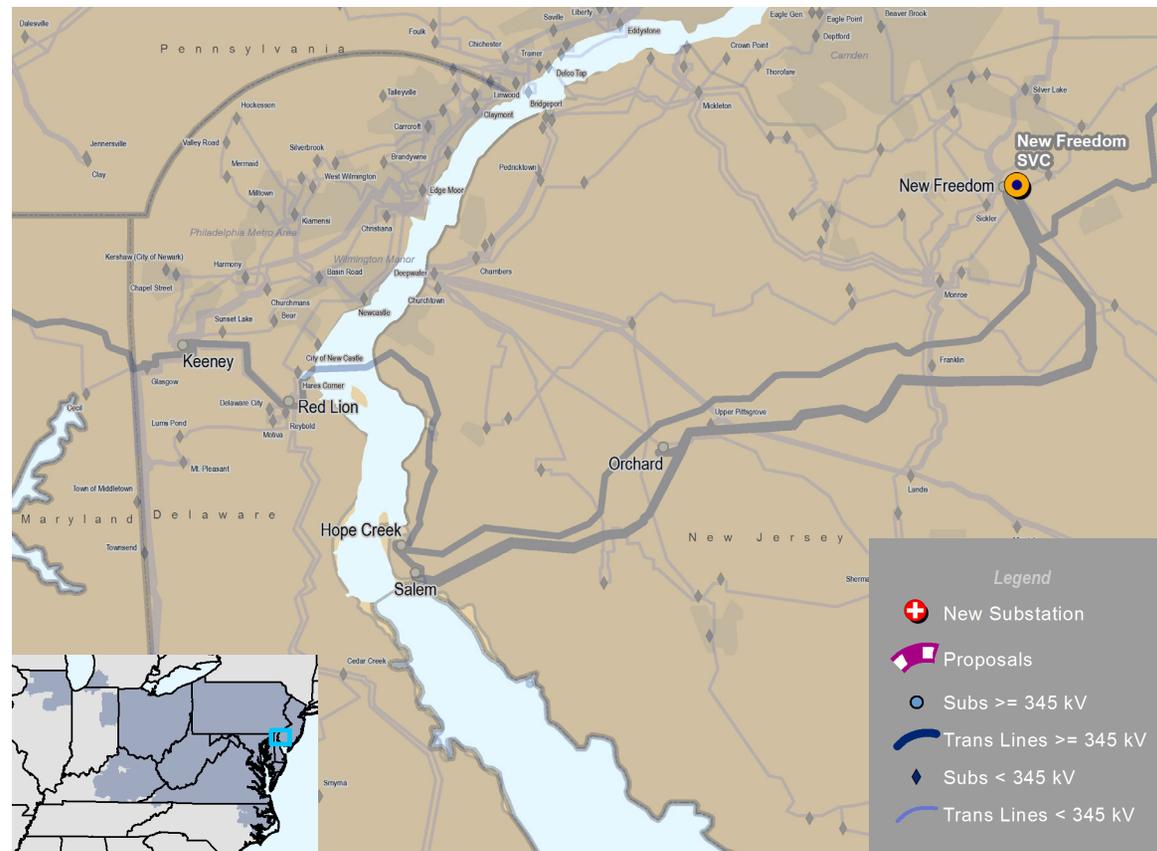
- Proposal DVP-1A, shown on **Map 3.4**, submitted by Dominion Virginia Power, included a new switching station, cutting the Hope Creek-New Freedom 500 kV line (operational designation 5023) and the Salem-New Freedom 500 kV line (5024), near New Freedom. The new substation would include 500 kV SVC devices and a thyristor controlled series compensation device.

**Sensitivity Studies**

Focusing on the proposals of the five finalists, PJM proceeded with sensitivity studies to evaluate system performance in light of several additional solution elements:

- Artificial Island generator step-up transformer (GSU) tap setting adjustments to improve voltage control
- SVC device installation at New Freedom in combination with the four transmission line proposals to help provide reactive power to control dynamic voltage swings
- Optical ground wire communications and new protection systems on a number of critical 500 kV circuits in the vicinity of Artificial Island:
  - Hope Creek - Red Lion (operational designation 5015)
  - Salem - Orchard (5021)
  - East Windsor - Deans (5022)
  - Hope Creek - New Freedom (5023)
  - Salem - New Freedom (5024)

**Map 3.4: Proposal DVP-1A**



- Salem - Hope Creek Line (5037)
- New Freedom - East Windsor (5038)
- New Freedom - Orchard (5039)

This would provide faster fault clearing times, thereby improving stability margin and the operational performance sought by PJM's request for proposal.

**3.0.3 — Sub-Synchronous Resonance (SSR)**

Sub-synchronous resonance (SSR) is the build-up of mechanical oscillations in a turbine shaft arising from the electro-mechanical interaction between the turbine generator and the rest of the power system. This can lead to turbine shaft damage, even catastrophic loss. The term “sub-synchronous” refers to the fact that the oscillations a shaft can experience occur at levels below 60 Hz (cycles-per-second). Power plants close to series

compensation devices may be prone to SSR. Specific technical analysis – such as that performed by consultants for PJM – can assess the potential for SSR to arise.

Specifically, the Dominion 1A proposal includes a new substation with a 750/-375 MVAR static VAR compensator (SVC) device plus two thyristor controlled series compensation devices, one each on the Salem–New Freedom 500 kV line and Hope Creek–New Freedom 500 kV line. PJM engaged consultant expertise to conduct a screening study to assess the potential for the device to create SSR conditions on Salem and Hope Creek turbine shafts. Using available mass moment-of-inertia and torsional model data for the machines at Artificial Island, studies evaluated the SSR impact by simulating a disturbance on the base operating scenario and monitoring the coupling torque in the shaft model. Screening study results, while far from conclusive, identified potential “negative damping” at Artificial Island for several resonant frequencies. In other words, the shaft would have the potential to experience growing, damaging oscillations at a frequency below 60 Hz.

PJM enlisted a separate, independent consultant to review the screening study results. The following recommendations and observations were made:

#### ***Detailed Spring-Mass Models***

Detailed spring-mass models of the turbine-generator shaft system should be considered when assessing the actual potential risk of SSR, particularly torsional interactions.

#### ***Post-Contingency Thyristor Controlled Series Compensation Level***

The 90 percent *post-contingency* thyristor controlled series compensation level proposed by Dominion should be examined further. PJM’s consultant identified 70-80 percent as the upper limit used for series capacitive compensation in industry power system applications today. A 90 percent level leaves little operating margin for avoiding SSR. From an engineering perspective, post-contingency compensation at 100 percent would effectively create a reactance roughly equal to zero, causing difficulty controlling transient voltages and currents following a system disturbance.

#### ***Real-Time Digital Power System Simulation***

PJM’s consultant also recommended additional study using real-time digital power system (RTDS) simulation to lend additional credibility to screening studies. More detailed modeling of the turbine-generator shaft system, the two thyristor controlled series compensation devices and the SVC device would provide simulation results much closer to actual operating conditions. The effectiveness and robustness of the thyristor controlled series compensation control systems and interactions with neighboring controlled equipment could also be validated.

Conducting a real-time digital power system study itself is complex. PJM consulted Dominion, who has this simulation capability to identify what would be required to do so. Once all required machine data were obtained, an estimated 26 weeks would be required for study completion. However, as modeling parameter data can likely only be obtained in coordination with a generating unit outage, significant risk of study delay also exists. Additionally, the 26 weeks does not include review time between various study stages.

#### **3.0.4 — Transient Stability Margin**

In engineering terms, suddenly changing the system impedance when lines fail, or when load is added or removed, causes a generator rotor to decelerate, accelerate or swing with respect to the stator magnetic field. Under such conditions, a generator can become unstable, causing relays to trip the unit within several cycles following the fault to avoid unit damage. Computer simulations study transient stability for several seconds, where one second equals 60 cycles or Hertz (Hz). If the system is found to be stable during the first swing, subsequent swings are likely to be less severe – “dampened” – allowing the system to return to a stable state thereafter. To that end, PJM conducted a series of studies to ensure Artificial Island unit transient stability following a 500 kV line tripping during the maintenance outage of another critical 500 kV line in the same area.

Table 3.2: Transient Stability Study Results – Margin Analysis

Project Name	OPGW and GSU Tap Optimization	TCSC: Normal / Transient	SVC Device Size	Max Angle Swing (Degrees)	Fault Clearing Time (Cycles)	CCT (1) (Cycles)	Margin to CCT (Cycles)	M14B Margin (Cycles)	Margin Results (Cycles)
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10
LS Power P2013_1-5A 230 kV	Yes	N/A	0	114	9.06(5)	9.31	0.25	0.50	-0.25
			300 MVAR	91	9.06	10.31	1.25	0.50	0.75
	No		650 MVAR	112	10.40	10.65	0.25	0.50	-0.25
Transource P2013_1-2B 230 kV	Yes	N/A	0	107	9.06	9.56	0.50	0.50	0.00
			300 MVAR	88	9.06	10.56	1.50	0.50	1.00
	No		650 MVAR	109	10.14	10.64	0.50	0.50	0.00
PSE&G P2013_1-7K 500 kV	Yes	N/A	0	100	9.06	9.81	0.75	0.50	0.25
			300 MVAR	83	9.06	10.81	1.75	0.50	1.25
	No		650 MVAR	107	4.02	4.27	0.25	0.25	0.00
DVP P2013_1-1C 500 kV	Yes	N/A	0	100	9.06	10.06	0.75	0.50	0.25
			300 MVAR	83	9.06	10.81	1.75	0.50	1.25
	No		650 MVAR	107	4.02	4.27	0.25	0.25	0.00
DVP P2013_1-1A TCSC only	Yes	40,45/90%	0	<b>Unstable</b>	<b>2.90</b>	<b>&lt; 2.90</b>	-	-	-
DVP P2013_1-1A TCSC + SVC		40,45/90%	500 MVAR	93	2.90	3.15	0.25	0.25	0.00
		0/50%	750 MVAR	99	2.90	2.90	0.00	0.25	-0.25
		0/70%	750 MVAR	81	2.90	3.40	0.50	0.25	0.25

300 MVAR SVC Results    Criteria Violation

**TCSC** – Thyristor Controlled Series Compensation  
**OPGW** – Optical Ground Wire  
**GSU** – Generator Step-Up Transformer  
**SVC** – Static VAR Compensation  
**CCT** – Critical Clearing Time

### Study Results

As **Table 3.2** shows, PJM conducted transient stability tests for each of the finalist proposals (Column 1) under varying SVC device sizes (Column 4) both with and without optical ground wire and generator step-up transformer tap optimization (Column 2). Across 15 of the 16 cases studied, maximum machine angle ranged from 81 to 114 degrees (Column 5) but did not become unstable. A sixteenth project - DVP P2013\_1-1A – exhibited instability. PJM conducted that particular run in order to model Dominion’s thyristor controlled series compensation project without its associated proposed SVC device to confirm if it would be needed for the proposal to be effective. As studied, the thyristor controlled series compensation case without a SVC device became unstable within three cycles.

Transient stability studies for the same 15 runs also confirmed that sufficient fault clearing time margin existed for each alternative before transient instability would otherwise occur. As **Table 3.2** shows, the 15 cases had “as-designed” relay fault clearing times (Column 6) that were less than the maximum (critical) fault clearing time (Column 7), the point after which that case became unstable. Subtracting the “as-designed” clearing time value from the maximum fault clearing time yielded transient stability margins (Column 8) from 0.00 to 1.75 cycles.

### Regional Reliability Requirements

PJM’s regional reliability requirements also require that studies evaluate remaining transient stability margin (Column 10) after a one-fourth and one-half permissible cycle of fault clearing time (Column 9) is deducted, to account primarily for uncertainty in actual clearing times. As **Table 3.2** shows, PJM added 0.25 cycle margin for normally cleared faults and 0.5 cycle margin for faults with delayed clearing time.

The results (Column 10) revealed zero or negative margin for eight of the 15 cases (indicated in red in Column 10). Notably, the greatest transient margin – between 0.75 and 1.25 – was observed for proposals which included a New Freedom SVC device with 300 MVAR capability (Column 4).

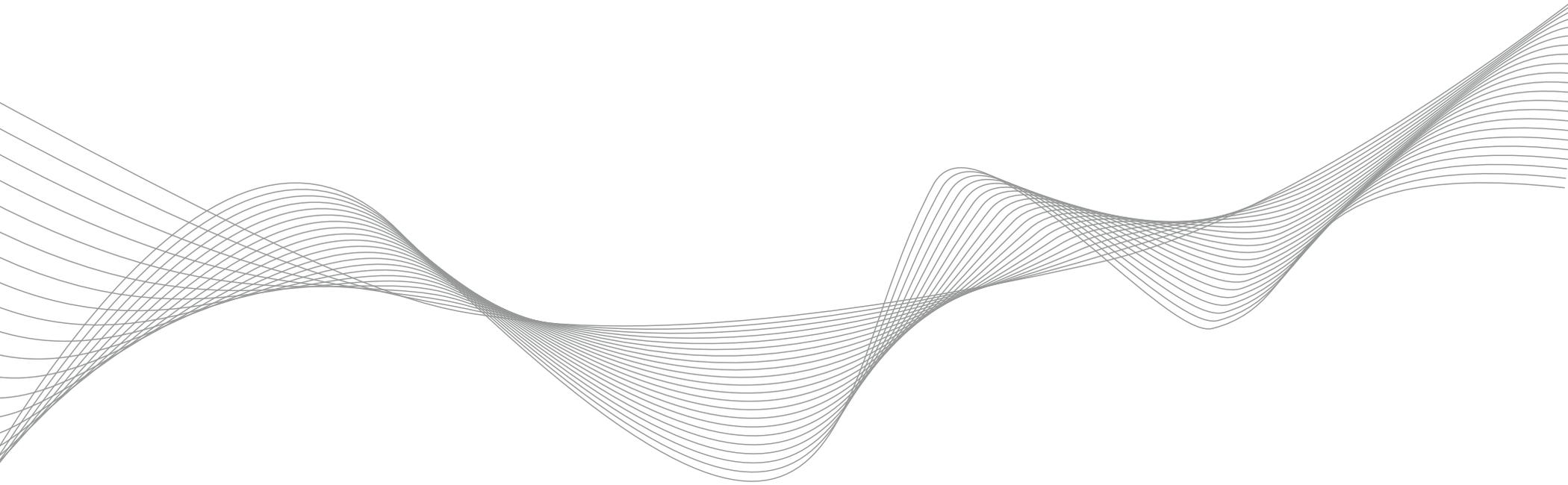
### 3.0.5 — Technical Observations

Based on the technical evaluation, PJM noted the following key points:

- A 300 MVAR SVC device at New Freedom provides key operational performance benefits needed under fault conditions: transient stability margin to meet PJM’s regional planning criteria and reactive power to control dynamic voltage swings.
- Artificial Island generator step-up transformer (GSU) tap setting adjustments improve voltage control.
- Optical ground wire (OPGW) communications added to the protection systems of eight identified 500 kV circuits in the vicinity of Artificial Island provides faster fault clearing times.

- Thyristor controlled series compensation presents downside challenges with respect to sub-synchronous resonance and transient stability: (1) the necessary real-time data simulator SSR study would require six months after data acquisition that is tied to Salem and Hope Creek unit outages; (2) the 90 percent post-contingency thyristor controlled series compensation level is well above 70-80 percent industry norms; and (3) transient stability performance at lower compensation levels is not as robust as that provided by transmission line solutions.

Reliability studies comprised just one component of PJM’s overall evaluation of Artificial Island proposals. Constructability evaluation provided PJM with additional key information in developing its recommendation to the PJM Board, as discussed next.



## Section 4 – Constructability Evaluation

### 4.0: Constructability Evaluation

#### 4.0.1 — Assessing Project Risks

In parallel with analytical evaluation, PJM enlisted engineering consultant expertise to evaluate project proposal constructability – cost, scheduling, siting, permitting, rights-of-way and land acquisition, project complexity, coordination and other risk areas. Any one or more factors could impact project completion or increase project costs. PJM consultants drew attention to a number of such factors. This section first discusses constructability risk factors across many proposals regardless of whether they are northern or southern route based. Then, **Section 4.0.2** and **Section 4.0.3** go on to highlight key factors pertinent to the northern route and southern route proposals.

#### ***Regulatory and Permitting Agencies***

All projects evaluated included the need to acquire land and rights-of-way. Much of PJM's constructability evaluation focused on the potential risks associated with Delaware River crossings – either overhead or submarine – that were elements of 18 proposals. Nearly 50 different federal, state and local permits and agencies could be involved. PJM had discussions with a number of these agencies to understand the scope of permitting and other issues:

- New Jersey Department of Environmental Protection
- United States Army Corps of Engineers
- National Oceanic and Atmospheric Administration
- United States Fish and Wildlife Service
- Delaware Department of Natural Resources and Environmental Control

Meetings with these agencies assisted PJM with identifying cost and scheduling risks associated with project complexity, rights-of-way, land acquisition, siting, permitting and public opposition. Several important considerations emerged:

- The permitting issues identified by consultants are consistent with the kind of constructability reviews and stakeholder comments associated with other prior transmission projects.
- River crossings must address the regulatory requirements of the U.S. Army Corps of Engineers, Delaware River Basin Commission, U.S. Coast Guard and National Marine Fisheries Service.
- State CPCN filings must address potential wetland, view-shed, archeological, transportation infrastructure, endangered species, historic, parks, and other environmental and cultural resource impacts.

The following index of regulatory names and acronyms is provided for ease of reference throughout this section.

- Certificate of Public Convenience and Necessity – CPCN
- Code of Federal Regulations – CFR
- Delaware Department of Natural Resources and Environmental Control – DNREC
- Delaware Public Service Commission – DEPSC
- Delaware River Basin Commission – DRBC

#### **Note:**

- Environmental Impact Statement – EIS
- National Environmental Policy Act – NEPA
- National Oceanic and Atmospheric Administration – NOAA
- New Jersey Board of Public Utilities – NJBPU
- New Jersey Department of Environmental Protection – NJDEP
- Nuclear Regulatory Commission – NRC
- United States Army Corps of Engineers – USACE
- United States Fish and Wildlife Service – USFWS

The National Environmental Policy Act (NEPA) defines the federal environmental permitting process and will have a major impact on path feasibility: the environmental effects of transmission projects requiring navigable water crossings, for example. PJM's consultants indicated a possibility that a full Environmental Impact Statement (EIS) would be required, which can extend a project schedule by one to two years.

The Delaware River is also an important flyway for migratory birds. Any options that involves an overhead line and associated tower structures could cause potential impact. The need for bird diversion devices placed on the towers and conductors would mostly likely be identified through the consultation and permitting process with federal agencies like the USACE and the U.S. Fish and Wildlife Service (Migratory Bird Treaty Act). Project cost and schedule could be affected.

#### ***Wetlands/Endangered Species***

All proposed routes would cross wetlands and potentially impact threatened or endangered plants and animals, requiring consultation with state and federal agencies, including the USACE. In some instances, like a crossing of the Delaware River itself, before-and-after environmental studies may be required. These could take up to two years to complete before approval could be granted.

#### ***Public Opposition***

PJM's consultants emphasized that public opposition should be expected. Many of the proposals include a Delaware River crossing either by overhead or submarine cable. Temporary impacts from submarine cable construction may be viewed as less harmful than the potential permanent impacts to view-shed, migratory bird flyways and other environmental impacts from an overhead river crossing. In general, public opposition has occurred more often with overhead than submarine options.

Impacts to the scenic river landscape and aquatic habitats together with safety concerns of commercial shipping traffic and recreational watercraft can generate the biggest objections to an overhead crossing. Consultant review of other recent river crossings also suggested that when siting and permitting overhead electric transmission lines, visual impacts from tall transmission tower structures routinely experience high levels of public opposition.

#### ***Rights-of-Way***

Proposed transmission lines comprising new facilities require new rights-of-way. In Delaware, utilities do not have eminent domain authority subject to state law. Rather, they must negotiate with private property owners for easements for new facilities. This lack of eminent domain authority must be addressed in budget and timeline assumptions.

#### ***Existing Facility Expansion***

The extent to which proposals require modifications to the Artificial Island substations must be considered. A solution that minimizes modifications at Salem in particular would be preferable. Space for expansion is limited and installing new protection and control equipment in the secure area of Salem generating station adds to project complexity.

- Any 500 kV line bay additions to the Salem substation would require careful design given the proximity to the Salem 1 generator step-up transformer leads. Installing equipment in this section of the substation would impede access to station auxiliary transformers.
- All Salem substation controls are located within the protected area of the generating station. Currently, only limited spare conduit from the substation back into the plant is available that could be used for any of the control cable associated with the new substation facilities.
- New Salem to Red Lion 500 kV transmission lines would encounter the need to relocate and/or cross existing lines. Line crossings add design, construction and operational complexity.

By comparison, expansion space and design complexity are less of an issue at the Hope Creek substation:

- Sufficient space exists to accommodate a new 500 kV line bay for a transmission line to Red Lion.
- Using existing space would not significantly impede access to station equipment compared to the alternatives out of Salem. Hope Creek substation equipment controls are located in a separate control building in the substation yard, eliminating the need to run new control cable into protected areas.
- A new 500 kV line from the Hope Creek substation to Red Lion would not introduce any new 500 kV line crossing.

Coordination with incumbent substation owners would be necessary before a final design could be developed. Additionally, construction could require numerous sequential outages.

#### ***Outages Required for System Expansion***

Transmission Owner and Generation Owner coordination would be necessary to address the need for construction sequencing, existing facility relocation, expansion, modification and reconfiguration complexities. All projects will require outages to connect to the existing grid. In particular, outages of the existing Red Lion-Hope Creek 500 kV line (operational designation 5015) have historically proven to be difficult to schedule for any extended duration. Outage delays could jeopardize project completion within the planned schedule and budget. By way of example, one

project as proposed would require three outages on the 5015 line totaling approximately 40 days. Artificial Island is geographically and electrically located close to several other Transmission Owner zones – Atlantic Electric, Jersey Central Power and Light, Delmarva Power and Light. Outages of existing facilities in the area must be closely coordinated among PJM and them.

#### ***Nuclear Plant Safety***

PSE&G Nuclear raised concerns regarding the potential for SSR events if thyristor controlled series compensation technology were to be implemented. In evaluating the impact of any project to the Artificial Island facility, the nuclear licensee (PSE&G Nuclear) performs a 10CFR50.59 Safety Evaluation. If the evaluation identifies nuclear safety impacts that require a technical specification change, then NRC approval would be required. The NRC did not raise concerns about the use of compensation devices in the vicinity of Artificial Island.

#### ***Ongoing Maintenance***

All projects would impose ongoing operational impacts to existing Artificial Island facilities to some degree. However, proposals that include Salem substation modification are likely to have greater impact. The 230 kV based projects are likely to impose on-going maintenance needs given their associated 500/230 kV transformers and appurtenant facilities. Projects that would utilize portions of the Salem substation would likely have additional maintenance needs caused by salt contamination given its proximity to Delaware Bay estuaries.

#### **4.0.2 — Northern Route Risk Factors**

PJM's independent consultants evaluated the constructability of a 500 kV transmission line from Artificial Island in Salem County, N.J., to the Red Lion 500 kV substation in New Castle County, Del. Based on their high-level review and analysis of the proposed projects, the proposed transmission line would most likely be feasible but the existence of several potential construction risks could affect the estimated costs and schedules proposed by the submitting entities.

#### ***Construction Challenges***

The landscape crossed by the line introduces a number of construction challenges with respect to both river crossing and on-land elements. The installation of structures and foundations in the Delaware River and coastal wetlands would introduce challenging access to structure locations, requiring extensive use of swamp mats and helicopter installation. Additionally, the river crossing element could potentially raise navigational concerns, depending on the location of the towers within the river.

#### ***Permitting and Agency Risk Factors***

Permitting of state lands and wetlands, cultural resources investigations and demonstration of public need could raise regulatory and right-of-way acquisition challenges. Consultants highlighted a number of permitting risks. In addition to the need to adopt special construction techniques for specific wetland types and field conditions, the type of wetlands has significant implications from a permitting and compensatory mitigation perspective. Forested wetlands in general tend to be considered a more sensitive, higher-quality resource than other wetlands types given their

ecological diversity, comparative rarity and long recovery time once disturbed. Although no critical habitats have yet been identified within the project study area, if a protected species or suitable habitat is identified during field surveys, specific mitigation measures may be required – timing restrictions and buffer zones, for example. However, in the absence of project-specific agency consultation, survey and mitigation requirements are uncertain.

The proposed northern route project corridor would cross three federally managed properties located within New Jersey: USFWS Supawna Meadows National Wildlife Refuge, USFWS Artificial Island and United States Army Corps of Engineers (USACE) Killcohook Coordination Area (formerly Killcohook Migratory Bird Refuge). The proposed route would also cross state public lands managed by New Jersey and Delaware, including wetland restoration sites, conservation areas and wildlife management areas. As with all properties on the proposed project route, the developer would need to seek access permission for pre-construction engineering and environmental surveys, as well as easement rights before the project goes to construction. The project requires coastal zone management approval from New Jersey Department of Environmental Protection (NJDEP) and Delaware Department of Natural Resources and Environmental Control (DNREC), which may involve a lengthy review process depending on construction techniques and proposed pathways needed to access the right-of-way. The project itself could potentially impact 32 acres of forested wetlands.

The Delaware River Basin Commission (DRBC) has regulatory mechanisms in place that drive overall state-level environmental evaluation. The New Jersey Board of Public Utilities Commission (NJBPU) and Delaware Public Service Commission

(PSC) would coordinate with the NJDEP and DNREC through the process that leads to issuance of Certificate of Public Convenience and Necessity (CPCN), in the case of New Jersey. Issuance would likely occur concurrently with USACE, USFWS and state agency approvals. The state commissions would be hesitant to approve the project without assurance that it is being coordinated with NJDEP and DNREC.

**Supawna National Wildlife Refuge**

Crossing the Supawna National Wildlife Refuge could be challenging and difficult with the availability of other viable alternatives. Permitting must address the combination of technical and regulatory complexities associated with the combined approximately six-mile line section that crosses the federally protected wildlife refuge. A right-of-way permit will need to be obtained from USFWS to cross Supawna National Wildlife Refuge. The process for obtaining easements on federally managed lands is typically lengthy and complex. If the project becomes controversial, the permitting process may extend well beyond the anticipated project schedule.

**Operational Robustness**

The northern 500 kV options were considered to be more operationally robust than the 230 kV projects.

**4.0.3 — Southern Route Risk Factors**

PJM also engaged independent consultants to evaluate the constructability of overhead and submarine 230 kV transmission from Artificial Island to the existing Red Lion – Cedar Creek 230 kV line on the Delmarva Peninsula. Siting and permitting a new river crossing will be a major project schedule component.

**Permitting and Agency Risk Factors**

As with the northern route, PJM’s consultant highlighted a number of on-land and Delaware River crossing transmission risks as summarized earlier in **Section 4.0.1**. Southern route permitting would be required by the United States Army Corp of Engineers who would likely coordinate review among most agencies from whom approval would be needed. From an on-land transmission construction risk perspective, however, Delaware’s DNREC project review will likely give increased scrutiny to the impact to Highway 9, a narrow two-lane road classified as a “Coastal Heritage Scenic Byway” by the State of Delaware. At the very least, this highway designation could add to the level of public opposition.

**Augustine Wildlife Area**

The Augustine Wildlife Area is owned by DNREC Division of Fish and Wildlife. If the area cannot be avoided through route selection, a permit will be required. Acquiring easements on state public lands – conservation easements, wetland restoration sites and wildlife management areas – typically involves multiple reviews and coordination between state environmental and real estate divisions. Obtaining a permit for Augustine Wildlife Area could be difficult if other viable alternatives exist.

### ***Submarine Construction Challenges***

A Delaware River submarine cable crossing poses unique construction challenges. The cable will require a depth of 25 feet below the river bottom within the shipping channel, as noted in discussions with the Army Corps of Engineers. PJM's consultants noted, however, that with proper consultation with the Coast Guard and other regulatory agencies, shipping channel issues associated with such normal waterway activities as fishing, anchors and other new river installations should be minimized.

Consultant reports also cited recent experience with dredging projects against which much public opposition was raised and many legal challenges were mounted. Opponents drew attention to potential river bottom ecosystem and water quality issues caused by cable installation, particularly that caused by jet-plowing techniques. Horizontal directional drilling installation techniques, in contrast, may mitigate these concerns.

### ***Horizontal Directional Drilling***

Unlike jet-plowing techniques, which impact the riverbed over the length of the installation, horizontal directional drilling impacts will be limited to the area associated with two coffer dams within the river, greatly reducing the disturbance area. Horizontal directional drilling employs a long, flexible drill bit to bore horizontally underground. This technology is a trench-less method in which no surface excavation is required except for drill entry and exit points. This minimizes surface restoration to a fraction of that associated with installations completed with open-cutting and associated ecological disturbances and environmental impacts.

Utilizing horizontal drilling is less likely to require a National Environmental Policy Act (NEPA) Environmental Impact Statement (EIS).

Notwithstanding the potential permitting issues identified, consultants suggested that the temporary disruption of Delaware River habitats as a result of submarine cable installation is preferable to the ongoing permanent disruption caused by overhead transmission river crossings and associated tower structures.

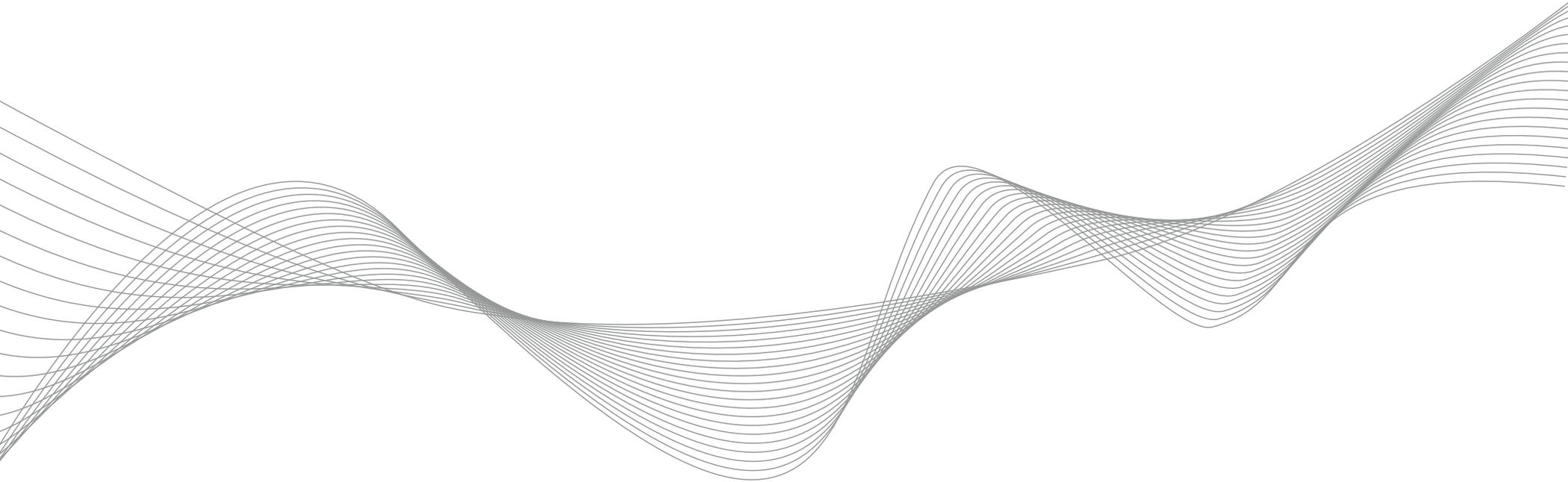
### **4.0.4 — SVC Device Constructability Analysis**

PJM's technical analysis indicated that a SVC device located at Artificial Island performed marginally better than one located at New Freedom or Orchard substations. Consultant expertise was engaged to contrast the constructability risks of the proposed locations. Based on their analyses, PJM determined that the project complexities of installing an SVC device at Artificial Island outweighed marginal performance gains over the New Freedom 500 kV substation.

### **4.0.5 — Constructability Observations**

Several key observations have guided PJM Artificial Island solution development:

- A solution that can mitigate permitting is preferred, particularly in such areas as the Supawna Meadows National Wildlife Refuge (impacted by the 500 kV Red Lion-Hope Creek transmission line proposal) and the Augustine Wildlife Area (impacted by 230 kV southern transmission line proposals). Permitting agencies would not state the likelihood of project permitting success without detailed design and route information in hand. They did note, however, that permitting through the sensitive Supawna Meadows National Wildlife Refuge and Augustine Wildlife Area could be more difficult if other viable alternatives were available.
- Siting and permitting for a new river crossing will be a major project schedule component under all proposals. Lower risk appears to exist for solutions that utilize horizontal directional drilling to minimize environmental impacts.





## Section 5 – Cost Commitment Evaluation

### 5.0: Cost Commitment Evaluation

#### 5.0.1 — Cost Estimate Submittals

Transmission project construction costs are influenced by many factors. The Artificial Island proposals are no exception. Cost estimates submitted to PJM addressed line routing, siting and permitting, environmental remediation, engineering, material procurement, line construction, expansion of existing substations, project management and contingency.

##### *Initial Cost Estimates*

Seven different sponsors submitted 26 separate proposal packages during the Artificial Island Window. Cost estimates ranged from approximately \$100 million to \$1.55 billion and reflected a diverse range of technologies at both 500 kV and 230 kV. Utilizing input from previous RTEP projects and consultant expertise, PJM developed cost estimates that permitted a more level-playing-field comparison.

##### *Supplemental Project Information*

In July 2014, LS Power submitted a cost commitment of \$146 million for all costs for its proposed 230 kV transmission line and new substation in Delaware. At its July 2014 meeting, the PJM Board reviewed PJM's technical and constructability evaluation to that point, as well as LS Power's proposed cost commitment. In light of LS Power's submittal, the PJM Board directed PJM

to allow PSE&G, Transource Energy and Dominion the opportunity to supplement their proposals as well. The PJM Board did reiterate, however, that cost was only one among a number of considerations that would guide its Artificial Island solution decision. Among the four finalists, LS Power, Transource and PSE&G elected to provide a cost commitment or cost containment mechanism.

##### *LS Power Cost Commitment Summary*

The LS Power cost commitment for the 230 kV line between Salem substation and the 230 kV right-of-way in Delaware and for the new substation in Delaware included the costs for the items below:

- Obtaining permits and other governmental approvals;
- Acquiring land and land rights
- Performing environmental assessments or mitigation activities
- Design and engineering
- Procurement of equipment, supplies and materials
- All other development and construction-related activities – e.g. site clearing, equipment assembly and erection, testing and commissioning

- Applied to overhead, submarine or horizontal directional drilling river crossing alternatives

Costs excluded from the LS Power commitment included the following:

- Escalation, taxes, and financing (e.g. AFUDC) costs. Escalation of the cost commitment would be tied to an industry standard index.
- Additions and modifications to the project scope due to:
  - Material change in the enforcement, interpretation of application of any statute, rule, regulation, order or other applicable existing law
  - Breach or default by PJM of its obligations under the Designated Entity Agreement
  - Request by PJM to delay or suspend project activities
  - Breach, default, interference or failure to cooperate by any Transmission Owner in connection with the Interconnection Coordination Agreement or interconnection agreement
  - Ongoing project maintenance and operations costs.

LS Power affirmed that the scope of work included all activities required to achieve an overhead or submarine crossing of the Delaware River.

#### **PSE&G Cost Commitment Summary**

PSE&G proposed an *in-service year* cost commitment of \$221 million. The scope of work under the commitment comprised the 500 kV line between Hope Creek and Red Lion substations and the upgrades required at the Hope Creek substation. PSE&G indicated that the cost commitment included all project costs, with exceptions as noted below:

- Costs associated with PJM modifications or additions to the scope of work
- Costs incurred from the following events deemed outside of the control of PSE&G:
  - Changes in applicable laws and regulations
  - Obtaining governmental approvals and permits
  - Obtaining necessary property rights
  - Environmental permitting, remediation and mitigation
  - Orders of courts or action or inaction by governmental agencies

#### **Transource Cost Commitment Summary**

Transource provided a cost containment mechanism in which it would forego certain incentive rates if project costs exceeded certain thresholds. The scope of work under the mechanism included the 230 kV line and the new substations – one in Delaware and the other adjacent to or near the Salem substation. The work at Salem substation and on the right-of-way in Delaware required to connect the new substations would not be under the mechanism. The proposed tier levels and incentive rate changes are summarized below:

- Up to \$243 million
  - Entitled to recover all FERC-approved ROE plus incentives
- Portion from \$243 to \$299.8 million
  - Forego 50 percent of any FERC-approved ROE incentives
- Above \$299.8 million
  - Forego 100 percent of any FERC-approved ROE incentives

#### **5.0.2 — Cost Commitment Evaluation**

Subsequent to the July 2014 PJM Board meeting, PJM factored into its evaluation the supplemental project cost information submitted by PSE&G, Transource Energy, LS Power and Dominion. PJM enlisted the assistance of third party consultant expertise to assess the validity of the submitted estimates and to support the development of additional cost estimates where required.

#### **Comparing Cost Commitments**

**Figure 5.1** provides a cost commitment comparison. The estimates couple the Proposing Entity's cost commitment numbers with PJM's own cost estimates for those elements that were not provided: expansion of existing substations and additional solution elements identified by PJM to satisfy requirements of the solicitation. Total project cost estimates were derived from the components described below.

- *Cost commitment* estimates were provided by PSE&G, Transource Energy and LS Power for the transmission facility elements included in their respective supplemental submittals. Dominion did not provide a cost containment value.
- *Upgrade project elements* capture the cost of the Transmission Owner work required to accommodate the proposed line.
- *Optical Ground Wire (OPGW)* installation for proposals Transource-2B and LS Power-5A is estimated to cost \$25 million. That estimate is reduced to \$20 million for proposals Dominion – 1C and PSE&G-7K given that certain OPGW costs would be included in the cost for the Hope Creek to Red Lion Line construction.
- *Generator Step-Up (GSU) Transformer tap settings* can be changed at minimal additional cost and were not a determining cost factor.
- *SVC Device* installation for each proposal is estimated by PJM to cost between \$31 and \$38 million based on input from PJM's consultants.

Figure 5.1: Cost Commitment Comparison

	Dominion 1C Hope Creek - Red Lion 500 kV Line (\$M)	Transource 2B 230 kV Submarine Line (\$M)	LS Power 5A 230 kV Submarine Line (\$M)	PSE&G Hope Creek - Red Lion 500 kV Line (\$M)
Cost Containment (Per Supplemental Proposals)	n/a	\$203 - \$259	\$146	\$221
Project Cost Estimate (Where Not Provided)	\$211 - \$257	n/a	n/a	n/a
<b>Additional Proposal Elements:</b>				
· New Salem Substation	n/a	\$41	n/a	n/a
· Existing Salem Substation Expansion	n/a	\$14 - \$17	\$61 - \$74	n/a
· Existing Red Lion Substation Expansion	n/a	n/a	n/a	\$4 - \$6
OPGW / GSU Taps	\$20	\$25	\$25	\$20
SVC Cost Estimate	\$31 - \$38	\$31 - \$38	\$31 - \$38	\$31 - \$38
<b>Project Capital Cost Total Estimate Current Year Dollars</b>	<b>\$263 - \$316</b>	<b>\$313 - \$380</b>	<b>\$263 - \$283</b>	<b>\$277 - \$285</b>
<b>Project Capital Cost Total Estimate Future Year Dollars</b>	<b>\$284 - \$341</b>	<b>\$346 - \$411</b>	<b>\$284 - \$306</b>	<b>\$281 - \$290</b>

**Capital Cost Total Estimates**

PJM developed a *Project Capital Cost Total Estimate* for each proposal in both *current-year* dollars and *in-service year* dollars, given that PSE&G provided their cost commitment numbers in terms of in-service year dollars. In order to compare the costs on a common basis, PJM applied an escalation factor to the other three proposals at 2.5 percent per year. PJM selected 2.5 percent based on historical data from various resources, including the Bureau of Labor Statistics and PJM's Cost Development Subcommittee.

**Note:**

We note that on July 24, 2015, PSE&G submitted a modification to its proposal. This late-filed submission came too late in the process to afford all stakeholders due process and an opportunity to review the revised proposal. As a result, it was not considered as a timely modification of PSE&G's proposal. However, even if PJM had considered the latest PSE&G modification, it does not modify the PJM staff's recommendation since PSE&G has still left uncapped a potentially significant level of environmental mitigation costs, which could well occur under its proposal.

### 5.0.3 — Cost Commitment Observations

Key cost commitment observations that influenced PJM's Artificial Island solution recommendation included the following:

- Proposals Transource-2B and Dominion 1C have higher estimated costs relative to proposals PSE&G-7K and LS Power-5A,
- PJM evaluated the proposed cost commitments and found that LS Power's terms and conditions provide fewer exclusions than those proposed by PSE&G. PJM considered the potential magnitude of the cost impact of the proposed non-standard terms and conditions that address exclusions to the cost commitments provided by LS Power and PSE&G. Risks considered were the potential for route change, for schedule delays and for additional costs associated with environmental mitigation. As a result, PSE&G's proposal shows greater potential for increased costs. When considering the potential cost of such factors, the net effect is a further overlapping of the range, from low to high, of the total cost estimates for the two projects.

## Section 6 – Recommended Solution & Next Steps

### 6.0: Recommended Solution and Next Steps

#### 6.0.1 — Recommendation to the PJM Board

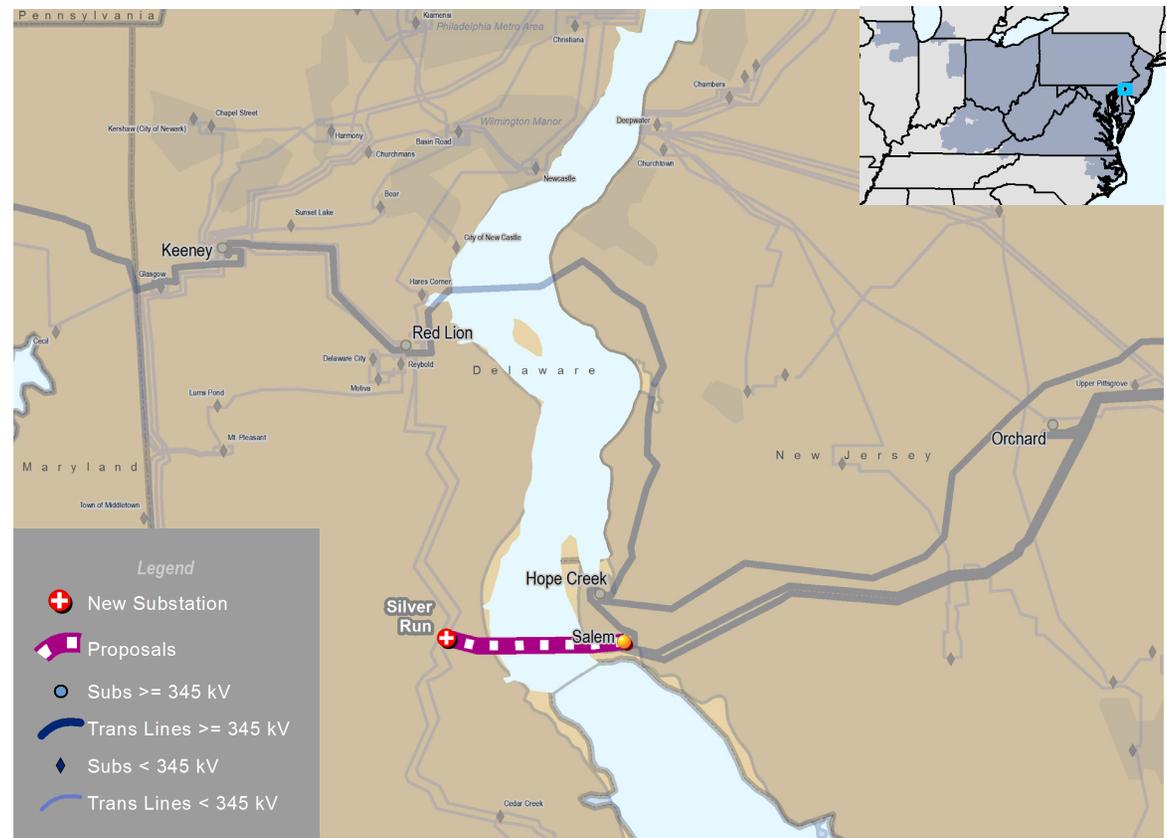
Each project offers certain advantages and risks with regard to performance, cost commitment and constructability. However, based on its technical analysis and constructability assessments, PJM staff is recommending the following projects to the Board because they represent the best balanced solution that both satisfies the technical performance requirements and provides a constructible solution with reasonable cost commitment.

#### ***New 230 kV Transmission Line Delaware River Crossing***

A new 230 kV transmission line to be designated to LS Power should be constructed under the Delaware River from Salem to a new substation in Delaware that would tap the existing Red Lion - Carranza and Red Lion - Cedar Creek 230 kV lines, as shown on **Map 6.1**. Associated substation work at Salem would be designated to PSE&G and associated work on the 230 kV right-of-way in Delaware would be designated to Pepco Holdings, Inc. (PHI).

The LS Power proposal provides greater cost certainty with fewer exclusions to its cost commitment. From a constructability perspective, utilizing horizontal directional drilling techniques could mitigate siting and permitting risks.

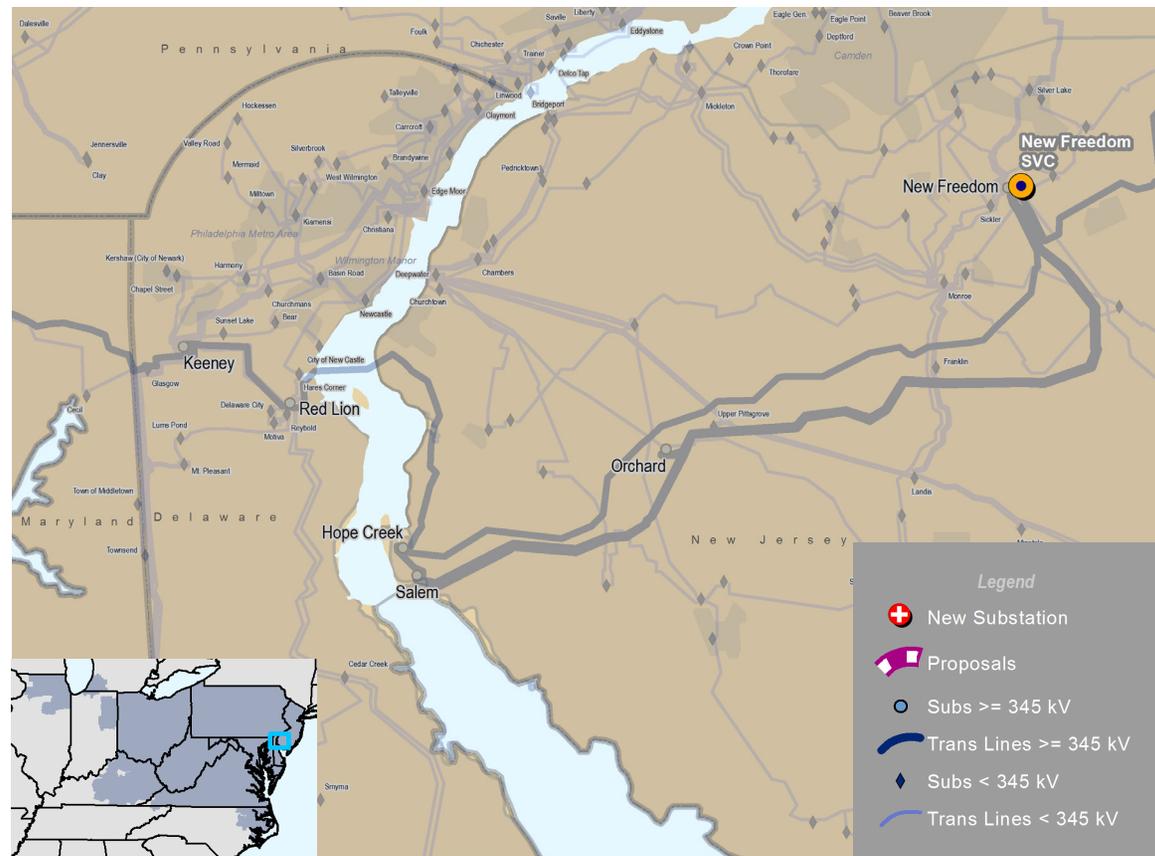
**Map 6.1: New 230 kV Transmission Line Delaware River Crossing**



**New Freedom 300 MVAR SVC Device**

A new 300 MVAR SVC device should be constructed at the New Freedom 500 kV substation, shown on **Map 6.2**, and designated to PSE&G. When compared to the simulations without an SVC device, proposals with SVC devices provided better voltage and machine MVAR response at Artificial Island, correlating to better post-fault system stability operational performance as sought by PJM’s request for proposal.

**Map 6.2: New Freedom 300 MVAR SVC Device**

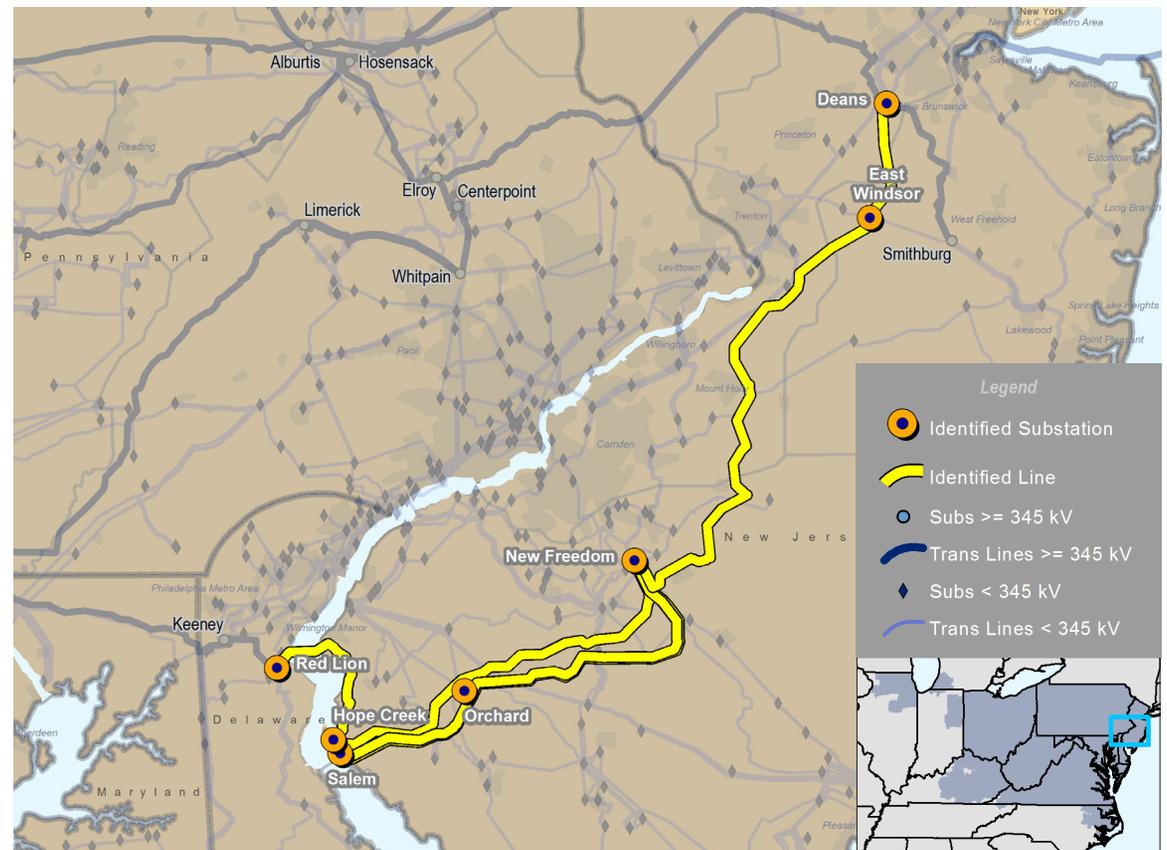


**High Speed Optical Ground Wire Communications**

High speed relaying utilizing optical ground wire (OPGW) communications should be added to the protection systems of a number of critical 500 kV circuits in the vicinity of Artificial Island, listed below and shown on **Map 6.3**, to provide faster fault clearing times, thereby providing additional stability margin:

- Hope Creek - Red Lion (operational designation 5015)
- Salem - Orchard (5021)
- East Windsor - Deans (5022)
- Hope Creek - New Freedom (5023)
- Salem - New Freedom (5024)
- Salem - Hope Creek Line (5037)
- New Freedom - East Windsor (5038)
- New Freedom - Orchard (5039)

Doing so would improve the operational performance sought by PJM's request for proposal. OPGW upgrades to these facilities would be designated to PSE&G, PHI and FirstEnergy accordingly.

**Map 6.3: 500 kV Lines for Optical Ground Wire Communications**

### **Artificial Island Generator Step-Up Transformer**

#### **Tap Settings**

Tap settings for the generator step-up transformers at the three Artificial Island units – Salem 1, Salem 2 and Hope Creek – should be changed, as designated to PSE&G. Doing so would improve the voltage control operational performance sought by PJM's request for proposal in accordance with NERC TPL Standards.

#### **6.0.2 — Next Steps**

If the PJM Board elects to approve the recommended solution, PJM staff will then notify LS Power that it has been assigned as the Designated Entity for the 230 transmission line portion of the solution. PJM will also draft the Designated Entity Agreement and Interconnection Coordination Agreements, which will detail the duties, accountabilities, obligations and responsibilities of each party. The terms of the Designated Entity Agreement will incorporate those presented by LS Power in documents posted publicly on PJM's website and shared with PJM stakeholders. Existing Transmission Owners with responsibility for portions of the recommended solution will be notified of their respective Designated Entity assignments as well.

Likewise, Board approval will include cost allocation identified by PJM consistent with the terms of the PJM's Operating Agreement and Open Access Transmission Tariff (OATT).

#### **Designated Entity Agreement**

When a project is designated as greenfield and not reserved for the Transmission Owner, a Designated Entity Agreement must be executed. The Designated Entity Agreement defines the terms, duties, accountabilities and obligations of each party, and relevant project information, including project milestones. Once construction is complete and the Designated Entity has met all Designated Entity Agreement requirements, the Agreement is no longer needed. The Designated Entity must execute the Consolidated Transmission Owners Agreement as a requirement for Designated Entity Agreement termination. Once a project is energized, a Designated Entity that is not already a Transmission Owner must become a Transmission Owner, subject to the Consolidated Transmission Owners Agreement.

#### **Interconnection Coordination Agreement (ICA)**

Because a Designated Entity may not qualify to be a party to the Consolidated Transmission Owners Agreement at the time the Designated Entity is selected, the execution of an Interconnection Coordination Agreement acts as a precursor to a wires-to-wires agreement between the interconnecting Transmission Owner and the Designated Entity. The Interconnection Coordination Agreement covers only coordination of construction prior to energizing the Designated Entity's project and defines the terms, duties, accountabilities and obligations of each party.

#### **Cost Allocation**

PJM is responsible for determining RTEP upgrade cost allocation, seeking PJM Board approval and filing those allocation percentages with the FERC under the terms of PJM's Operating Agreement, Schedule 6, and Open Access Transmission Tariff, Schedule 12. To that end, PJM has developed preliminary cost responsibility percentages – as shown in **Appendix 1** – for Artificial Island solution project elements whose costs will be allocated to multiple transmission zones. PJM notes that the aggregate total amount of the project to be assigned to the Delmarva transmission zone is \$246.42 million, 89.46 percent of the total \$275.45 million cost estimate. The remaining \$29.03 million would be assigned to other transmission zones based on load ratio shares.



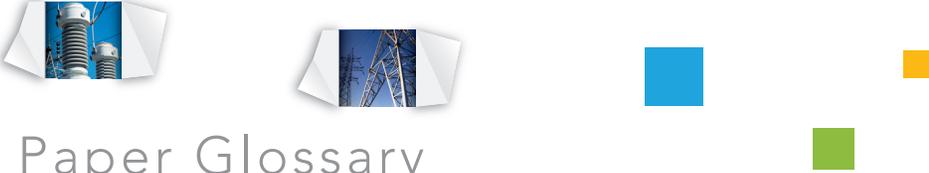
# Appendix 1 – Preliminary Artificial Island Project Recommendation Cost Responsibility Percentages

Preliminary cost responsibility percentages are shown in the table below for Artificial Island solution project elements whose costs will be allocated to multiple transmission zones.

Baseline Upgrade ID	Description	Cost Estimate (\$M)	Designated Entity	Cost Responsibility	Required In-service Date
b2633.1	Build a new 230 kV transmission line between Salem and Silver Run	\$146.00	LS Power	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.2	Construct a new Silver Run 230 kV substation	*	LS Power	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.3	Install an SVC at New Freedom 500 kV substation	\$34.45	PSE&G	AEC - 0.77%, AEP - 7.66%, APS - 2.94%, ATSI - 3.88%, BGE - 2.09%, COMED - 6.19%, ConEd - 0.29%, DAYTON - 1.01%, DEO&K - 1.61%, DL - 0.85%, DPL - 51.21%, DVP - 6.21%, ECP - 0.1%, EKPC - 1.08%, JCPL - 1.78%, ME - 0.89%, NEPTUNE - 0.21%, HTP - 0.10%, PECO - 2.59%, PENELEC - 0.96%, PEPCO - 1.99%, PPL - 2.53%, PSE&G - 2.99%, RE - 0.13%	4/1/2019
b2633.4	Add a new 500 kV bay at Salem (Expansion of Salem substation)	\$7.35	PSE&G	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.5	Add a new 500/230 kV autotransformer at Salem	\$60.65	PSE&G	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.6	Implement high speed relaying utilizing OPGW on Deans - East Windsor 500 kV and East Windsor - New Freedom 500 kV lines	\$1.00	JCPL	AEC - 0.77%, AEP - 7.66%, APS - 2.94%, ATSI - 3.88%, BGE - 2.09%, COMED - 6.19%, ConEd - 0.29%, DAYTON - 1.01%, DEO&K - 1.61%, DL - 0.85%, DPL - 51.21%, DVP - 6.21%, ECP - 0.1%, EKPC - 1.08%, JCPL - 1.78%, ME - 0.89%, NEPTUNE - 0.21%, HTP - 0.10%, PECO - 2.59%, PENELEC - 0.96%, PEPCO - 1.99%, PPL - 2.53%, PSE&G - 2.99%, RE - 0.13%	4/1/2019

Baseline Upgrade ID	Description	Cost Estimate (\$M)	Designated Entity	Cost Responsibility	Required In-service Date
b2633.7	Implement high speed relaying utilizing OPGW on Red Lion - Hope Creek 500 kV line	\$0.50	DPL	AEC - 0.77%, AEP - 7.66%, APS - 2.94%, ATSI - 3.88%, BGE - 2.09%, COMED - 6.19%, ConEd - 0.29%, DAYTON - 1.01%, DEO&K - 1.61%, DL - 0.85%, DPL - 51.21%, DVP - 6.21%, ECP - 0.1%, EKPC - 1.08%, JCPL - 1.78%, ME - 0.89%, NEPTUNE - 0.21%, HTP - 0.10%, PECO - 2.59%, PENELEC - 0.96%, PEPCO - 1.99%, PPL - 2.53%, PSE&G - 2.99%, RE - 0.13%	4/1/2019
b2633.8	Implement high speed relaying utilizing OPGW on Salem - Orchard 500 kV, Hope Creek - New Freedom 500 kV, New Freedom - Salem 500 kV, Hope Creek - Salem 500 kV, and New Freedom - Orchard 500 kV lines	\$23.50	PSE&G	AEC - 0.77%, AEP - 7.66%, APS - 2.94%, ATSI - 3.88%, BGE - 2.09%, COMED - 6.19%, ConEd - 0.29%, DAYTON - 1.01%, DEO&K - 1.61%, DL - 0.85%, DPL - 51.21%, DVP - 6.21%, ECP - 0.1%, EKPC - 1.08%, JCPL - 1.78%, ME - 0.89%, NEPTUNE - 0.21%, HTP - 0.10%, PECO - 2.59%, PENELEC - 0.96%, PEPCO - 1.99%, PPL - 2.53%, PSE&G - 2.99%, RE - 0.13%	4/1/2019
b2633.9	Implement changes to the tap settings for the three Artificial Island unit's step up transformers	~0.00	PSE&G	DPL - 99.99%, JCPL - 0.01%	4/1/2019
b2633.10	Interconnect the new Silver Run 230 kV substation with the existing Red Lion - Cartanza and Red Lion - Cedar Creek 230 kV lines	\$2.00	DPL	DPL - 99.99%, JCPL - 0.01%	4/1/2019

\*Note: Cost for the new Silver Run 230 kV substation is included in the \$146 M estimate for upgrade b2633.1



# Artificial Island White Paper Glossary

Term	Acronym	Definition
<b>Bulk Electric System</b>	BES	As defined by NERC and ReliabilityFirst, BES facilities include the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.
<b>Consolidated Transmission Owners Agreement</b>	CTOA	Signatories to the CTOA agree to (i) facilitate the coordination of planning and operation of their respective Transmission Facilities within the PJM Region; (ii) transfer certain planning and operating responsibilities to PJM; (iii) provide for regional transmission service pursuant to the PJM Tariff and subject to administration by PJM; and (iv) establish certain rights and obligations that will apply to the signatories and PJM. Any entity that: (i) owns, or, in the case of leased facilities, has rights equivalent to ownership in, Transmission Facilities; (ii) has in place all equipment and facilities necessary for safe and reliable operation of such Transmission Facilities as part of the PJM Region; and (iii) has committed to transfer functional control of its Transmission Facilities to PJM must become a Party to the CTOA.
<b>Designated Entity Agreement</b>	DEA	When a project is designated as a greenfield project that is not reserved for the Transmission Owner, a Designated Entity Agreement is required to be executed. The Designated Entity Agreement defines the terms, duties, accountabilities and obligations of each party, and relevant project information, including project milestones. Once construction is complete and the Designated Entity has met all Designated Entity Agreement requirements the Agreement is no longer needed. The Designated Entity must execute the Consolidated Transmission Owners Agreement as a requirement for Designated Entity Agreement termination. Once a project is energized, a Designated Entity that is not already a Transmission Owner must become a Transmission Owner, subject to the Consolidated Transmission Owners Agreement.
<b>Generator Step-Up Transformer</b>	GSU	A GSU transformer 'steps-up' generator power output voltage level to a suitable grid level voltage for transmission of electricity to load centers.
<b>Good Utility Practice</b>		Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the region.
<b>Horizontal Directional Drilling</b>	HDD	Horizontal directional drilling technology for laying transmission cable employs a long, flexible drill bit to bore horizontally underground. Horizontal directional drilling is a trench-less method in which no surface excavation is required except for drill entry and exit points, which minimizes surface restoration, ecological disturbances and environmental impacts. By contrast, jet-plowing techniques impact the riverbed over the length of the installation.
<b>Interconnection Coordination Agreement</b>	ICA	Because the Designated Entity may not qualify to be a party to the Consolidated Transmission Owners Agreement at the time the Designated Entity is selected, the execution of an Interconnection Coordination Agreement acts as a precursor to a wires-to-wires agreement between the interconnecting Transmission Owner and the Designated Entity. The Interconnection Coordination Agreement covers only coordination of construction prior to energizing the Designated Entity's project and defines the terms, duties, accountabilities and obligations of each party.

Term	Acronym	Definition
<b>Megavolt-ampere reactive</b>	MVAR	Megavolt-ampere reactive. See “Reactive Power.”
<b>North American Electric Reliability Corporation</b>	NERC	NERC is an international, independent, self-regulatory, not-for-profit organization, whose mission is to ensure the reliability of the bulk power system in North America.
<b>North American Electric Reliability Corporation Transmission Planning Standards</b>	NERC TPL	NERC transmission planning reliability standards establish system planning performance requirements within a defined planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.
<b>Open Access Transmission Tariff</b>	OATT	A FERC filed tariff specifying the terms of conditions under which PJM provides transmission service including how PJM carries out its generation and merchant transmission interconnection process.
<b>Optical Grounding Wire Communications</b>	OPGW	A type of fiber optic cable used in the construction of electric power transmission and distribution lines which combines the functions of grounding and communications
<b>Reactive Power (expressed in MVAR)</b>		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is expressed in megavars (MVAR).
<b>Regional Transmission Expansion Plan</b>	RTEP	The plan prepared by PJM pursuant to Schedule 6 of the PJM Operating Agreement for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.
<b>Regional Transmission Organization</b>	RTO	An independent, FERC-approved organization of sufficient regional scope, which coordinates the interstate movement of electricity under FERC-approved Tariffs by operating the transmission system and competitive wholesale electricity markets and ensuring reliability and efficiency through expansion planning and interregional coordination.
<b>Reliability</b>		A reliable bulk power system is one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity.
<b>ReliabilityFirst Corporation</b>		ReliabilityFirst is a not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. ReliabilityFirst was approved by the North American Electric Reliability Council (NERC) on January 1, 2006 to become one of eight Regional Reliability Councils in North America. ReliabilityFirst is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR) and the Mid-American Interconnected Network (MAIN) organizations
<b>Right-of-Way</b>	ROW	A corridor of land on which electric lines may be located. The transmission owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
<b>Static VAR Compensation</b>	SVC	A SVC device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system transmission and distribution performance.

Term	Acronym	Definition
<b>Sub-Synchronous Resonance</b>	SSR	Power system sub-synchronous resonance (SSR) is the build-up of mechanical oscillations in a turbine shaft arising from the electro-mechanical interaction between the turbine generator and the rest of the power system. This can lead to turbine shaft damage, even catastrophic loss. The term “sub-synchronous” refers to the fact that the oscillations a shaft can experience occur at levels below 60 Hz (cycles-per-second).
<b>System Stability</b>		Stability studies examine the grid’s ability to return to a stable operating point following a system fault or similar disturbance. Such contingencies can cause a nearby generator’s rotor’s position to change in relation to the stator’s magnetic field, affecting the generator’s ability to maintain synchronism with the grid. Power system engineers measure this stability in terms of generator bus voltage and maximum observed angular displacement between a generator’s rotor axis and the stator magnetic field. Stability in actual operations is affected by machine MW, system voltage, machine voltage, duration of the disturbance and by system impedance. Transient stability examines this phenomenon over the first several seconds following a system disturbance.
<b>Thyristor Controlled Series Compensation</b>	TCSC	A TCSC device comprises a series capacitor bank shunted by a bidirectional thyristor valve in series with an inductor. This combination of devices is used to lower the apparent line impedance resulting in increased power transfer capability. A TCSC makes a long transmission line act like a much shorter transmission
<b>Transmission Expansion Advisory Committee</b>	TEAC	A committee established by PJM to provide advice and recommendations to aid in the development of the Regional Transmission Expansion Plan.
<b>Transmission System</b>		The transmission facilities operated by PJM used to provide transmission services. These facilities that transmit electricity: are within the PJM region; meet the definition of transmission facilities pursuant to FERC’s Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and have been demonstrated to the satisfaction of PJM to be integrated with the transmission system of PJM and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.
<b>Transmission Owner</b>		A PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a transmission owner.

