Building New Transmission — The Changing Regulatory Landscape

Presented by **IHS THE ENERGY DAILY** *and*
THE GIBSON DUNN ENERGY GROUP

Panel Discussion & Teleconference

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GIBSON DUNN

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Today's Panelists

George Lobsenz

Executive Editor, The Energy Daily

George Lobsenz has been editor of IHS The Energy Daily since 2000. Previously, he was energy and environmental editor for United Press International and a UPI congressional correspondent.

He has won numerous awards from the National Press Club for journalistic excellence and has appeared on C-Span, National Public Radio and CNN, among other major media.

Sharon K. Segner

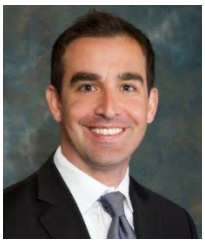
Vice President, LS Power Development

Ms. Segner is an Energy Developer at LS Power with a focus on PJM / Mid-Atlantic Markets. She has successfully led, designed, and implemented the company's national goals related to national energy policy through a combination of direct lobbying, legislative coalition-building and FERC regulatory / legal strategy. The result of the effort has been to help open a major new sector of the energy business for independent and private equity investors.

Ms. Segner worked for Senator Lamar Alexander during the passage of the Energy Policy Act of 2005 and was previously a Program Examiner with the White House Office of Management and Budget.

Ms. Segner holds an MBA from Rice University and a bachelor's degree in Economics from the University of Texas at Austin.

Antonio Smyth



President, Transource Energy, American Electric Power

Antonio Smyth is president of Transource Energy, the subsidiary of American Electric Power responsible for the development and construction of competitive electric transmission infrastructure projects across the United States.

Prior to his role as president, Smyth held positions of increasing responsibility throughout the past 11 years within AEP and has worked in both the Columbus, Ohio, headquarters and the London, U.K., offices.

Smyth most recently served as director of Transmission Development and was responsible for the identification and evaluation of new projects, acquisitions, and strategic business alliances. Smyth also served as vice president of Electric Transmission America, a joint venture between AEP and MidAmerican Energy Holdings Company.

Prior to his roles in the transmission organization, Smyth managed the strategic initiatives group, responsible for corporate strategy and mergers and acquisitions, and the corporate finance group, responsible for debt and equity capital markets and rating agency activities.

Smyth earned both a bachelor’s degree and master’s degree in economics from The Ohio State University, and is a graduate of the Management Development Program at The Ohio State University.

Smyth is a veteran of the United States military and serves on the board of the Childhood League Center, Inc.

Dr. William R. Hollaway

Partner, Gibson, Dunn & Crutcher LLP

William Hollaway is a partner in Gibson Dunn's Washington, D.C. office. He has extensive experience representing clients on a broad range of issues in the energy regulatory and energy transactional fields, including numerous proceedings and matters before the Federal Energy Regulatory Commission (FERC).

He is experienced in all type of power plant and transmission, including wind, solar, nuclear, natural gas, hydro, coal, and AC/HVDC transmission. Dr. Hollaway has represented clients in major energy transactions, generation and transmission development, and interconnection. He handles transactions, project development, regulatory approvals, litigation, and compliance before the FERC, state regulators, and RTO/ISOs, including complaints under the Federal Power Act and PURPA. He also advises on the regulations of the Nuclear Regulatory Commission and state regulators under the Atomic Energy Act.

Dr. Hollaway received his Juris Doctor degree, *magna cum laude*, from Georgetown University, where he served as an Articles Editor on the *Georgetown Law Review* and was a member of the *Order of the Coif*. In addition to his law degree, Dr. Hollaway has three degrees in nuclear engineering. He earned his Ph.D. and Master of Science degrees in nuclear engineering from the Massachusetts Institute of Technology (M.I.T.).

January 30, 2014

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: California Independent System Operator Corporation, Docket No. ER14--____
Competitive Transmission Improvements

Dear Secretary Bose:

The California Independent System Operator Corporation (ISO) submits proposed tariff changes developed through a stakeholder process to clarify and enhance the ISO's transmission planning process. In particular, the tariff changes will implement process and policy enhancements to the project sponsor competitive selection process that takes place during phase 3 of the ISO's transmission planning process if eligible transmission solutions are identified and approved in phase 2. The Competitive Transmission Improvements stakeholder initiative began in September 2013 and the ISO governing board approved the proposed enhancements in December 2013. With these changes, the ISO seeks to further promote competition in the transmission planning process and to implement a mechanism to recover the costs of administrating phase 3 of the process.

The process and policy enhancements proposed in this submittal address the following topics:

1) The need for a mechanism by which an approved project sponsor that is not a participating transmission owner can recover Commission-authorized transmission revenue requirements associated with projects under construction prior to the time that the facilities are turned over to ISO operational control;

2) Tariff clarification that an approved project sponsor that is not a participating transmission owner but that has existing transmission assets will be required to turn over to ISO operational control only the project it was selected to build;

3) The implementation of an application fee, up to a cap of $150,000, that will enable the ISO to recover the costs of evaluating project sponsor applications, determining qualified project sponsors and selecting an approved project sponsor for each of the transmission solutions subject to the competitive solicitation;

4) Provisions in response to stakeholder requests that the ISO eliminate or clarify the tariff requirement that an approved project sponsor initiate siting approval within 120 days after selection; and

5) Provisions in response to stakeholder requests that the ISO clarify the standards set forth in section 24.5.2.1 that must be met by an approved project sponsor transferee if the ISO is to approve the assignment.

The ISO requests an effective date of April 1, 2014, for the proposed modifications, which will allow the ISO to implement them during Phase 3 of the 2013-2014 transmission planning cycle.

I. Introduction and Background

In 2010, the ISO reformed its transmission planning process to explicitly consider public policy requirements as a potential driver for transmission facilities and to afford both participating transmission owners and independent transmission developers nondiscriminatory opportunities to compete to finance, own and construct transmission facilities that the ISO found necessary for public policy or economic efficiency reasons.[1] Specifically, as part of the transmission planning process revisions, the ISO proposed, and the Commission approved, a third phase of the transmission planning process during which the ISO would open a bid window for all proposed project sponsors to submit applications for each transmission solution eligible for competitive solicitation. The Commission also approved ISO proposals for project sponsor qualification criteria and, should there be multiple qualified project sponsors for the same transmission facilities, criteria that the ISO would use to conduct a comparative selection evaluation of all qualified applicants to determine the approved project sponsor for each solution.

The opportunities for competition expanded when the ISO submitted, consistent with Order No. 1000 directives, proposed tariff revisions to eliminate certain remaining ISO tariff provisions granting a federal "right of first refusal" for incumbent participating transmission owners to build and own certain transmission facilities whose costs will be allocated regionally. On April 18, 2013, the FERC approved the ISO's proposed tariff modifications addressing this issue.[2]

The first time that the ISO conducted the competitive solicitation process was for transmission solutions identified in the 2012-2013 planning cycle.[3] Based on

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[1] *California Indep. Sys. Operator Corp.,* 133 FERC ¶ 61,224 (2010), *order on reh'g*, 137 FERC ¶ 61,062 (2011) (RTPP Order).

[2] *California Indep. Sys. Operator Corp.,* 143 FERC ¶61,057 (2013). The ISO was directed to make a supplemental compliance filing modifying other tariff sections which was submitted on August 16, 2013.

[3] The ISO identified three transmission solutions in the 2013-2013 planning cycle eligible for competition:

- Imperial Valley Policy Element, for which the selection report was issued on July 11, 2013;

experience with the process and discussions with stakeholders, the ISO identified additional improvements to clarify the process approved by the Commission and to help further level the playing field between participating transmission owners and other transmission developers. In particular, under the ISO's current tariff and transmission control agreement construct, a non-participating transmission owner selected as an approved project sponsor would have no existing tariff mechanism by which to recover Commission-approved operational costs (such as construction work in progress or "CWIP" and abandoned plant cost recovery) before the project was energized and turned over to ISO operational control. However, a participating transmission owner selected as an approved project sponsor would be able to recover these costs through its existing transmission revenue requirement and approved transmission owner tariff. The ISO concluded that this inability to recover Commission-approved pre-operational costs could be a barrier to participation in the competitive solicitation process.

Similarly, stakeholders expressed concern that the general tariff and transmission control agreement obligations requiring participating transmission owners to turn over all transmission facilities to ISO operational control might also apply to non-participating transmission owners with existing transmission facilities that are selected in the process. Although the ISO believed that the existing tariff provisions did not create such an obligation for approved project sponsors, uncertainty as to how the tariff would be interpreted could cause non-incumbent transmission owners to be reluctant to submit proposals in the competitive solicitation process.

Thus, the ISO initiated a stakeholder process to consider tariff modifications that would address these competitive solicitation topics. In addition, based on information about the time and resources needed to conduct a robust solicitation process, the ISO decided to propose an application fee and related true-up mechanism as part of this stakeholder process. As discussed in more detail below, the ISO and stakeholders developed other tariff modifications as well that respond to matters raised by stakeholders and add clarity to the competitive solicitation process.

II. The Competitive Transmission Improvements Stakeholder Initiative

The Competitive Transmission Improvements stakeholder initiative began on September 10, 2013, when the ISO posted an issue paper and straw proposal. The proposal was discussed during a web conference on September 20, with written comments submitted by fourteen parties on October 3. The ISO posted the draft final proposal on October 17 and held another web conference on October 29. Nine stakeholders submitted comments on the draft final proposal on November 12. The ISO

- The Gates-Gregg Project, for which the selection report was issued on November 6, 2013;
- Sycamore-Penasquitos 230 kV Line Element, which is still in the comparative selection process.

(See http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx)

made adjustments based on stakeholder feedback and presented its recommendations to the governing board for approval on December 19.

Following governing board approval, the ISO posted draft tariff language on December 23 and asked that comments be provided by January 6, 2014. Four stakeholders submitted comments on the proposed tariff language. A stakeholder call to discuss the proposed tariff language and comments was held on January 13. On January 30, 2014 the ISO posted the final tariff language that incorporated many of the changes suggested by stakeholders.[4]

III. Proposed Tariff Modifications

A. Recovery of Commission Approved Pre-Operational Revenues

Section 1241 of the Energy Policy Act of 2005 added a new section 219 to the Federal Power Act directing the Commission to establish incentive-based rate treatments that promote capital investment in reliable and economically efficient transmission and generation of electricity by promoting capital investment. In 2006, the Commission issued Order No. 679 to establish incentives to support the development of transmission infrastructure.[5] These incentives include enhanced rate of return on equity, recovery of 100 percent of prudently incurred costs associated with abandoned transmission projects due to factors beyond the control of the utility, use of hypothetical capital structures, incentives to join a transmission organization, inclusion of 100 percent construction work in progress in rate base, accelerated depreciation used for rate recovery, and expensing pre-commercial operations costs associated with new transmission investment, among others.[6]

If a project is approved by the ISO in its transmission planning process, which is the case for projects open for bid in the competitive solicitation process, Order No. 679 establishes a rebuttable presumption that the project is eligible for rate incentives.[7]

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[4] http://www.caiso.com/informed/Pages/StakeholderProcesses/CompetitiveTransmissionImprovements.aspx

[5] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 FR 43294 (Jul. 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[6] The Commission provided further guidance on the application of Order No. 679 in a November 2012 policy statement, *Promoting Transmission Investment Through Pricing Reform,* 141 FERC ¶ 61,129 (2012).

[7] Order No. 679 states that each applicant must demonstrate that the facilities for which it seeks incentives satisfy the requirements of section 219 by either ensuring reliability or reducing the cost of delivered power by reducing congestion. The Order establishes a rebuttable presumption that a project is eligible for incentives under section 219 if it: (1) results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (2) has received construction approval from an appropriate state commission or state siting authority.

Accordingly, the ISO anticipates that approved project sponsors selected in the competitive solicitation process will have the opportunity to seek one or more rate incentives pursuant to Order No. 679.

Most of the rate incentives contemplated under Order No. 679 are not included in the transmission revenue requirement of the transmission owner until the new transmission facilities are turned over to the operational control of the ISO upon completion and incorporated in the transmission revenue requirement that is approved by FERC. However, two of these—inclusion of construction work in progress in rate base and recovery of abandoned plant costs—are unique in that they may be recovered prior to completion of the new transmission project or after abandonment of the project.

1. Construction Work In Progress

Order No. 679 allows utilities to include, where appropriate and approved by the Commission, 100 percent of prudently incurred transmission-related construction work in progress costs in rate base. The Commission determined that this rate treatment furthers the goals of section 219 by providing up-front regulatory certainty, rate stability, reduced interest expense, and improved cash flow, by reducing the pressures on an applicant's finances caused by investing in transmission projects with long lead times that can negatively affect cash flow and the ability of the project sponsor to attract capital at reasonable rates.

Typically the Commission may accept an applicant's proposal to recover 100 percent of construction work in progress in rate base conditioned upon the applicant fulfilling the Commission's requirements in a subsequent section 205 filing.

2. Abandoned Plant Cost Recovery

Order No. 679 also allows a utility to seek recovery of 100 percent of prudently incurred costs associated with a transmission project that is cancelled or abandoned for reasons outside the utility's control. The purpose of this incentive is to reduce the risk associated with potential solutions or other improvements to the transmission system. In Order No. 679 the Commission found that the abandonment incentive is an effective means of encouraging transmission development by reducing the risk of non-recovery of costs.

Typically, if the request is approved, an applicant's request for recovery of 100 percent of prudently incurred transmission-related costs associated with abandonment of a project is contingent upon a showing that the abandonment is a result of factors beyond the control of the applicant. This must be demonstrated in a subsequent section 205 filing for recovery of abandoned plant costs.

3. The ISO's Access Charge and a Participating Transmission Owner's Transmission Revenue Requirement.

All market participants withdrawing energy (i.e. loads and exports) from the ISO controlled grid pay access charges, either the transmission access charge or the wheeling access charge. In accordance with section 26 and Schedule 3 of Appendix F of the ISO tariff, the ISO's access charge is designed to recover the transmission revenue requirement of each participating transmission owner. Only participating transmission owners may recover their transmission revenue requirement through the ISO access charge and only costs associated with transmission facilities turned over to ISO operational control may be recovered through the access charge.

Consistent with the current tariff provisions, a participating transmission owner's transmission revenue requirement consists of total authorized annualized revenues associated with transmission facilities turned over to the operational control of the ISO. A participating transmission owner's transmission revenue requirement includes, for the purposes of construction work in progress and abandoned plant cost recovery, transmission facilities under construction that have been approved by the ISO and are to be turned over to the operational control of the ISO upon completion.

The ISO tariff defines a participating transmission owner as "a party to the Transmission Control Agreement whose application under section 2.2 of the Transmission Control Agreement has been accepted and who has placed its transmission assets and Entitlements under the CAISO's Operational Control in accordance with the Transmission Control Agreement." According to this definition, an approved project sponsor would not become a participating transmission owner until its eligible transmission assets are turned over to ISO operational control, and facilities cannot be turned over to ISO operational control until they have been energized and are in operation.

Thus, because only a participating transmission owner has a transmission revenue requirement, there is no current tariff mechanism by which an approved project sponsor has the ability to collect construction work in progress costs under the ISO tariff before the transmission facility is energized and turned over to ISO operational control. In the case of authorized abandoned plant costs, an approved project sponsor would be unable to recover such costs if the project ultimately was not completed.

4. Tariff Modifications Permitting Pre-Operational Cost Recovery

In the September 10 straw proposal, the ISO suggested that the cost recovery mechanism for construction work in progress and abandoned plant costs be specifically addressed both with tariff language and in a pro-forma agreement for use between the ISO and approved project sponsors. The ISO proposed that this pro-forma agreement would establish the obligations, roles and responsibilities of the approved project sponsor, including reporting requirements so that the ISO can proactively monitor the

status of approved facilities and take the necessary actions if projects are not on schedule. The ISO noted that the agreement might overlap the Transmission Control Agreement once the approved project sponsor enters into it and the transmission facilities have achieved commercial operation.

In the comments submitted on October 3, stakeholders supported the ISO proposal with some suggestions for modifications. Stakeholders recommended that the opportunity to recover costs associated with approved projects prior to completion should not be limited to construction work in progress and abandoned plant costs, consistent with cost recovery opportunities for participating transmission owners. They noted that the cost recovery mechanism should be described in the tariff and not in the approved project sponsor agreement. One stakeholder stated that the agreement should contain language requiring the approved project sponsor to refund monies collected through the access charge if the Commission subsequently denies recovery of abandoned plant costs and should include provisions restricting the sale of the project unless the new entitlement holder becomes a participating transmission owner. In the draft final proposal, the ISO agreed to confine the cost recovery mechanism to tariff language, and to make many of the other changes proposed by stakeholders. The approved project sponsor agreement would contain the other provisions described in the straw proposal.

Consistent with these representations, the ISO proposes changes to tariff section 26; appendix F, section 3; a new definition ("Approved Project Sponsor Tariff"); and modifications to several other definitions. In section 26.1 the ISO added subject headings, removed some language no longer needed in the tariff and added language describing the construct for approved project sponsors to recover pre-operational revenues approved by the Commission.

Specifically, section 26.1(a) generally describes an approved project sponsor's revenue recovery opportunity and section 26.1(b) addresses the allocation of these revenues between regional and local access charges. Because a non-participating transmission owner approved project sponsor would seek recovery for local transmission facilities only under the very limited circumstances described in section 24.4.10[8], the ISO originally proposed that costs associated with local facilities be recovered through the approved project sponsor's regional revenue requirement. However, two stakeholders noted that the ISO has an existing process for allocating local transmission facility costs to the participating transmission owner with a service territory and with which the facility would interconnect, and the ISO agreed to incorporate this allocation in 26.1(b) as well as appendix F, schedule 3, section 5.2.

[8] By definition, local transmission facilities are financed, constructed and owned by participating transmission owners and are not subject to the competitive solicitation process except as described in section 24.4.10.

Changes were also made to the definitions and other sections of appendix F, schedule 3, consistent with this concept.

The ISO's proposed tariff modifications address the concerns of two stakeholders that the pre-operational revenue recovery mechanism be equally applicable to participating transmission owners and those who are approved project sponsors but not yet participating transmission owners. It is also clear that only approved project sponsors are entitled to an approved project sponsor tariff, addressing the concern that only project sponsors selected in the competitive solicitation process be entitled to cost recovery. While the tariff reflects that revenues recovered through the regional or local transmission revenue requirement must be Commission-approved, the ISO did not agree with one stakeholder that there be a requirement put in the tariff that the approved project sponsor seek a declaratory order for such recovery.

Finally, the ISO agrees with stakeholder comments that the approved project sponsor agreement should contain a provision that requires it to refund monies collected through the access charge if the Commission subsequently denies recovery of abandoned plant costs. As the ISO explained to stakeholders, an approved project sponsor agreement is currently being negotiated with the Imperial Irrigation District ("IID") for the Imperial Valley Element, and that agreement will be filed for approval with the Commission as soon as possible. Because the Imperial Valley Element must be completed by mid-2015, there was not sufficient time to engage in a stakeholder process to develop a pro forma agreement. Nonetheless, the ISO hopes to use much of the IID agreement as a template and, during conference calls, the ISO held out the possibility of a later stakeholder process to take comments and suggestions for a pro forma agreement.

B. Non-Participating Transmission Owners with Existing Facilities

In the initial straw proposal, the ISO stated its belief that existing tariff language adequately addressed the issue as to whether an approved project sponsor that became a new participating transmission owner upon completion of the project would be required to turn over to ISO operational control all existing transmission facilities and entitlements, or just the project which was subject to the competitive solicitation process. The ISO noted that in accordance with tariff section 4.3.1, a new participating transmission owner is required to turn over operational control of all facilities and entitlements that (1) satisfy the Commission's functional criteria for determining what transmission facilities should be placed under the ISO's operational control, (2) satisfy the criteria adopted by the ISO governing board identifying facilities for which the ISO should assume operational control, and (3) are the subject of mutual agreement between the ISO and participating transmission owners.

However, some stakeholders expressed concern that current tariff provisions lacked clarity with respect to the disposition of the existing transmission assets when an

approved project sponsor becomes a participating transmission owner. Because many different transmission developers with existing facilities located throughout the United States (or elsewhere) might seek to participate in the competitive solicitation process, and the ISO seeks to maximize participation in the process, the ISO sought stakeholder comment on further clarification, either in the tariff or by agreement.

Stakeholders expressed strong support for this proposal. Stakeholders agreed that while the current tariff provides an approach for new participating transmission owners with existing facilities, further clarification to eliminate actual or perceived uncertainty would provide benefits to the competitive solicitation process.

The ISO determined that adding a paragraph to tariff section 4.3.1.3 would provide clarification on this point. The tariff proposal states that any approved project sponsor that was not a participating transmission owner as of April 1, 2014, will be required to turn over to ISO operational control only its rights and interests in the regional transmission facility it was selected to construct and own in the competitive solicitation process. There were no objections to this proposed tariff language when presented to stakeholders, and IID – a non- participating approved project sponsor with a project to be placed in service in 2015 – strongly supported this approach.

C. The Project Sponsor Application Deposit and Fee

This proposal feature sparked the most discussion among stakeholders, with a wide range of opinions expressed regarding the various options proposed by the ISO. As noted above, over the past few years the ISO has made significant tariff revisions in order to promote competition in the transmission planning process and now has gained experience in the administration of a competitive solicitation process that provides an opportunity for project sponsors to submit proposals to finance, own, and construct facilities subject to competitive solicitation identified in the comprehensive transmission plan. Under this process the ISO carries out multiple resource-intensive tasks, including (1) determining whether a project sponsor meets certain qualification criteria, (2) determining whether a project sponsor's proposal meets certain proposal qualification criteria, and (3) selecting an approved project sponsor.

The ISO views these tasks as a significant undertaking that requires an extensive commitment of internal resources. In addition, the tariff requires the ISO to retain a consultant to assist it in the selection of an approved project sponsor, at substantial additional cost. This workload is likely to increase with each successive annual transmission planning process cycle because more transmission solutions will be subject to competitive solicitation under the ISO's Order No. 1000 transmission planning framework than under the process that was in effect for the 2012-2013 process cycle.

Thus far the ISO has been funding this significant incremental workload and cost without a corresponding increase in its operations budget (i.e., through the board-approved grid management charge paid by scheduling coordinators using the ISO's

markets). However, the ISO believes that project sponsors should bear the costs of the individual applicants competing to build and own specific transmission solutions. For example, the ISO notes that resources seeking to interconnect to the ISO grid via the generator interconnection process pay fees to support processing their applications and conducting the necessary studies, and now pay fees to process modifications for their projects. Furthermore, similar application deposits and fees have also been approved by the Commission for the Midcontinent Independent System Operator ("MISO"), Tampa Electric Company ("Tampa") and the Southwest Power Pool ("SPP"), as discussed in more detail below.

1. Application Deposit and Fee in the Straw Proposal

The ISO first proposed, in the September 10 straw proposal and issue paper, that each project sponsor be required to provide an application deposit in the amount of $100,000 to be applied as a pool of funds to pay for actual costs incurred by the ISO to perform and administer the competitive solicitation process. If the amount required to pay actual costs is determined to be greater than $100,000 per application, then each project sponsor would be obligated to provide the additional amount. Conversely, if the amount required to pay actual costs was determined to be less than $100,000, then each project sponsor would be refunded the unused balance of its deposit, with interest.[9]

The ISO also indicated that it was considering whether approved project sponsors should bear the actual costs incurred by the ISO to ensure that the project is on track for completion. These tasks would include negotiating an agreement with the approved project sponsor, monthly project status review, change management if applicable, coordination of commissioning activities, and coordination with existing participating transmission owners.

Stakeholder comments on this initial proposal ran the gamut from complete opposition to an application deposit of any amount, to support for the proposal with modifications. Some parties expressed concern that charging an application fee could discriminate against non-incumbents because participating transmission owners could recover such costs in ISO access charge rates, which non-incumbents would be unable to do. Others argued that because the competitive solicitation process benefits ratepayers as well as project sponsors, they should share in paying the costs.

Stakeholders sought clarification as to the actual cost basis for the proposed $100,000 deposit; some suggested that the fee should be based only on the ISO's external costs and others proposed a cap. Some parties supported establishing an application fee for the competitive solicitation, but argued that the ISO needs to provide

[9] Interest is based on the interest that the ISO receives on the deposit, not based on the federal rate in 18 CFR 35.19(a).

some clarity regarding how it will calculate costs associated with evaluating bid proposals and that the fee should be supported by enough detail to show its cost basis. A large number of stakeholders encouraged the ISO to evaluate its solicitations on an ongoing basis to ensure that the initial application fee remains appropriate. Finally, almost all stakeholders opposed the notion that the fee should include the ISO's actual costs of negotiating an agreement with the approved project sponsor and monitoring the project once the approved project sponsor had been selected.

2. Modified Application Deposit and Fee in the Draft Final Proposal

Based on stakeholder feedback and precedent from other jurisdictions, the ISO proposed to retain the application fee concept but with the modifications described in the draft final proposal and approved by the governing board. The application deposit and fee will capture the costs of qualifying applicants and selecting an approved project sponsor from among multiple applicants, but will not capture the costs of negotiating the agreement and monitoring the project after the project sponsor has been selected.

As set forth in proposed tariff section 24.5.6, each project proposal will be required to include an application deposit of $75,000. If the pro rata amount required to pay actual costs of the validation, qualification and selection process for each solution is determined to be greater than $75,000 per application, then each project sponsor would be obligated to provide the additional amount up to a cap of $150,000. Conversely, if the pro rata amount required to pay actual costs was determined to be less than $75,000, then each project sponsor would be refunded the unused balance of its deposit, with interest.[10] The deposit will be applied as a pool of funds to pay for costs incurred by the ISO, or third parties at the direction of the ISO, as applicable, to perform and administer the competitive solicitation process and to communicate with applicants with respect to their proposal applications.

The ISO proposes to make refunds as follows: (1) following the ISO's qualification decisions, to the extent the ISO finds a project sponsor to be unqualified for the project, the ISO will make its refund within 75 days after the qualification decision; and (2) for qualified project sponsors, the ISO will make refunds within 75 days after the approved project sponsor is selected. The ISO will publicly post an accounting of the total costs incurred in determining the qualified project sponsors for each solution and in selecting the approved project sponsor from among the qualified project sponsors for each solution.

As described in the draft final proposal, the application fee of $75,000 with a cap of $150,000 is based on the internal and external expenditures incurred by the ISO for recent competitive solicitations conducted by the ISO. Estimated expenditures for the

[10] Interest is based on the interest that the ISO receives on the deposit, not based on the federal rate in 18 CFR 35.19(a).

Imperial Valley Policy Element competitive solicitation were slightly more than $200,000 which included the evaluation of two project sponsor applicants (approximately $100,000 per applicant). Expenditures for the Gates-Gregg 230 kV Line competitive solicitation ran approximately $280,000 which included the evaluation of five project sponsors (approximately $56,000 per applicant). In addition, it is estimated that the expenditures for the ongoing evaluation of the Sycamore-Penasquitos 230 kV Line Element will run approximately $275,000 which includes the evaluation of four project sponsors (approximately $68,700 per applicant).

Also, the Gates-Gregg 230 kV Line and the Sycamore-Penasquitos elements only involve construction of single lines with no substations, so these solicitations do not reflect all of the comparative analysis that might occur with a more complex, multi-facility proposal (including substations). On the other hand, the Imperial Valley Policy Element included a 230 kV line and collector substation.

The ISO believes that its proposal takes into account most of the suggestions and concerns raised by stakeholders. For example, the proposed cap incorporates the notion that some actual costs will be shared with ratepayers if the cap is exceeded. The ISO has based the deposit and cap on the actual costs incurred in two competitive solicitations and the estimated costs from a third currently underway. The ISO will provide accountings of the costs incurred for all future competitive solicitations, and will, in the process, review costs to ascertain whether the deposit, cap and fee structure reasonably align with the process. The ISO found that, at this time, there was no cost basis to support the suggested tiered application fee approach.

Contrary to stakeholder suggestions, the ISO is not proposing a separate fee for qualification and selection, but rather one deposit to cover costs incurred to perform and administer all aspects of the competitive solicitation process. The ISO believes that adding a two-step invoicing and payment process would add delay to the overall process by requiring separate invoicing for all project sponsors who were qualified, allowing sufficient time for payment, and then re-starting the comparative selection analysis only after all of the project sponsors had remitted their fees. The ISO has attempted to bridge the gap by proposing a separate refund opportunity after the qualification process is completed.

Stakeholders expressed much more support for the deposit fee and cost cap described in the draft final proposal than the earlier ISO recommendation. Most parties voiced targeted concerns about the deposit details and not the overall concept.[11] At least one stakeholder objected to the cap on actual expenses, arguing that project

[11] LS Power stated that its objections to the deposit were based on its position that the qualification and selection process should be completely separate, and not on the reasonableness of the deposit itself. The ISO believe these objections relate to aspect of the ISO's approved planning process that are not modified by the ISO's filing.

sponsors should pay for all of the costs incurred by the ISO in administering the competitive solicitation. The ISO believes its proposal provides a fair balance of allocating some costs to project sponsors while providing sponsors with assurances that the costs of participating in the solicitation will be limited by a reasonable cap. The CPUC staff took a different position, stating that the deposit should be $50,000 and that ISO's market ratepayers should be responsible for the rest of the costs. As explained above, the ISO believes an application fee of $75,000 with a cap of $150,000 is more appropriate based on actual data from recent planning cycles.

MidAmerican Transmission maintained that the fee should apply only to external costs, and that applicants should be provided an opportunity to withdraw if costs are estimated to be very high for a particular solicitation process which would provide further certainty for prospective applicants.[12] The ISO believes its proposal for a cap provides sponsors with an appropriate level of certainty. Other stakeholders encouraged the ISO to continue to review its costs and make adjustments to the application deposit and fee arrangement once it has further knowledge of actual costs, and the ISO has agreed to do so.

Finally, stakeholders continued to question whether charging a deposit discriminates against non-participating transmission owners who would have no opportunity to recover such fees from ratepayers in the event that they are not selected in the process. The ISO disagrees with those stakeholders that argue that the application fee process is unduly discriminatory. As discussed below, the Commission has approved the establishment of application fees for transmission project sponsors in MISO, SPP, and Tampa Electric *et al.* and did not find such a fee to be unduly discriminatory.

Furthermore, it is highly speculative to assume that incumbent participating transmission owners who lose a competitive solicitation would automatically be permitted by the Commission to recover the application fee in rates. The ISO believes that such a request would be a case of first impression, and it may be that the Commission would require such costs to be borne by shareholders (such as other promotional, lobbying, and advertising costs that benefit shareholders).

Notably, the ISO tariff defines the transmission revenue requirement as "the total annual *authorized revenue requirements associated with transmission facilities and Entitlements turned over to the Operational Control of the CAISO* by a Participating TO."[13] Further, the tariff states that "[w]here the need for a transmission addition or upgrade is determined by the CAISO, the cost of the transmission addition or upgrade shall be borne by the Participating TO *that will be the owner of the transmission addition*

[12] The ISO believes that the cap provides this certainty. Project sponsors will be aware, when they choose to submit an application, that the application fee could be as high as $150,000.

[13] ISO tariff appendix A (definition of Transmission Revenue Requirement) (emphasis added).

or upgrade and shall be reflected in its Transmission Revenue Requirement."[14] A participating transmission owner *not* selected in the competitive solicitation process would *not* be turning the project facilities over to ISO operational control, making it difficult to argue that the application is associated with rate base for which revenues will be recovered through the ISO's access charges.

3. Precedent from Other ISOs and Transmission Utility Providers

The ISO's proposed application deposit and fee structure is reasonable and consistent with similar fees recently approved by the Commission for MISO,[15] Tampa Electric Company *et. al.*[16] and SPP[17], as discussed in this section.

For example, MISO proposed a competitive solicitation application fee equal to 1% of the estimated cost of the project for which the project sponsors were being evaluated, not to exceed $500,000. At the end of the process there would be a true-up with interest paid on any deposit amounts to be refunded. The Commission approved the application fee in concept, but found that MISO had failed to provide sufficient information justifying the level of the deposit fee beyond a reference to the MISO generation interconnection deposits of $250,000.

Because MISO provided no evidence that the costs required to evaluate a generator interconnection were comparable to those necessary to conduct a competitive solicitation, the Commission found the proposed fee level could constitute a barrier to entry. The Commission ordered MISO to (1) clarify how it would calculate the cost it will incur to evaluate bid for purposes of refunding a bidder's deposit; and (2) clarify whether or not disqualified applicants must wait until after the selection of a project sponsor before they get their refund, because these factors could lead to uncertainty as to whether a transmission developer should submit a bid. Based on discussions with stakeholders, in its 120-day compliance filing, MISO revised the application fee to $100,000 with a true-up of any shortfall at the end of the process and interest paid on any refunded amounts.

Tampa Electric Co. *et al.* proposed a one-time $50,000 fee for outside consultants to review a non-incumbent transmission developer's qualifications, as a one-time event for each transmission developer. Unexpended amounts would be refunded. For transmission developers proposing a Cost Effective and/or Efficient Regional Transmission Solution (CEERTS) project for evaluation in the regional transmission planning process, Tampa Electric Co., *et. al.* proposed charging a

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[14] ISO tariff section 24.14.2 (emphasis added).

[15] *Midwest Indep. Transmission Sys. Operator,* 142 FERC ¶ 61,215 at PP 300-01 (2013).

[16] *Tampa Elec. Co., et. al.* 143 FERC ¶ 61,254 at PP 147-49; PP 171-72 (2013).

[17] *Southwest Power Pool,* 144 FERC ¶ 61,059 at PP 230, 242-44 (2013).

separate deposit of $100,000 for each $10 million of project cost, to be capped at a maximum deposit of $500,000. This deposit would be used to cover both internal cost and out-of-pocket costs incurred by the regional planner to evaluate the project sponsor's project. The costs would be trued up at the end of the process.

The Commission approved the one time qualification fee with the requirements that (1) interest be paid on refunded amounts, (2) the filing parties provide a description of which costs the deposit will be applied to, how they will be calculated, and an accounting of the actual costs to which the deposit is applied.

The Commission also approved the separate CEERTS project study fee in concept but found that the filing parties had failed to provide justification of the level of the fee and the step function aspect of the proposal. Among other things, the Commission directed Tampa Electric Co. *et al.* to: (1) clarify why the full deposit would be required at the initial stages of the project review process rather than once a project is selected in the regional plan; (2) provide an accounting to each transmission developer describing the costs the deposit would be applied to, how those costs will be calculated, and an accounting of the actual costs incurred to which the deposit is applied; and (3) pay interest on refunded amounts.

Finally, SPP proposed a separate qualifications application fee to be applied only to non-incumbents. The application fee was equal to the amount of the SPP annual membership fee. SPP proposed to post the amount of the qualifications application fee on its website as part of the application form. The fee was intended to offset SPP's costs of processing such qualification applications.

The Commission found the fee might be unduly discriminatory because both incumbents and non-incumbents submit qualifications applications, and directed SPP to either impose the charge on both incumbents and non-incumbents or explain why it is not unduly discriminatory to charge non-incumbents this fee, but not incumbents.

SPP also proposed a separate deposit for both incumbents and non-incumbents participating in the competitive solicitation to compensate SPP for the costs of the solicitation. SPP proposed that the level of the fee would be set at the level of SPP's estimate of what participation in the competitive solicitation would cost. At the end of the process each participant would receive an invoice for additional payments or receive a refund based on the reconciliation of the deposits collected and the actual costs incurred.

The Commission found that Order No. 1000 expressly permits transmission planning regions to require additional procedural protections such as the posting of deposits. However, the Commission found that SPP had not provided enough information to justify the proposed fee, had not specified a precise dollar amount or a formula for determining the amount of the fee, and therefore a transmission developer did not have sufficient information to assess whether or not to submit a bid. The

Commission also imposed all of the information, calculation, accounting, and interest requirements it had imposed on MISO and the Florida parties.

The ISO's proposed application fee meets all of the Commission's directives in the MISO, SPP and Tampa cases. The level of the proposed deposit and cost cap is consistent with the ISO's actual costs of evaluating project sponsor qualifications and selecting an approved project sponsor. The ISO proposes to charge both incumbents and non-incumbents who submit applications, and will refund deposit amounts within a set period of time and with interest at the rate that the ISO collects on these funds. The cost cap provides certainty and the level of the deposit does not constitute a barrier to participation. Finally, the ISO will continuously evaluate its costs and the application deposit and fee structure.

D. Other Issues

In the course of this proceeding, stakeholders raised, for the ISO's consideration, several other issues related to the competitive solicitation process. Regarding these issues, the ISO agreed to propose tariff modifications to two sections that would address these concerns. Other proposals will be considered in upcoming stakeholder consultations.

1. <u>The Requirement to Initiate Siting Approval within 120 Days</u>

Both SCE and PG&E argued that the existing tariff provision in sections 24.5.3.4 and 24.5.3.5, requiring the approved project sponsor to initiate the siting process within 120 days of selection, was onerous and unworkable. Although the ISO had clarified, in language set forth in the business practice manual, that this tariff section did not require submission of a complete siting application with the agency undertaking environmental siting review, these stakeholders nonetheless argued that the tariff provisions created uncertainty and should be modified.

During the stakeholder process the ISO agreed to remove this requirement and instead to address permitting and siting in the approved project sponsor agreement. The ISO proposed that approved project sponsors would be required to enter into the agreement within 120 days of selection notification, and this language has been added to sections 24.5.3.4 and 24.5.3.5. Stakeholders supported this revision, although LS Power suggested that a shorter time period might be appropriate. The ISO explained that negotiating the details of the agreement, even if based on a future *pro forma* agreement, could require 120 days, and that approved project sponsors have 120 days to provide the construction plan required in section 24.6.1. After this informed discussion, the ISO believes that this 120-day period for entering into the approved project sponsor agreement will keep the project moving along, which was the intent of the siting approval requirement, and allow the approved project sponsor to develop its construction plan which would include the detail required for the agreement, and it is a reasonable substitute.

2. Requirements for Transferees of Approved Project Sponsors

Current tariff section 24.6 provides that approved project sponsors shall not "sell, assign or otherwise transfer" the project without the ISO's written consent. During the stakeholder process, SCE submitted that any project transferee should be held to the same standards that the ISO used for the approved project sponsor selection. These standards are embodied in the qualification and selection criteria, and in particular would include the approved project sponsor's commitment to adhere to a binding cost cap. LS Power also recommended that the ISO add to section 24.6 a statement that the ISO's project transfer approval will not be unreasonably withheld.

Accordingly, and with the assistance of stakeholders during the tariff drafting process, the ISO has added the language requested by LS Power to section 24.6 and also proposes that a project transferee be required to: 1) meet the qualification criteria; 2) agree to honor any binding cost cap agreed to by the approved project sponsor; 3) agree to meet the selection factors relied upon by the ISO in selecting the approved project sponsor; and, 4) assume all of the rights and responsibilities set forth in the approved project sponsor agreement.

IV. Communications

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

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V. Service

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all parties with effective Scheduling Coordinator Service Agreements under the ISO Tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO website.

VI. Attachments

The following documents, in addition to this transmittal letter, support the instant filing:

Attachment A Final Draft Proposal

Attachment B Memorandum to ISO Governing Board

Attachment C Clean Tariff Sections

Attachment D Blacklined Tariff Sections

VII. Conclusion

For the foregoing reasons, the ISO respectfully requests that the Commission accept the proposed tariff modifications that will: 1) provide an opportunity for approved project sponsors to recover Commission approved pre-operational costs through an approved project sponsor tariff; 2) clarify that approved project sponsors with existing transmission facilities are required to turn only the project subject to the competitive solicitation process over to ISO operational control; 3) institute an application deposit and fee for project proposals in the competitive solicitation process; 4) remove the requirement that approved project sponsors initiate siting approval within 120 days of selection; and 5) clarify the conditions under which the ISO will approve approved project sponsor transfers or assignments.

Respectfully submitted,

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Attachment A – Final Draft Proposal

Competitive Transmission Improvements Tariff Amendment

California Independent System Operator Corporation

January 30, 2014

Competitive Transmission Improvements

Draft Final Proposal

October 17, 2013

Table of Contents

Competitive Transmission Improvements

Draft Final Proposal

1 Executive summary

The ISO launched this stakeholder process in September 2013 when it posted an issue paper and straw proposal on September 10 in which several improvements were proposed to further support competition in the ISO transmission planning process. One proposed change would create a mechanism by which approved project sponsors who are not a participating transmission owner can recover their FERC authorized transmission revenue requirement associated with projects under construction and prior to the time that the facilities are turned over to ISO operational control. A second proposed change would clarify that approved project sponsors who are not a participating transmission owner, but who have existing transmission assets, are only required to turn over to ISO operational control the project they were selected to build. Taken together, these two proposed changes are intended to help provide nondiscriminatory opportunities for incumbents and non-incumbents alike. A third change proposed in the September 10 paper would impose a project sponsor application deposit as a means to mitigate costs incurred by the ISO to perform and administer the competitive solicitation process and manage any potential agreements with approved project sponsors.

The ISO held a stakeholder web conference on September 20 to discuss the September 10 issue paper and straw proposal. The ISO received written comments from stakeholders on October 3. Stakeholder feedback indicates general support for the first two features of the ISO's proposal and the third feature raised the most discussion. Based on this feedback, the ISO is proposing to move forward with all three proposed changes while making some modification to its proposal regarding the third feature.

Following publication of this draft final proposal, the ISO will hold a stakeholder web conference on October 29. Written stakeholder comments are due November 12. The ISO intends to present this proposal to the ISO Board of Governors at its meeting scheduled for December 18-19.

2 Introduction

The ISO supports the FERC's stated goals of promoting competition in the transmission planning process.

Just a few years ago the ISO reformed its transmission planning process to explicitly consider public policy requirements as a potential driver for transmission facilities and afford both incumbent and non-incumbent transmission developers nondiscriminatory opportunities to compete to build transmission facilities that the ISO finds are needed for public policy or economic efficiency reasons.

More recently in its Order No. 1000 compliance filing, the ISO expanded on these changes and proposed tariff revisions to further promote competition in the transmission planning process. The ISO proposed to eliminate from the ISO tariff the remaining provisions that grant a federal "right of first refusal" for incumbent participating transmission owners to build and own certain transmission facilities whose costs will be allocated regionally. These changes reflect a significant "scaling-back" of participating transmission owners' existing right of first refusal to build all transmission facilities needed for reliability or to maintain the simultaneous of long-term congestion revenue rights ("CRRs"). On April 18, 2013, the FERC approved these changes.

In this paper the ISO is proposing three changes to further promote competition in the transmission planning process. First, the ISO proposes to create a mechanism by which non-PTO approved project sponsors that have no existing rate recovery mechanism can recover their FERC authorized transmission revenue requirement (e.g., construction work-in-progress in rate-base and abandoned plant) associated with transmission projects under construction and prior to the time that the facilities are turned over to the operational control of the ISO. Second, the ISO proposes to clarify that non-PTO approved project sponsors with existing transmission assets are only required to turn over to ISO operational control the project they were selected to build. Third, to mitigate costs incurred by the ISO to perform and administer the competitive solicitation process, the ISO proposes to impose a project sponsor application deposit.

3 Stakeholder process and next steps

Following the release of this draft final proposal, the ISO will hold a stakeholder web conference on October 29 to discuss the draft final proposal and solicit final stakeholder comments. The ISO is requesting written stakeholder comments by November 12. The ISO's proposal will be presented to the ISO Board of Governors at its December 18-19 meeting.

Table 1 provides a summary of this stakeholder process.

Table 1 – Stakeholder process schedule

Date	Milestone
September 10	Post issue paper and straw proposal
September 20	Stakeholder web conference

Date	Milestone
October 3	Stakeholder comments due by 5:00pm
October 17	Post draft final proposal
October 29 (1:00-3:00)	Stakeholder web conference
November 12	Stakeholder comments due by 5:00pm
December 18-19	ISO Board meeting
Early 2014	FERC filing

4 Recovery of FERC authorized transmission revenue requirements prior to becoming a PTO

4.1 FERC transmission rate incentives

Section 1241 of the Energy Policy Act of 2005 ("EPAct 2005") added new section 219 to the Federal Power Act ("FPA") directing the FERC to establish incentive-based rate treatments that promote capital investment in reliable and economically efficient transmission and generation of electricity by promoting capital investment. In 2006, FERC issued Order Nos. 679 and 679-A to establish incentives to support the development of transmission infrastructure.[1] These incentives include enhanced rate of return on equity ("ROE"), recovery of 100 percent of prudently-incurred costs associated with abandoned transmission projects due to factors beyond the control of the utility, use of hypothetical capital structures, incentives to join a transmission organization, and inclusion of 100 percent construction work-in-progress ("CWIP") in rate base, accelerated depreciation used for rate recovery, and expensing pre-commercial operations costs associated with new transmission investment, among others.

Most of these rate incentives are not included in the transmission revenue requirement of the transmission owner until the new transmission facilities are turned over to the operational control of the ISO upon completion and incorporated in the transmission revenue requirement that is approved by FERC. However, two of these—inclusion of CWIP in rate base and recovery of abandoned plant—are unique in that they may be recovered prior to completion of the new transmission project or after abandonment of the project.

[1] For purposes of convenience in this paper, the ISO will generally use the term Order No. 679.

To be eligible for these incentives, the subject project must have been vetted and approved by the ISO in its transmission planning process.[2]

Typically an applicant will file a petition for declaratory order requesting FERC approval of certain incentive rate treatments for its proposed project under FPA section 219 and Order No. 679. FERC reviews such requests for incentives on a case-by-case basis. The ISO anticipates that approved project sponsors similarly may seek incentive rate authority once selected in the ISO's competitive solicitation process.

4.1.1 *CWIP*

In Order No. 679, FERC established a policy that allows utilities to include, where appropriate, 100 percent of prudently-incurred transmission-related CWIP in rate base. FERC stated that this rate treatment will further the goals of FPA section 219 by providing up-front regulatory certainty, rate stability, reduced interest expense, and improved cash flow, by reducing the pressures on an applicant's finances caused by investing in transmission projects. Order 679 allows inclusion of 100 percent CWIP in rate base and expensing pre-commercial operations costs associated with new transmission investment because of the long lead times required to plan and construct new transmission can negatively affect cash flow and the ability of the sponsor to attract capital at reasonable prices. Traditional rate recovery mechanisms would not allow a utility to recover the costs of construction until the project is placed into service. Without CWIP in rate base, all of an applicant's borrowing costs would be accrued over several years and then capitalized after the new project goes into service, along with a return of the investment cost through depreciation expense. Such a process would increase an applicants' customers' bills more significantly than if the FERC were to allow inclusion of CWIP in rate base. Permitting a utility to recover CWIP in rate base allows investors to receive a return on their investment before the project is placed into service thereby increasing the attractiveness of these investments. Further, recovery of CWIP in rate base may facilitate financing and improve coverage ratios used by rating agencies to determine credit quality and debt ratings.

Typically FERC may accept an applicant's proposal to recover 100 percent of CWIP in rate base conditioned upon the applicant fulfilling FERC's requirements for CWIP inclusion for the project in a subsequent section 205 filing.

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[2] Order No. 679 states that each applicant must demonstrate that the facilities for which it seeks incentives satisfy the requirements of section 219 by either ensuring reliability or reducing the cost of delivered power by reducing congestion. The Order establishes a rebuttable presumption that a project is eligible for incentives under section 219 if it: (1) results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the FERC; or (2) has received construction approval from an appropriate state commission or state siting authority. FERC will consider incentive requests for projects that are still undergoing consideration in a regional planning process, but may make any requested incentive rate treatment contingent on the project being approved under the regional planning process.

4.1.2 *Abandoned plant*

Under Order No. 679, the FERC allows applicants to seek recovery of 100 percent of prudently-incurred costs associated with a transmission project that is cancelled or abandoned for reasons outside the applicant's control. The purpose of this incentive is to reduce the risk associated with potential upgrades or other improvements to the transmission system. The ability to recover the costs of abandoned plant is an important consideration when applicants evaluate investment opportunities with significant risk associated with factors beyond their control, such as generation developers' decisions to develop or terminate the development of the potential generation resources that drove the need for the line in the first place (e.g., it may be uncertain whether renewable generation resources connecting to a transmission project will ultimately be developed) or difficulty obtaining state or local siting approvals (e.g., some projects may require multiple approvals involving multiple regulatory jurisdictions which can increase the possibility that a project may be subject to forced abandonment). In Order No. 679 the FERC found that the abandonment incentive is an effective means of encouraging transmission development by reducing the risk of non-recovery of costs.

Typically, if the request is approved, FERC would conditionally grant an applicant's request for recovery of 100 percent of prudently-incurred transmission-related costs associated with abandonment of a project, provided that the abandonment is a result of factors beyond the control of the applicant, which must be demonstrated in a subsequent FPA section 205 filing for recovery of abandoned plant.

4.2 Relationship between the ISO access charge and a PTO's transmission revenue requirement

All market participants withdrawing energy (i.e. loads and exports) from the ISO controlled grid pay access charges, either the transmission access charge or the wheeling access charge.

In accordance with Section 26 and Schedule 3 of Appendix F of the ISO Tariff, the ISO access charge is designed to recover each Participating Transmission Owner's ("PTO") transmission revenue requirement. Only PTOs may recover their transmission revenue requirement through the ISO access charge. Under the ISO tariff, a PTO is defined as "a party to the Transmission Control Agreement whose application under section 2.2 of the Transmission Control Agreement has been accepted and who has placed its transmission assets and Entitlements under the CAISO's Operational Control in accordance with the Transmission Control Agreement."

Each PTO's transmission revenue requirement is the total annual FERC authorized revenue requirement associated with transmission facilities turned over to the operational control of the ISO by the PTO, including projects under construction that are to be turned over to the operational control of the ISO upon completion (this latter point is relevant in the case of CWIP and abandoned plant).

Simply put, the ISO tariff contains provisions to collect the necessary funds and provide revenue to a PTO for use of transmission assets. The ISO tariff contains no such provisions for non-PTOs. The ISO pays access charge revenues to PTOs on a monthly basis.

4.3 September 10 straw proposal

In phase 3 of the annual transmission planning process, the ISO evaluates proposals to construct, own, operate, and maintain regional transmission facilities identified in the comprehensive transmission plan and subject to competitive solicitation. The project sponsor selected may be a PTO or a non-PTO. Presumably the selected project sponsor would request FERC approval of incentive rate treatments for its proposed project under FPA section 219 and Order No. 679, including recovery of 100 percent of CWIP in rate base and recovery of 100 percent of prudently-incurred costs associated with project abandonment. If the approved project sponsor is a PTO, then the revenues associated with CWIP and abandoned plant could be recovered through the PTO's existing revenue requirement; however, a non-PTO approved project sponsor would have no such mechanism to recover the revenue requirement associated with CWIP and abandoned plant. As previously stated, the ISO tariff does not contain any provision to collect the necessary funds and provide revenue to a non-PTO for use of transmission assets.

Project sponsors that the ISO (or authorized governmental body) selects to build and own a needed transmission solution identified in the ISO's comprehensive transmission plan, whether a PTO or non-PTO, are similarly situated because they both face similar risks and financing pressures caused by investing in transmission projects. Recognizing these similarities and in order to provide a more level playing field and support a competitive transmission process, the ISO proposes to create a new mechanism by which non-PTO project sponsors that are selected to build and own an identified transmission solution in the ISO's competitive solicitation process can, through the ISO access charge, recover these components of their FERC authorized transmission revenue requirements prior to the completion of the project. This recovery would be limited to CWIP and abandoned plant.

In the case of CWIP, once the project is completed and turned over to the operational control of the ISO, and the project sponsor becomes a party to the TCA, the remaining portions of its FERC authorized transmission revenue requirement would be recoverable through the ISO access charge. An approved project sponsor of a project that is ultimately abandoned, for which FERC has authorized recovery of prudently incurred expenditures prior to the time that the project was discontinued, would continue to recover these costs for the remainder of the authorized amortization period.

To implement this new mechanism, the ISO stated in the September 10 issue paper and straw proposal that it is exploring the following options:

1. Add a new Section 4.17 to the ISO Tariff describing the relationship between the ISO and non-PTO approved project sponsors.
2. Amend Section 26 and Schedule 3 of Appendix F and Section 11 of the ISO Tariff to include recovery of a non-PTO approved project sponsor's FERC authorized transmission revenue requirement associated with transmission projects under construction that was approved by the ISO through the transmission planning process and is intended to be turned over to the operational control of the ISO upon completion or with abandoned facilities for reasons beyond the approved project sponsor's control.
3. Develop a pro-forma agreement for use between the ISO and each approved project sponsor to accomplish a number of purposes including:
    a. Acknowledge acceptance of the selection of the project sponsor.
    b. Establish the obligations, roles and responsibilities of the project sponsor including reporting requirements so that the ISO can proactively monitor the status of approved facilities and to take the necessary actions if projects are not on schedule. This agreement may overlap with the Transmission Control Agreement ("TCA") once the project sponsor enters into the TCA with respect to the facility that the project sponsor was selected to construct and own as a result of the competitive solicitation process, and the transmission facilities have achieved commercial operation.
    c. Allow the project sponsor to file with FERC for CWIP and abandoned plant, if applicable, to be funded through the ISO's access charge.

The ISO invited stakeholders to comment on these potential changes and to identify other alternative (or additive) tariff options/revisions that would (i) enable non-PTOs to recover their transmission revenue requirement in rates before they become PTOs and (ii) ensure that transmission solutions are successfully completed in a timely manner.

4.4 Stakeholder comments

A review of the October 3 stakeholder comments indicates that there is general support for this feature of the straw proposal.

Several stakeholders commented that this should be accomplished through tariff changes and not a new contract mechanism, and that a contract is unnecessary.

PG&E sought the following conditions: (1) the non-PTO must file a petition for declaratory order and obtain FERC authorization to recover the costs; (2) the non-PTO must have a FERC approved transmission owner tariff rate filing setting forth its cost recovery prior to turning the project over to ISO operational control; (3) the non-PTO should enter into some transitional agreement with the ISO that requires it to refund monies collected through the access charge if FERC subsequently

denies recovery of abandoned plant costs and include provisions restricting the sale of the project unless the new entitlement holder becomes a PTO (see TCA sections 4.4.4, 4.4.5, and 4.4.6).

SCE's support is conditioned on assurances that non-PTOs will have to go through the same approval process and be held to the same standards for recovery as PTOs.

Some stakeholders stated that the proposed mechanism should allow for recovery of all types of costs that FERC may permit recovery of before a facility is turned over to ISO control and not just CWIP and abandoned plant. LS Power said the ISO should make it clear that if an applicant is not selected in the competitive solicitation, there is no cost recovery, citing paragraph 332 of Order No. 1000. LS Power also recommended a general catch all phrase like that proposed in PJM's Order No. 1000 docket.

4.5 Draft final proposal

Based on stakeholder comments, the ISO proposes to retain all of the elements of the September 10 straw proposal and complements those with the following refinements:

- The tariff would state that approved project sponsors are permitted to recover all of FERC-approved, pre-PTO costs. This provision would only be reflected in the tariff not in any pro forma agreement between the ISO and an approved project sponsor.
- The tariff language will permit the recovery of all such FERC-approved costs and not single out CWIP or abandoned plant. This approach should be consistent with the language in the tariff regarding what PTO costs can be recovered through the transmission revenue requirement.
- Non-PTO approved project sponsors would have to go through the same rate approval process in the tariff that PTO's go through to establish a FERC approved transmission revenue requirement and a transmission owner tariff that is then reflected in the ISO's access charge. The intent is to make the ISO tariff provisions applicable to both PTOs and Non-PTOs selected as approved project sponsors.
- There is no basis to state in the tariff that the non-PTO must obtain a petition for declaratory order from FERC as a pre-condition. Such a provision is not present in the current tariff for PTOs selected as an approved project sponsor, and this is more of a FERC issue than an ISO tariff issue.
- Provisions similar to those found in sections 4.4.4, 4.4.5, and 4.4.6 of the TCA would serve as the model.
- A transitional pro-forma agreement would be used to (1) acknowledge acceptance of the selection of the approved project sponsor, (2) establish the obligations, roles and responsibilities of the project sponsor, including project specific milestones; and, (3) any binding cost control measures, including binding cost caps that the approved project sponsor agreed to in their application.

5 Non-PTO approved projects sponsors with existing transmission assets

5.1 September 10 straw proposal

In the September 10 straw proposal, the ISO stated its belief that this issue is already addressed in the current tariff. Under ISO tariff section 4.3.1, a new PTO is required to turn over operational control of all facilities and entitlements that (1) satisfy FERC's functional criteria for determining what transmission facilities should be placed under the ISO's operational control, (2) satisfy the criteria adopted by the ISO governing board identifying facilities for which the ISO should assume operational control, and (3) are the subject of mutual agreement between the ISO and the PTOs.

However, some stakeholders have indicated that these tariff provisions lack clarity with respect to the disposition of the existing transmission assets of a non-PTO approved project sponsor. Thus, under the scenario in which a non-PTO with existing transmission assets is selected as the approved project sponsor for a particular transmission solution, the issue has arisen whether that approved project sponsor will not only be required to turn over to the ISO's operational control the particular transmission solution but will also be required to turn over all of its existing transmission assets to ISO operational control.

To be clear, the ISO believes it important to maximize participation in the competitive solicitation process and recognizes that many different transmission developers with existing facilities located throughout the US, or elsewhere, may seek to compete in the competitive solicitation process.

Thus the ISO stated in the straw proposal that an approved project sponsor that is not an existing PTO should be required to turn over to the ISO's operational control *only* the facilities that it was awarded the right to build, not all of its transmission facilities. The ISO further indicated that it is evaluating what would be required to implement this change—a new agreement, changes to the transmission control agreement, and/or targeted tariff provisions (e.g., perhaps this could be addressed in a new section 4.17 to the ISO tariff as discussed in section 3.3 above).

The ISO invited stakeholders to comment on its proposal to address the issue of non-PTO approved project sponsors with existing transmission assets and discuss what specific changes they believe are necessary to effectuate the proposal.

5.2 Stakeholder comments

A review of the October 3 stakeholder comments indicates that there is strong support for this feature of the straw proposal.

SCE noted that the TCA already allows applicants to justify why certain transmission facilities should not be placed under ISO operational control and also provides the ISO discretion to reject taking operational control over facilities under certain circumstances. SCE also references section

4.3.1 of the ISO tariff. SCE thus believes that changes may be unnecessary. SCE conditions its support on fair application among PTOs and non-PTOs.

IID believes that further clarification is needed on this issue and supports ISO's efforts to do so.

DATC supports the proposal because it eliminates uncertainty that could be an obstacle to participation by some non-PTOs.

MidAmerican Transmission supports clarification, if determined to be needed by the ISO. MidAmerican Transmission notes that historical approaches taken for projects such as Path 15 (with participation by the Western Area Power Administration) appear to already support the premise without the need for additional tariff changes.

Pinnacle West Capital believes that the ISO tariff already makes clear that non-PTOs are required to turn over operational control of only the specific project for which they were selected to build and not all transmission facilities. However, they believe that eliminating any actual or perceived uncertainty will benefit the process.

SMUD supports the ability of non-PTO project sponsors to place discrete ISO-approved projects under ISO operational control.

Critical Path Transmission, NV Energy, and Exelon support the ISO's efforts to explore options for additional clarity on this issue.

5.3 Draft final proposal

The ISO proposes to proceed with this feature of the straw proposal. The ISO proposes to make any necessary changes to section 4 of the tariff and to the TCA to implement this feature of the proposal.

6 Project sponsor application deposit

Over the last several years the ISO has made a number of significant tariff revisions in order to promote competition in the transmission planning process. As a direct result, the ISO now administers a competitive solicitation process providing an opportunity for project sponsors to submit proposals to finance, own, and construct facilities subject to competitive solicitation identified in the comprehensive transmission plan. Under this process the ISO carries out several significant tasks including (1) determining whether a project sponsor meets certain qualification criteria, (2) determining whether a project sponsor's proposal meets certain proposal qualification criteria, and (3) selecting an approved project sponsor. In addition, once the project sponsor is selected, the ISO may also devote a significant amount of time ensuring that the project is on-track for completion including (1) negotiating a contract with the project sponsor to provide obligations, roles and responsibilities of the parties; (2) monthly project status review; (3) change management,

if applicable; (4) coordination of commissioning activities; (5) recovery of CWIP and abandoned plant, and any other FERC authorized pre-PTO costs, ; (6) coordination with existing PTOs; and (7) any binding cost control measures, including binding cost caps that the approved project sponsor agreed to in their application.

The ISO views these tasks as a significant undertaking that requires an extensive commitment of resources and the need to bring in outside contractors to support internal ISO staff, at significant additional cost. Also, the ISO tariff requires that ISO to retain a consultant to assist it in the selection of an approved project sponsor. This workload is likely to increase with each successive annual transmission planning process cycle because more transmission solutions will be subject to competitive solicitation under the ISO's Order No. 1000 transmission planning framework than under the process in effect for the 2012-2013 process.

Thus far the ISO has been funding this significant incremental workload and cost without a corresponding increase in its operations budget (i.e., through the Board approved grid management charge paid by scheduling coordinators). This raises the question whether it is appropriate for ISO ratepayers to fund the costs of individual applicants competing to build and own specific transmission solutions. For example, the ISO notes that resources seeking to interconnect to the ISO grid via the generator interconnection process pay fees to support processing their applications and conducting the necessary studies, and shortly will pay fees to process modifications for their projects. The ISO also notes that FERC authorized the Midcontinent Independent System Operator ("MISO") to charge transmission developers participating in the competitive solicitation process a deposit.[3] Similarly, FERC authorized the Southwest Power Pool ("SPP") to charge an application fee for purposes of the qualification determination and a deposit for applicants submitting project proposals.[4]

6.1 September 10 straw proposal

To mitigate the aforementioned impacts, the ISO believes that all project sponsors should bear the costs of the competitive solicitation process. To accomplish this, the ISO proposed in the September 10 paper that project sponsors be required to provide an application deposit in the amount of $100,000 to be applied as a pool of funds to pay for actual costs incurred by the ISO to perform and administer the competitive solicitation process. If the amount required to pay actual costs is determined to be greater than $100,000 per application, then each project sponsor would be obligated to provide the additional amount. Conversely, if the amount required to pay actual

[3] *Midwest Independent Transmission System Operator,* 142 FERC ¶61,215 at PP 300-01 (2013).
[4] *Southwest Power Pool,* 144 FERC ¶61,059 at PP 230 242-44 (2013).

costs was determined to be less than $100,000, then each project sponsor would be refunded the unused balance of its deposit, with interest.[5]

The ISO also indicated that it was considering whether approved project sponsors should bear the actual costs incurred by the ISO to ensure that the project is on-track for completion (e.g., negotiating an agreement with the approved project sponsor, monthly project status review, change management, if applicable; coordination of commissioning activities, and coordination with existing PTOs).

The ISO invited stakeholders to provide comment on the ISO's proposal on a project sponsor application deposit. Stakeholder were also asked to comment on whether approved project sponsors should bear the actual costs incurred by the ISO to manage any potential agreements with approved project sponsors.

6.2 Stakeholder comments

This feature of the straw proposal raised the most discussion, with a broad range of perspectives expressed.

Two stakeholders – Critical Path Transmission and Duke American Transmission Company (DATC) – completely opposed it. Critical Path Transmission claimed that the proposal would be discriminatory toward non-incumbents. DATC argued that: (1) all ratepayers benefit from the competitive solicitation and thus the ISO's administrative costs incurred to run the competitive solicitation benefit ratepayers; (2) unlike the costs of interconnection studies, the costs incurred to manage the competitive solicitation process do not directly benefit the participants, they benefit the ISO and ratepayers; (3) the ISO has not demonstrated any actual cost basis for the $100,000 and shown that it is reasonably base on the competitive solicitations the ISO has conducted; (4) the fee favors incumbents because there is no showing that they cannot recover these costs in their rates; (5) the cost responsibility obligation is open ended; and, (6) an application fee might be supportable to deter participation by unqualified applicants or large numbers of applications that do not meet the ISO's requirements, but that does not appear to be the case here.

Imperial Irrigation District (IID) and Pinnacle West Capital conceptually support charging an application fee to perform and administer the competitive solicitation process with respect to external consultant charges but not to cover internal ISO costs.

SCE and CPUC staff also conceptually support charging an application fee, and SCE goes further in its comments and supports charging the approved project sponsor for costs associated with negotiating and administering a contract. CPUC staff believes that such deposits should be trued-up after the winning bidder is selected.

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[5] Interest is based on the interest that the ISO receives on the deposit, not based on the federal rate in 18 CFR 35.19(a).

MidAmerican Transmission supports imposition of an application fee for the competitive solicitation, but argues that the ISO needs to provide some clarity regarding how it will calculate costs associated with evaluating bid proposals (e.g., will these funds be used to pay for external consultants or to offset internal ISO staff time) and that the fee should be supported by enough detail to show its cost basis. MidAmerican Transmission, as well as numerous other stakeholders (e.g., CPUC staff, Pinnacle West Capital) opposes any type of fee for monitoring whether a project is on track and meeting milestones.

A large number of stakeholders (e.g., Pinnacle West Capital, Pattern Transmission, PG&E, and CPUC staff) encourage the ISO to evaluate its solicitations on an ongoing basis to ensure that the initial application fee remains appropriate.

Two stakeholders (Pinnacle West Capital and Pattern Transmission) suggest capping the costs that the ISO can recover in connection with running the competitive solicitation or setting a fixed fee, in order to reduce uncertainty.

LS Power suggests a tiered application fee with a clear 45-day refund mechanism: $25,000 for non-transmission line proposals and transmission lines less than 10 miles in length; and, $75,000 for solicitations involving lines greater than 10 miles.

Pattern Transmission argues that $100,000 is an inappropriate amount because project sponsors can't control the process and will be reliant on the ISO to develop an efficient process, and that ratepayers should bear some of the costs because they benefit from competition. Pattern Transmission suggests an annual $20,000 qualification fee reduced to $10, 000 in future years for any qualification process that occurs two or more years after the previous qualification, and a fixed competitive solicitation fee of $50,000.

PG&E argues that the ISO has not shown that a $100,000 fee is just and reasonable or cost-justified. PG&E also wants the ISO to eliminate the collaboration step in the process, claiming that it results in duplicative qualification cost incurrence. PG&E wants the ISO to report to the ISO Board of Governors 90 days after each competitive solicitation stating the costs incurred for outside consultants and discussing the efficiency and effectiveness of the process.

Exelon states that the proposed application fee disadvantages independent developers because it is a hurdle to market participation. Exelon contends that incumbent PTO's will be permitted to recover the cost of the application fee as a prudent expenditure because FERC will have found the imposition of such a fee and the amount of the fee to be just and reasonable. Exelon also states that incumbent utilities will be able to recover this cost even if they are not selected as the approved project sponsor in the competitive solicitation. Finally, Exelon recommends that if ISO retains the application fee, the costs be shared between ratepayers and project sponsors.

6.3 Applicable precedent

In the September 10 straw proposal, the ISO noted that FERC authorized MISO and SPP to charge deposits and fees related to competitive solicitation processes. In this section the ISO provides further information on the applicable precedent.

6.3.1 *Midcontinent Independent System Operator*

For purposes of evaluating project sponsors and selecting a designated project sponsor in the competitive solicitation, the Midcontinent Independent System Operator (MISO) proposed a fee equal to 1% of the estimated cost of the project not to exceed $500,000. At the end of the process there would be a true up with interest paid on any deposit amounts to be refunded. FERC approved the application fee in concept, but found that MISO had failed to provide sufficient information justifying the level of the deposit fee. MISO cited generation interconnection deposits of $250,000 but provided no evidence that the costs required to evaluate a generator interconnection were comparable to those necessary to conduct a competitive solicitation.

FERC found MISO's fee level as proposed could therefore constitute a barrier to entry. FERC required interest to be paid on the refunded amount consistent with FERC's policy. FERC also directed MISO to (1) clarify how it would calculate the cost it will incur to evaluate bid for purposes of refunding a bidder's deposit; and (2) clarify whether or not disqualified applicants must wait until after the selection of a project sponsor before they get their refund, because these factors could lead to uncertainty as to whether a transmission developer should submit a bid. Based on discussions with stakeholders, in its 120-day compliance filing, MISO revised the application fee to $100,000 with a true up of any shortfall at the end of the process and interest paid on any refunded amounts.

6.3.2 *Tampa Electric Company, et al*

Tampa Electric Co. *et al.*proposed a one-time $50,000 fee for outside consultants to review a non-incumbent transmission developer's qualifications. This is a one-time event for each transmission developer. Unexpended amounts would be refunded. For transmission developers proposing a CEERTS project (one where the transmission line is subject to the Florida Transmission Line Siting Act, or a sub-station flexible AC transmission system such as series of series compensation or static VAR compensators developed to operate above 200 kV), a separate deposit of $100,000 for each $10 million of project cost is required, to be capped at a maximum deposit of $500,000, which is used to cover both internal cost and out-of-pocket costs incurred by the regional planner to evaluate the project sponsor's project. The costs would be trued up at the end of the process.

FERC approved the one time qualification fee with the requirements that (1) interest be paid on refunded amounts, (2) the filing parties provide a description of which costs the deposit will be

applied to, how they will be calculated, and an accounting of the actual costs to which the deposit is applied.

FERC approved the separate CEERT project study fee in concept but found that the filing parties has failed to provide justification of the level of the fee and the step function aspect of the proposal. FERC, *inter alia,* directed Tampa Electric Co. *et al.* to: (1) clarify why the full deposit is required at the initial stages of the project review process rather that once a project is selected in the regional plan; (2) provide an accounting of to each transmission developer describing the costs the deposit would be applied to, how those costs will be calculated, and an accounting of the actual costs incurred to which the deposit is applied; and, (3) pay interest on refunded amounts.

6.3.3 *Southwest Power Pool ("SPP")*

Southwest Power Pool (SPP) proposed a separate qualifications application fee to be applied only to non-incumbents. The application fee was equal to the amount of the SPP annual membership fee. SPP proposed to post the amount of the qualifications application fee on its website as part of the application form. The fee is intended to offset SPP's costs of process such qualification applications.

FERC found the fee might be unduly discriminatory because both incumbents and non-incumbent submit qualifications applications. FERC directed that SPP must either impose the charge on both incumbents and non-incumbents or explain why it is not unduly discriminatory to charge non-incumbents this fee, but not incumbents.

SPP also proposed a separate deposit for both incumbents and non-incumbents participating in the competitive solicitation to compensate SPP for the costs of the solicitation. SPP proposed that the level of the fee would be set at the level of SPP's estimate of what participation in the competitive solicitation would cost. At the end of the process each participant would receive an invoice for additional payments or receive a refund based on the reconciliation of the deposits collected and the actual costs incurred.

FERC found that Order No. 1000 expressly permit transmission planning regions to require additional procedural protections such as the posting of deposits and agreed with SPP that a deposit would prevent flooding the process with duplicative proposals. However, FERC found that SPP had not provided enough information to justify the proposed fee, had not specified a precise dollar amount or a formula for determining the amount of the fee, and therefore a transmission developer did not have sufficient information to assess whether or not to submit a bid. FERC also imposed all of the information, calculation, accounting, and interest requirements it had imposed on MISO and the Florida parties.

6.4 Draft final proposal

Based on a review of stakeholder feedback and applicable precedent, the ISO presents its draft final proposal in this section.

The ISO proposes to retain the application fee concept as described in the September 10 straw proposal. Each proposal will be required to include an application deposit in the amount of $75,000. The application fee amount is based on the internal and external expenditures incurred by the ISO for the Imperial Valley Policy Element competitive solicitation (slightly more than a total of $200,000 for two project sponsors) and an estimate of the final cost of the Gates-Gregg 230 kV Line competitive solicitation (approximately $250,000 total for five project sponsors). There are still a number of consultant invoices pending and there are ongoing internal and consultant costs yet to be incurred before the final selection is made and report posted. Internal costs will be based on the amount of time each ISO employee charged to the specific competitive solicitation analysis, multiplied by the imputed hourly rate of such employee. Also, the Gates-Gregg 230 kV Line only involves construction of a single line with no substations, so it does not reflect all of the comparative analysis that might occur with a more complex, multi-facility proposal (including substations). On the other hand, the Imperial Valley Policy Element included a collector substation. The deposit will be applied as a pool of funds to pay for costs incurred by the ISO, or third parties at the direction of the ISO, as applicable, to perform and administer the competitive solicitation process and to communicate with applicants with respect to their proposal applications. If the amount required to pay actual costs is determined to be greater than $75,000 per application, then each project sponsor would be obligated to provide the additional amount up to a cap of $150,000. Conversely, if the amount required to pay actual costs was determined to be less than $75,000, then each project sponsor would be refunded the unused balance of its deposit, with interest.[6] The ISO would make refunds as follows: (1) following the ISO's qualification decisions, to the extent the ISO finds a project sponsor to be unqualified for the project, the ISO will make its refund within 75 days after the qualification decision; and (2) for qualified project sponsors, the ISO will make refunds within 75 days after the approved project sponsor is named.

The ISO's tariff provisions will (1) clarify what costs the deposit will apply to and how it will calculate the costs it will incur for purposes of refunding a bidder's deposit and how the deposit is to be applied, and (2) provide an accounting, to be made public, of the actual costs incurred to which the deposit applied.

The ISO is not proposing a separate fee for qualification and selection, but rather one deposit to cover costs incurred to perform and administer all aspects of the competitive solicitation process. The ISO developed its competitive solicitation process to be as efficient as possible. This enabled

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[6] Interest is based on the interest that the ISO receives on the deposit, not based on the federal rate in 18 CFR 35.19(a).

the ISO to open up all regional transmission solutions to competitive solicitation, including near-term reliability projects (unlike some of the other ISOs that maintained a ROFR for such projects). Adding a two-step invoicing/payment process would add delay to the process. In that regard, after the qualification process the ISO would need to send out separate invoices to all project sponsors who were qualified, allow sufficient time for payment, and then re-start the comparative selection analysis only after all of the project sponsors had remitted their fees. The ISO has attempted to bridge the gap by proposing a separate refund opportunity after the qualification process is completed.

At this time there is no basis to support a tiered application fee based on the mileage of the line. The Imperial Valley Policy Element was significantly shorter than the Gates-Gregg 230 kV Line, but the costs incurred for that solicitation were higher. As indicated above, that also required a comparative analysis regarding a new substation in addition to a transmission line. The ISO will monitor future competitive solicitations to see whether any trends become discernible. To the extent they are, the ISO will be prepared to convene a stakeholder process to reassess the application fee structure.

The ISO disagrees with those stakeholders that argue that the application fee process is unduly discriminatory or that ratepayers should bear the costs of the competitive solicitation because it is ratepayers, not project sponsors that benefit. As discussed above, FERC approved the imposition of application fees on project sponsors in MISO, SPP, and Tampa Electric *et al.* FERC did not find the imposition of such a fee to be unduly discriminatory or require that all or a portion of the costs of the selection process be borne by ratepayers. In particular, MISO and SPP had ROFRs in place prior to Order No. 1000 and did not charge an application fee for incumbent transmission owners to propose new projects. That fact did not prevent FERC from finding that it is just and reasonable to charge an application fee to all project sponsors participating in a competitive solicitation. The suggestion that only ratepayers benefit from the competitive solicitation is not sustainable. Project sponsors benefit because if they are selected they will earn a return on equity for their shareholders. The suggestion that incumbent participating transmission owners that lose a competitive solicitation will automatically be permitted by FERC to recover their application fee in rates is speculative at this time. This would be an issue of first impression at FERC. It is uncertain whether FERC would require such costs to be borne by shareholders (such as other promotional, lobbying, and advertising costs that benefit shareholders) or would allow such costs to be recovered from ratepayers. In any event, this is a FERC issue not an ISO tariff issue because the ISO cannot dictate to FERC what it must, or must not, include in rates.

The ISO does not propose in this draft final proposal to retain the concept of charging approved project sponsors for costs incurred by the ISO to ensure that the project is on-track for completion (e.g., negotiating an agreement with the approved project sponsor, monthly project status review,

change management if applicable, coordination of commissioning activities, and coordination with existing PTOs).

7 Other issues raised by stakeholders

7.1 The requirement to initiate siting and other approvals

SCE and PG&E argue that the 120-day window (sections 24.5.2.2 and 24.5.2.3) to initiate siting approval in unnecessary and unworkable. SCE says it is unrealistic to complete the environmental work within 120 days, and the tariff should be revised to tie the requirement to the operating date of the project. PG&E suggests using the wording in sections 5.5.1 and 5.5.2.1 of the BPM that "the Project Sponsor must provide the ISO with documentation that it has commenced the process to seek siting approval and other necessary approvals."

There is no basis for these concerns. The tariff literally does not require the filing of a CPCN/CEQA application or any other application within 120 days. Both the tariff and BPM merely require that that the approved project sponsor take steps to initiate the process with regulators. As the ISO stated at page 49, footnote 121 of its October 11, 2012 Order No. 1000 compliance filing:

> However, to ease the up-front workload burdens on project sponsors, the ISO is clarifying the existing provisions in section 24.5.2.3 which require a project sponsor to seek siting approval within 120 days of the ISO's qualification determination or selection of an approved project sponsor. Specifically, the ISO is making it clear that project sponsors are not required to submit a complete siting application within 120 days; they are only required to demonstrate that they have taken steps to initiate the siting approval process. This should reduce the upfront burdens on project sponsors.

This conclusion applies to "other approvals" as well. The cited tariff language does not establish separate standards with respect to siting approvals and other approvals. Rather, they are both addressed in a single sentence with the same requirement applying to both. Thus, the clarification cited above applies with equal force both to the requirements for siting approvals and for "other approvals." The ISO also recognizes that many of the other approvals are intimately tied to the siting process and siting approvals and cannot be pursued until that process is completed. To the extent stakeholders still require additional clarification, the ISO can add these specific clarifications to the BPM when it makes its BPM changes related to Order No. 1000 compliance.

7.2 Requirements for the transferee of an approved project sponsor

SCE argues that transferee of an approved project sponsor must be held to the same standards needed to be an approved project sponsor, namely the criteria specified in tariff section 24.5.2.1. The ISO notes that tariff section 24.6 already provides that an approved project sponsor may not

sell, assign, or otherwise transfer its rights to finance, construct, and own a transmission solution or any element thereof before the project has been energized and turned over to the ISO's operational control unless the ISO approves such transfer. There must be a reasonable basis for the ISO's decision, which would include taking into account the results of the competitive solicitation. In addition, the ISO is willing to add language to this section requiring any transferee to (1) satisfy the provisions of section 24.5.3.1 (formerly 24.5.2.1), and (2) agree to honor any binding cost containment measures or cost caps that remain applicable at the time of the proposed transfer and reflected in the agreement between the ISO and the approved project sponsor.

7.3 Removing the collaboration tariff provisions

PG&E recommends eliminating the collaboration phase of the competitive solicitation process. The ISO declines to eliminate the collaboration step from the competitive solicitation process. Collaboration was a key component of the RTPP tariff amendment and the Order No. 1000 compliance filing. FERC has approved the provision twice and has been very supportive of it. Other stakeholders that participated in the Order No. 1000 compliance effort, such as the Public Interest Groups, strongly supported it. There are no material changed circumstances since the collaboration step was re-approved in FERC's April 18, 2013 Order on the ISO's Order No. 1000 compliance filing that would require us to revisit the issue.

7.4 Efficiency enhancements in the competitive solicitation process

PG&E suggests that the ISO: (1) eliminate certain questions from the project sponsor application as not adding value or being too much detail; (2) create a virtual/digital data room in which each bidder would populate its proposal documents; (3) reference all relevant market notices regarding the competitive solicitation on the ISO's transmission planning process webpage; and, (4) submit an annual report to the ISO Board regarding the efficiency and effectiveness of the ISO's transmission planning process Phase 3 procedures and a disclosure of the costs of outside consultants, total ISO costs incurred for each competitive solicitation, and the amount of time that was needed to complete each project selection process.

The ISO does not believe that these are really tariff issues to be addressed in this stakeholder process, but pertain more to ISO process and administration of the competitive solicitation process. The ISO appreciates the points made by PG&E, and as a part of this proposal, the ISO will commit to ongoing monitoring of its efficiency and effectiveness in performing and administering the solicitation and pursuing possible enhancements that will improve efficiency and reduce costs. As indicated above, the ISO will be providing a full accounting of the costs and time associated with each competitive solicitation. The ISO will make this public. With respect to the amount of time associated with each competitive solicitation, that is readily discernible from the ISO's website. Under the BPM, there are specified dates for the submission of project sponsor applications, and the ISO will post it selection decisions and reports (which will reflect the dates when the process

ends). Also, prior to the start of the competitive solicitation process for any regional transmission solutions identified in the 2013-2014 transmission plan, the ISO intends to hold a meeting with all interested parties to discuss what changes to the project sponsor application might be appropriate. This discussion can also address the other efficiency recommendations made by PG&E. Finally, as indicated above, to the extent the ISO can identify any trends in the competitive solicitation process or durable efficiency gains, the ISO is willing to open a new stakeholder process to address whether any changes in the application fee structure are appropriate.

Attachment B – Memorandum to ISO Governing Board

Competitive Transmission Improvements Tariff Amendment

California Independent System Operator Corporation

January 30, 2014

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market and Infrastructure Development

Date: December 11, 2013

Re: **Decision on competitive transmission improvements proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

The ISO has made a number of significant tariff revisions in recent years to promote competition in the transmission planning process. As a direct result, the ISO now administers a competitive solicitation process that provides opportunities for project sponsors, both incumbents and non-incumbents alike, to submit proposals to finance, own, and construct facilities subject to competitive solicitation identified in the comprehensive transmission plan. For example, in 2010, the ISO reformed its transmission planning process to explicitly consider public policy requirements as a potential driver for transmission facilities and afford both incumbent and non-incumbent transmission developers nondiscriminatory opportunities to compete to build transmission facilities that the ISO finds are needed for public policy or economic efficiency reasons. More recently in its Order No. 1000 compliance filing, the ISO expanded on these changes and proposed tariff revisions to eliminate the remaining provisions that grant a federal "right of first refusal" for incumbent participating transmission owners to build and own certain transmission facilities whose costs will be allocated regionally. These changes reflect a significant scaling-back of participating transmission owners' existing incumbent rights and obligations to build all transmission facilities needed for reliability or to maintain the simultaneous feasibility of allocated long-term congestion revenue rights. On April 18, 2013, the Federal Energy Regulatory Commission approved these changes.

Management recommends four additional changes to further promote competition through the transmission planning process. First, Management proposes to permit approved project sponsors to recover all Federal Energy Regulatory Commission-approved, pre-participating transmission owner costs associated with the project it was selected to build. Under the current tariff, this is permitted only for approved project

sponsors who are participating transmission owners.[1] Expanding this mechanism to approved project sponsors beyond participating transmission owners would promote competition in the transmission planning process by further leveling the playing field between incumbents and non-incumbents.

Second, Management proposes to clarify in the tariff that approved project sponsors who are not participating transmission owners, but who have existing transmission assets, are only required to turn over to ISO operational control the project they are selected to build. This change would promote competition in the transmission planning process by maximizing participation in the competitive solicitation process.

Third, Management proposes to impose a project sponsor application deposit as a means to mitigate costs incurred by the ISO to perform and administer the competitive solicitation process. Management expects that this workload is likely to increase with each successive annual transmission planning process cycle because more transmission solutions will be subject to competitive solicitation under the ISO's transmission planning framework.

Finally, Management proposes to clarify current tariff provisions requiring approved project sponsors to take the necessary steps to initiate the process of seeking siting approval from the appropriate authorities within 120 days of being selected as the approved project sponsor.

Management recommends the following motion:

> ***Moved, that the ISO Board of Governors approves the proposal for competitive transmission improvements, as described in the memorandum dated December 11, 2013; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

DISCUSSION AND ANALYSIS

Management recommends changes in the following four areas to further promote competition through the transmission planning process.

[1] Under the ISO tariff, a participating transmission owner is defined as a party to the Transmission Control Agreement whose application to become a participating transmission owner has been accepted and who has placed its transmission assets and entitlements under the ISO's operational control.

Recovery of FERC-authorized transmission revenue requirement prior to becoming a participating transmission owner

In phase 3 of the annual transmission planning process, the ISO administers a competitive solicitation process providing an opportunity for project sponsors to submit proposals to construct, own, operate, and maintain eligible transmission facilities identified in the comprehensive transmission plan. This opportunity is open to participating transmission owners and non-participating transmission owners alike as both may submit proposals, be selected as the approved project sponsor, and have Federal Energy Regulatory Commission-approved costs. However, under current tariff rules, only participating transmission owners may recover FERC-approved costs through the transmission access charge prior to the facility being placed into service. This is because the transmission access charge is currently designed to recover each participating transmission owner's transmission revenue requirement. The ISO tariff contains no such provisions for non-participating transmission owner approved project sponsors. Thus, to address this gap and improve opportunities for non-incumbents, Management proposes to amend the tariff to provide that approved project sponsors be permitted to recover all FERC-approved, pre-participating transmission owner costs associated with the project it was selected to build. Management also proposes to develop a pro forma agreement for approved project sponsors selected through the competitive solicitation process, whether they are a participating transmission owner or a non-participating transmission owner, to (1) acknowledge acceptance of the selection as the approved project sponsor; (2) establish the obligations, roles and responsibilities of the project sponsor, including project-specific milestones; and (3) reflect any binding cost containment measures, including binding cost caps that the approved project sponsor agreed to in its application.

Non-participating transmission owner approved project sponsors with existing transmission assets

If a non-participating transmission owner with existing transmission assets is selected as the approved project sponsor for a particular transmission solution, the sponsor will only be required to turn over to the ISO's operational control the particular solution it was selected to build. This clarification addresses some potential sponsors' concern that the ISO's current tariff provisions lack clarity with respect to the disposition of the existing transmission assets of a non-participating transmission owner approved project sponsor. Management believes this clarification is important to maximize participation in the competitive solicitation process. Many different transmission developers with existing facilities located throughout the U.S., or elsewhere, may seek to compete in the competitive solicitation process. In addition, once a non-participating transmission owner with existing transmission assets is selected as the approved project sponsor for a particular transmission solution and the Transmission Control Agreement is negotiated for it to become a participating transmission owner, the ISO will amend the Transmission Control Agreement to align with this concept.

Project sponsor application deposit

In performing and administering the competitive solicitation process, the ISO carries out several significant tasks including (1) determining whether a project sponsor meets certain qualification criteria; (2) determining whether a project sponsor's proposal meets certain proposal qualification criteria; and, (3) selecting an approved project sponsor. These tasks require an extensive commitment of resources and the need to bring in outside consultants to support internal ISO staff, at significant additional cost. Thus far, the ISO has been funding this significant incremental workload and cost without a corresponding increase in its operations budget which raises the question whether it is appropriate for ISO ratepayers to fund the costs of individual applicants competing to build and own specific transmission solutions. Management believes that project sponsors should bear the costs of the competitive solicitation process, and notes that FERC has approved the imposition of application fees on project sponsors under similar circumstances.[2] To accomplish this, Management proposes that project sponsors be required to provide an application deposit in the amount of $75,000 with each proposal submitted. This amount is based on the internal and external expenditures incurred by the ISO for the Imperial Valley Policy Element competitive solicitation (slightly more than a total of $200,000 for two project sponsors) and an estimate of the final cost of the Gates-Gregg 230 kV Line competitive solicitation (approximately $250,000 total for five project sponsors). The deposit will be applied as a pool of funds to pay for costs incurred by the ISO, or third parties at the direction of the ISO, as applicable, to perform and administer the competitive solicitation process, and to communicate with applicants with respect to their proposal applications. If the amount required to pay actual costs is determined to be greater than $75,000 per application, then each project sponsor would be obligated to provide the additional amount up to a cap of $150,000. Conversely, if the amount required to pay actual costs was determined to be less than $75,000, then each project sponsor would be refunded the unused balance of its deposit, plus interest. The ISO would make refunds at two different points in the process as follows: (1) within 75 days following the ISO's qualification decisions, to the extent the ISO finds a project sponsor not to be qualified for the project; and, (2) within 75 days after the approved project sponsor is named for project sponsors found to be qualified for the project.

Clarification of tariff requirement to seek siting approval within 120 days

Based on feedback received from stakeholders, Management proposes to clarify current tariff provisions requiring approved project sponsors to take the necessary steps to initiate the process of seeking siting approval from the appropriate authorities within 120 days of being selected as the approved project sponsor. Stakeholders have expressed concern that this provision would require a project sponsor to submit a completed siting application within the 120 day window. Management would like to clarify that the tariff merely requires that the approved project sponsor takes the

[2] These include application fees assessed by Midcontinent Independent System Operator, Tampa Electric Co. and Southwest Power Pool.

necessary steps to initiate the process with regulators, which can be accomplished without developing and filing a complete application.

POSITIONS OF THE PARTIES

First, all stakeholders either fully support, or support with qualification, Management's proposal to permit approved project sponsors to recover all FERC-approved, pre-participating transmission owner costs associated with the project it was selected to build. The qualifications expressed and Management's responses are summarized in the attached stakeholder matrix.

Second, all stakeholders either fully support, or support with qualification, Management's proposal to clarify in the tariff that approved project sponsors who are not a participating transmission owner, but who have existing transmission assets, are only required to turn over to ISO operational control for the project they are selected to build. The qualifications expressed and Management's responses are summarized in the attached stakeholder matrix.

Third, a majority of stakeholders either fully supports, or supports with qualification, Management's proposal to impose a project sponsor application deposit as a means to mitigate costs incurred by the ISO to perform and administer the competitive solicitation process. The qualifications expressed and Management's responses are summarized in the attached stakeholder matrix. Only one stakeholder, LS Power, expressed opposition but clarifies that its position is driven more by its preference that the qualification and selection processes be separate rather than by the reasonableness of the deposit requirements contained in the proposal. Management does not propose separate fees for qualification and selection, but rather proposes one deposit to cover costs incurred to perform and administer all aspects of the competitive solicitation process. Nevertheless, Management proposes a separate refund opportunity after the qualification process is completed.

Finally, Management intends to address stakeholder concerns, through the tariff development process, to clarify that the tariff merely requires that the approved project sponsor takes the necessary steps to initiate the process with regulators, which can be accomplished without developing and filing a complete application.

CONCLUSION

Management recommends that the Board approve the proposal described in this memorandum. Management's proposal is broadly supported by stakeholders and was refined to address their major comments and concerns. Management believes that its proposal will further promote competition in the transmission planning process by maximizing participation in the competitive solicitation process and improving the ISO's ability to perform and administer the process.

Attachment A

Stakeholder Process: Decision on Competitive Transmission Improvements

Summary of Submitted Comments

Stakeholders submitted two rounds of written comments to the ISO on the following dates:

- Round One: Issue Paper and Straw Proposal posted on September 10, 2013; comments received October 3.
- Round Two Draft Final Proposal posted on October 17, 2013; comments received November 12.

Stakeholder comments are posted at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/CompetitiveTransmissionImprovements.aspx

Other stakeholder efforts include:

- Stakeholder web conferences were held on September 20, 2013 and November 4, 2013.

Parties that submitted written comments on the Draft Final Proposal: California Public Utilities Commission ("CPUC") staff, Duke American Transmission Company ("DATC"), Imperial Irrigation District ("IID"), Isolux Infrastructure, LS Power, MidAmerican Transmission, Pinnacle West Capital Corporation ("PNW"), Pacific Gas and Electric Company ("PG&E"), Six Cities[1], and Southern California Edison ("SCE").

Other parties that also participated in the initiative: Abengoa, Bonneville Power Administration, California Department of Water Resources, California Energy Commission, Clean Coalition, Critical Path Transmission, Customized Energy Solutions, Exelon Corporation, Flynn Resource Consultants, Idaho Power, ITC Holdings, NV Energy, Northern Tier Transmission Group, Northeast Utilities, Pasadena Water & Power, Pattern Transmission LP, Power Engineers, Powerex, Powerlink Transmission Company, Sacramento Municipal Utility District, San Diego Gas & Electric, Sempra, Smart Wire Grid, Terra-Gen Power, Trans Bay Cable, Transmission Agency of Northern California, Tres Amigas, Western Area Power Administration, and Xtreme Power.

[1] Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside, California ("Six Cities").

Management Proposal	Transmission Developers	Participating Transmission Owners	Government Agencies	Management Response
Permit approved project sponsors to recover all FERC-approved, pre-participating transmission owner costs associated with the project it was selected to build.	• DATC: Strongly supports. • Isolux Infrastructure: No comment. • LS Power: Supports with qualification. Needs to review exact tariff language. • MidAmerican Transmission: Supports with qualification. Requests clarification that a declaratory order from FERC is an option for the project sponsor, not a requirement. The pro forma approved project sponsor agreement should apply to both PTOs and non-PTOs and should not include provisions more onerous than the obligations and requirements of project sponsors of non-competitive projects. • PNW: Supports with qualification. Would not support a pro forma approved sponsor agreement that would impose more onerous provisions on non-incumbents than those imposed on incumbents.	• PG&E: Supports with qualification. The pro forma approved project sponsor agreement should include a provision establishing an obligation for the sponsor to refund construction work in progress ("CWIP") revenues collected via the transmission access charge ("TAC") in the event FERC subsequently denies recovery of 100% abandoned plant costs and the project does not become operational. • SCE: Supports. • Six Cities: Does not categorically object but believes ISO should enhance its approach to evaluating the cost impacts of proposals submitted through the competitive solicitation process.	CPUC: Fully supports.	Management does not believe it is necessary to state in the tariff that a non-PTO selected as an approved project sponsor must obtain a petition for declaratory order from FERC as a pre-condition. Such a provision is not present in the current tariff for PTOs selected as an approved project sponsor. The pro forma approved project sponsor agreement will apply to all approved project sponsors selected through the competitive solicitation process whether a PTO or non-PTO with no difference in the provisions applied to either. For non-competitive projects, the obligations and requirements imposed on the PTOs are set forth in the transmission control agreement and the tariff; however, there are not similar provisions for competitive projects until they are energized and turned over to ISO operational control. The matters addressed in the agreement will be similar to these obligations and requirements and will be no more or less onerous. Establishing an obligation for the sponsor to refund CWIP revenues is outside the scope of this initiative and is a FERC

Management Proposal	Transmission Developers	Participating Transmission Owners	Government Agencies	Management Response
				matter. Reviewing and enhancing the approach to evaluating the cost impacts of proposals submitted through the competitive solicitation process is outside the scope of this initiative.
An approved project sponsor that is not an existing participating transmission owner should be required to turn over to the ISO's operational control only the facilities that it is selected to build, not all of its transmission facilities.	• DATC: Fully supports. • IID: Supports. • Isolux Infrastructure: No comment. • LS Power: Supports with qualification. Needs to review exact tariff language. • MidAmerican Transmission: Fully supports. • PNW: Supports. Requests clarification regarding disposition of existing transmission facilities for non-PTO approved project sponsors with existing facilities who become PTOs and are subsequently selected as the approved project sponsor in a subsequent competitive solicitation.	• PG&E: Supports. • SCE: Supports. • Six Cities: Takes no position.	CPUC: Fully supports.	Management clarifies that if a non-PTO with existing transmission facilities is selected as an approved project sponsor, completes the project, becomes a PTO, and is later selected as an approved project sponsor in a subsequent competitive solicitation, then it would be required to turn over to ISO operational control only the facilities that it is selected to build.
Project sponsors should be required to provide an application deposit in the amount of $75,000 with each proposal submitted. If the amount required to	• DATC: Supports with qualifications. ISO should commit to periodically reviewing its process to ensure efficiency and cost effective administration of the competitive solicitation process. ISO should commit to	• PG&E: Supports. However, remains concerned with the competitive solicitation feature that allows sponsors to request an opportunity to collaborate. Recommends that the ISO	CPUC: Supports with qualification. Suggests a $50,000 deposit with any costs above this level to be funded by the overall transmission customers.	Management commits to continually monitor the efficiency and effectiveness of the competitive solicitation process and pursue enhancements to improve efficiency and cost. Management believes that all

Management Proposal	Transmission Developers	Participating Transmission Owners	Government Agencies	Management Response
pay actual costs is determined to be greater than $75,000 per application, then each project sponsor would be obligated to provide the additional amount up to a cap of $150,000.	reviewing the deposit requirements in the event that there is any evidence the deposit is discouraging participation by qualified project sponsors. • Isolux Infrastructure: Proposes a $25,000 non-refundable application fee. ISO should recover the balance of its costs through rates. • LS Power: Expresses opposition but clarifies that its position is driven more by its preference that the qualification and selection processes be separate rather than by the reasonableness of the proposed deposit requirements. • MidAmerican Transmission: Supports with qualification. The deposit should only apply to the evaluation of the competitive project that the depositor is applying for. Requests clarification that no additional costs will be incurred following the selection of the successful sponsor. ISO should apply deposits only to incremental costs for the competitive solicitation process, not internal labor costs. ISO should provide up front estimates to determine the need for additional fees and allow a withdrawal window if these fees are deemed too high. Sponsors which collaborate after the initial	continually monitor the efficiency and effectiveness of the competitive solicitation process and pursue enhancements to improve efficiency and cost. • SCE: Supports and believes that the ISO has adequately justified the proposed amounts. • Six Cities: Generally supports; however, does not support a cap (believes that sponsors should pay for all actual costs).		project sponsors should bear the costs of the competitive solicitation process rather than ratepayers funding the costs of individual applicants competing to build and own specific transmission solutions. Management's proposed $75,000 deposit amount is based on actual costs incurred in recent competitive solicitations. Setting the deposit at an amount less than $75,000 would likely result in ratepayers funding the balance of the actual costs. Management does not propose a separate fee for qualification and selection, but rather one deposit to cover costs incurred to perform and administer all aspects of the competitive solicitation process. Nevertheless, Management proposes a separate refund opportunity after the qualification process is completed. An applicant's deposit will apply to the actual costs incurred relative to the competitive project that the depositor is applying for. No additional costs will be incurred following selection. The entire competitive solicitation process represents incremental costs for the ISO. To not include internal ISO labor costs in the calculation of costs incurred would result in ratepayers funding the balance of actual costs

Management Proposal	Transmission Developers	Participating Transmission Owners	Government Agencies	Management Response
	submittal and subsequently resubmit competitive proposals should be required to continue to fund and be individually responsible for the initial deposit and any additional amounts required. • PNW: Supports. Requests clarification whether the true-up and cost cap apply only to selected project sponsors or to both selected and unsuccessful project sponsors. Also recommends elimination of the true-up and cap in order to provide cost certainty to applicants. Requests clarification on the calculation of refunds for sponsors found not qualified.			incurred. Management proposes to cap an applicant's cost responsibility at $150,000 in direct response to stakeholder concerns about cost certainty. Moreover, the proposed deposit amount of $75,000 is based on actual costs in recent competitive solicitations and believes this to be a reasonable estimate of costs going forward. Thus, Management believes that any further need for up front estimates and withdrawal windows has been reasonably mitigated. Sponsors that collaborate after the initial submittal will be required to continue to fund and be individually responsible for the initial deposit and any additional amounts required. Both selected and unsuccessful project sponsors are responsible for actual costs incurred up to the cost cap. Once the ISO finds a project sponsor not to be qualified for the project, no additional costs will be incurred relative to that sponsor and any refund due to that sponsor will be made within 75 days. Management does not recommend eliminating the collaboration step from the competitive solicitation process, as it is a key component of the

Management Proposal	Transmission Developers	Participating Transmission Owners	Government Agencies	Management Response
				revised transmission planning process (“RTPP”) tariff amendment and the Order No. 1000 compliance filing. FERC has approved the provision twice and has been very supportive of it. There are no material changed circumstances since the collaboration step was re-approved in FERC’s April 18, 2013 order on the ISO’s Order No. 1000 compliance filing that would require us to revisit the issue.

Attachment C – Clean

Competitive Transmission Improvements Tariff Amendment

California Independent System Operator Corporation

January 30, 2014

4.3.1.3 CAISO Relationship with Specific Participating TOs

(a) **Western Path 15.** Western Path 15 shall be required to turn over to CAISO Operational Control only its rights and interests in the Path 15 Upgrade and shall not be required to turn over to CAISO Operational Control Central Valley Project transmission facilities, Pacific AC Intertie transmission facilities, California-Oregon Transmission Project facilities, or any other new transmission facilities or Entitlements not related to the Path 15 Upgrade. For purposes of the CAISO Tariff, Western Path 15 shall be treated with respect to revenue recovery as a Project Sponsor in accordance with Section 24.14.3.1.

(b) **New Participating TOs After April 1, 2014.** An Approved Project Sponsors that was not a Participating TO as of April 1, 2014, shall be required to turn over to CAISO Operational Control only its rights and interests in the Regional Transmission Facilities it has been selected to finance, construct and own under section 24.5. Such a Participating Transmission Owner will be subject to all obligations of a Participating TO with regard to the facilities placed under CAISO Operational Control.

*** * ***

24.5.3.4 Single Qualified Project Sponsor and Proposal

If only one (1) Project Sponsor, including joint Project Sponsors resulting from a collaboration submits a proposal to finance, own, and construct a specific transmission solution and the CAISO determines that the Project Sponsor is qualified to own and construct the transmission solution under the criteria set forth in Section 24.5.3.1 and the proposal meets the proposal qualification criteria in Section 24.5.3.2, the Project Sponsor will be the Approved Project Sponsor and must execute an Approved Project Sponsor Agreement with the CAISO within one-hundred twenty (120) calendar days of CAISO approval, unless otherwise agreed by the Parties.

24.5.3.5 Multiple Qualified Project Sponsors and Proposals: Selection of Approved Project Sponsor

If there are multiple qualified Project Sponsors and proposals for the same transmission solution, the CAISO will select one qualified Approved Project Sponsor based on a comparative analysis of the degree to which each Project Sponsor's proposal meets the qualification criteria set forth in Section 24.5.3.1 and the selection factors set forth in 24.5.4. The CAISO will engage an expert consultant to assist with the selection of the Approved Project Sponsor. Thereafter, the Approved Project Sponsor must execute an Approved Project Sponsor Agreement with the CAISO within one-hundred twenty (120) calendar days of CAISO approval, unless otherwise agreed by the Parties.

* * *

24.5.6 Competitive Solicitation Project Proposal Fee

(a) **In General.** Project Sponsors shall, on a pro rata basis, be responsible for the actual costs that the ISO incurs in qualifying and selecting an Approved Project Sponsor through the competitive solicitation process, including the costs of the expert consultant engaged to assist with the selection process pursuant to Section 24.5.3.5, not to exceed $150,000 per Project Sponsor application. Such costs include the actual costs of the validation, qualification and selection process for each solution subject to the competitive solicitation process.

(b) **Deposit.** Each Project Sponsor will pay a deposit of $75,000 to the CAISO with the submission of each Project Sponsor application project proposal under section 24.5.2. A separate deposit is required for each solution for which a Project Sponsor submits an application.

(c) **Reconciliation of costs for unqualified Project Sponsors.** Within seventy-five days of the final listing of qualified Project Sponsors for each solution under Section 24.5.3.3, in accordance with the schedule in the Business Practice Manual, the CAISO will determine each Project Sponsor's pro rata share of the costs that the CAISO incurred in determining the qualified Project Sponsors for that solution and will refund to each Project Sponsor that the CAISO did not include in the list of qualified Project Sponsors the difference between its pro rata costs, not to exceed $150,000 per Project Sponsor, and

the deposit. If a refund is owed the Project Sponsor, the refund shall include interest at the rate that the CAISO earned on the deposit.

(d) **Reconciliation of Costs for Qualified Project Sponsors.** Within seventy-five days of the CAISO's Notice to qualified Project Sponsors under Section 24.5.5, in accordance with the schedule in the Business Practice Manual, the CAISO will determine each Project Sponsor's pro rata share of the costs that the CAISO incurred in selecting an Approved Project Sponsor from among the qualified Project Sponsors for each solution. The ISO will refund to or charge each qualified Project Sponsor the difference between its pro rata costs, not to exceed $150,000 per qualified Project Sponsor, and the deposit. If a refund is owed to the Project Sponsor, the refund shall include interest at the rate that the CAISO earned on the deposit.

(e) **Posting of Incurred Costs**. Following the reconciliation of costs in (d) above, the ISO will post an accounting of the costs incurred in qualifying and selecting the Approved Project Sponsor for each solution and how the deposit reconciliation for each Project Sponsor was calculated.

* * *

24.6 Obligation to Construct Transmission Solutions

The Approved Project Sponsor selected to construct the needed transmission solution or the applicable Participating TO where there is no Approved Project Sponsor, must make a good faith effort to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of the required transmission solution. This obligation includes the Approved Project Sponsor's use of eminent domain authority, where provided by state law. A Participating TO in whose PTO Service Territory or footprint either terminus of the transmission solution is located shall be obligated to construct all regional transmission solutions included in the comprehensive Transmission Plan for which there is no Approved Project Sponsor either from the first competitive solicitation or future competitive solicitations. The Approved Project Sponsor shall not sell, assign or otherwise transfer its rights to finance, construct and own the needed transmission solution, or any element thereof, before the facilities have been energized and, if applicable, turned over to the CAISO's Operational Control unless

the CAISO has not approved such proposed transfer, which approval shall not be unreasonably withheld. The CAISO shall not approve such sale, assignment or transfer unless the purchaser, transferee or assignee (i) meets the qualification requirements set forth in section 24.5.3.1; (ii) agrees to honor any binding cost containment measures or cost caps agreed to by the Approved Project Sponsor in its proposal; (iii) agrees to meet the factors that the ISO relied upon in selecting the proposal of the Approved Project Sponsor; and (iv) assumes the rights and obligations set forth in the Approved Project Sponsor Agreement.

* * *

26.1 Access Charges

(a) In General. All Market Participants withdrawing Energy from the CAISO Controlled Grid shall pay Access Charges in accordance with this Section 26.1 and Appendix F, Schedule 3, except as provided in Section 4.1 of Appendix I (Station Power Protocol). The Access Charge shall comprise two components, which together shall be designed to recover each Participating TO's or Approved Project Sponsor's Transmission Revenue Requirement. The first component shall be the annual authorized revenue requirement, as approved by FERC, associated with (1) the transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating TO or (2) transmission facilities that are not yet in operation, but approved under Section 24, and assigned to an Approved Project Sponsor. The second component shall be based on the Transmission Revenue Balancing Account (TRBA), which shall be designed to flow through the Participating TO's Transmission Revenue Credits calculated in accordance with Section 5 of the TO Tariff and other credits identified in Sections 6 and 8 of Schedule 3 of Appendix F of the CAISO Tariff.

The Access Charges shall be paid by any UDC or MSS Operator that is serving Gross Load in a PTO Service Territory, and shall consist, where applicable, of a Regional Access Charge, and a Local Access Charge. The Regional Access Charge and the Local Access Charges shall each comprise two components, which together shall be designed to recover each Participating TO's Regional Transmission Revenue

Requirement and Local Transmission Revenue Requirement, as applicable. The Regional Access Charge and the Local Access Charge for the applicable Participating TO shall be paid by each UDC and MSS Operator based on its Gross Load in the PTO Service Territory.

(b) Allocation of Transmission Revenue Requirement. Each Participating TO or Approved Project Sponsor shall provide in its TO Tariff or Approved Project Sponsor Tariff filing with FERC an appendix to such filing that states the Participating TO's or Approved Project Sponsor's Regional Transmission Revenue Requirement, its Local Transmission Revenue Requirement (if applicable) and its Gross Load used in developing the rate. The allocation of each Participating TO's Transmission Revenue Requirement between the Regional Transmission Revenue Requirement and the Local Transmission Revenue Requirement shall be undertaken in accordance with Section 11 of Schedule 3 of Appendix F. To the extent necessary, each Participating TO shall make conforming changes to its TO Tariff. A Participating TO that is a UDC or MSS Operator to whom the Local Access Charge of a Non-Load-Serving Participating TO is assessed shall include these billed Local Access Charge amounts in its Local TRBA adjustment for its Local Access Charge, together with all other applicable Local TRBA adjustments. If an Approved Project Sponsor that is a Non-Load-Serving Participating TO has been assigned responsibility to construct and own a Local Transmission Facility because the CAISO concluded, pursuant to Section 24.4.10, that it was not reasonable to divide construction responsibility, the Approved Project Sponsor shall include any pre-operational cost recovery approved by FERC for the Local Facility in its Local Transmission Revenue Requirement, The division of the total revenue requirement associated with the facility between Regional and Local Transmission Revenue Requirements shall consistent with Appendix F, Schedule 3, Sections 11 and 12.

(c) Assessment of Regional Access Charge. The Regional Access Charge shall be paid to the CAISO by each UDC and MSS Operator based on its Gross Load connected to a Regional Transmission Facility in a PTO Service Territory, either directly or through

intervening distribution facilities, but not through a Local Transmission Facility. The applicable Regional Access Charge shall be assessed by the CAISO as a charge for transmission service under this CAISO Tariff, shall be determined in accordance with Schedule 3 of Appendix F, and shall include all applicable components of the Regional Access Charge set forth therein.

(d) Assessment of Local Access Charge of Load-Serving Participating TO. The Local Access Charge for each Load-Serving Participating TO is set forth in that Participating TO's TO Tariff. Each Participating TO shall charge for and collect the Local Access Charge, as provided in its TO Tariff, except that the CAISO shall charge for and collect the Local Access Charge of each Non-Load-Serving Participating TO that qualifies under this Section 26.1 and Appendix F, Schedule 3, Section 13, unless otherwise agreed by the affected Participating TOs. If a Participating TO that is also a UDC, MSS Operator, or Scheduling Coordinator serving End-Use Customers is using the Local Transmission Facilities of another Participating TO, such Participating TO shall also be assessed the Local Access Charge of the other Participating TO by such other Participating TO, or by the CAISO pursuant to Section 13 of Schedule 3 of Appendix F. The CAISO shall provide to the applicable Participating TO a statement of the amount of Energy delivered to each UDC and MSS Operator serving Gross Load that utilizes the Local Transmission Facilities of that Participating TO on a monthly basis. If a UDC or MSS Operator that is serving Gross Load in a PTO Service Territory has Existing Rights to use another Participating TO’s Local Transmission Facilities, such entity shall not be charged the Local Access Charge for delivery of Energy to Gross Load for deliveries using the Existing Rights.

(e) Standby Transmission Charges. Each Participating TO shall recover Standby Transmission Revenues directly from the Standby Service Customers of that Participating TO through its applicable retail rates.

(f) Assessment of Local Access Charge of Non-Load Serving Participating TOs. Where a Non-Load-Serving Participating TO has Local Transmission Facilities, the CAISO shall

assess the Local Access Charge for each project of that Non-Load-Serving Participating TO to the UDC or MSS Operator of each Participating TO that is directly connected to one or more Local Transmission Facilities of that project, unless otherwise agreed by the affected Participating TOs. The Non-Load-Serving Participating TO shall calculate separately its Local Transmission Revenue Requirement for each individual transmission project that includes one or more Local Transmission Facilities. If the Non-Load-Serving Participating TO's Local Transmission Facilities projects are directly connected to the facilities of the same Participating TO(s), the Local Access Charge shall be calculated for the group of Local Transmission Facilities. A separate Local Access Charge shall apply based on the Local Transmission Revenue Requirement for the relevant project or projects of such Non-Load-Serving Participating TO divided by the Gross Load of all UDCs or MSS Operators of a Participating TO that are directly connected to the relevant Local Transmission Facility or group of facilities.

A Non-Load-Serving Participating TO must include any over- or under-recovery of its annual Local Transmission Revenue Requirement for the relevant project or group of projects in its Local TRBA adjustment for its Local Access Charge for the relevant project or group of projects pursuant to Section 13.1 of Schedule 3 of Appendix F.

* * *

26.1.1 Publicly Owned Electric Utilities Access Charge

Local Publicly Owned Electric Utilities whose transmission facilities are under CAISO Operational Control or who are Approved Project Sponsors shall file with the FERC their proposed Regional Transmission Revenue Requirements, and any proposed changes thereto, under procedures determined by the FERC to be applicable to such filings and shall give notice to the CAISO and to all Scheduling Coordinators of any such filing. A prospective New Participating TO that is a Local Publicly Owned Electric Utility shall submit its first proposed Regional Transmission Revenue Requirement to the FERC and the CAISO at the time the Local Publicly Owned Electric Utility submits its application to become a New Participating TO in accordance with the Transmission Control Agreement. Federal power marketing agencies whose

transmission facilities are under CAISO Operational Control shall develop their Regional Transmission Revenue Requirement pursuant to applicable federal laws and regulations.

The procedures for public participation in a federal power marketing agency's ratemaking process are posted on the federal power marketing agency's website. Each federal power marketing agency shall also post on its website the Federal Register notices and FERC orders for rate making processes that impact the federal power marketing agency's Regional Transmission Revenue Requirement. At the time the federal power marketing agency submits its application to become a New Participating TO in accordance with the Transmission Control Agreement, it shall submit its first proposed Regional Transmission Revenue Requirement to the FERC and the CAISO.

* * *

26.1.3 Disbursement Of RAC Revenues

The CAISO shall collect and pay, on a monthly basis, to Participating TOs and Approved Project Sponsors all Regional Access Charge revenues at the same time as other CAISO charges and payments are settled. Regional Access Charge revenues received with respect to the Regional Access Charge shall be distributed to Participating TOs and Approved Project Sponsors in accordance with Appendix F, Schedule 3, Section 10.

* * *

26.2 [Not Used]

* * *

26.3 Addition Of New Facilities After CAISO Implementation

The costs of transmission facilities placed in service after the CAISO Operations Date shall be recovered consistent with the cost recovery determinations made pursuant to Appendix F, Schedule 3 and Section 24.

* * *

Appendix A

* * *

- Approved Project Sponsor Agreement

An agreement between an Approved Project Sponsor and the CAISO establishing the terms and

conditions under which the Approved Project Sponsor will complete the siting and construction of the transmission facilities that the Approved Project Sponsor was selected to construct and own under Section 24. Among other terms, the Agreement shall include any binding cost control measures, including cost caps, that the Approved Project Sponsor specified in its proposal.

* * *

- Approved Project Sponsor Tariff

A tariff specifying the rates and charges of an Approved Project Sponsor that is not a Participating TO to recover the costs of transmission facilities that are not yet in operation but have been approved under Section 24 and assigned to the Approved Project Sponsor, and associated terms and conditions.

* * *

- Local Transmission Revenue Requirement (LTRR)

The portion of a Participating TO's TRR associated with and allocable to the Participating TO's Local Transmission Facilities and Converted Rights associated with Local Transmission Facilities that are under the CAISO Operational Control or, in the case of an Approved Project Sponsor that is a Participating Transmission Owner, Transmission Facilities not yet in operation, but approved under Section 24 and assigned to the Approved Project Sponsor, that will be Local Transmission Facilities when placed under the CAISO's Operational Control.

* * *

- Regional Transmission Revenue Requirement (RTRR)

The portion of a Participating TO's or an Approved Project Sponsor's Transmission Revenue Requirement associated with and allocable to: 1) the Participating TO's Regional Transmission Facilities and Converted Rights associated with Regional Transmission Facilities, 2) the CAISO's assigned share of Interregional Transmission Project costs, and 3) Location Constrained Resource Interconnection Facilities that are under the CAISO Operational Control or Transmission Facilities not yet in operation, but approved under Section 24 and assigned to the Approved Project Sponsor, that will be Regional Transmission Facilities or, in the case of an Approved Project Sponsor that is not a Participating Transmission Owner, Local Transmission Facilities when placed under the CAISO's Operational Control.

* * *

- Transmission Revenue Balancing Account (TRBA)

A mechanism to be established by each Participating TO and Approved Project Sponsor that will ensure that all Transmission Revenue Credits and other credits specified in Sections 6, 8, and 13 of Appendix F, Schedule 3, flow through to transmission customers.

* * *

- Transmission Revenue Credit

The proceeds a Participating TO received from the CAISO for Wheeling service, plus (a) the revenues received from any LCRIG with respect to an LCRIF, unless FERC has approved an alternative mechanism to credit such revenues against the Participating TO's TRR, and (b) the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the CAISO's rules and protocols, minus any Local Access Charge amounts paid for the use of the Local Transmission Facilities of a Non-Load-Serving Participating TO pursuant to Section 26.1 and Appendix F, Schedule 3, Section 13.

* * *

- Transmission Revenue Requirement (TRR)

The Transmission Revenue Requirement is the total annual authorized revenue requirements associated with (1) transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating TO or (2) transmission facilities that are not yet in operation, but have been approved under Section 24 and assigned to an Approved Project Sponsor. The costs of any transmission facility turned over to the Operational Control of the CAISO shall be fully included in the Participating TO's Transmission Revenue Requirement. The Transmission Revenue Requirement of a Participating TO includes the costs of transmission facilities and Entitlements and deducts Transmission Revenue Credits and credits for Standby Transmission Revenue and the transmission revenue expected to be actually received by the Participating TO for Existing Rights and Converted Rights.

* * *

Appendix F Rate Schedules

* * *

Schedule 3

Regional Access Charge and Wheeling Access Charge

* * *

5.2 Each Participating TO and Approved Project Sponsor will develop, in accordance with Section 6 of this Schedule 3, a Regional Transmission Revenue Requirement (RTRR $_{PTO}$) consisting of a Transmission Revenue Requirement for (i) Regional Transmission Facilities; (2) Transmission Facilities that are not yet in operation but have been approved under Section 24 and assigned to the Approved Project Sponsor, that will be Regional Transmission Facilities when placed under the CAISO's Operational Control; and (iii) to the extent the costs have not been recovered, Location Constrained Interconnection Facilities. The RTRR $_{PTO}$ includes the TRBA adjustment described in Section 6.1 of this Schedule 3. If an Approved Project Sponsor that is a Non-Load-Serving Participating Transmission Owner has been assigned responsibility to construct and own a Local Transmission Facility because the CAISO concluded, pursuant to Section 24.4.10, that it was not reasonable to divide construction responsibility, the Approved Project Sponsor shall include any authorized pre-operational cost recovery for the Local Transmission Facility in its Local Transmission Revenue Requirement. The division of the total revenue requirement associated with the facility between Regional and Local Transmission Revenue Requirements shall consistent with Appendix F, Schedule 3, Sections 11 and 12.

* * *

5.4 The Regional Access Charge shall be equal to the sum of the Regional Transmission Revenue Requirements of all Participating TOs and Approved Project Sponsors, divided by the sum of the Gross Loads of all Participating TOs.

6. Regional Transmission Revenue Requirement.

6.1 The Regional Transmission Revenue Requirement of a Participating TO or an Approved Project Sponsor will be determined consistent with CAISO procedures posted on the CAISO Website and shall be the sum of:

(a) the Participating TO's Regional Transmission Revenue Requirement (including costs related to Existing Contracts associated with transmission by others and deducting transmission revenues actually expected to be received by the Participating TO related to transmission for others in accordance with Existing Contracts and Interregional Transmission Projects, less the sum of the Standby Transmission Revenues) or the Approved Project Sponsors Regional Transmission Revenue Requirement; and

(b) the annual Regional TRBA adjustment, which shall be based on the principal balance in the Regional TRBA as of September 30 and shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. A Non-Load-Serving Participating TO shall include any over- or under-recovery of its annual Regional Transmission Revenue Requirement in its Regional TRBA. If the annual Regional TRBA adjustment

involves only a partial year of operations, the Non-Load-Serving Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Non-Load-Serving Participating TO's Regional Transmission Revenue Requirement by the number of days the Regional Transmission Facilities were under the CAISO's Operational Control divided by the number of days in the year. An Approved Project Sponsor shall include any over- or under-recovery of its annual Regional Transmission Revenue Requirement in its Regional TRBA. If the annual Regional TRBA adjustment involves only a partial year, the Approved Project Sponsor's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Approved Project Sponsor's Regional Transmission Revenue Requirement by the number of days the transmission facilities were under construction based on the construction plan required in accordance with Section 24.6.1, as such plan may be updated by the construction plan status report, divided by the number of days in the year.

7. [NOT USED]

8. Updates to Regional Access Charges.

8.1 Regional Access Charges and Regional Wheeling Access Charges shall be adjusted: (1) on January 1 and July 1 of each year when necessary to reflect the addition of any New Participating TO and (2) on the date FERC makes effective a change to the Regional Transmission Revenue Requirements of any Participating TO or Approved Project Sponsor. Using the Regional Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for each Participating TO and Approved Project Sponsor, the CAISO will recalculate on a monthly basis the Regional Access Charge applicable during such period. Revisions to the Transmission Revenue Balancing Account adjustment shall be made effective annually on January 1 based on the principal balance in the TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

8.2 Any refund associated with a Participating TO's or Approved Project Sponsor's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced in the CAISO Market Invoice.

* * *

9. Approval of Updated Regional Revenue Requirements.

9.1 Participating TOs and Approved Project Sponsors will make the appropriate filings at FERC to establish their Transmission Revenue Requirements for their Local Access Charges and the Regional Access Charge, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the RTRR, LTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The Participating TO or Approved Project Sponsor will provide a copy of its filing to the CAISO and the other Participating TOs and Approved Project Sponsors in accordance with the notice provisions in the Transmission Control Agreement.

* * *

10. Disbursement of Regional Access Charge Revenues.

10.1 Regional Access Charge revenues shall be calculated for disbursement to each Participating TO and Approved Project Sponsor on a monthly basis as follows:

(a) the amount determined in accordance with Section 26.1.2 of the CAISO Tariff ("Billed RAC");

(b)

(i) for a Participating TO that is a UDC or MSS Operator and has Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, then calculate the amount each UDC or MSS Operator would have paid and the Participating TO would have received by multiplying the Regional Utility-Specific Rates for the Participating TO whose Regional Transmission Facilities served such UDC and MSS Operator times the actual Gross Load of such UDCs and MSS Operators; or

(ii) for a Non-Load-Serving Participating TO and Approved Project Sponsors, then calculate the Non-Load-Serving Participating TO's or Approved Project Sponsor's portion of the total Billed RAC in subsection (a) based on the ratio of the Non-Load-Serving Participating TO's and Approved Project Sponsors Regional Transmission Revenue Requirement to the sum of all Participating TOs' and Approved Project Sponsor's Regional Revenue Requirements.

(c) if the total Billed RAC in subsection (a) received by the CAISO less the total dollar amounts calculated in in subsection (b)(i) and subsection (b)(ii) is different from zero, the CAISO shall allocate the positive or negative difference among those Participating TOs that are subject to the calculations in subsection (b)(i) based on the ratio of each Participating TO's Regional Transmission Revenue Requirement to the sum of all of those Participating TOs' Regional Transmission Revenue Requirements that are subject to the calculations in subsection (b)(i). This monthly distribution amount is the "RAC Revenue Adjustment";

(d) the sum of the RAC revenue share determined in subsection (b) and the RAC Revenue Adjustment in subsection (c) will be the monthly disbursement to the Participating TO.

* * *

11. Determination of Transmission Revenue Requirement Allocation Between Regional and Local Transmission Facilities.

11.1 Each Participating TO shall allocate its Transmission Revenue Requirement between the Regional Transmission Revenue Requirement and Local Transmission Revenue Requirement based on the Procedure for Division of Certain Costs Between the Regional and Local Transmission Access Charges contained in Section 12 of this Schedule.

Attachment D – Marked

Competitive Transmission Improvements Tariff Amendment

California Independent System Operator Corporation

January 30, 2014

4.3.1.3 CAISO Relationship with Specific Participating TOs

(a) **Western Path 15.** Western Path 15 shall be required to turn over to CAISO Operational Control only its rights and interests in the Path 15 Upgrade and shall not be required to turn over to CAISO Operational Control Central Valley Project transmission facilities, Pacific AC Intertie transmission facilities, California-Oregon Transmission Project facilities, or any other new transmission facilities or Entitlements not related to the Path 15 Upgrade. For purposes of the CAISO Tariff, Western Path 15 shall be treated with respect to revenue recovery as a Project Sponsor in accordance with Section 24.14.3.1~~24.10~~.

(b) **New Participating TOs After April 1, 2014.** An Approved Project Sponsors that was not a Participating TO as of April 1, 2014, shall be required to turn over to CAISO Operational Control only its rights and interests in the Regional Transmission Facilities it has been selected to finance, construct and own under section 24.5. Such a Participating Transmission Owner will be subject to all obligations of a Participating TO with regard to the facilities placed under CAISO Operational Control.

* * *

24.5.3.4 Single Qualified Project Sponsor and ~~–~~Proposal

If only one (1) Project Sponsor, including joint Project Sponsors resulting from a collaboration submits a proposal to finance, own, and construct a specific transmission solution and the CAISO determines that the Project Sponsor is qualified to own and construct the transmission solution under the criteria set forth in Section 24.5.3.1 and the proposal meets the proposal qualification criteria in Section 24.5.3.2, the Project Sponsor will be the Approved Project Sponsor and must execute an Approved Project Sponsor Agreement with the CAISO ~~initiate the process of seeking siting approval, and any other necessary approvals, from the appropriate authority or authorities~~ within one-hundred twenty (120) calendar days of CAISO approval, unless otherwise agreed by the Parties.

24.5.3.5 Multiple Qualified Project Sponsors and Proposals: Selection of Approved Project Sponsor

If there are multiple qualified Project Sponsors and proposals for the same transmission solution, the CAISO will select one qualified Approved Project Sponsor based on a comparative analysis of the degree to which each Project Sponsor's proposal meets the qualification criteria set forth in Section 24.5.3.1 and the selection factors set forth in 24.5.4. The CAISO will engage an expert consultant to assist with the selection of the Approved Project Sponsor. Thereafter, the Approved Project Sponsor must execute an Approved Project Sponsor Agreement with the CAISO~~initiate the process of seeking siting approval, and any other necessary approvals, from the appropriate authority or authorities~~ within one-hundred twenty (120) calendar days of CAISO approval, unless otherwise agreed by the Parties.

* * *

24.5.6 Competitive Solicitation Project Proposal Fee

(a) **In General.** Project Sponsors shall, on a pro rata basis, be responsible for the actual costs that the ISO incurs in qualifying and selecting an Approved Project Sponsor through the competitive solicitation process, including the costs of the expert consultant engaged to assist with the selection process pursuant to Section 24.5.3.5, not to exceed $150,000 per Project Sponsor application. Such costs include the actual costs of the validation, qualification and selection process for each solution subject to the competitive solicitation process.

(b) **Deposit.** Each Project Sponsor will pay a deposit of $75,000 to the CAISO with the submission of each Project Sponsor application project proposal under section 24.5.2. A separate deposit is required for each solution for which a Project Sponsor submits an application.

(c) **Reconciliation of costs for unqualified Project Sponsors.** Within seventy-five days of the final listing of qualified Project Sponsors for each solution under Section 24.5.3.3, in accordance with the schedule in the Business Practice Manual, the CAISO will determine each Project Sponsor's pro rata share of the costs that the CAISO incurred in

determining the qualified Project Sponsors for that solution and will refund to each Project Sponsor that the CAISO did not include in the list of qualified Project Sponsors the difference between its pro rata costs, not to exceed $150,000 per Project Sponsor, and the deposit. If a refund is owed the Project Sponsor, the refund shall include interest at the rate that the CAISO earned on the deposit.

(d) **Reconciliation of Costs for Qualified Project Sponsors.** Within seventy-five days of the CAISO's Notice to qualified Project Sponsors under Section 24.5.5, in accordance with the schedule in the Business Practice Manual, the CAISO will determine each Project Sponsor's pro rata share of the costs that the CAISO incurred in selecting an Approved Project Sponsor from among the qualified Project Sponsors for each solution. The ISO will refund to or charge each qualified Project Sponsor the difference between its pro rata costs, not to exceed $150,000 per qualified Project Sponsor, and the deposit. If a refund is owed to the Project Sponsor, the refund shall include interest at the rate that the CAISO earned on the deposit.

(e) **Posting of Incurred Costs**. Following the reconciliation of costs in (d) above, the ISO will post an accounting of the costs incurred in qualifying and selecting the Approved Project Sponsor for each solution and how the deposit reconciliation for each Project Sponsor was calculated.

* * *

24.6 Obligation to Construct Transmission Solutions

The Approved Project Sponsor selected to construct the needed transmission solution or the applicable Participating TO where there is no Approved Project Sponsor, must make a good faith effort to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of the required transmission solution. This obligation includes the Approved Project Sponsor's use of eminent domain authority, where provided by state law. A Participating TO in whose PTO Service Territory or footprint either terminus of the transmission solution is located shall be obligated to construct all regional transmission solutions included in the comprehensive Transmission Plan for which there is no Approved Project Sponsor either from the first competitive solicitation or future

competitive solicitations. The Approved Project Sponsor shall not sell, assign or otherwise transfer its rights to finance, construct and own the needed transmission solution, or any element thereof, before the facilities have been energized and, if applicable, turned over to the CAISO's Operational Control unless the CAISO has not approved such proposed transfer~~.~~, which approval shall not be unreasonably withheld. The CAISO shall not approve such sale, assignment or transfer unless the purchaser, transferee or assignee (i) meets the qualification requirements set forth in section 24.5.3.1; (ii) agrees to honor any binding cost containment measures or cost caps agreed to by the Approved Project Sponsor in its proposal; (iii) agrees to meet the factors that the ISO relied upon in selecting the proposal of the Approved Project Sponsor; and (iv) assumes the rights and obligations set forth in the Approved Project Sponsor Agreement.

* * *

26.1 Access Charges

(a) In General. All Market Participants withdrawing Energy from the CAISO Controlled Grid shall pay Access Charges in accordance with this Section 26.1 and Appendix F, Schedule 3, except as provided in Section 4.1 of Appendix I (Station Power Protocol). The Access Charge shall comprise two components, which together shall be designed to recover each Participating TO's or Approved Project Sponsor's Transmission Revenue Requirement. The first component shall be the annual authorized revenue requirement, as approved by FERC, ~~-~~associated with (1) the transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating TO or (2) transmission facilities that are not yet in operation, but approved ~~by FERC~~under Section 24, and assigned to an Approved Project Sponsor. The second component shall be based on the Transmission Revenue Balancing Account (TRBA), which shall be designed to flow through the Participating TO's Transmission Revenue Credits calculated in accordance with Section 5 of the TO Tariff and other credits identified in Sections 6 and 8 of Schedule 3 of Appendix F of the CAISO Tariff.

The Access Charges shall be paid by any UDC or MSS Operator that is serving Gross Load in a PTO Service Territory, and shall consist, where applicable, of a Regional

Access Charge, and a Local Access Charge. The Regional Access Charge~~s~~ and the Local Access Charges shall each comprise two components, which together shall be designed to recover each Participating TO's Regional Transmission Revenue Requirement and Local Transmission Revenue Requirement, as applicable. The ~~first component shall be based on the annual authorized Transmission Revenue Requirement associated with the Regional Transmission Facilities or Local Transmission Facilities, as applicable, and Entitlements turned over to the CAISO Operational Control by a~~ Regional Access Charge and the Local Access Charge for the applicable Participating TO~~. The second component shall be the Transmission Revenue Balancing Account~~ shall be paid by each UDC and MSS Operator based on its Gross Load in the PTO Service Territory.

(~~TRBA~~b)~~, which shall be designed to flow through the Participating TO's~~ Allocation of Transmission Revenue ~~Credits associated with the Regional or Local, as applicable, Transmission Facilities and Entitlements and calculated in accordance with Section 5 of the TO Tariff and other credits identified in Sections 6, 8 and 13 of Schedule 3 of Appendix F of the CAISO Tariff~~Requirement. Each Participating TO or Approved Project Sponsor shall provide in its TO Tariff or Approved Project Sponsor Tariff filing with FERC an appendix to such filing that states the Participating TO's or Approved Project Sponsor's Regional Transmission Revenue Requirement, its Local Transmission Revenue Requirement (if applicable) and its Gross Load used in developing the rate. The allocation of each Participating TO's Transmission Revenue Requirement between the Regional Transmission Revenue Requirement and the Local Transmission Revenue Requirement shall be undertaken in accordance with Section 11 of Schedule 3 of Appendix F. To the extent necessary, each Participating TO shall make conforming changes to its TO Tariff. A Participating TO that is a UDC or MSS Operator to whom the Local Access Charge of a Non-Load-Serving Participating TO is assessed shall include these billed Local Access Charge amounts in its Local TRBA adjustment for its Local Access Charge, together with all other applicable Local TRBA adjustments. If an

Approved Project Sponsor that is a Non-Load-Serving Participating TO has been assigned responsibility to construct and own a Local Transmission Facility because the CAISO concluded, pursuant to Section 24.4.10, that it was not reasonable to divide construction responsibility, the Approved Project Sponsor shall include any pre-operational cost recovery approved by FERC for the Local Facility in its Local Transmission Revenue Requirement, The division of the total revenue requirement associated with the facility between Regional and Local Transmission Revenue Requirements shall consistent with Appendix F, Schedule 3, Sections 11 and 12.

(c) Assessment of Regional Access Charge. The ~~applicable~~ Regional Access Charge shall be paid to the CAISO by each UDC and MSS Operator based on its Gross Load connected to a Regional Transmission Facility in a PTO Service Territory, either directly or through intervening distribution facilities, but not through a Local Transmission Facility. The applicable Regional Access Charge ~~and the Local Access Charge for the applicable Participating TO shall be paid by each UDC and MSS Operator based on its Gross Load in the PTO Service Territory. The applicable Regional Access Charge~~ shall be assessed by the CAISO as a charge for transmission service under this CAISO Tariff, shall be determined in accordance with Schedule 3 of Appendix F, and shall include all applicable components of the Regional Access Charge set forth therein.

(d) Assessment of Local Access Charge of Load-Serving Participating TO. The Local Access Charge for each Load-Serving Participating TO is set forth in that Participating TO's TO Tariff. Each Participating TO shall charge for and collect the Local Access Charge, as provided in its TO Tariff, except that the CAISO shall charge for and collect the Local Access Charge of each Non-Load-Serving Participating TO that qualifies under this Section 26.1 and Appendix F, Schedule 3, Section 13~~.~~, unless otherwise agreed by the affected Participating TOs. If a Participating TO that is also a UDC, MSS Operator, or Scheduling Coordinator serving End-Use Customers is using the Local Transmission Facilities of another Participating TO, such Participating TO shall also be assessed the Local Access Charge of the other Participating TO by such other Participating TO, or by

the CAISO pursuant to Section 13 of Schedule 3 of Appendix F. The CAISO shall provide to the applicable Participating TO a statement of the amount of Energy delivered to each UDC and MSS Operator serving Gross Load that utilizes the Local Transmission Facilities of that Participating TO on a monthly basis. If a UDC or MSS Operator that is serving Gross Load in a PTO Service Territory has Existing Rights to use another Participating TO's Local Transmission Facilities, such entity shall not be charged the Local Access Charge for delivery of Energy to Gross Load for deliveries using the Existing Rights.

(e) Standby Transmission Charges. Each Participating TO shall recover Standby Transmission Revenues directly from the Standby Service Customers of that Participating TO through its applicable retail rates.

(f) Assessment of Local Access Charge of Non-Load Serving Participating TOs. Where a Non-Load-Serving Participating TO has Local Transmission Facilities, the CAISO shall assess the Local Access Charge for each project of that Non-Load-Serving Participating TO to the UDC or MSS Operator of each Participating TO that is directly connected to one or more Local Transmission Facilities of that project, unless otherwise agreed by the affected Participating TOs. The Non-Load-Serving Participating TO shall calculate separately its Local Transmission Revenue Requirement for each individual transmission project that includes one or more Local Transmission Facilities. If the Non-Load-Serving Participating TO's Local Transmission Facilities projects are directly connected to the facilities of the same Participating TO(s), the Local Access Charge shall be calculated for the group of Local Transmission Facilities. A separate Local Access Charge shall apply based on the Local Transmission Revenue Requirement for the relevant project or projects of such Non-Load-Serving Participating TO divided by the Gross Load of all UDCs or MSS Operators of a Participating TO that are directly connected to the relevant Local Transmission Facility or group of facilities.

A Non-Load-Serving Participating TO must include any over- or under-recovery of its annual Local Transmission Revenue Requirement for the relevant project or group of

projects in its Local TRBA adjustment for its Local Access Charge for the relevant project or group of projects pursuant to Section 13.1 of Schedule 3 of Appendix F.

~~A Participating TO that is a UDC or MSS Operator to whom the Local Access Charge of a Non-Load-Serving Participating TO is assessed shall include these billed Local Access Charge amounts in its Local TRBA adjustment for its Local Access Charge, together with all other applicable Local TRBA adjustments.~~

* * *

26.1.1 Publicly Owned Electric Utilities Access Charge

Local Publicly Owned Electric Utilities whose transmission facilities are under CAISO Operational Control or who are Approved Project Sponsors shall file with the FERC their proposed Regional Transmission Revenue Requirements, and any proposed changes thereto, under procedures determined by the FERC to be applicable to such filings and shall give notice to the CAISO and to all Scheduling Coordinators of any such filing. A prospective New Participating TO that is a Local Publicly Owned Electric Utility shall submit its first proposed Regional Transmission Revenue Requirement to the FERC and the CAISO at the time the Local Publicly Owned Electric Utility submits its application to become a New Participating TO in accordance with the Transmission Control Agreement. Federal power marketing agencies whose transmission facilities are under CAISO Operational Control shall develop their Regional Transmission Revenue Requirement pursuant to applicable federal laws and regulations.

The procedures for public participation in a federal power marketing agency's ratemaking process are posted on the federal power marketing agency's website. Each federal power marketing agency shall also post on its website the Federal Register notices and FERC orders for rate making processes that impact the federal power marketing agency's Regional Transmission Revenue Requirement. At the time the federal power marketing agency submits its application to become a New Participating TO in accordance with the Transmission Control Agreement, it shall submit its first proposed Regional Transmission Revenue Requirement to the FERC and the CAISO.

* * *

26.1.3 Disbursement Of RAC Revenues

The CAISO shall collect and pay, on a monthly basis, to Participating TOs and Approved Project Sponsors all Regional Access Charge revenues at the same time as other CAISO charges and payments

are settled. Regional Access Charge revenues received with respect to the Regional Access Charge shall be distributed to Participating TOs and Approved Project Sponsors in accordance with Appendix F, Schedule 3, Section 10.

* * *

26.2 ~~Tracking Account~~[Not Used]

~~If the Access Charge rate methodology implemented pursuant to Section 26.1 results in Access Charge rates for any Participating TO which are different from those in effect prior to the CAISO Operations Date, an amount equal to the difference between the new rates and the prior rates for the remainder of the period, if any, during which a cost recovery plan established pursuant to Section 368 of the California Public Utilities Code (as added by AB 1890) is in effect for such Participating TO shall be recorded in a tracking account. The balance of that tracking account will be recovered from customers and paid to the appropriate Participating TO after termination of the cost recovery plan set forth in Section 368 of California Public Utilities Code (as added by AB 1890). The recovery and payments shall be based on an amortization period not exceeding three years in the case of electric corporations regulated by the CPUC or five years for Local Publicly Owned Electric Utilities.~~

* * *

26.3 Addition Of New Facilities After CAISO Implementation

The costs of transmission facilities placed in service after the CAISO Operations Date shall be recovered consistent with the cost recovery determinations made pursuant to Appendix F, Schedule 3 and Section ~~24.10.3~~24.

* * *

Appendix A

* * *

- Approved Project Sponsor Agreement

An agreement between an Approved Project Sponsor and the CAISO establishing the terms and conditions under which the Approved Project Sponsor will complete the siting and construction of the transmission facilities that the Approved Project Sponsor was selected to construct and own under

Section 24. Among other terms, the Agreement shall include any binding cost control measures, including cost caps, that the Approved Project Sponsor specified in its proposal.

* * *

- Approved Project Sponsor Tariff

A tariff specifying the rates and charges of an Approved Project Sponsor that is not a Participating TO to recover the costs of transmission facilities that are not yet in operation but have been approved under Section 24 and assigned to the Approved Project Sponsor, and associated terms and conditions.

* * *

- Local Transmission Revenue Requirement (LTRR)

The portion of a Participating TO's TRR associated with and allocable to the Participating TO's Local Transmission Facilities and Converted Rights associated with Local Transmission Facilities that are under the CAISO Operational Control or, in the case of an Approved Project Sponsor that is a Participating Transmission Owner, Transmission Facilities not yet in operation, but approved under Section 24 and assigned to the Approved Project Sponsor, that will be Local Transmission Facilities when placed under the CAISO's Operational Control.~~.~~

* * *

- Regional Transmission Revenue Requirement (RTRR)

The portion of a Participating TO's or an Approved Project Sponsor's Transmission Revenue Requirement associated with and allocable to: 1) the Participating TO's Regional Transmission Facilities and Converted Rights associated with Regional Transmission Facilities, 2) the CAISO's assigned share of Interregional Transmission Project costs, and 3) Location Constrained Resource Interconnection Facilities that are under the CAISO Operational Control or Transmission Facilities not yet in operation, but approved under Section 24 and assigned to the Approved Project Sponsor, that will be Regional Transmission Facilities or, in the case of an Approved Project Sponsor that is not a Participating Transmission Owner, Local Transmission Facilities when placed under the CAISO's Operational Control.~~.~~

* * *

- Transmission Revenue Balancing Account (TRBA)

A mechanism to be established by each Participating TO and Approved Project Sponsor that ~~which~~ will ensure that all Transmission Revenue Credits and other credits specified in Sections 6, 8, and 13 of Appendix F, Schedule 3, flow through to transmission customers.

* * *

- Transmission Revenue Credit

The proceeds a Participating TO received from the CAISO for Wheeling service, plus (a) the revenues received from any LCRIG with respect to an LCRIF, unless FERC has approved an alternative mechanism to credit such revenues against the Participating TO's TRR, and (b) the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the CAISO's rules and protocols, minus any Local Access Charge amounts paid for the use of the Local Transmission Facilities of a Non-Load-Serving Participating TO pursuant to Section 26.1 and Appendix F, Schedule 3, Section 13.

* * *

- Transmission Revenue Requirement (TRR)

The Transmission Revenue Requirement is the total annual authorized revenue requirements associated with (1) transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating TO or (2) transmission facilities that are not yet in operation, but have been approved under Section 24 and assigned to an Approved Project Sponsor. The costs of any transmission facility turned over to the Operational Control of the CAISO shall be fully included in the Participating TO's Transmission Revenue Requirement. The Transmission Revenue Requirement of a Participating TO includes the costs of transmission facilities and Entitlements and deducts Transmission Revenue Credits and credits for Standby Transmission Revenue and the transmission revenue expected to be actually received by the Participating TO for Existing Rights and Converted Rights.

* * *

Appendix F Rate Schedules

* * *

Schedule 3

Regional Access Charge and Wheeling Access Charge

* * *

5.2 Each Participating TO and Approved Project Sponsor will develop, in accordance with Section 6 of this Schedule 3, a Regional Transmission Revenue Requirement ($RTRR_{PTO}$) consisting of a Transmission Revenue Requirement for (i) Regional Transmission Facilities; (2) Transmission Facilities that are not yet in operation but have been approved under Section 24 and assigned to the Approved Project Sponsor, that will be Regional Transmission Facilities when placed under the CAISO's Operational Control; and (iii), to the extent the costs have not been recovered, Location Constrained Interconnection Facilities. The $RTRR_{PTO}$ includes the TRBA adjustment described in Section 6.1 of this Schedule 3. If an Approved Project Sponsor that is a Non-Load-Serving Participating Transmission Owner has been assigned responsibility to construct and own a Local Transmission Facility because the CAISO concluded, pursuant to Section 24.4.10, that it was not reasonable to divide construction responsibility, the Approved Project Sponsor shall include any authorized pre-operational cost recovery for the Local Transmission Facility in its Local Transmission Revenue Requirement. The division of the total revenue requirement associated with the facility between Regional and Local Transmission Revenue Requirements shall consistent with Appendix F, Schedule 3, Sections 11 and 12.

* * *

5.4 The Regional Access Charge shall be equal to the sum of the Regional Transmission Revenue Requirements of all Participating TOs and Approved Project Sponsors, divided by the sum of the Gross Loads of all Participating TOs.

6. Regional Transmission Revenue Requirement.

6.1 The Regional Transmission Revenue Requirement of a Participating TO or an Approved Project Sponsor will be determined consistent with CAISO procedures posted on the CAISO Website and shall be the sum of:

(a) the Participating TO's Regional Transmission Revenue Requirement (including costs related to Existing Contracts associated with transmission by others and deducting transmission revenues actually expected to be received by the Participating TO related to transmission for others in accordance with Existing Contracts and Interregional Transmission Projects, less the sum of the Standby Transmission Revenues) or the Approved Project Sponsors Regional Transmission Revenue Requirement; and

(b) the annual Regional TRBA adjustment, which shall be based on the principal balance in the Regional TRBA as of September 30 and shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. A Non-Load-Serving Participating TO shall include any over- or under-recovery of its annual Regional Transmission Revenue Requirement in its Regional TRBA. If the annual Regional TRBA adjustment involves only a partial year of operations, the Non-Load-Serving Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Non-Load-Serving Participating TO's Regional Transmission Revenue Requirement by the number of days the Regional Transmission Facilities were under the CAISO's Operational Control divided by the number of days in the year. An Approved Project Sponsor shall include any over- or under-recovery of its annual Regional Transmission Revenue Requirement in its Regional TRBA. If the annual Regional TRBA adjustment involves only a partial year, the Approved Project Sponsor's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Approved Project Sponsor's Regional Transmission Revenue Requirement by the number of days the transmission facilities were under construction based on the construction plan required in accordance with Section 24.6.1, as such plan may be updated by the construction plan status report, divided by the number of days in the year.

7. [NOT USED]

8. Updates to Regional Access Charges.

8.1 Regional Access Charges and Regional Wheeling Access Charges shall be adjusted: (1) on January 1 and July 1 of each year when necessary to reflect the addition of any New Participating TO and (2) on the date FERC makes effective a change to the Regional Transmission Revenue Requirements of any Participating TO or Approved Project Sponsor. Using the Regional Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for each Participating TO and Approved Project Sponsor, the CAISO will recalculate on a monthly basis the Regional Access Charge applicable during such period. Revisions to the Transmission Revenue Balancing Account adjustment shall be made effective annually on January 1 based on the principal balance in the TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

8.2 Any refund associated with a Participating TO's or Approved Project Sponsor's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced in the CAISO Market Invoice.

* * *

9. Approval of Updated Regional Revenue Requirements.

9.1 Participating TOs and Approved Project Sponsors will make the appropriate filings at FERC to establish their Transmission Revenue Requirements for their Local Access Charges and the ~~applicable~~ Regional Access Charge~~s~~, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the RTRR, LTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The Participating TO or Approved Project Sponsor will provide a copy of its filing to the CAISO and the other Participating TOs and Approved Project Sponsors in accordance with the notice provisions in the Transmission Control Agreement.

* * *

10. Disbursement of Regional Access Charge Revenues.

10.1 Regional Access Charge revenues shall be calculated for disbursement to each Participating TO and Approved Project Sponsor on a monthly basis as follows:

(a) the amount determined in accordance with Section 26.1.2 of the CAISO Tariff ("Billed RAC");

(b)

(i) for a Participating TO that is a UDC or MSS Operator and has Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, then calculate the amount each UDC or MSS Operator would have paid and the Participating TO would have received by multiplying the Regional Utility-Specific Rates for the Participating TO whose Regional Transmission Facilities served such UDC and MSS Operator times the actual Gross Load of such UDCs and MSS Operators; or

(ii) for a Non-Load-Serving Participating TO and Approved Project Sponsors, then calculate the Non-Load-Serving Participating TO's or Approved Project Sponsor's portion of the total Billed RAC in subsection (a) based on the ratio of the Non-Load-Serving Participating TO's and Approved Project Sponsors Regional Transmission Revenue Requirement to the sum of all Participating TOs' and Approved Project Sponsor's Regional Revenue Requirements.

(c) if the total Billed RAC in subsection (a) received by the CAISO less the total dollar amounts calculated in in subsection (b)(i) and subsection (b)(ii) is different from zero, the CAISO shall allocate the positive or negative difference among those Participating TOs that are subject to the calculations in subsection (b)(i) based on the ratio of each Participating TO's Regional Transmission Revenue Requirement to the sum of all of those Participating TOs' Regional Transmission Revenue Requirements that are subject to the calculations in subsection (b)(i). This monthly distribution amount is the "RAC Revenue Adjustment";

(d) the sum of the RAC revenue share determined in subsection (b) and the RAC Revenue Adjustment in subsection (c) will be the monthly disbursement to the Participating TO.

* * *

11. Determination of Transmission Revenue Requirement Allocation Between ~~Regioanl~~ Regional and Local Transmission Facilities.

11.1 Each Participating TO shall allocate its Transmission Revenue Requirement between the Regional Transmission Revenue Requirement and Local Transmission Revenue Requirement

based on the Procedure for Division of Certain Costs Between the Regional ~~High~~ and Local Transmission Access Charges contained in Section 12 of this Schedule.

PJM RTEP – Artificial Island Area Proposal Window Problem Statement & Requirements Document

PJM Interconnection

Original Document: April 29, 2013

Version 14.0

Revised: May 16, 2013

Email: RTEP@pjm.com with any questions or clarifications and include a reference to Artificial Island Window

REQUEST FOR PROPOSAL - Improve Artificial Island Area System Performance

I. Purpose of Proposal

PJM seeks technical solution alternatives (hereinafter referred to as "Proposals") to improve PJM Operational Performance in the Artificial Island area under a range of anticipated system conditions and to eliminate potential planning criteria (PJM, NERC, RFC, and Local Transmission Owner criteria) violations in the Artificial Island area.

II. Terminology

Artificial Island Area = "AI"
The system consisting of the transmission and generation facilities as depicted in Figure 1-Artificial Island 500 kV network. The Artificial Island includes the Salem #1, Salem #2, and Hope Creek #1 nuclear generation facilities

System Operating Limit = "SOL"
A System Operating Limit (SOL) is defined as:
The value (such as MW, MVAr, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Thermal Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings or Limits (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings or Limits (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Ratings or Limits (Applicable pre- and post-Contingency Voltage Limits)

Critical Contingency:
The most limiting (i.e. the "worst") contingency.

III. Scope of Work

Objectives

1. Generate maximum power (3818 MW total) from all AI Units (Salem1: 1253MW, Salem-2: 1245MW, Hope Creek: 1320MW) without a minimum MVAr requirement from the AI. Full maximum power must be maintained under both the baseline and all N-1 outage conditions of 500kV transmission lines in the AI area. For both the baseline and N-1 outage conditions, AI voltage must be maintained within operating limits and stable for all NERC Category B and C contingencies. NERC Category C3 contingencies "N-1-1 contingencies" do not need to be run on top of the N-1 outage condition.
2. Maximum MW output from AI should not be affected by the simultaneous outage of Power System Stabilizers (PSS) of Artificial Island units Hope Creek and Salem-2. The Salem-1 PSS is assumed to be on for all scenarios.
3. Reduce operational complexity.
4. Improve Artificial Island stability.
5. Maintain PJM System Operating Limits (SOLs)

What PJM Provides:

The following data and related information is required for this project and is expected to be available from PJM:

Modeling Data:

The following data is provided:

1. **Base power flow case.** This case has all lines in service with AI units at maximum real power output. This case has been developed based on the NERC MMWG 2011 Series 2017 Summer Light Load case in PSS/E version 32 (separate file).
2. **Dynamic Case.** This case has been developed based on the NERC SSDWG 2011 Series 2017 Summer Light Load case in PSS/E version 32 (separate files)
3. **Short Circuit Case.** This case has a 2017 short circuit model in PSS/E version 32 and ASPEN *.olr format. (separate file)
4. **Contingency list** to ensure stability in Table 2 – Fault List.
5. **Fault clearing times** for buses at/near the Artificial Island are provided in Tables 3 and 4. Examples of fault clearing time calculation using Tables 3 and 4 are also provided for contingency creation.
6. **Machine Capability Curves** ("D Curves") of the AI Units in Figures 2~4 for reactive power capability at the target MW output.
7. **Description of Salem unit 1 user-defined exciter model (USAC6AU).**

Other Supporting Data:

1. One-line diagram of Artificial Island Area in Fig. 1.
2. Applicable stability criteria (system performance criteria).

3. AI case description (separate file: "Artificial Island Dynamics Case.docx")

Response back to PJM (Deliverables)

1. Description of the proposed solution.
2. Detailed analysis report on proposed solutions, including:
    a) Response plots (e.g. Machine angles over time)
    b) Breaker one-line diagrams to illustrate system topology
    c) Spreadsheets (e.g. Table of system voltages)
    d) High level estimate of:
        i. Time to construct the proposed solutions
        ii. Cost estimates with a description of assumptions (e.g. base cost, risk and contingency (R&C) costs, and total cost)
        iii. Availability of right of ways
3. Equipment parameters and assumptions
    a) All parameters (Ratings, impedances, mileage, etc.)
    b) For reactive devices, settings and outputs
    c) For synchronous machines, MW and MVAR output assumptions
4. Complete set of power flow and dynamic cases containing proposed solutions. If possible, also provide a PSS/E IDEV file so that the modeling of the proposal may be easily applied to other models. This may be difficult for non PSS/E users, please contact PJM with any questions. Provide any other necessary data including critical contingency files to reproduce the proposed solutions. All cases and data files for dynamic simulations should be in PSS/E ver. 32 format.
5. Any other supporting documentation required for the proposal performance validation by PJM.
6. Submission of Deliverables
    a) Preferred - VIA electronic mail to RTEP@pjm.com
    b) Alternate - VIA FedEx to Nancy Muhl, PJM Interconnection, 955 Jefferson Avenue, Norristown, PA 19403

Timeline

Monday, 4/29/2013, Opening of Artificial Island RTEP Proposal window
Friday, 6/28/2013, Close of Artificial Island RTEP Proposal window

- All proposals and pre-qualification documentation due by 6/28

Action	Target Date
PJM distributes RFP to Artificial Island RTEP proposal window participants	4/29/2013
RFP recipients submit questions to PJM	4/29/2013 – 6/28/2013

PJM distributes answers to questions to all recipients*	4/29/2013 – 6/28/2013
Recipients submit proposals to PJM**	On or before 6/28/2013
Recipients submit pre-qualification packages to PJM**	On or before 6/28/2013

*PJM will maintain confidentiality of individual proposals for the duration of the window, but will distribute general information to the Artificial Island RTEP proposal window participants

**Any proposals received after close of the proposal will not be accepted.

Stability Performance Criteria

PJM Manual 14B, Attachment G.
http://www.pjm.com/~/media/documents/manuals/m14b.ashx

(a) *Steady state voltage*: pre-fault voltages at selected 500 kV buses should be within operating range in Table 1. This pre-fault voltage must be noted for the following buses:

Table 1 – Steady State Voltage Limits

Bus Name	Bus Voltage	Bus # Identifier	Steady state pre-fault Voltage
Branchburg	500 kV	200002	1.0 – 1.1 p.u.
Deans	500 kV	200006	1.0 – 1.1 p.u.
Keeney	500 kV	200010	1.0 – 1.1 p.u.
New Freedom	500 kV	200012	1.0 – 1.1 p.u.
Peach Bottom	500 kV	200013	1.0 – 1.1 p.u.
Salem	500 kV	200014	1.0 – 1.1 p.u.
Red Lion	500 kV	200027	1.0 – 1.1 p.u.
East Windsor	500 kV	200028	1.0 – 1.1 p.u.
Hope Creek	500 kV	200029	1.0 – 1.1 p.u.
Orchard	500 kV	200063	1.0 – 1.1 p.u.

1. Post-fault steady state voltage shall not be below 0.986 pu at the Salem and Hope Creek 500kV buses.
2. The voltage drop magnitude from pre-trip to post-trip conditions for any of the Artificial Island Units shall not exceed:
   a) 2% - Salem Unit 1 and Unit 2
   b) 2.5% - Hope Creek
3. The operating voltage range of AI generator terminal (25kV bus) is from 0.95 pu to 1.05 pu.

(b) *Transient stability*: PJM's transient stability criteria are applied:

1. Monitored Facilities:
    a) All machines in Artificial Island and neighboring areas. Area numbers in the power flow case to monitor include areas 225, 227, 228, 229, 230, 231, 232, 234, 235, 201 (please refer to the area information embedded in the power flow case to map the area numbers to area names).
    b) PJM 500kV bus voltages (500kV bus voltages in area 225) and Deans, New Freedom, Red Lion and Keeney 230kV bus voltages.
2. Monitored Data Channels
    a) Rotor angles of all machines in the monitored areas. Real and reactive power output, EFD (generator field voltage), speed and terminal voltage of machines in area 225 (PJM) must be monitored in the simulation.
    b) PJM 500kV bus voltages (500kV bus voltages in area 225) and Deans, New Freedom, Red Lion and Keeney 230kV bus voltages are also monitored.
    c) Monitored facilities and data channel information for the given cases are stored in the snap shot file (.snp) in dynamics case. If proposed solutions include new dynamic devices and/or topology, proper data channels need to be included in the snap shot file to monitor stability.
3. Fault List
    a) See “Fault List” section below.
4. Overall test procedure:
    a) A minimum of fifteen (15) seconds time domain simulation shall be conducted for each contingency.
    b) The system must be stable for all faults considered.
    c) Rotor angles should be represented in relative quantities with respect to a reference machine’s rotor angle. In the dynamics case, a reference machine shall be set to Sea Brook unit 1 (bus 105568)
    d) If the system performance simulation is stable but the maximum angle swing of any unit (relative to the reference generator) exceeds 120 degrees, a safety margin test is performed.
    e) Safety margin test procedure: Delay fault clearance by a half cycle and re-run the simulation. The case is not considered secure if the system is unstable for the delayed fault clearance.
    f) Post-fault transient voltages at AI 500 kV buses shall not be below 0.7 pu after fault clearing.

(c) *Damping*:

1. Monitored Facilities:
    a) Same facilities to those in transient stability.
2. Monitored Data Channels:
    a) Rotor angles.
3. Fault List
    a) See “Fault List” section below.
4. Overall test procedure

a) Fifteen (15) seconds time domain simulation shall be conducted for each contingency.
b) Damping ratio of rotor angle is calculated for the period of 10~15 seconds using a modal analysis tool (e.g. PSSPLT modal analysis tool).
c) Damping ratio shall be above 3% and remains above 3% until the end of the simulation.
d) If nonlinearity is significant for the period of 10 to 15 seconds, it is necessary to extend the time domain simulation to longer time to capture system linear characteristics.

Fault List

All of the following faults, at a minimum, must be simulated whenever "Fault List" is referenced in the procedure above. If proposed solutions require modification of existing contingencies and/or creation of new contingencies due to topology changes, the modified and/or new contingencies should be added in the fault list with proper fault IDs.

Table 2 - Fault List

Fault ID	Fault Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

*SLG: Single-Line-to-Ground
**SB: Stuck Breaker

Artificial Island One-line Diagram

[redacted]

Figure 1 - Artificial Island Area 500 kV Network

Fault Clearing Times

All fault clearing times are in cycles.

Table 3 - Fault Clearing Times

Station	Faulted Line /Transformer	Fault Clearing Times (cycles)			
		Three phase or SLG fault on Line/Transformer with Normal Clearing	Delayed Clearing Due to Stuck Breaker		Three phase or SLG fault on Bus with Normal Clearing
			Local Station Clearing	Remote Station Clearing	
Hope Creek	5037	[redacted]			
	5015, 5023				
Salem*	5024, 5021				
Orchard	5039, 230kV Transformer				
Red Lion	5015, 230kV Transformer				
East Windsor	5022				
	5038				
New Freedom	5038				

*Note: for a fault on 5037 near Salem (e.g., contingency IDs 5a and 5b), please use the information for Hope Creek station related to 5037.

Table 4 – Transfer Trip Delay

Line	From	To	Transfer Trip Delay (cycles)*
5037	Hope Creek	Salem	[redacted]
5015	Hope Creek	Red Lion	
5023	Hope Creek	New Freedom	
5024	Salem	New Freedom	
5021	Salem	Orchard	
5039	Orchard	New Freedom	
5015	Red Lion	Hope Creek	
5038	New Freedom	East Windsor	

5022	East Windsor	Deans	[redacted]

*Note: it is assumed that the transfer trip delay is the same at both ends of the line unless both cases are specified in the table.

Examples of fault clearing time calculation using Tables 3 and 4 for contingency creation

Three Phase Bus Fault

Suppose a bus fault occurs at Salem bus [redacted] with no outages. The fault will clear in [redacted] cycles by opening breakers [redacted]

Line Fault and Transfer Trip

Suppose a line fault occurs on 5024 near Salem. The fault will clear at Salem by opening breakers [redacted] and [redacted] in [redacted] cycles. The transfer trip delay for 5024 is [redacted] cycles. Therefore, the fault at New Freedom will clear in [redacted] cycles [redacted]).

Line Fault with Breaker Failure

Suppose a line fault occurs on 5024 near Salem. Breaker [redacted] opens in [redacted] cycles but [redacted] fails to open. To clear the fault, breakers [redacted] and [redacted] will open after [redacted] cycles. At New Freedom, the fault clears in [redacted] cycles.

Line Fault with Breaker Failure involving remote station clearing

Suppose a line fault occurs on 5038 near New Freedom. Breaker [redacted] and [redacted] at New Freedom open in [redacted] cycles and breaker [redacted] at East Windsor opens in [redacted] cycles but breaker [redacted] at East Windsor fails to open. To clear the fault, breakers [redacted] will open after [redacted] cycles. At Deans, the fault clears in [redacted] cycles.

Generator Capability Curves

SALEM 1:

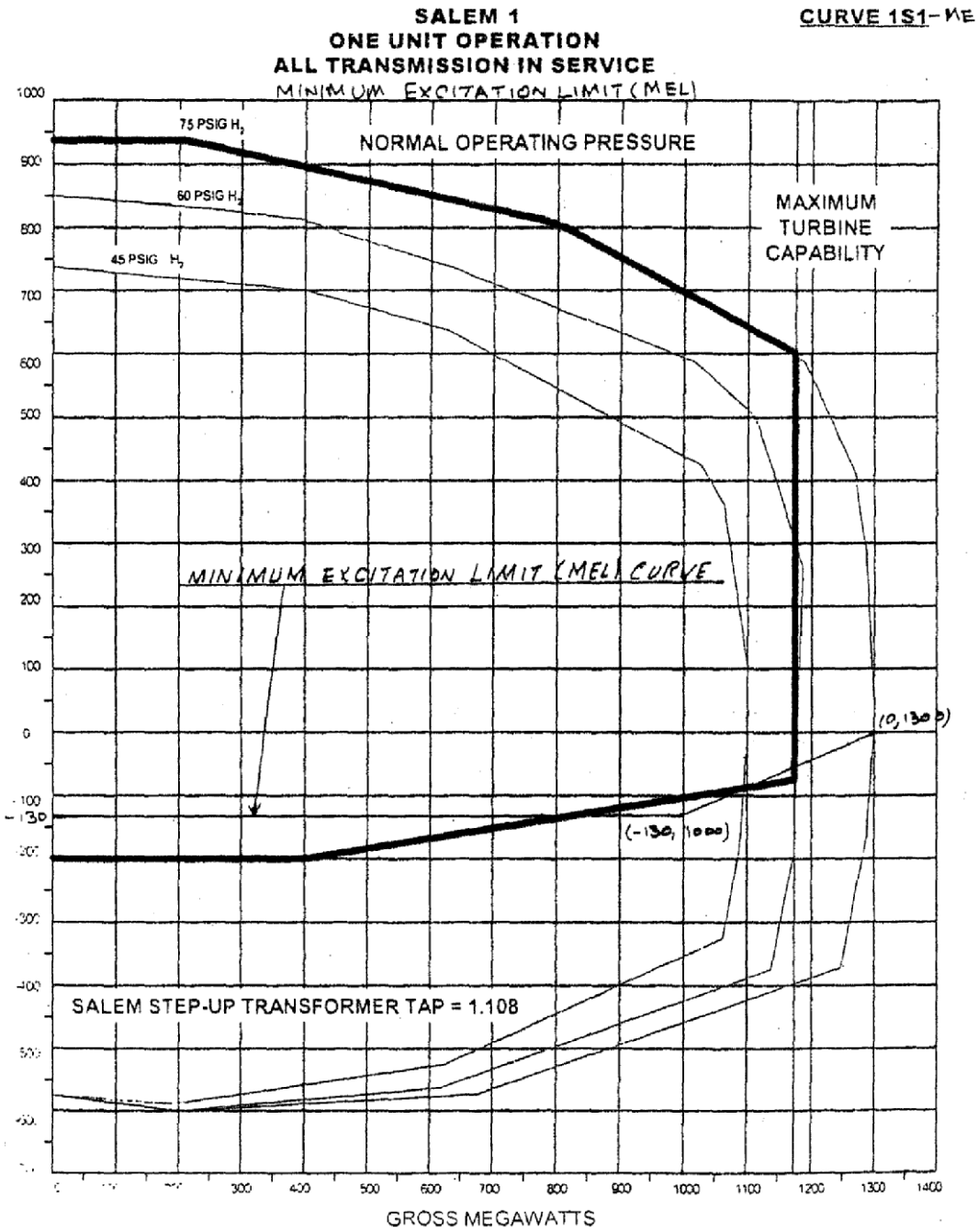


Figure 2 – Salem unit 1 capability curve

SALEM 2:

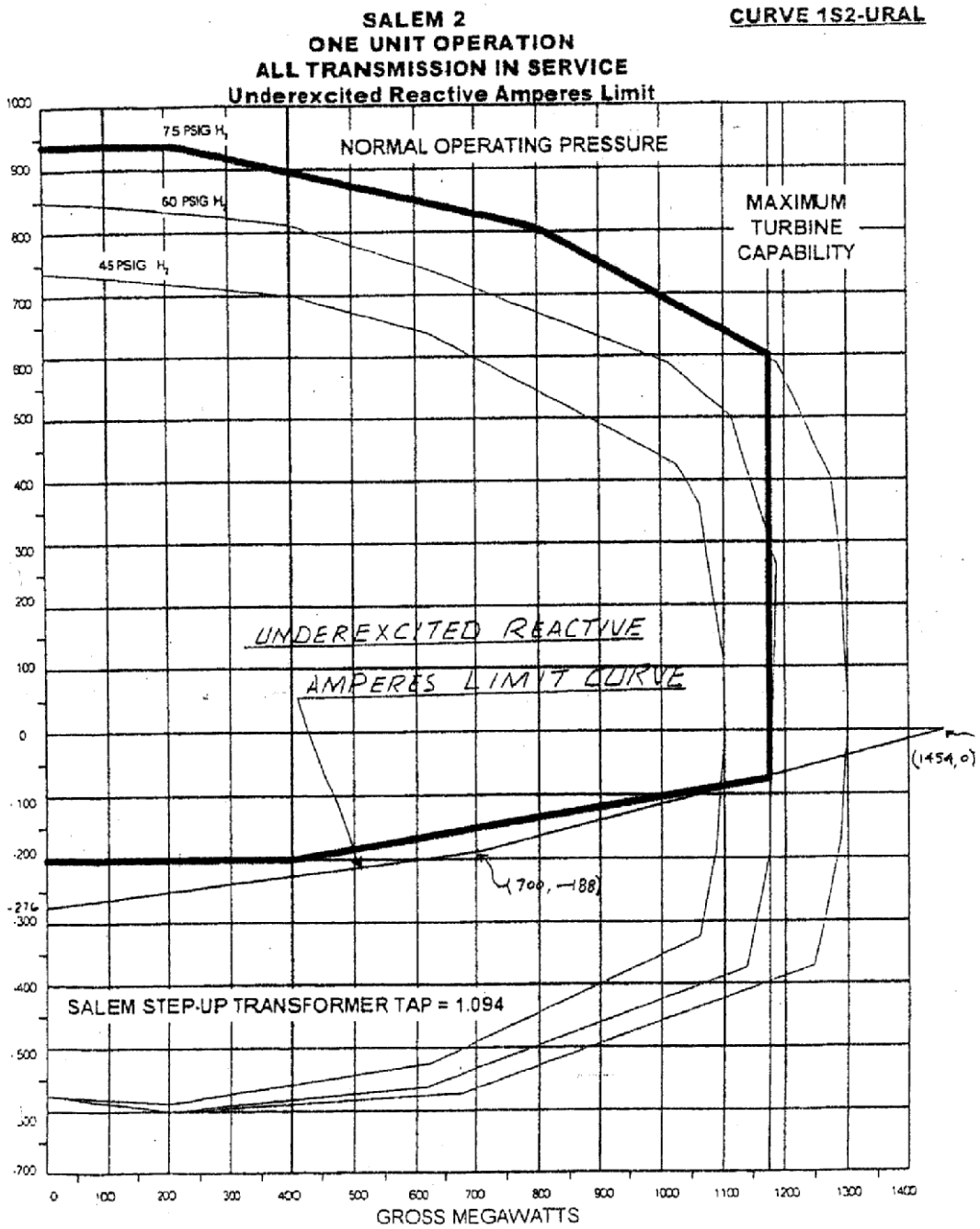


Figure 3 – Salem unit 2 capability curve

HOPE CREEK:

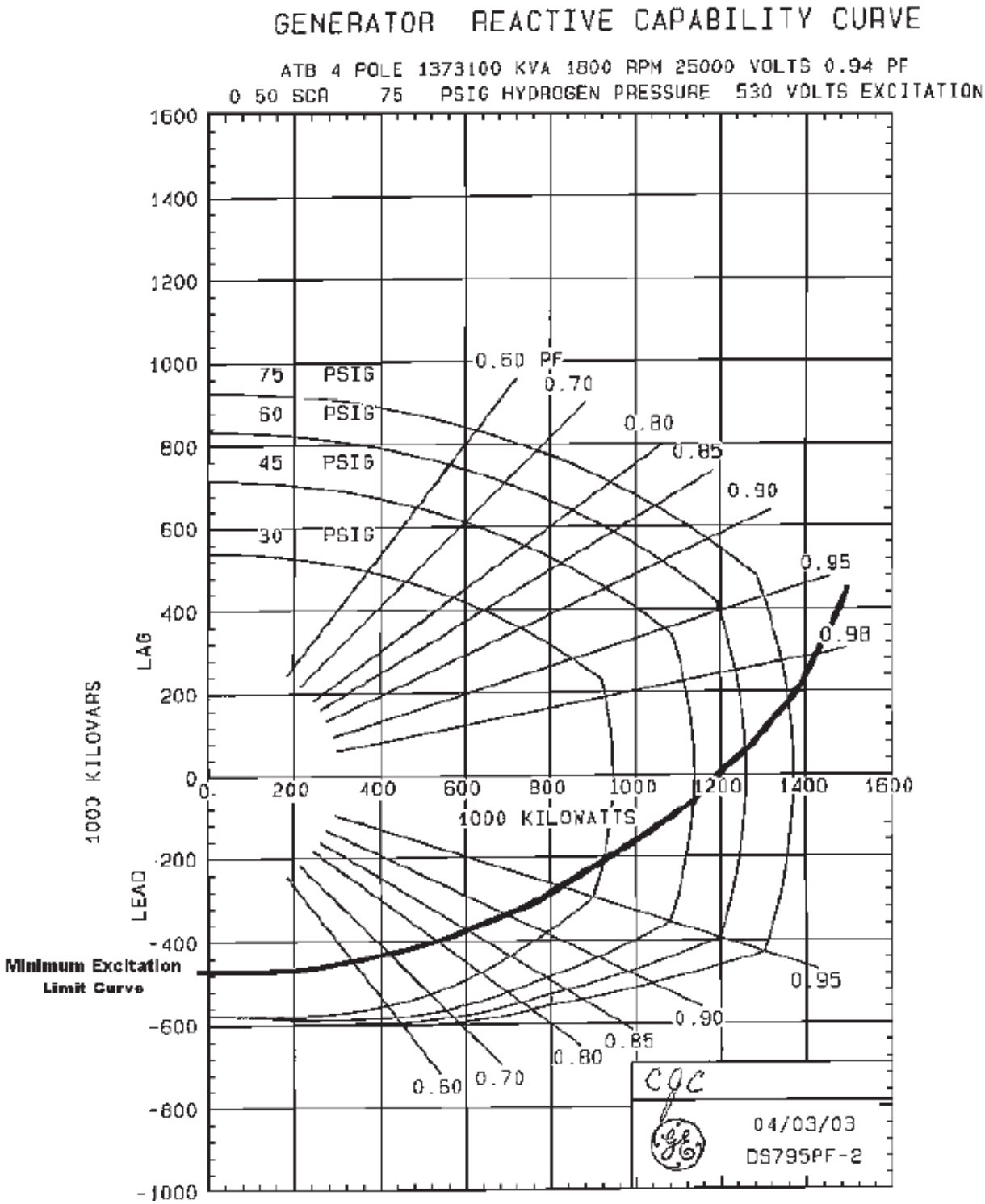


Figure 4 – Hope Creek unit capability curve

Salem unit 1 User-defined Exciter Model (USAC6AU – Modified ESAC6A)

The user-written model USAC6A is a modified version of the PSSE standard model ESAC6A. The difference between the USAC6A and ESAC6A is in the way the non-windup limit is applied on the lead-lag block (STATE(K+2)). In the USAC6A model, the implementation of the non-wind up limit on STATE(K+2) is consistent with the recommendation as given in the IEEE 421.5 2005 standard.

Table 5 – USAC6AU model parameter description

CONs	#	Value	Description
[redacted]			

Data format in the dyr file:
IBUS, 'USRMDL', ID, 'USAC6AU', 4, 0, 0, 23, 5, 0, CON(J) to CON(J+22) /

Table 6 – USAC6AU model dynamic states description

STATEs	#	Value	Description
[redacted]			

[redacted]

Figure 5 – Block Diagram of USAC6AU exciter model

Document Revision History

April 29, 2013
Original File Posted

April 30, 2013
Table 2 – Fault List updated
Table 3 – Fault Clearing Times updated
Table 4 – Transfer Trip Delay updated
Figure 1- Updated Deans bus number in the Figure from 20006 to 200006

May 3, 2013
Added a short circuit model in Aspen *.olr format
Added a Description of Salem unit 1 user-defined exciter model (USAC6AU), which includes a new Table 5 and Table 6
Described the operating voltage range of AI generator terminal (25kV bus) - from 0.95 pu to 1.05 pu

PJM Order 1000 Implementation:

Artificial Island Proposal Window

October 8, 2013

Steven R. Herling
Vice President, Planning
PJM Interconnection

Order 1000 Background

TOPICS:

- Competitive Solicitation for New Projects (ROFR Issue)
- Planning for Public Policy
- Cost Allocation
- Interregional Planning

COMPETITIVE SOLICITATION OPPORTUNITIES

PJM filing provides for competitive solicitation processes for each class of projects:

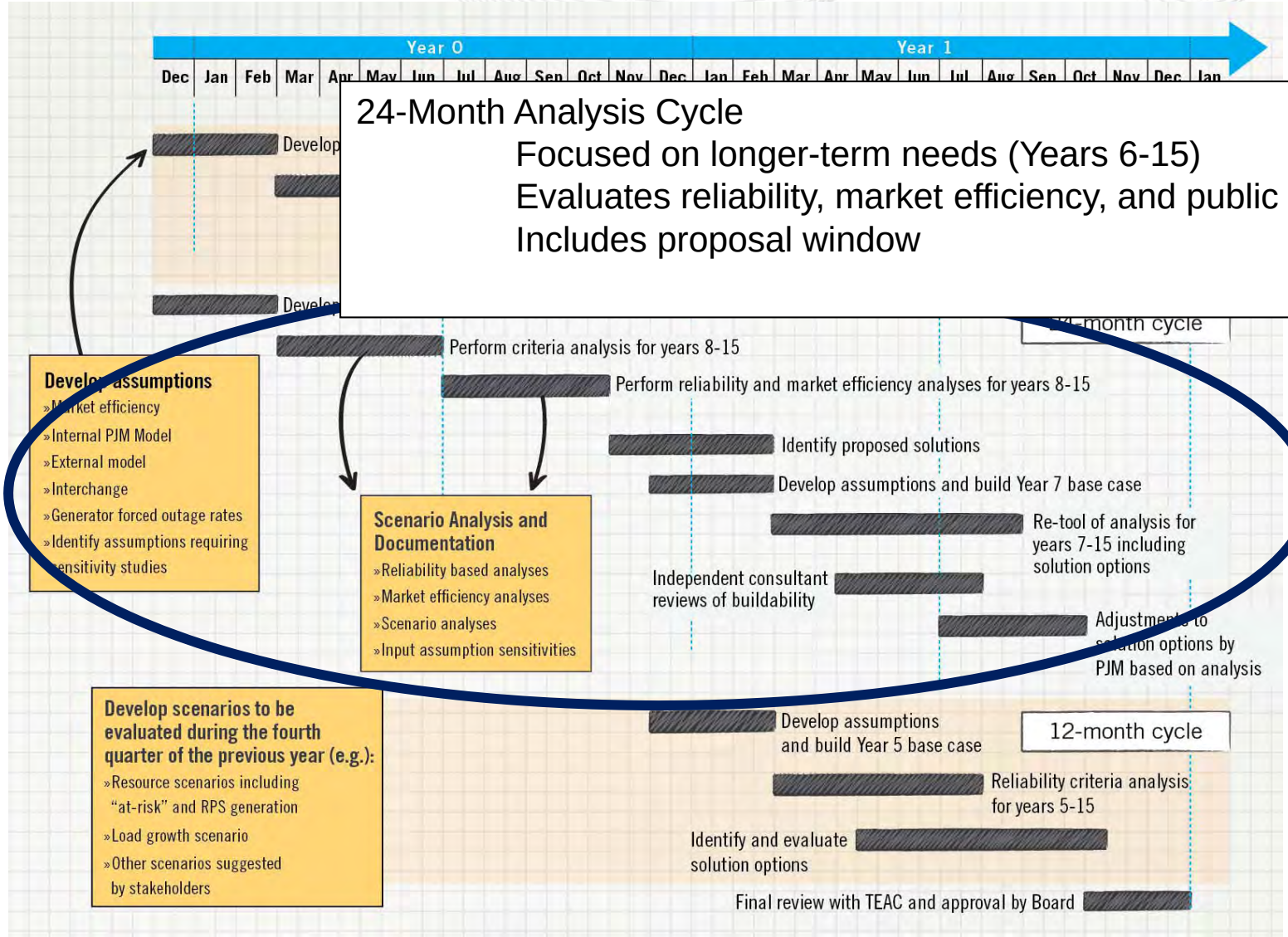
- Immediate need reliability projects (needed in 2-3 years or less)
  - Includes expedited designation to meet reliability in-service date
- Short term reliability projects (needed in 4-5 years)
- Long term reliability projects (needed in 5+ years)
- Market efficiency projects
- State agreement projects identified by states

.

COMPETITIVE SOLICITATION OPPORTUNITIES

- Length of “proposal window” tied to reliability need (7 days/30 days/120 days)
- Where insufficient time due to imminent reliability need, default is to incumbent T.O for reliability projects only
- Consistent with Order 1000 Existing ROFR Exceptions

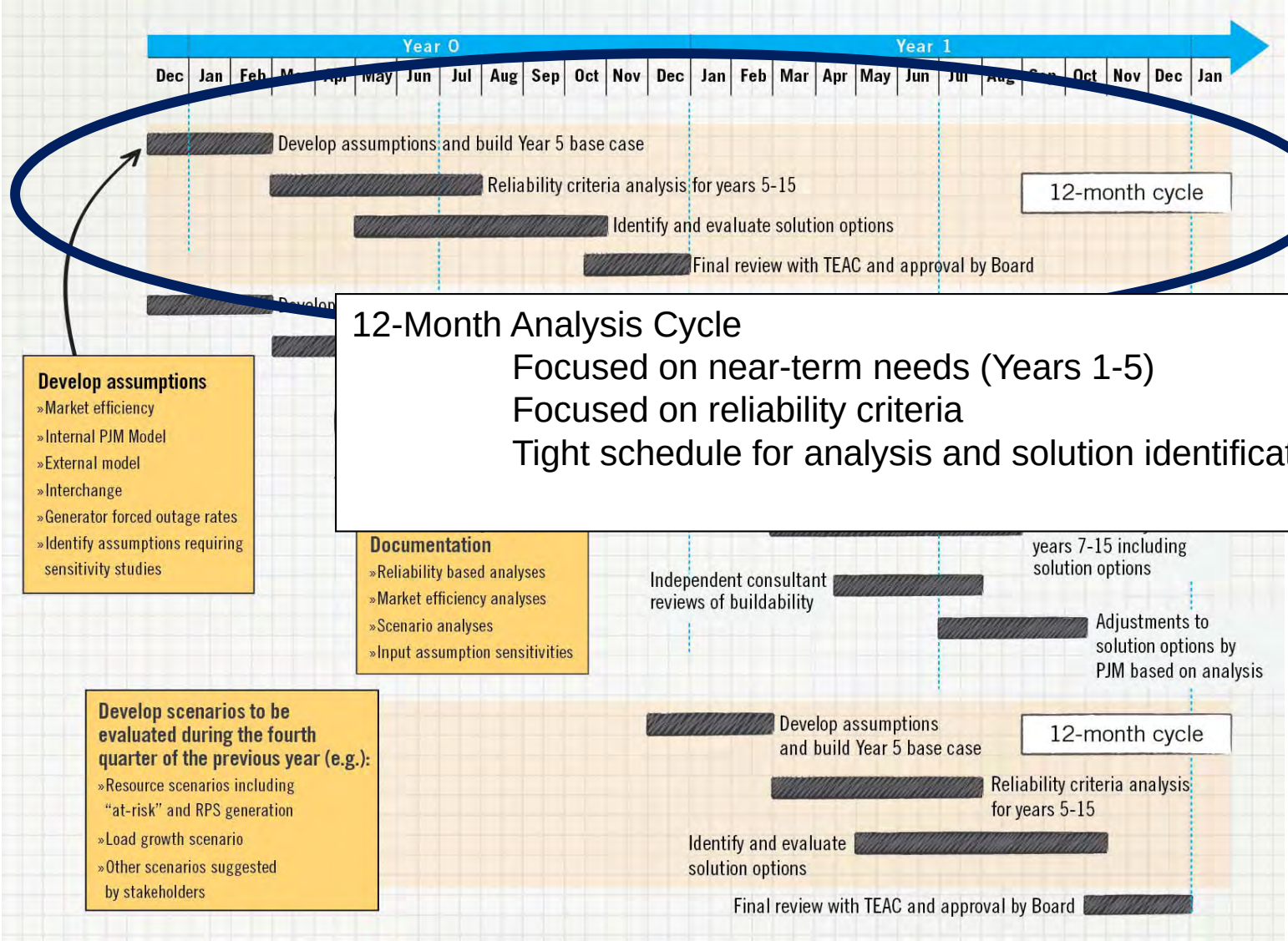
24 Month and 12 Month Planning Cycles



24-Month Analysis Cycle

- Focused on longer-term needs (Years 6-15)
- Evaluates reliability, market efficiency, and public policy
- Includes proposal window

24 Month and 12 Month Planning Cycles

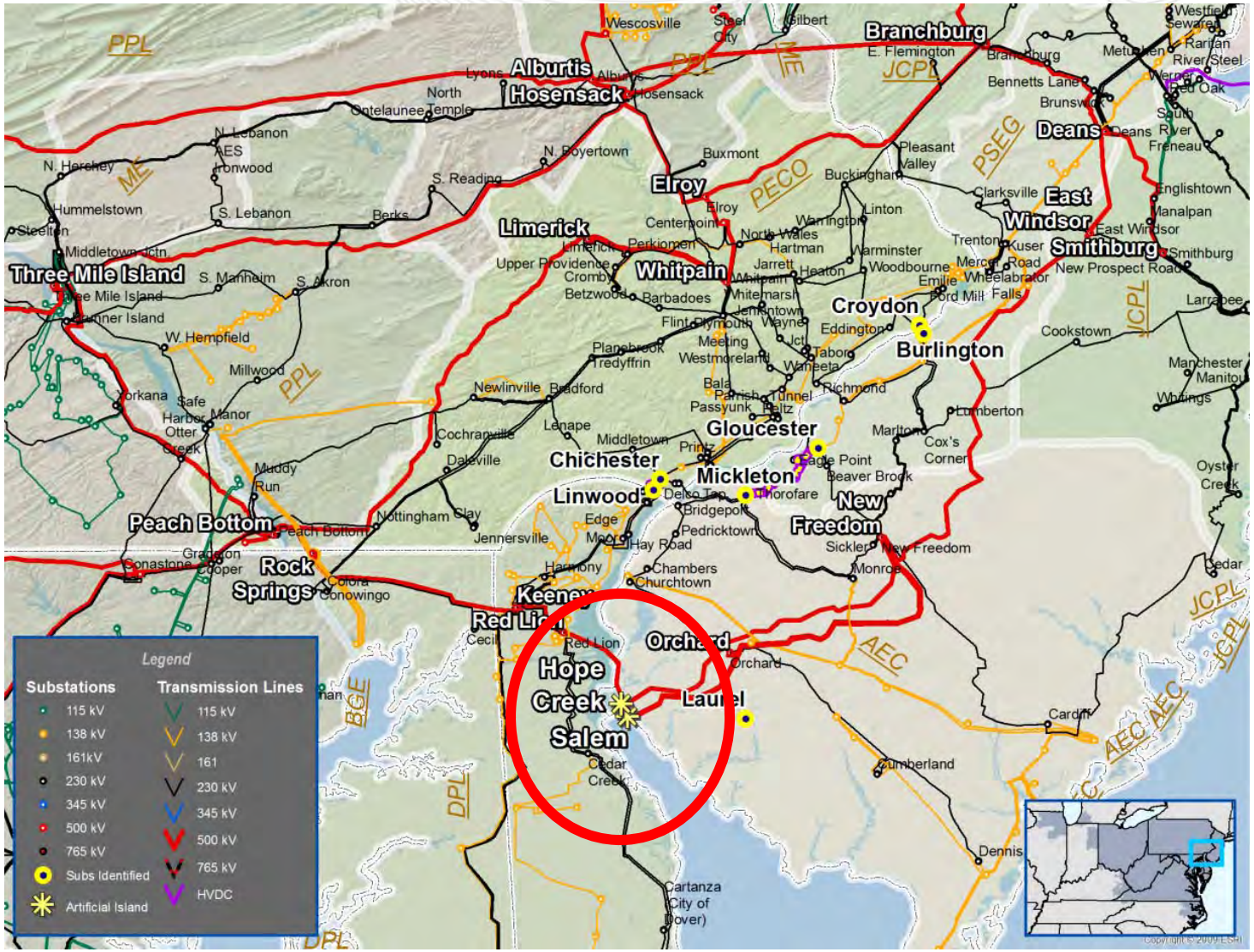


12-Month Analysis Cycle

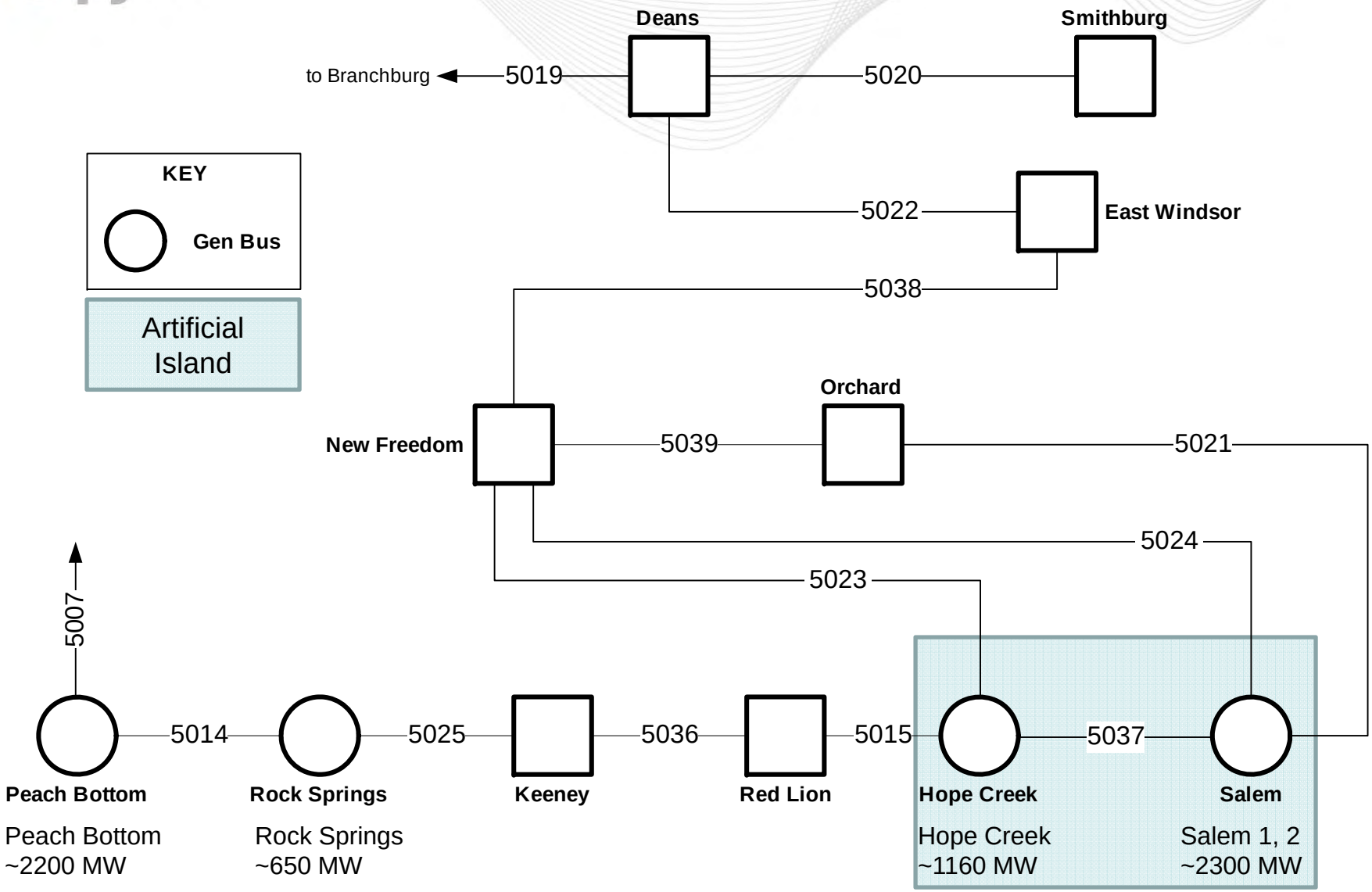
- Focused on near-term needs (Years 1-5)
- Focused on reliability criteria
- Tight schedule for analysis and solution identification

Artificial Island

Artificial Island



Artificial Island and Surrounding Network



Max generation power output for stable operation is expressed as:

$$P_{max} = (V_t \times E_i) / X_d$$

- V_t is system voltage
  - More is theoretically better, but has operational limits
- E_i is internal machine voltage
- X_d is system impedance
  - Smaller is better

- Stability Requirements
  - Artificial Island Operating Guide (AIOG)
  - Minimum MVAR output requirements from Hope Creek, Salem 1&2

- Reliability Issues
  - High voltage

- Goals
  1. System Performance
     - Outage conditions - improve system performance and AI stability margin under N-1 (forced or unforced)
     - Normal conditions - Improve system performance and stability margin under normal system conditions
  2. AIOG
     - Eliminate the AIOG

Proposal Process

Artificial Island Proposal Window Timeline

Announcement
(Presented at 3/7/2013 TEAC)
- Announce window and potential timeline
- Request CEII/NDA submittals from anticipated participants
- Request Designated Entity Pre-Qualification

→

PSS/E v32 Case Development
- Initial PSS/E v32 case created
- Benchmarking in Progress
- Develop and benchmark critical system condition cases

→

Open Window
(4/29/2013 - 60 Day Duration)
- Open the "Artificial Island" RTEP Proposal Window
- Complete problem statement available
- Analytical files available

↓

Coordinate with Window Participants and Receive Solution Proposals
- Coordination VIA www.pjm.com
- Data, Information
- Questions & Answers

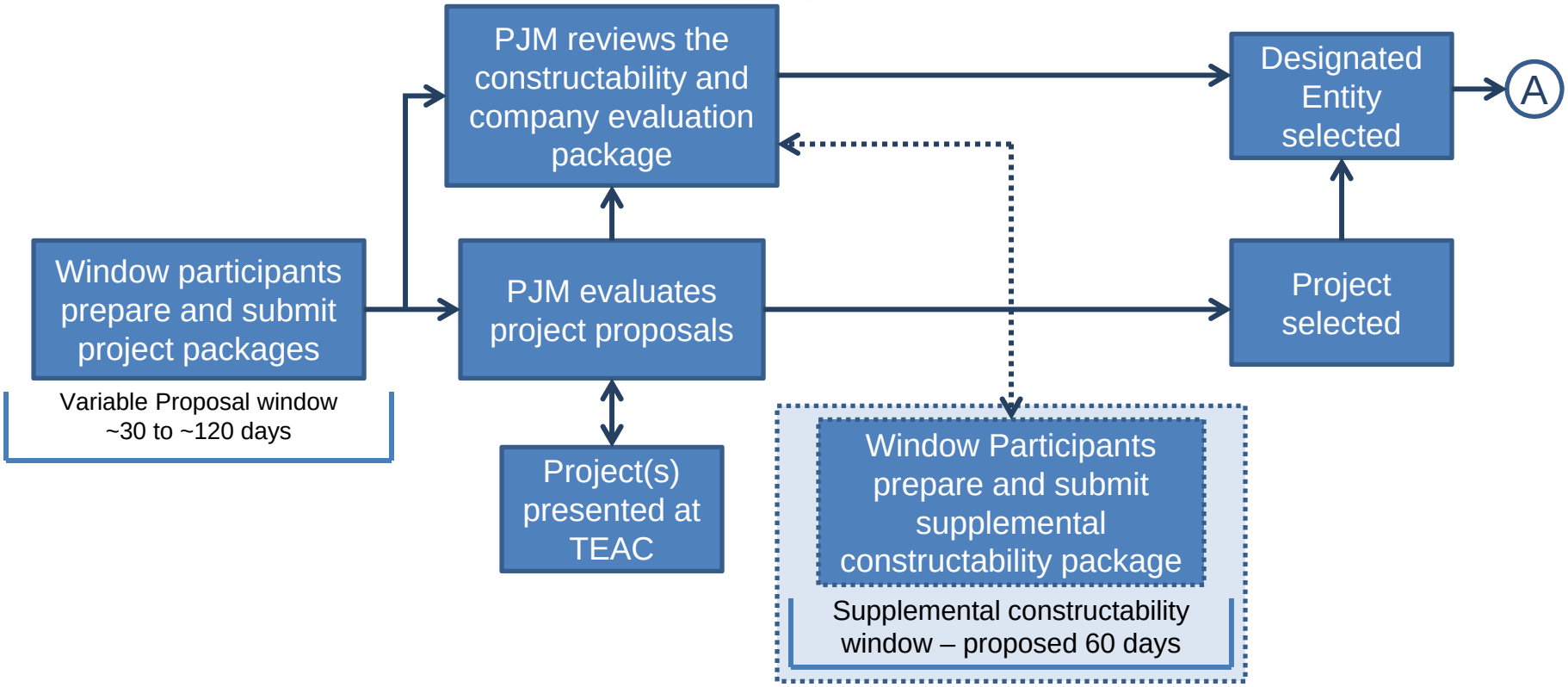
→

Proposal Window Closed on 6/28/2013

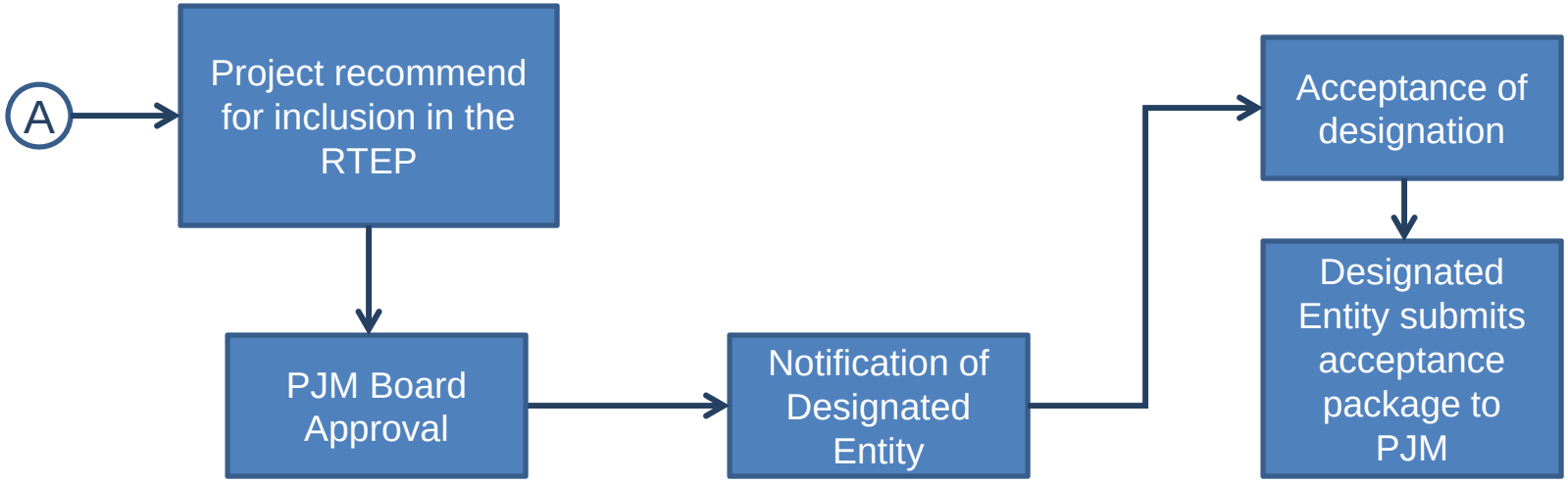
→

PJM Evaluates Solution Proposals

Project Evaluation and Selection Process



Project Evaluation and Selection Process



Company Qualifications

Project technical package	Prior company and affiliate experience	Project constructability information
Project evaluation	Company evaluation	Project constructability

- Project specific experience

Engineering / Design	Development / Right of Way Acquisition	Construction
Operations	Maintenance	

- Financial
  - Evidence of the ability to secure a financial commitment

Pre-Qualification Transparency

- All pre-qualification packages submitted will be made public on the PJM website approximately 2 weeks after the close of the window.
- The pre-qualification status will be made public in a table similar in format to queue projects.
- Companies may submit a redacted version of their pre-qualification package during the open window.

Pre-Qualification and Company Evaluation

- Developing an evaluation mechanism for both pre-qualification packages and company evaluations
  - Consistent evaluation
  - Mechanism to provide consistent response letters

Previous Experience / Plan to Gain Expertise
Criteria
The entity/individual has over 20 years of experience in areas specific to the proposed project
The entity/individual has experience in the areas specific to the proposed project of over 5 years and a robust plan that includes the participation of affiliates/partners that have over 20 years of experience
The entity has a robust plan that includes the participation of affiliates/partners that have over 20 years of experience
The entity has a plan
The proposed plan was found lacking sufficient detail
The filing did not include any information for this area

Conceptual Qualification Criteria

Previous Record
Criteria
The entity/individual has over 20 years of experience in areas specific to the proposed project
The entity/individual has over 10 years of experience in areas specific to the proposed project
The entity/individual has over 5 years of experience in areas specific to the proposed project
In the last 5 years, the company has had a major incident in this areas specific to the proposed project
No previous record supplied
In the last 5 years, the company has had a major incident in this areas specific to the proposed project and did not disclose this in their filing

Conceptual Qualification Criteria

Standardized Practices
Criteria
The company recognizes and has experience with the types of entities and applicable standards which they will need to comply with (ex. NESC, OSHA, NERC, IEEE, ANSI …)
The company recognizes the types of entities and applicable standards which they will need to comply with (ex. NESC, OSHA, NERC, IEEE, ANSI …)
The proposed plan was found lacking sufficient detail

Restoration of Equipment Failures
Criteria
Has prior experience remedying equipment failures which includes a spares policy
Has prior experience remedying equipment failures
Has a plan to remedy equipment failures which includes a spares policy
Has a plan to remedy equipment failures
The proposed plan was found lacking sufficient detail
The filing did not include any information for this area

Financial Statements
Criteria
Approved by PJM Finance
Not Approved by PJM Finance

Equipment Failures
Criteria
Has prior experience remedying equipment failures which includes a spares policy
Has prior experience remedying equipment failures
Has a plan to remedy equipment failures which includes a spares policy
Has a plan to remedy equipment failures
The proposed plan was found lacking sufficient detail
The filing did not include any information for this area

Conceptual Qualification Criteria

Right of Way Experience
Criteria
Project plan that recognizes the types of entities that will need to be engaged to acquire the RoW and prior experience in RoW procurement in the region and environment specific to the proposed project
Project plan that recognizes the types of entities that will need to be engaged to acquire the RoW and they have identified (but not secured) a contractor with prior experience in RoW procurement in the region specific to the proposed project
The entity/individual has experience procuring RoW in the region specific to the proposed project.
The entity/individual has experience procuring RoW across one or a few different regions in the US.
The entity/individual has experience outside of the US
The entity has a plan
The proposed plan was found lacking sufficient detail
The filing did not include any information for this area

Constructability

Project technical package	Prior company and affiliate experience	Project constructability information
Project evaluation	Company evaluation	Project constructability

Upgrade Constructability Data

- Upgrade to existing infrastructure - Incumbent Transmission Owner to provide
  - Project scope
  - Schedule
    - Engineering
    - Right of way acquisition
    - Long lead time equipment
    - CPCN requirements
    - Construction permitting
    - Construction activities
  - Estimated project costs

Greenfield Constructability Data

- Constructability data to be supplied for greenfield projects

- Project scope
- Project plan
  - Permitting
  - Right of way acquisition
  - Project one-line diagram
  - Projected transmission line route

- Schedule
  - Engineering
  - Right of way acquisition
  - Long lead time equipment
  - CPCN requirements
  - Construction permitting
  - Construction activities
- Estimated project costs

Post-Screening Constructability Data

- Cost estimate
- Project finance plan
- Project plan
  - Permitting
  - Right of way acquisition
  - Project one-line diagram
  - Station(s) general arrangement
  - Transmission line route
- Operational plan
  - Control center
  - Telemetry
- Maintenance plan
- Compliance with standards organizations

- Schedule
  - Engineering
  - Right of way acquisition
  - Long lead time equipment
  - CPCN requirements
  - Construction permitting
  - Construction activities
  - Long lead time equipment
  - Contract labor procurement plan
  - Outage plan
- Other data as required

Proposals

Project technical package	Prior company and affiliate experience	Project constructability information
Project evaluation	Company evaluation	Project constructability

Artificial Island Proposal Window Status

- Window opened on 4/29/2013
- Closed on 6/28/2013

- 26 individual proposals
- 7 entities

- Project Naming Convention
- Project Identification Taxonomy: 2013_1-1A

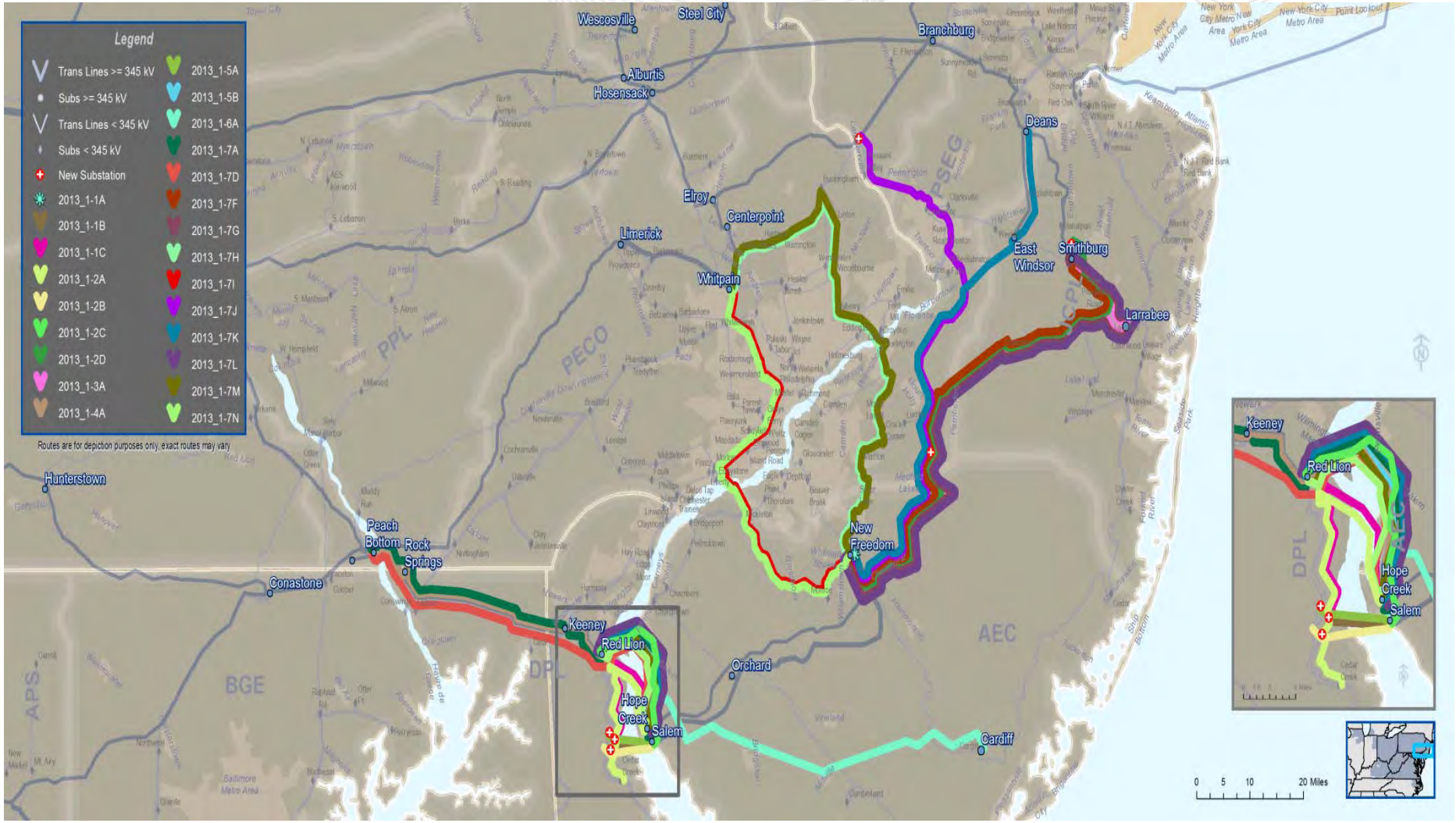
RTEP Year	RTEP Window Index (within the current year)	Project Sponsor index for this window	Proposal Index (for multiple proposals from the same Sponsor)

Artificial Island Proposal Requirements

- Sponsoring entity information
  - Company name, contact information etc.
- Project Description
  - Include scope, interconnection points, configurtion (e.g. overhead, underground, AC/DC etc>), ROW, high level project schedule including CPCN, engineering, construction start, and in-service date
  - Project cost estimate

- Technical Report
  - Include assumptions and calculations demonstrating the efficacy of the project
    - Report should include information about the origin of power flow case and any modifications, station single line drawings and results of any sensitivity studies
    - Modeling information such as conductor type, calculated impedances, contingency files, *.idev files and dynamic files

Artificial Island Proposals

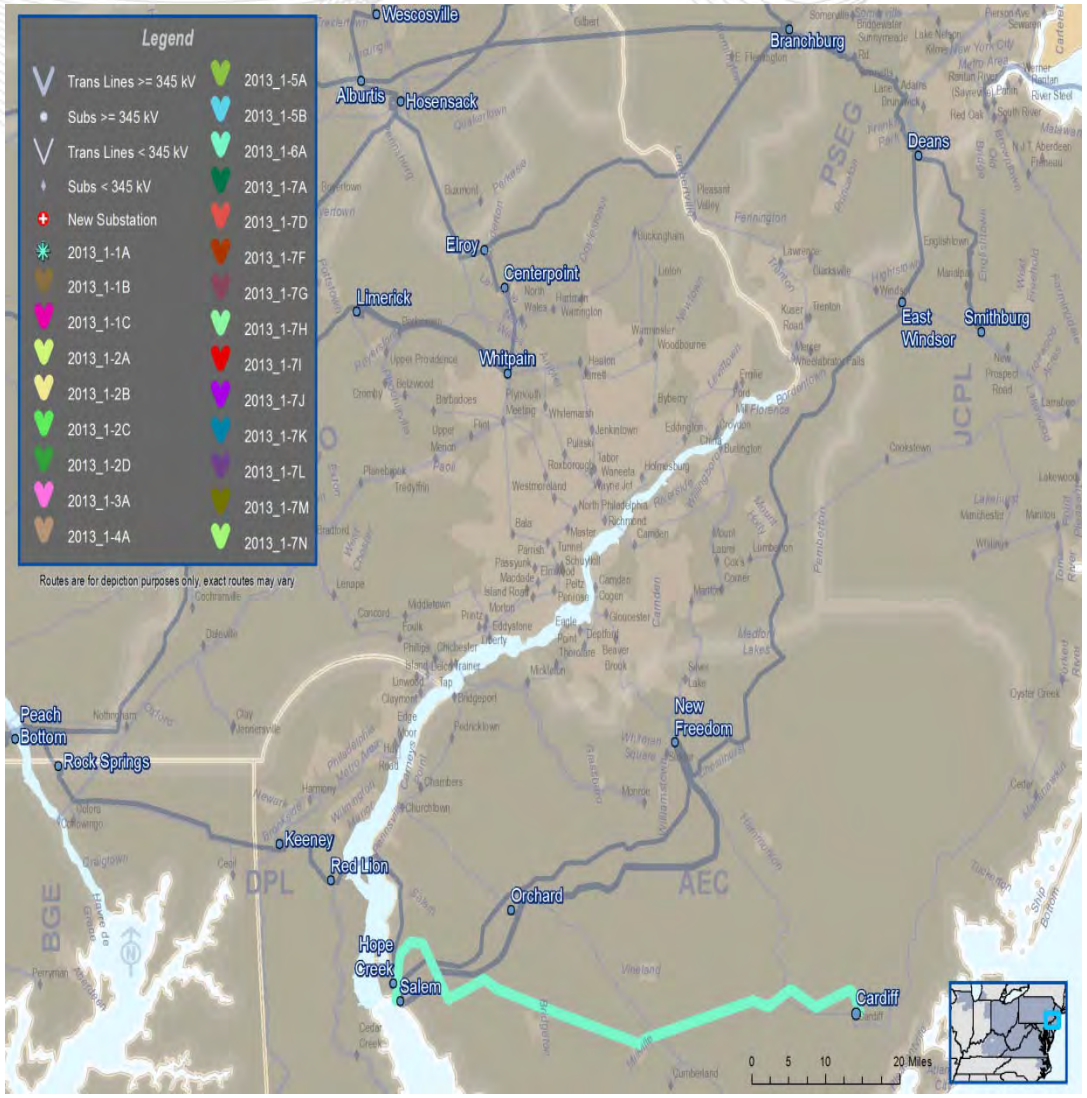


Artificial Island Proposals

Project ID	TO	Cost ($)	Major Componenets	Supporting info
P2013_1-1A	Virginia Electric and Power Comp	$ 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 Comp	$ 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 230kV and Catanza - Red Lion 230kV
P2013_1-1C	Virginia Electric and Power Comp	$ 202	New 500 kV from Hope Creek - a new Station in Delaware	New 500/230 kV station in Delaware that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV; 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	$452.3 (Only FirstEnergy portion)	New Freedom-Smithburg 500 kV line with a loop into Larrabee; Hope Creek - Red Lion 500 kV line;	Two (2) new 500/230 transformers at Larrabee
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; Reconductor Harmony-Chapel St 138 kV
P2013_1-5A	LS Power	$116.3M - $148.3M	Salem - Silver Run (new) 230 kV; Salem 500/230 kV Transformer	New 230 kV station that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
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 at 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 & Salem - Hope Creek 500 kV lines	
P2013_1-7F	PSE&G	$ 879	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Existing ROW
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 & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7E with Hope Creek - Red Lion
P2013_1-7L	PSE&G	$ 1,250	New Freedom - Smithburg & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7F with Hope Creek - Red Lion
P2013_1-7M	PSE&G	$ 1,548	New Freedom - Whitpain (North) & Salem - Hope Creek - Red Lion 500 kV lines w/ 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") & Salem-Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	

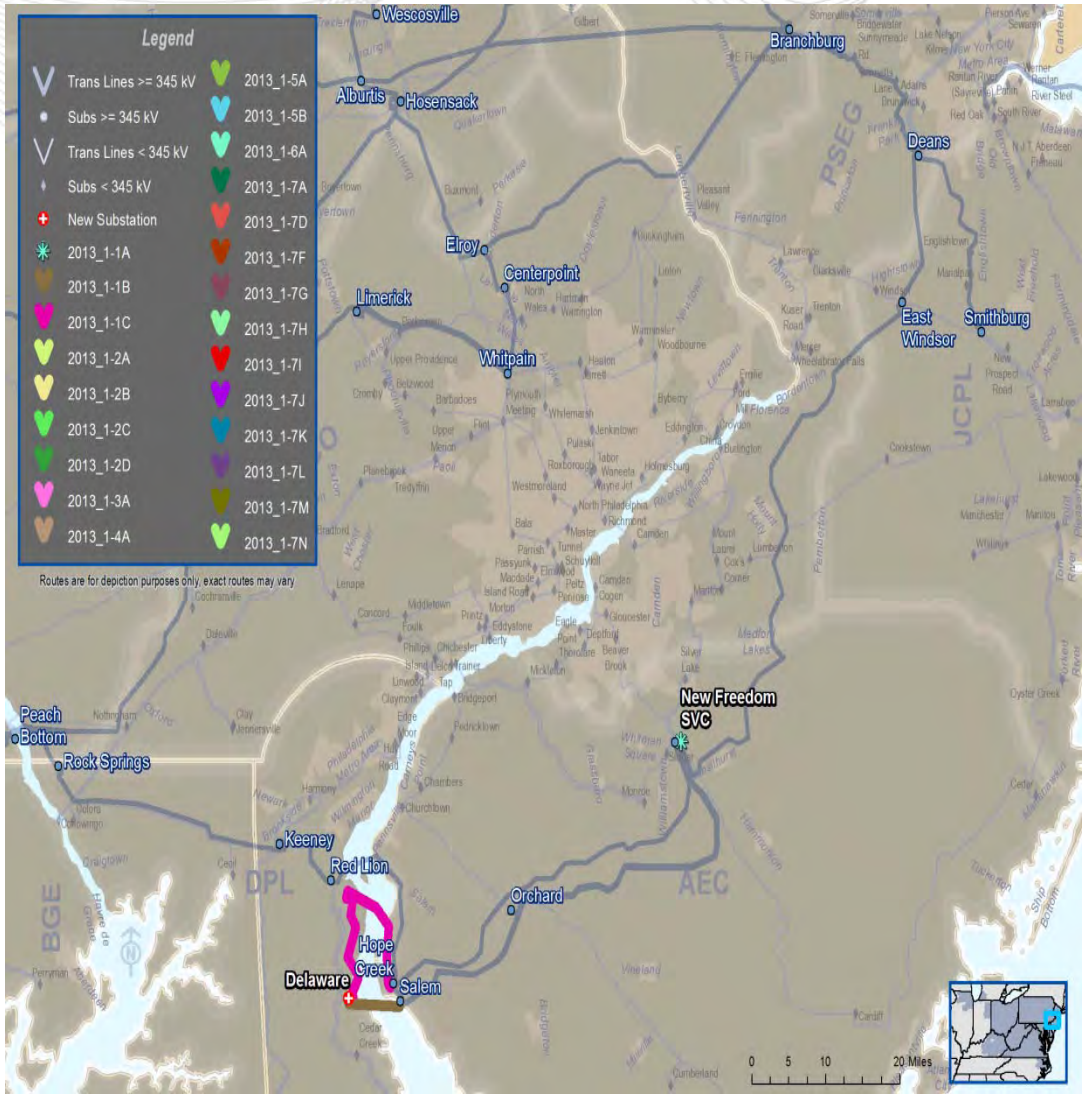
P2013_1-6A

- Install a HVDC converter station near the Artificial Island
  - Install a SVC at the new Artificial Island HVDC station
- Install a HVDC converter station near the existing Cardiff 230 kV
- Install a 320 kV HVDC facility from the new Artificial Island HVDC station and the new HVDC station near Cardiff 230 kV
- Cost: $1,012 M



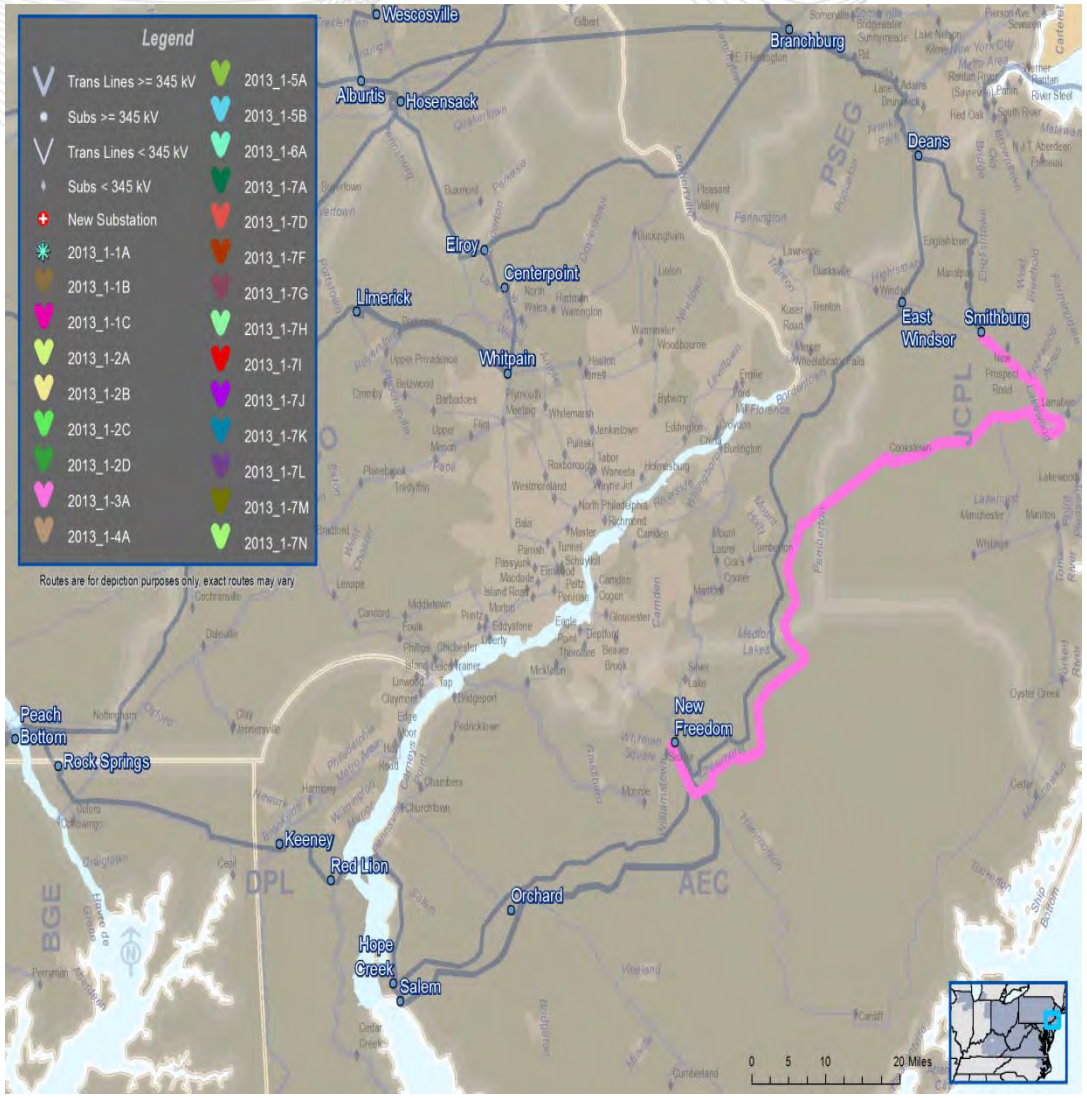
P2013_1-1A,1B,1C

- P2013_1-1A
  - Install a 500 MVAR SVC and 2 Thyristor Controlled Series Compensation (TCSC) devices near New Freedom
  - Cost: $133M
- P2013_1-1B
  - Install a new 500 kV line from Salem 500 kV to a new station in Delaware
  - Install a new station in Delaware that taps the existing Red Lion - Cartanza 230 kV and Red Lion - Cedar Creek 230 kV lines
  - Cost: $126M
- P2013_1-1C
  - Install a new 500 kV line from Hope Creek 500 kV to a new station in Delaware
  - Install a new 500 kV line from Hope Creek 500 kV to Red Lion
  - Install a new Salem – Hope Creek 500 kV line
  - Cost: $202M



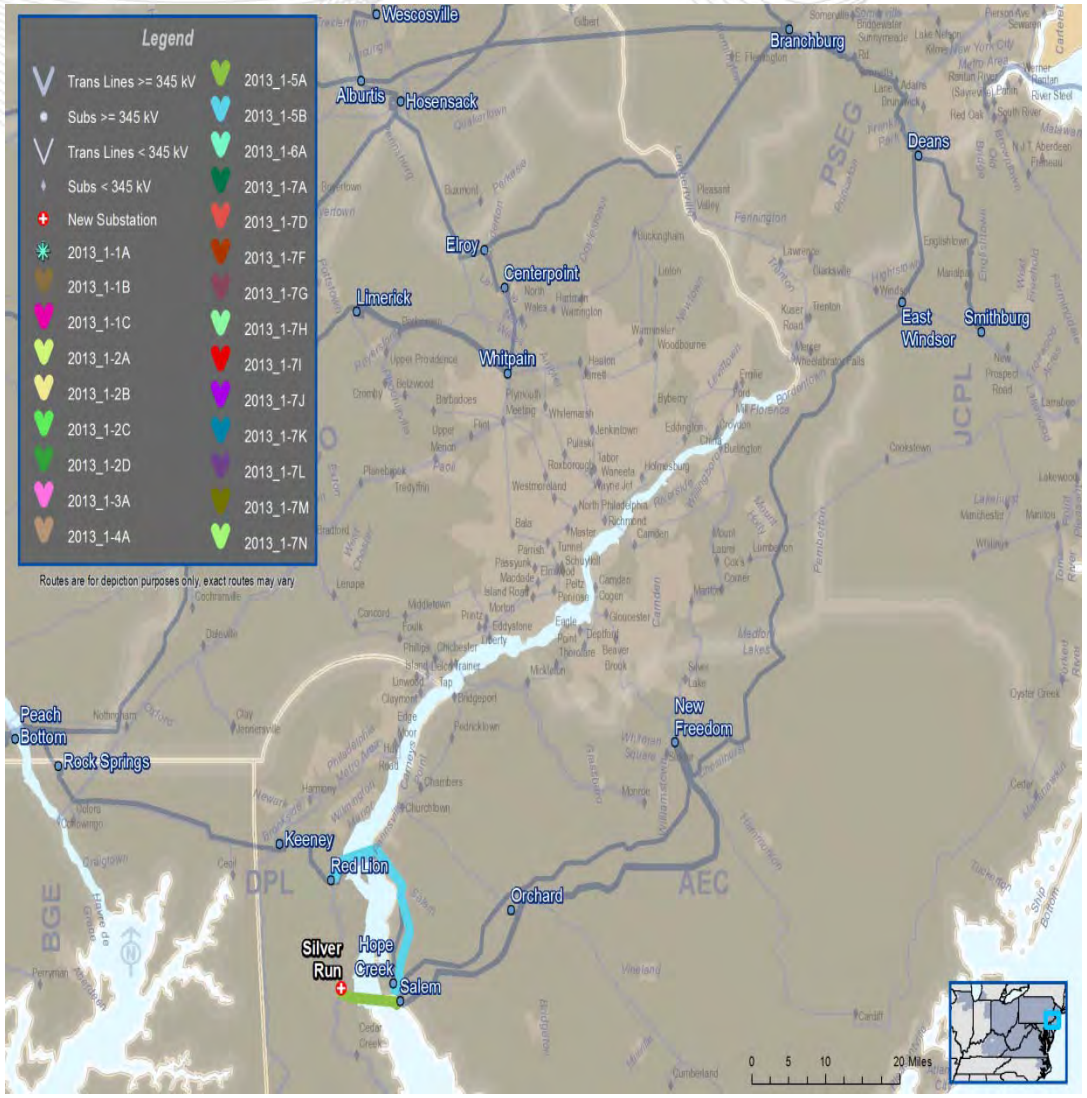
P2013_1-3A

- Install a new, New Freedom – Smithburg 500 kV line with a loop into Larrabee 500 kV
- Install 2 new 500/230 Transformers at Larrabee
- Install a Hope Creek – Red Lion 500 kV line
- Cost: $452.3*
  - *Cost submitted by project sponsor does not reflect entire project.



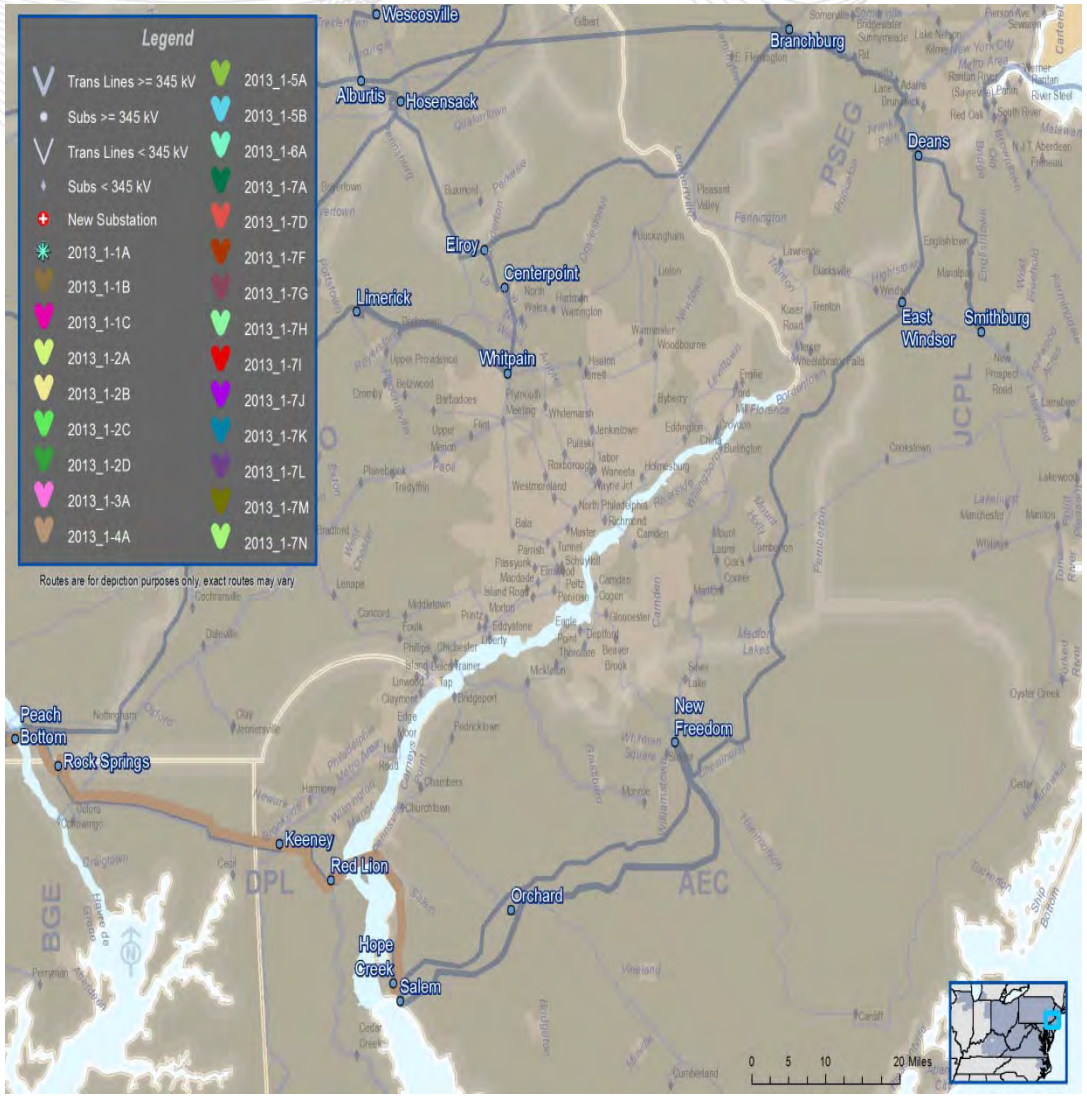
P2013_1-5A, 5B

- P2013_1-5A
  - Install a new Salem - Silver Run 230 kV line with a 500/230 kV transformer at Salem
  - Install a new 230 kV station that taps the existing Red Lion - Cedar Creek 230 kV and Red Lion - Cartanza 230 kV lines
  - Cost: $116.3-$148.3M
- P2013_1-5B
  - Install a new Salem – Red Lion 500 kV line
  - Cost: $170M



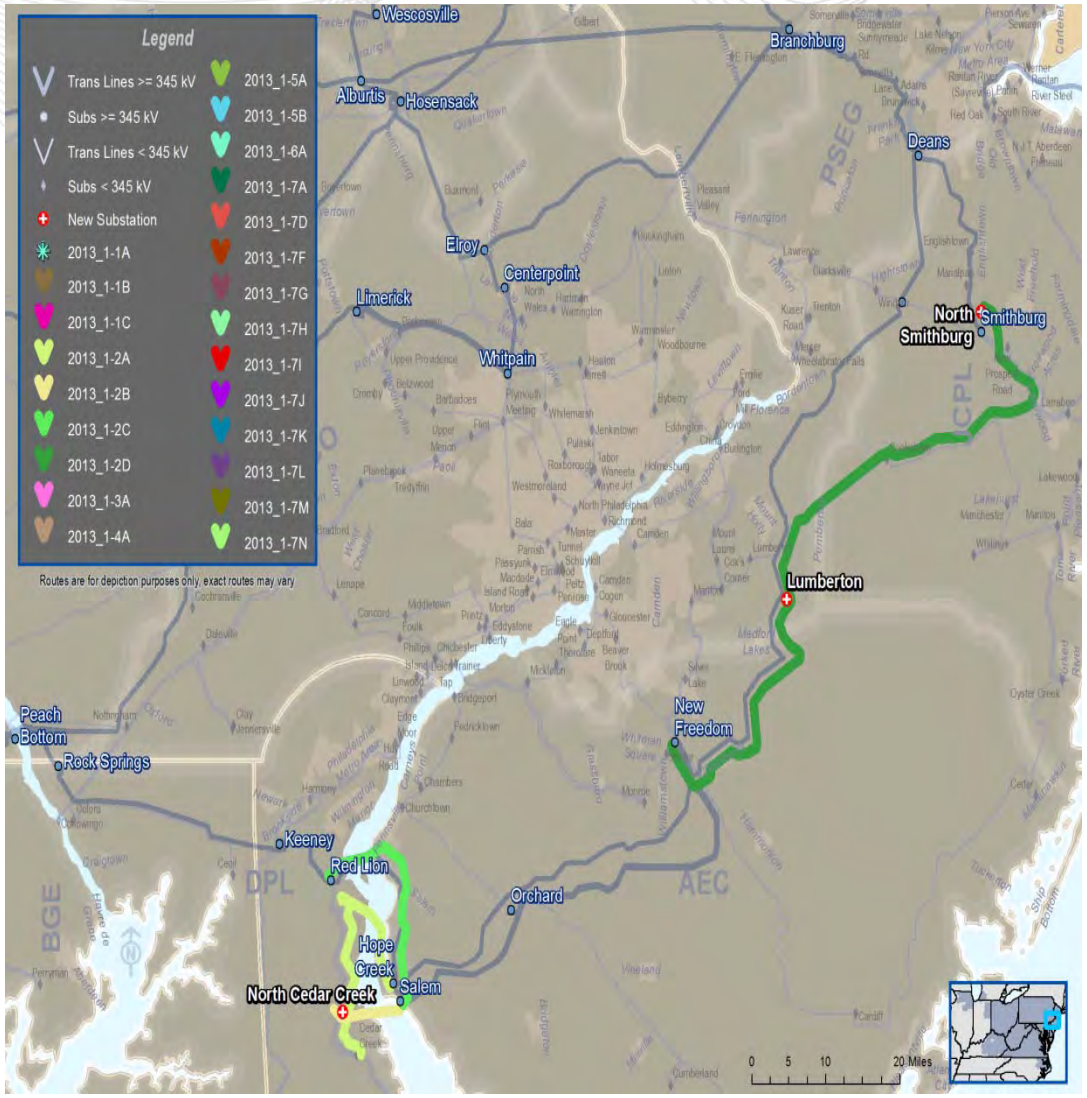
P2013_1-4A

- Install a new Peach Bottom – Keeney – Red Lion – Salem 500 kV line
- Remove existing Keeney - Red Lion 230 kV circuit
- Reconfigure the existing 230 kV line from Hay Road – Red Lion (23020) to terminate at Keeney instead of Red Lion
- Re-conductor the Harmony – Chapel Street 138 kV line
- Cost: $475M



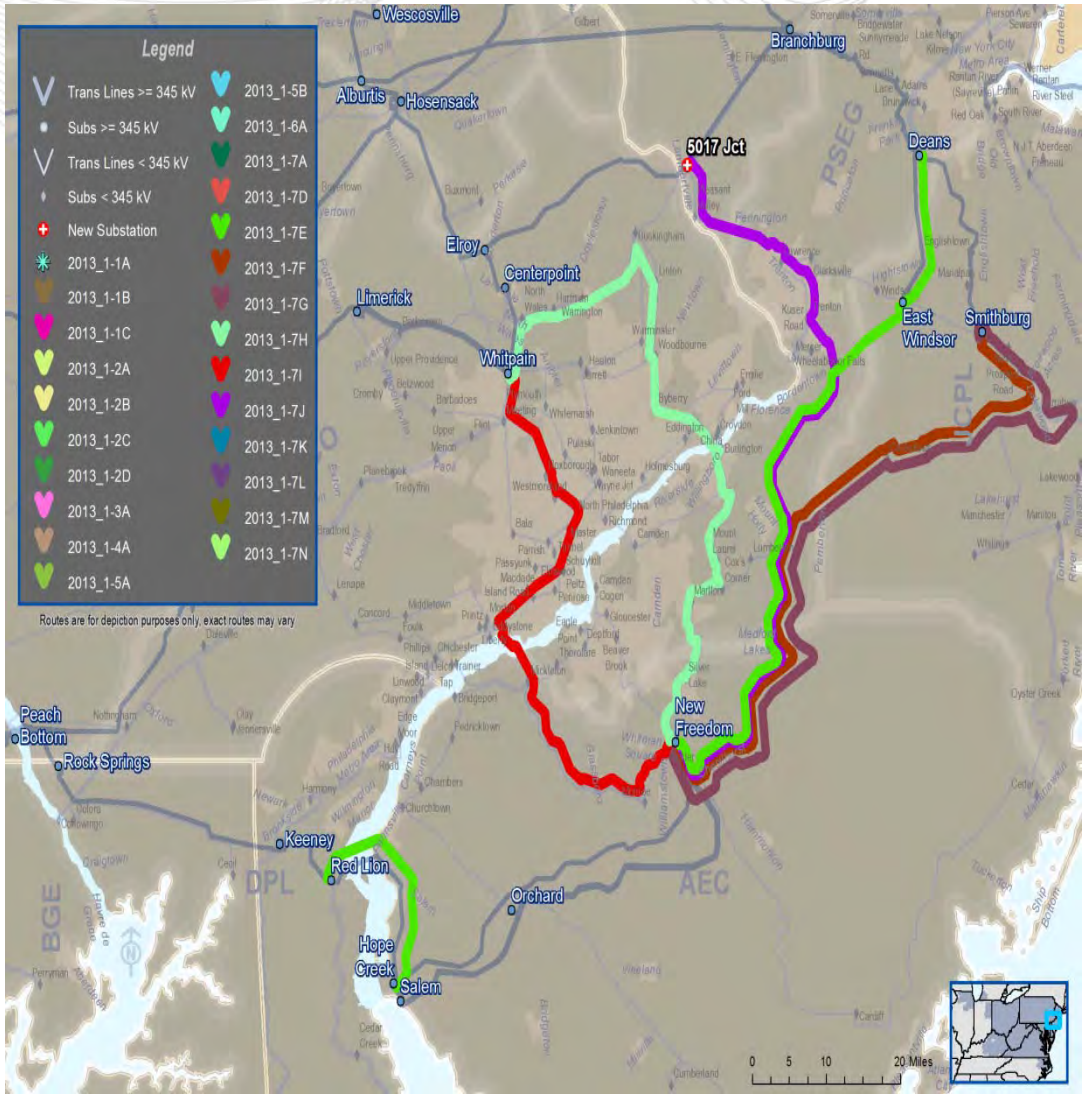
P2013_1-2A,2B,2C,2D

- P2013_1-2A
  - Install a new Salem-Cedar Creek 230 kV line w/ 2 new 500/230 kV XFMR at Salem + Loop Red Lion – Cartanza 230 kV line into Cedar Creek
  - Cost:$213-$269M
- P2013_1-2B
  - Install a new Salem- North Cedar Creek 230 kV line w/ 2 new 500/230 kV Transformer at Salem + Loop Red Lion – Cartanza and Red Lion – Cedar Creek 230 kV lines
  - Cost:$165-$208M
- P2013_1-2C
  - Install a new Salem – Red Lion 500 kV line
  - Cost:$123-$156M
- P2013_1-2D
  - Install a new, New Freedom – Lumberton – North Smithburg (new) 500 Kv line with new 500/230 sub east of Lumberton + New Hope Creek – Salem 500 kV line
  - Cost:$788M-$994M



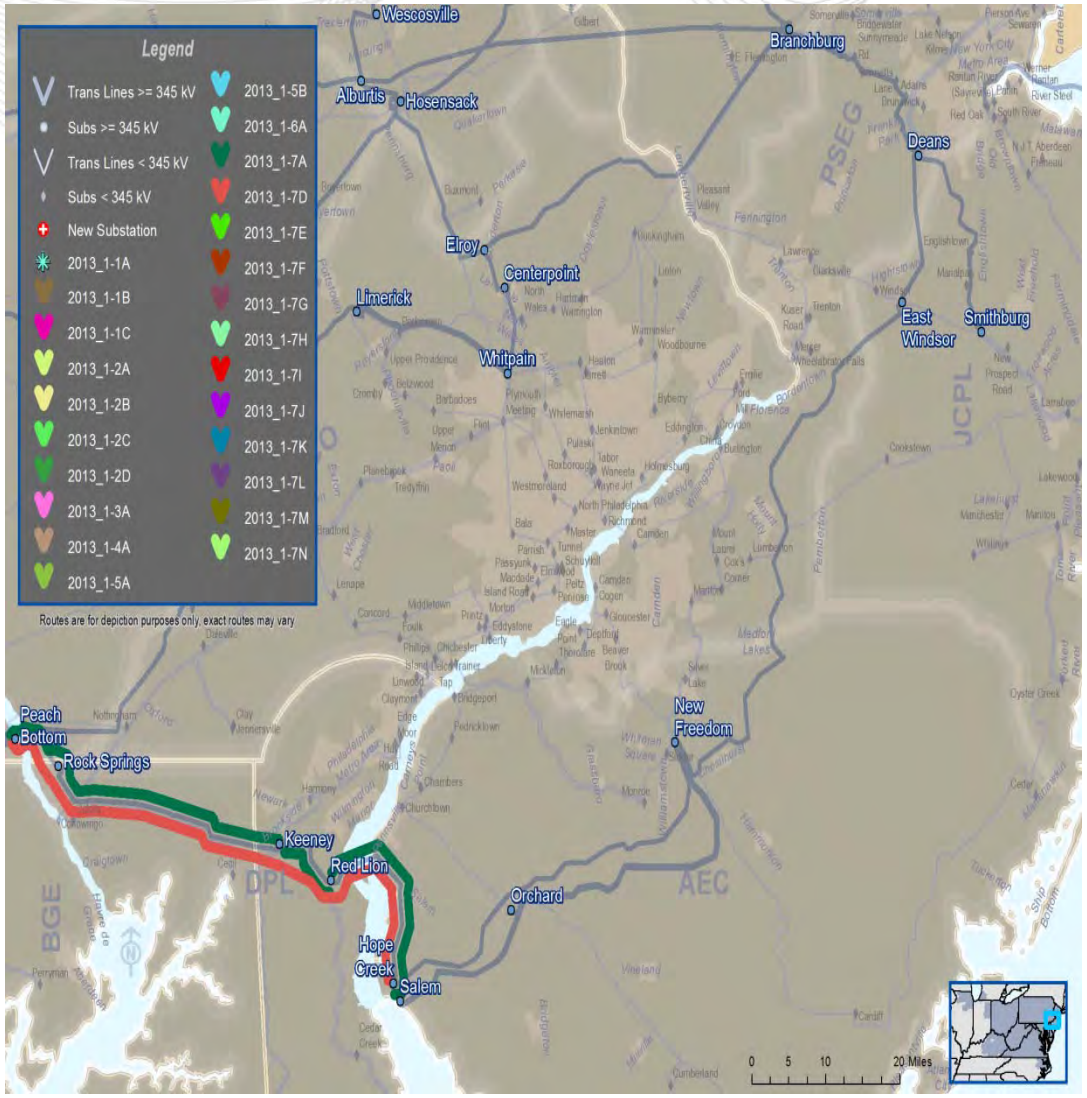
P2013_1-7E,F,G,H,I,J

- P2013_1-7E
  - Install a new New Freedom– Deans 500 kV line
  - Install a new Salem-Hope Creek 500 kV line
  - Cost:$692M
- P2013_1-7F
  - Install a new New Freedom-Smithburg 500 kV line
  - Install a new Salem-Hope Creek 500 kV line
  - Cost:$879M
- P2013_1-7G
  - Install a new New Freedom-Smithburg 500 kV line w/ loop into Larrabee 500 sub
  - Install a new Salem-Hope Creek 500 kV line
  - Cost:$1,034M
- P2013_1-7H
  - Install new New Freedom-Whitpain 500 kV line (Northern Route)
  - Install a new Salem-Hope Creek 500 kV line
  - Cost:$1,177M
- P2013_1-7I
  - Install new New Freedom-Whitpain 500 kV line (Southern Route)
  - Install a new Salem-Hope Creek 500 kV line
  - Cost:$1,353M
- P2013_1-7J
  - Install a new New Freedom-5017 Jct. 500 kV line
  - Install a new Salem-Hope Creek 500 kV line
  - Cost:$915M



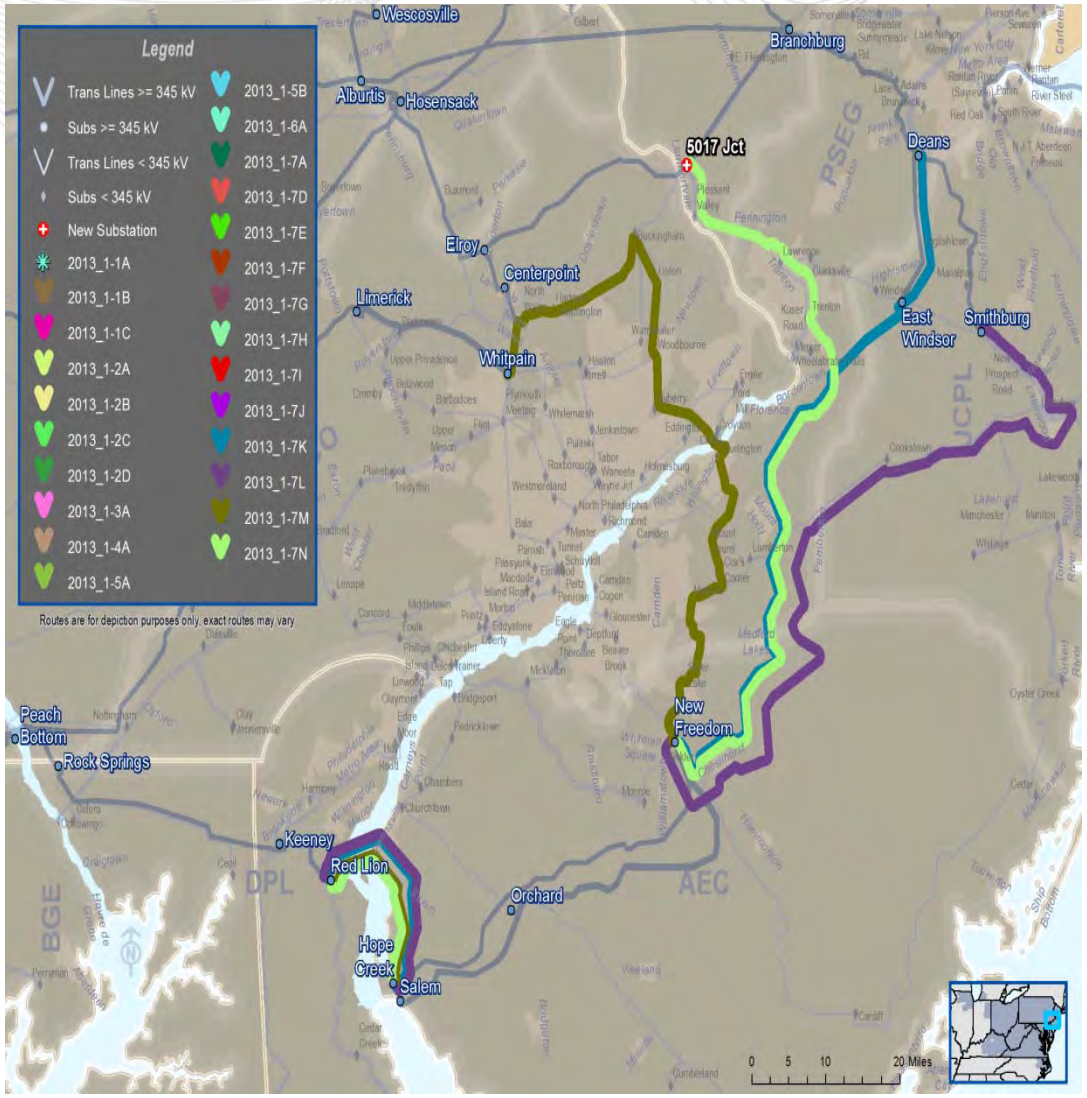
P2013_1-7A,B,C,D

- P2013_1-7A
  - Install a new Salem/Hope Creek-Peach Bottom 500 kV line (Existing ROW)
  - Cost:$1,371M
- P2013_1-7B
  - Install a new Salem/Hope Creek-Peach Bottom 500 kV line (Loop into Keeney)
  - Cost:$1,372M
- P2013_1-7C
  - Install a new Salem/Hope Creek-Peach Bottom 500 kV line (Loop into Red Lion)
  - Cost:$1,372M
- P2013_1-7D
  - Install a new Salem/Hope Creek-Peach Bottom 500 kV line (New ROW)
  - Cost:$1,372M



P2013_1-7K,L,M,N

- P2013_1-7K
  - Install new New Freedom-Deans 500 kV line
  - Install a new Salem-Hope Creek-Red Lion 500 kV line
  - Cost:$1,066M
- P2013_1-7L
  - Install new New Freedom-Smithburg 500 kV line
  - Install a new Salem-Hope Creek-Red Lion 500 kV line
  - Cost:$1,250M
- P2013_1-7M
  - Install new New Freedom-Whitpain North (new) 500 kV line
  - Install a new Salem-Hope Creek-Red Lion 500 kV line
  - Cost:$1,548M
- P2013_1-7N
  - Install new New Freedom-5017 Jct. 500 kV line
  - Install a new Salem-Hope Creek-Red Lion 500 kV line
  - Cost:$1,289M



AI Proposal Evaluation Methodology

- Performance with respect to AI Window scope of work
  - Stability & Voltage
- PJM Evaluation In-Progress
  - Physical Characteristics
  - Commonalities of design
  - Areas of concern
    - Line crossings, river crossings, ability to expand/reconfigure existing stations, required outages
  - Cost Review
- Independent Review

Objectives

1. Generate maximum power (3818 MW total) from all AI Units (Salem1: 1253MW, Salem-2: 1245MW, Hope Creek: 1320MW) without a minimum MVAr requirement from the AI. Full maximum power must be maintained under both the baseline and all N-1 outage conditions of 500kV transmission lines in the AI area. For both the baseline and N-1 outage conditions, AI voltage must be maintained within operating limits and stable for all NERC Category B and C contingencies. NERC Category C3 contingencies "N-1-1 contingencies" do not need to be run on top of the N-1 outage condition.
2. Maximum MW output from AI should not be affected by the simultaneous outage of Power System Stabilizers (PSS) of Artificial Island units Hope Creek and Salem-2. The Salem-1 PSS is assumed to be on for all scenarios.
3. Reduce operational complexity.
4. Improve Artificial Island stability.
5. Maintain PJM System Operating Limits (SOLs)

- Power factor assumptions from M14B

Dispatch

The assumptions used for generation dispatch can be critical to the results. It is generally accepted that units operating at their highest possible power output and generating as little reactive power as necessary to maintain voltages are likely to be less stable. Normally, the units in the vicinity of the project under study will be turned on to their maximum real power output with unity power factor at the high side of the GSU's, or units' VAR output will be adjusted to hold scheduled voltages, depending on specific Transmission Owner criteria. Wind turbines are tested at light load for stability and peak load for low voltage ride through at 100% of their maximum energy value. In addition, stability test scenarios necessitated by any applicable Transmission Owner operating guides will also factor into each analysis.

Margins:

The margins applied by PJM are intended to be applied in impact study stability analysis that uses a project's final stability study data as further discussed below. As such, these margins account primarily for uncertainty in actual clearing times, and the final data represents the "as built" performance. With the machine modeled at net unity power factor at the high-side of the GSU (or unity power factor at the generator terminals for wind turbine installations), transient stability must be maintained for tested faults when the following margins are included:

a. Add 0.25 cycles to the nominal primary clearing time for 3 phase, normally cleared faults.

b. Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 0.5 cycles added to the nominal backup clearing time for stuck breaker (.75 cycle total clearing time margin).

c. Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 1.25 cycles to the nominal Zone 2 clearing time for failure of primary relaying (1.5 cycle total clearing time margin).

Monitoring requirements:

Rotor angle, Real power output, EFD, speed and terminal voltage of units under study are monitored. Bus Voltages in the same area are also monitored.

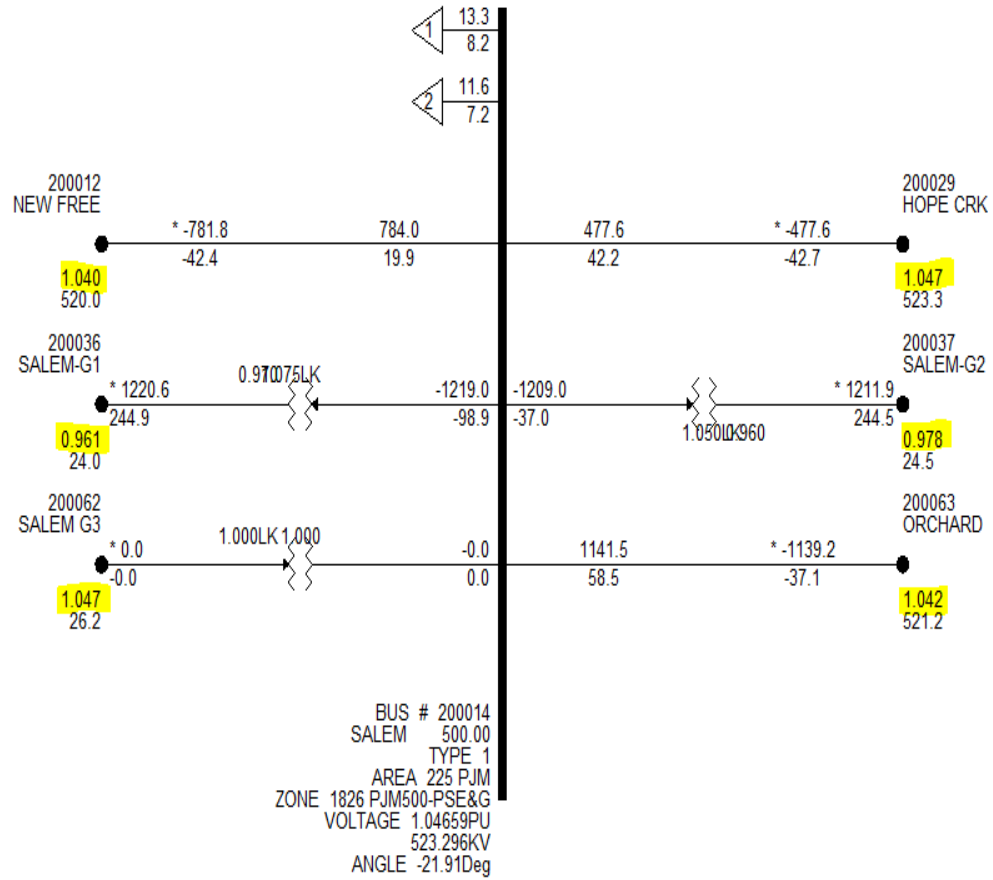
Acceptable Voltage Drop:

Following the disturbance, the voltages of the monitored buses maintain voltages within ±5% of the precontingency voltages

Acceptable Damping:

Dynamics Case Provided

- Defaulted AI units to 265 MVAR each (795 total)
  - Where 265 MVAR is the minimum MVAR in the current AIOG for no outages
- AI Voltages around 1.05 p.u.



Bus Number	Bus Name	Id	Code	VSched (pu)	Remote Bus	In Service	Pgen (MW)	Pmax (MW)	Pmin (MW)	Qgen (Mvar)	Qmax (Mvar)	Qmin (Mvar)
200036	SALEM-G1 25.000	1	-2	1.0000	0	☑	1253.0000	1253.0000	1253.0000	265.0000	265.0000	265.0000
200037	SALEM-G2 25.000	1	-2	1.0000	0	☑	1245.0000	1245.0000	1245.0000	265.0000	265.0000	265.0000
200039	HOPE CG1 25.000	1	-2	1.0000	0	☑	1320.0000	1320.0000	1320.0000	265.0000	265.0000	265.0000

Initial Approach

1. Evaluation of cases at 795 MVAR (1.05 p.u.)
   - This is what most sponsors evaluated against and declared success
2. PJM Baseline Criteria (Projects exactly as proposed)
   - Unity Power Factor = 1.0 p.u. on the high side of the GSU
   - Voltages < 1.05
   - See criteria on next slide
3. PJM Baseline Criteria (Projects modified by PJM)
   - Obvious enhancements
     - Not expected to significantly impact cost, scope, schedule, etc.

1. Evaluation of Cases at 795 MVAR

- Result:
  - Screened performance for critical conditions
  - Compared results with the results provided by the sponsoring entities
  - Observed generally good performance for most proposals

2. PJM Baseline Criteria (Projects exactly as proposed)

- Criteria:
  - Consistent with PJM baseline criteria where no operating guide exists
- Result:
  - Identified issues with most of the proposals

3. PJM Baseline Criteria (Projects modified by PJM)

- Criteria: Same as #2 but PJM made simple modifications
- Result:
  - Analysis is in-progress
  - Several have been completed with improved performance

Artificial Island Next Steps

- Additional analytical studies
  - Thermal studies
  - Voltage studies
  - Short Circuit studies
- Independent feasibility analysis

Lessons Learned

- Coordination with Pre-Qualification Process
  - Pre-Qualification Submittal
    - Review and follow-up with developers
    - Transparency issues
      - Redacted versions of submittals
      - Posting of pre-qualification packages
  - CEII & NDA Requirements

Pre-Qualification for Designated Entity Status

PJM - Pre-Qualification fo

www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/pre-qualification.aspx

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  - Stakeholder Process
  - Expansion Planning Process
    - FERC Order 1000 Implementation
    - Attachment BB
    - Attachment EE
    - Attachment FF
    - Attachment N
    - Attachment S
    - Attachment Y
    - Feasibility Study Data
    - Generator As Is Study

Home > Planning > RTEP Development > Expansion Planning Process > FERC Order 1000 Implementation > Pre-Qualification for Designated Entity Status

Pre-Qualification for Designated Entity Status

Entities that desire to participate in the proposal window process and be the designated entity for transmission projects must submit a pre-qualification package to the Office of the Interconnection during the pre-qualification window. Upon receiving the package, PJM will acknowledge receipt and assign the submittal a unique identifier for tracking purposes.

Companies will be evaluated based upon their ability to engineer, develop, construct, operate and maintain a generic transmission facility within PJM. If the filing company does not have experience in a specific area, PJM will request that the company provide a detailed plan for leveraging the experience of their affiliates and contractors.

- View the Pre-Qualification Evaluation Criteria (PDF)

Pre-qualification packages will be posted on PJM.com after a final determination has been made. A company may provide a redacted version for posting.

Please note that PJM retains the right to request any additional information deemed necessary. If PJM makes such a request, the submitting company will have 30 days to provide the additional information.

Once a company is pre-qualified they must submit any changes in their package to PJM. A company does not need to be pre-qualified on an annual basis.

Please email all questions and pre-qualification packages to O1kPreQualInfo@pjm.com. The PJM Amended and Restated Operating Agreement in Section 1.5.8(a) (FERC acceptance pending) states that the following information must be provided in all pre-qualification packages:

RELATED INFORMATION

- Manuals
- Compliance
- Transmission Expansion Advisory Committee
- Regional Planning Process Task Force
- 2012 Regional Transmission Expansion Plan Report

CONTACT INFORMATION

Need help finding information? Send us a question.

Live chat

For additional information, please contact Member Relations at (610) 666-8980 or toll free at (866) 400-8980.

Website Feedback

Pre-Window Information Flow

- Development and benchmarking of critical system condition case
  - Cases will be available in PSS/E v32.1.1 (*.sav format)
  - Power flow case and dynamics data file
  - Other environment files (.snp, .dll and .rsp)
- Problem Statement Parameters
  - System voltage limits
  - Stability
  - Minimize / eliminate the Artificial Island Operating Guide

Window Proposal Requirements Documentation

PJM RTEP – Artificial Island Area Proposal Window
Problem Statement & Requirements Document

PJM Interconnection

Original Document: April 29, 2013

Version 14.0

Revised: May 16, 2013

Email: RTEP@pjm.com with any questions or clarifications and include a reference to Artificial Island Window

REQUEST FOR PROPOSAL - Improve Artificial Island Area System Performance

I. Purpose of Proposal

PJM seeks technical solution alternatives (hereinafter referred to as "Proposals") to improve PJM Operational Performance in the Artificial Island area under a range of anticipated system conditions and to eliminate potential planning criteria (PJM, NERC, RFC, and Local Transmission Owner criteria) violations in the Artificial Island area.

II. Terminology

Artificial Island Area = "AI"
The system consisting of the transmission and generation facilities as depicted in Figure 1- Artificial Island 500 kV network. The Artificial Island includes the Salem #1, Salem #2, and Hope Creek #1 nuclear generation facilities

System Operating Limit = "SOL"
A System Operating Limit (SOL) is defined as:
The value (such as MW, MVAr, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Thermal Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings or Limits (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings or Limits (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Ratings or Limits (Applicable pre- and post-Contingency Voltage Limits)

Critical Contingency:
The most limiting (i.e. the "worst") contingency.

III. Scope of Work

Objectives

General Communication

- General Communication
  - PJM.com
    - http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000.aspx
  - Currently all communication through email to RTEP@pjm.com
  - FAQ page on web site
- Participant Communication
  - Need for CEII and NDA for access to information
  - Announcements
    - Opening of the window
    - Changes to models, assumptions, etc.

PJM.com Coordination and Information Exchange

PJM - FERC Order 1000 Im

www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000.aspx

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    - Attachment Y
    - Feasibility Study Data

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FERC Order 1000 Implementation

The Federal Energy Regulatory Commission (FERC) issued Order 1000 on July 21, 2011. The order requires that PJM consider transmission alternatives in its regional transmission planning processes, produce a regional transmission plan and implement a fair cost allocation methodology. The complete text of the order and related documents are available on the commission's website.

Considering Transmission Alternatives

PJM's compliance filing on Oct. 25, 2012, built on the existing Regional Transmission Expansion Plan (RTEP) process, already compliant with Order 1000 in most respects. The filing contained several key enhancements, including those needed to consider alternative upgrade solution proposals. Links to PJM's implementation resources are provided below. PJM's compliance filing (currently pending before the FERC) is also available (PDF).

- View the Pre-qualification for designated entity status page.
- View the RTEP Proposal Windows.
- View the Detailed Constructability Information Template (PDF).

RTEP Upgrade Cost Allocation

On Oct. 11, 2012, PJM transmission owners, acting through the Transmission Owners Agreement, submitted revisions to Schedule 12 of the PJM Open Access Transmission Tariff that reform existing RTEP upgrade cost allocation provisions. The proposal implements a hybrid cost allocation model in which half the cost of 500 kV and higher transmission lines would be collected from all system users while the other half would be assigned to specific project beneficiaries. The transmission owners' filing (currently pending before the FERC) is available (PDF).

RELATED INFORMATION

- Manuals
- Compliance
- Transmission Expansion Advisory Committee
- Regional Planning Process Task Force
- 2012 Regional Transmission Expansion Plan Report

CONTACT INFORMATION

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Live chat

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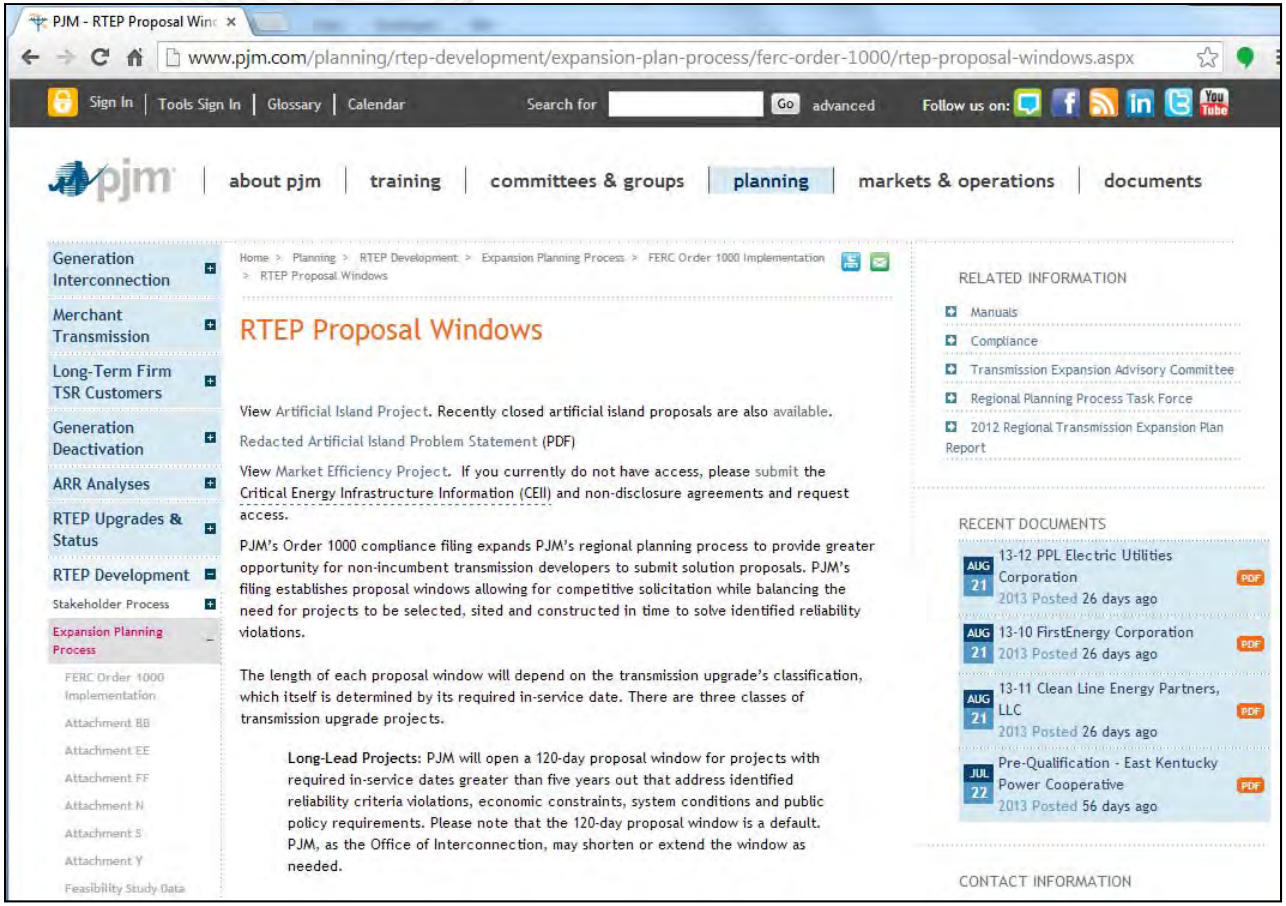
Website Feedback

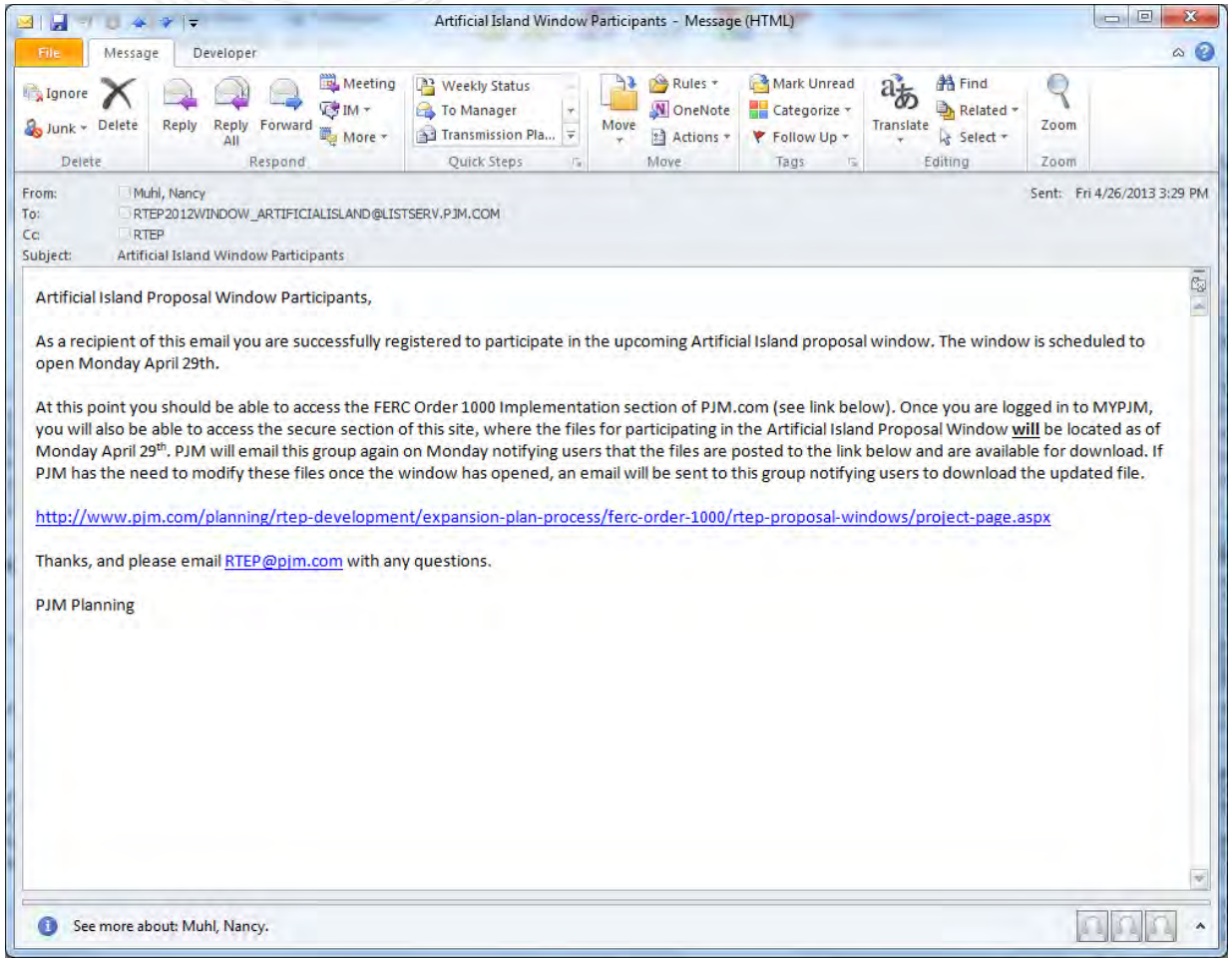
Window Information Coordination

- All announcements are posted to PJM.com and to the PJM stakeholder groups
- All CEII secured



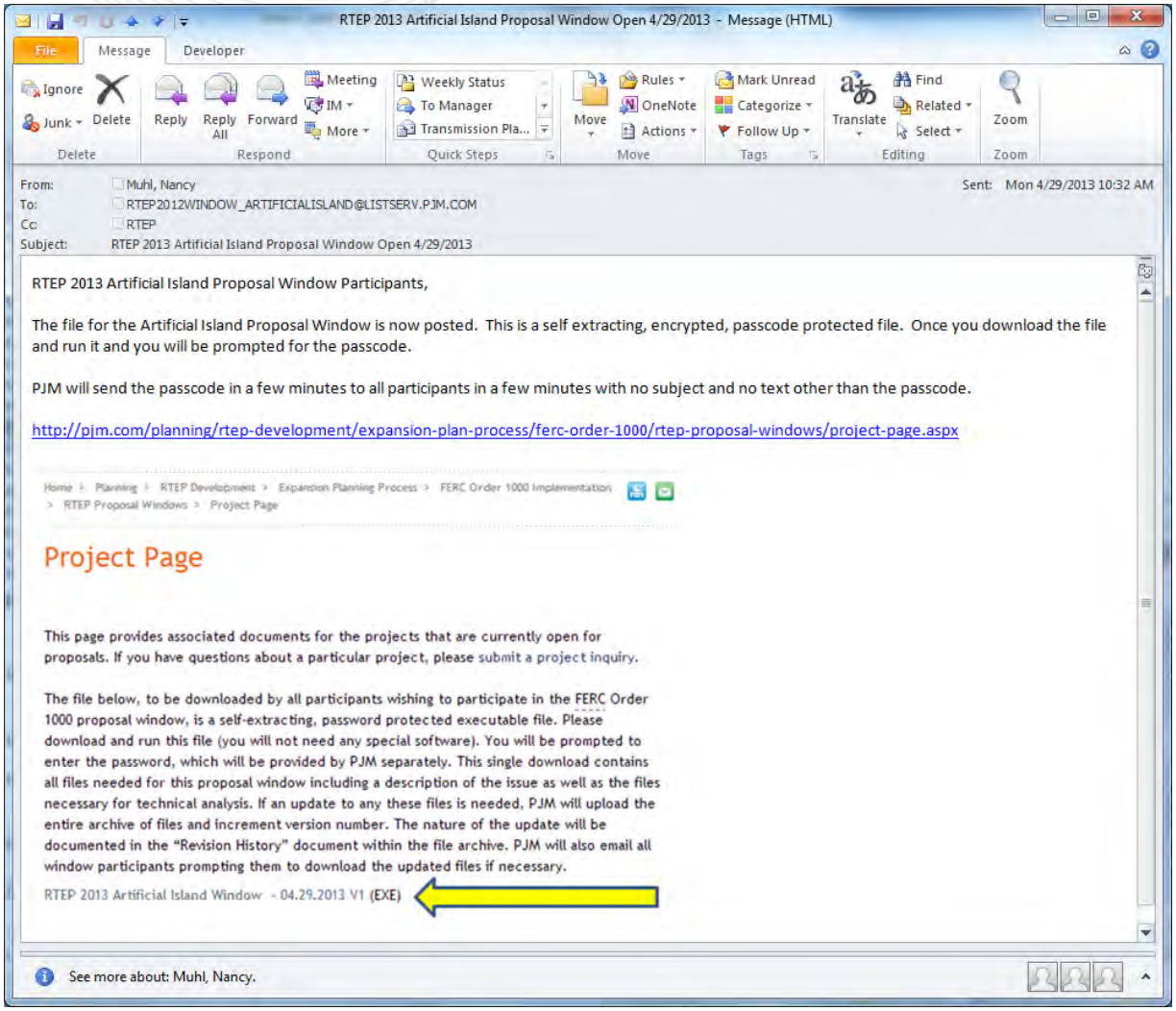
Communication Prior to Window Opening

- Encourage anticipated participants to complete necessary CEII and Non Disclosure Agreement (NDA) documentation



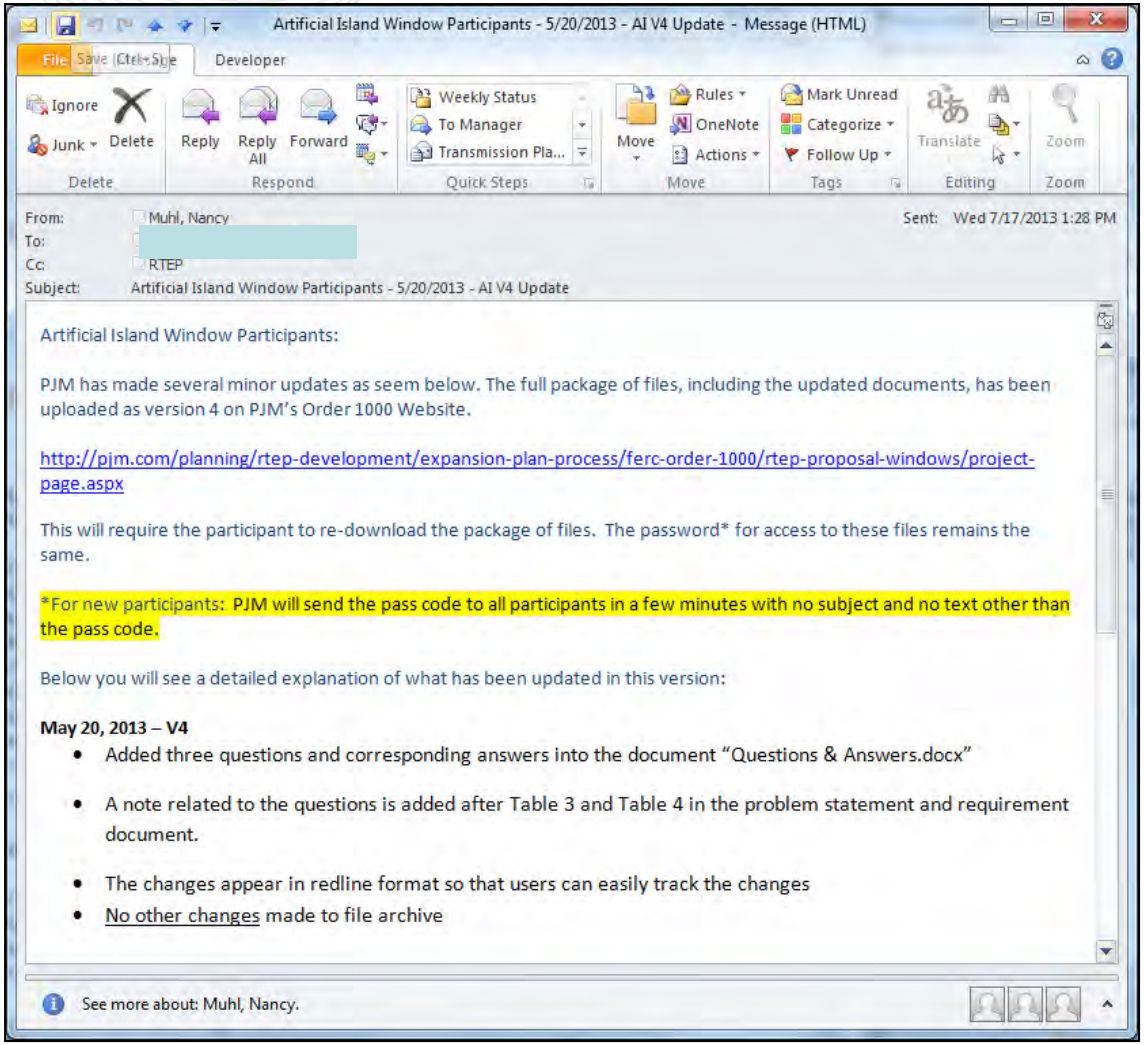
Opening of Window Announcement

- All participants notified at the same time
- All files and information posted securely to PJM.com



Updates During Window

- All updates posted to all participants at the same time
- Changes noted in revision histories and VIA email



Artificial Island Window Participants - 5/20/2013 - AI V4 Update - Message (HTML)

From: Muhl, Nancy
Sent: Wed 7/17/2013 1:28 PM
To:
Cc: RTEP
Subject: Artificial Island Window Participants - 5/20/2013 - AI V4 Update

Artificial Island Window Participants:

PJM has made several minor updates as seem below. The full package of files, including the updated documents, has been uploaded as version 4 on PJM's Order 1000 Website.

http://pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows/project-page.aspx

This will require the participant to re-download the package of files. The password* for access to these files remains the same.

*For new participants: PJM will send the pass code to all participants in a few minutes with no subject and no text other than the pass code.

Below you will see a detailed explanation of what has been updated in this version:

May 20, 2013 – V4

- Added three questions and corresponding answers into the document "Questions & Answers.docx"
- A note related to the questions is added after Table 3 and Table 4 in the problem statement and requirement document.
- The changes appear in redline format so that users can easily track the changes
- No other changes made to file archive

Artificial Island Window – Security

- Security
  - All CEII will be encrypted using PGP encryption
  - CEII will be distributed using a self extracting (*.exe) encrypted file
    - From a user perspective, this is similar to the familiar self extracting ZIP file, but the user will be asked for a security code.
      - E.g. PJM posts the files to the secure Artificial Island window section of PJM.com. Users download “Artificial Island Information (CEII).exe” to their local environment
      - Once downloaded, the user will be prompted for a security code
    - Security codes, per PJM Policy, are required to be distributed through a contextless email message.
      - E.g. PJM distributes the security code that will be used to access the CEII by the Artificial Island Window participants in the “Artificial Island Information (CEII).exe” file.

Communications Yet to Come

- Project Evaluation Process
  - Material reviewed through TEAC
- Developer Selection Process
  - Selection reviewed through TEAC
  - Development and filing of Designated Entity Agreement

Questions

SPP Southwest Power Pool Regional Entity

HELPING OUR MEMBERS AND REGISTERED ENTITIES KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE

FOR IMMEDIATE RELEASE
Tom Kleckner, SPP Communications
501.607.3153
tkleckner@spp.org

SPP Order 1000 compliance filing proposes open competitive transmission project process

NOVEMBER 14, 2012 – LITTLE ROCK, AR. Southwest Power Pool, Inc. ("SPP") submitted Tuesday its filing to comply with the regional requirements of Order 1000 to the Federal Energy Regulatory Commission ("FERC"). In its compliance filing, SPP proposes a competitive solicitation model that promotes open competition for 300kV (kilovolts) transmission projects and above.

The filing proposes to maintain SPP's Highway/Byway cost allocation methodology as well as SPP's Integrated Transmission Planning (ITP) process approved by FERC just two years ago. The Highway/Byway cost allocation methodology and the ITP process were developed and approved by SPP's stakeholders and SPP's Regional State Committee (RSC), comprising state retail regulators in SPP's footprint. When the ITP process and the Highway/Byway methodology were approved, FERC heralded both as positive and innovative steps toward the construction of transmission in the SPP region.

SPP describes in its compliance filing how the proposed competitive solicitation process was developed over dozens of stakeholder meetings during the last year and has the support of its members. The filing also includes a letter from the RSC demonstrating its unanimous support for the compliance filing's cost-allocation aspects.

SPP's Senior Vice President of Regulatory Policy and General Counsel, Paul Suskie, expressed gratitude and appreciation to SPP's stakeholders – including the RSC – for their careful work in developing this filing. "For more than a year, SPP's stakeholders have diligently worked to develop a competitive model for new transmission projects with the removal of a federal right of first refusal in the SPP footprint in accordance with FERC's policy contained in Order 1000", Suskie said. "As a result of this diligent work, SPP's tariff revisions were approved unanimously by all stakeholder groups involved in the process."

SPP was a founding member of the North American Electric Reliability Corporation in 1968, and was designated by the Federal Energy Regulatory Commission (FERC) as a Regional Transmission Organization (RTO) in 2004 and a Regional Entity (RE) in 2007. SPP interacts with FERC and the Environmental Protection Agency around the issues of regulations and reliability of the bulk electrical systems. Additionally, SPP's Regional Statement Committee, which is a central part of an overall governance structure, is comprised of the state regulators in its footprint.

Founded in 1941, SPP is a group of 68 members in Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas that serve more than 15 million customers. Membership is comprised of investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, wholesale generators, power marketers, and independent transmission companies. SPP's footprint includes 48,930 miles of transmission lines and 370,000 square miles of service territory. As an RTO, SPP ensures reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. The SPP RE oversees compliance enforcement and reliability standards development. Learn more about SPP by visiting our Newsroom.

News Release
January 16, 2012

Tweet 0

Nearly $8.7 billion in transmission projects planned in next five years

More than $870 million in transmission improvements completed last year

Jan. 16, 2012, AUSTIN – Nearly $8.7 billion in transmission improvements are planned in the next five years, according to the annual transmission report from the Electric Reliability Council of Texas, (ERCOT), the state grid operator and manager of the wholesale electric market.

The planned projects are expected to improve or add nearly 7,000 circuit miles of transmission lines and more than 17,000 megavolt amperes (MVA) of autotransformer capacity to the grid, including the Competitive Renewable Energy Zones (CREZ) transmission additions that are scheduled to be in service by 2013.

The 2011 Electric System Constraints and Needs Report, filed Friday with the Public Utility Commission, identifies existing and potential constraints in the transmission systems that pose reliability concerns or may increase costs to the electric power market and Texas consumers.

Since 2010, ERCOT transmission providers have completed construction and improvements to approximately 966 miles of transmission and more than 5,000 MVA of autotransformer capacity, at an estimated capital cost of $870 million. The largest project completed last year was a 173-circuit-mile 345 kilovolt (kV) line in South Central Texas, the Zorn/Clear Springs – Gilleland Creek – Hutto Switch.

TRANSMISSION PLANNING PROCESS

As the transmission planning coordinator for the region, ERCOT works with the region's transmission and distribution providers and other stakeholders to identify the need for new transmission facilities based on engineering analysis of operational results, load forecasting, generation interconnections, and transmission and system studies. As part of the planning process, ERCOT seeks input from all market participants and stakeholders about options and possible solutions through the ERCOT-led Regional Planning Group. Major projects must be also endorsed by the ERCOT Board of Directors.

TRANSMISSION COSTS

In the ERCOT region, the cost for transmission construction and upgrades is rolled into costs that all ratepayers pay – also known as a "postage-stamp transmission rate" because it is the same access fee regardless of location. Transmission and distribution providers must offer access to their wires to all electric providers on a non-discriminatory basis. The Public Utility Commission regulates transmission and distribution providers and approves the rates they are allowed to charge for the delivery of power to retail customers.

ERCOT TRANSMISSION SNAPSHOT

- 40,530 miles of high-voltage transmission, including:
  - 9,249 miles of 345 kV
  - 19,565 miles of 138 kV
  - 11,715 miles of 69 kV
- $8.7 billion under development in five-year plan, including approximately $5 billion to support 18,000 MW of renewable generation
- More than 8,500 circuit miles of transmission improvements since 1999
- Approximately $6.6 billion in transmission improvements added since 1999

ON LINE

ERCOT 2011 Electric System Constraints and Needs
ERCOT 2010 Electric System Constraints and Needs

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 24 million Texas customers -- representing 85 percent of the state's electric load. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects 40,500 miles of transmission lines and more than 550 generation units. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for 6.7 million premises in competitive choice areas. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT's members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities (transmission and distribution providers), and municipal-owned electric utilities.

Contact

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rsearcy@ercot.com

Panhandle Renewable Energy Zone (PREZ) Study
Preliminary Results

Shun-Hsien (Fred) Huang
ERCOT System Planning

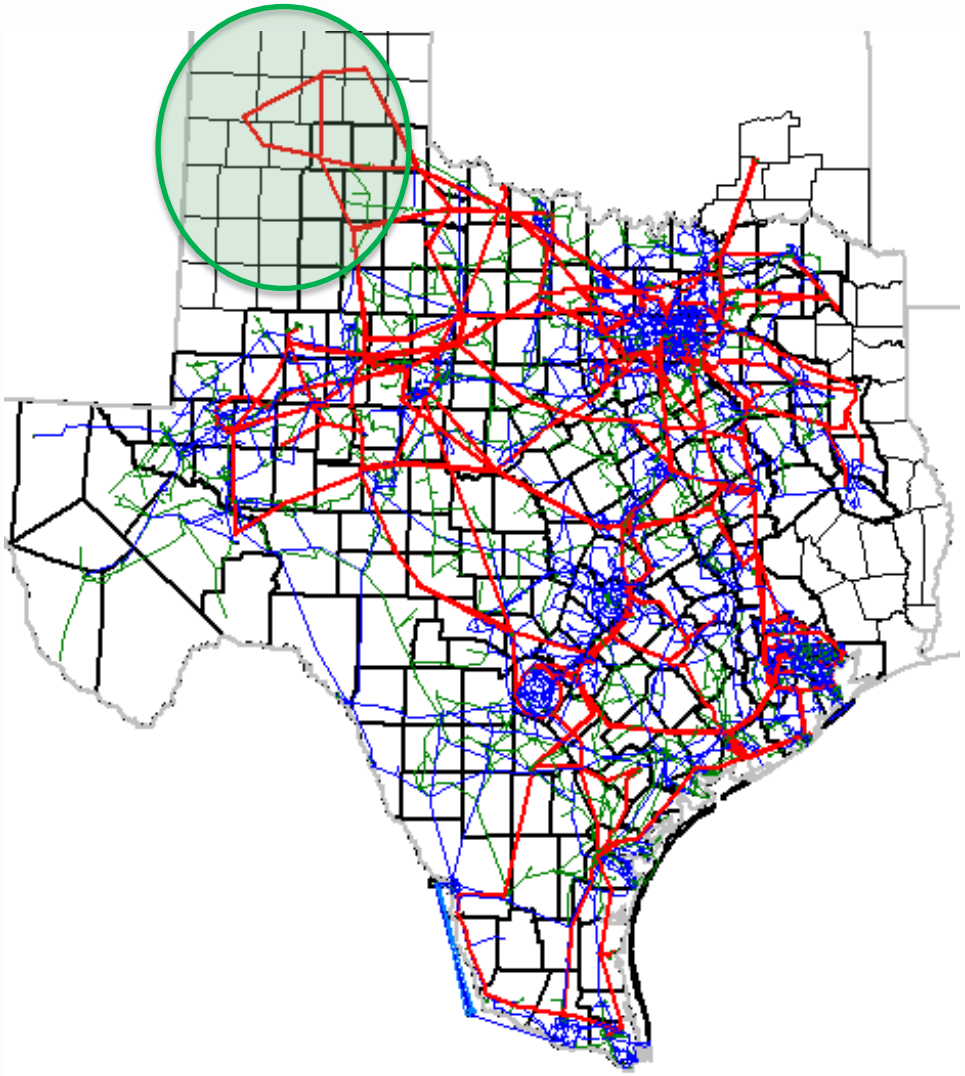
ERCOT Regional Planning Group (RPG) Meeting
12-17-2013

Outlines

- CREZ Implementation in Panhandle
- PREZ Needs and Study Objective
- Preliminary Results and Key Findings
- Summary and Conclusion
- Future Work

CREZ Implementation in Panhandle

- Original CREZ plan called for ~5.5 GW of capacity in Panhandle, but reactive support equipment initially installed for ~2.4 GW
- Panhandle transmission remote from ERCOT load and synchronous generation
- Stability constrained
  - Most of the activity is at the edge of the Panhandle system which exacerbates the stability constraints



Standard Generation Interconnection Agreements in Panhandle (12/12/2013)

GINR	ProjectName	County	IA Capacity (MW)	FC Capacity (MW)	IA Signed Date	Projected COD
13INR0048	Spinning Spur Wind Two	Oldham	161	161	2/27/2013	6/1/2014
14INR0012a	Miami Wind 1 Project	Gray	289	289	3/1/2013	7/31/2014
14INR0030a2	Panhandle Wind	Carson	218	218	12/19/2012	8/1/2014
11INR0050	Moore Wind 1	Crosby	149	0	7/12/2012	8/8/2014
14INR0030b	Panhandle Wind (Ph2)	Carson	198	0	10/2/2013	9/1/2014
13INR0059a	Hereford Wind	Castro	200	200	6/10/2013	9/4/2014
13INR0010a	Mariah Wind	Parmer	200	0	1/31/2013	10/30/2014
13INR0005	Conway Windfarm	Carson	600	600	10/24/2012	12/1/2014
14INR0023	Longhorn Energy Center	Briscoe	361	0	12/10/2012	12/1/2014
14INR0032a	Route66 Wind	Randall	150	0	10/31/2013	12/1/2014
13INR0059b	Hereford Wind	Castro	300	0	6/10/2013	4/15/2015
14INR0012b	Miami Wind 1 Project	Gray	112	0	3/1/2013	8/15/2015
13INR0010b	Mariah Wind	Parmer	200	0	1/31/2013	12/31/2015
13INR0010c	Mariah Wind	Parmer	200	0	1/31/2013	12/31/2016
12INR0029	Comanche Run Wind	Swisher	500	0	7/24/2013	12/31/2016
12INR0018	Pampa Wind Project	Gray	500	0	11/12/2013	3/31/2017
			4,338	1,468		

IA: Interconnection Agreement
FC: Financial Commitment
COD: Commercial Operating Day

Needs of PREZ Study

- 2012 Long Term System Assessment
  - Significant expansion of wind resources in the Panhandle under a range of future outcomes.
  - If the northwestern-most portion of the Panhandle CREZ system becomes over-subscribed, voltage stability limits will constrain wind power delivery to the rest of the ERCOT system.

- Generation projects will exceed the CREZ design capacity for the Panhandle area (based on the CREZ Reactive Study "Initial Build" recommendations).

- No near-term Panhandle transmission projects being developed post CREZ 2013.

Purpose of PREZ Study

- To identify system constraints and upgrades to accommodate future wind generation projects.

- To provide a project roadmap for both ERCOT and TSPs to accommodate additional generation resources in the study area.
  - List of potential system upgrade projects.
  - Triggers for when those projects will be recommended.

Disclaimer

- PREZ study focuses on the upgrade needs to increase Panhandle export capability. Other ERCOT regions may require further studies for potential thermal and stability challenges.
- The identified upgrades may be revised based on the actual implementation of wind projects in Panhandle.
- The upgrades identified in this study are “NOT” approved projects. The identified projects may still require RPG review.

Study Process

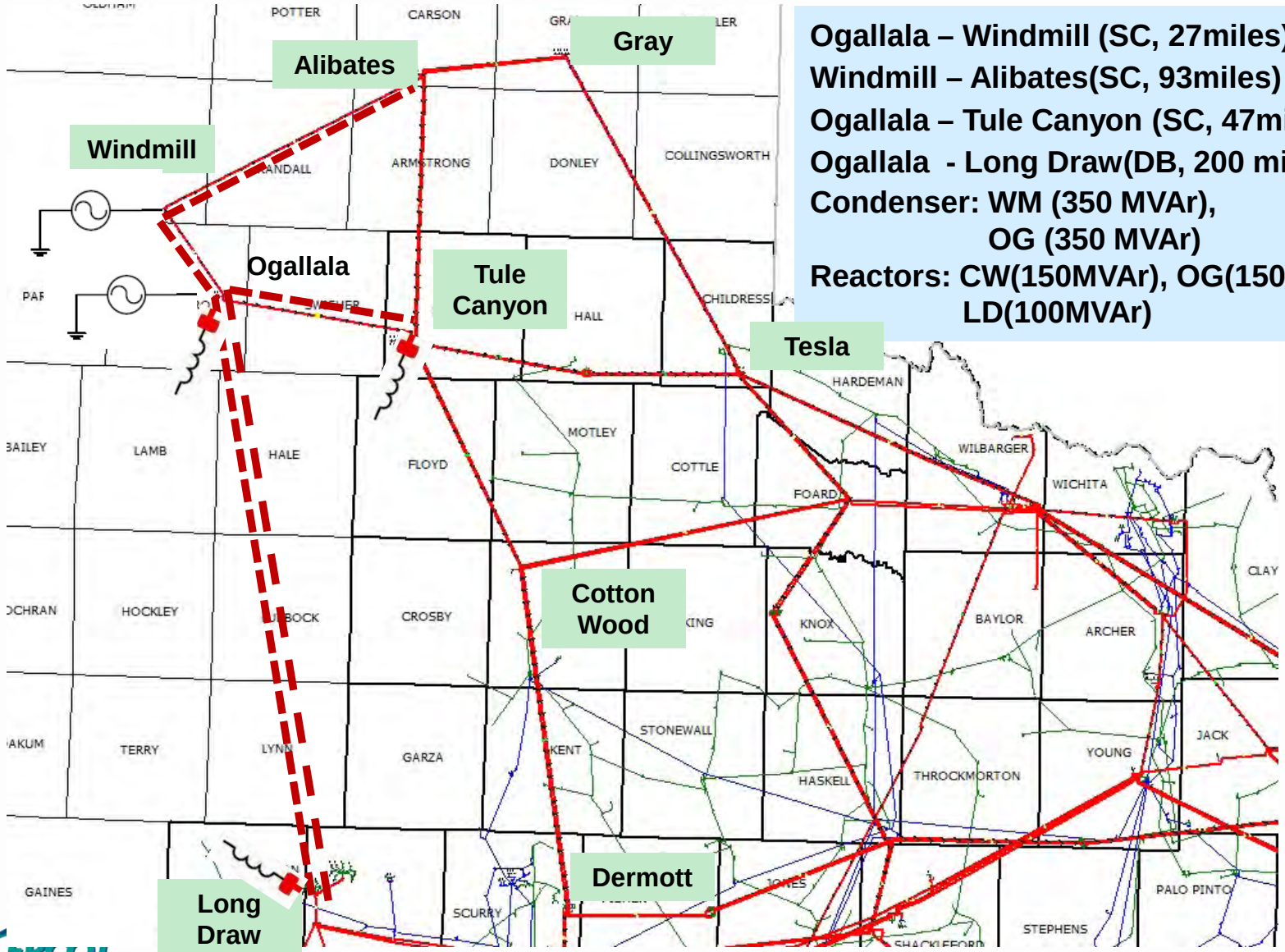
- Study Base Case
  - Reliability Analysis: 2016 HWLL DWG (8,946 MW wind output / 36.5 GW load, 24.5% wind penetration)
  - Economic Cost Analysis: 2017 UPLAN case from 2012 Five-Year Transmission Plan

- Study Tasks
  - Scenario 1:
    - Add 5,043 MW of Panhandle wind at 95% output
    - Wind penetration: ~35% (13.7GW wind output)
  - Scenario 2:
    - Add 7,845 MW of Panhandle wind at 95% output
    - Wind penetration: ~45% (16.4GW wind output)
  - Roadmap and triggering point for upgrades

Study Progress

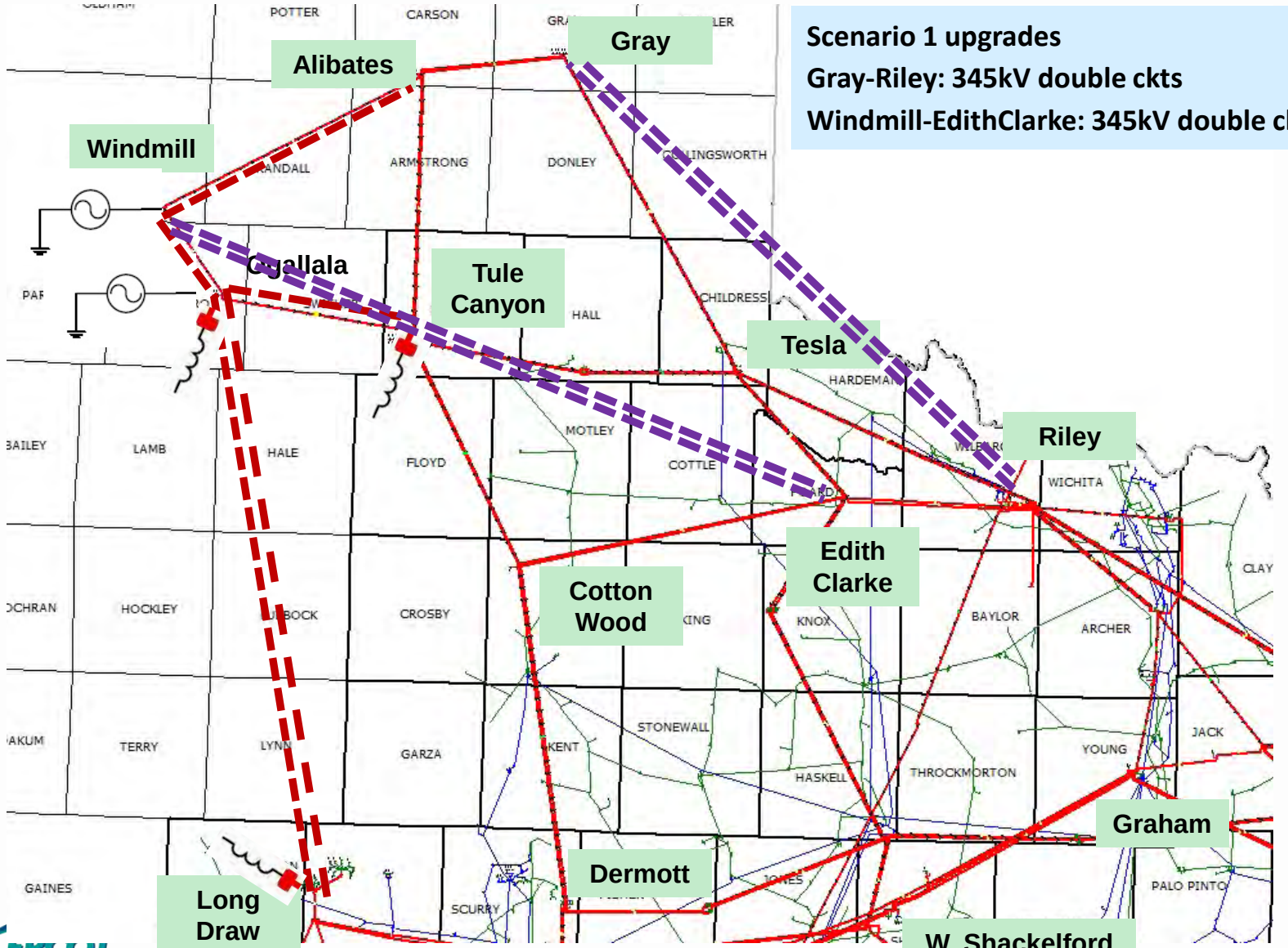
Mar-13	Present PREZ study scope in RPG
May-13	Complete Steady State Voltage Stability Analysis
	Complete Dynamic Flat Start Cases
Jun-13	Complete Scenario 1 (5GW Wind Gen in Panhandle)
	Identify High Voltage Ride Through (HVRT) Needs
Aug-13	Propose HVRT requirement (NOGRR 124)
	Complete Scenario 2 (7.5GW Wind Gen in Panhandle) and observe system constraint in other ERCOT region
Oct-13	Complete Roadmap Upgrade 1 (Panhandle export limit: 3.5 GW)
	Propose SCR criteria and identification for system strength enhancement
Nov-13	RPG synchronous condenser presentation (3 vendors and 1 utility)
	Complete Roadmap Upgrade 2 (Panhandle export limit: 5.2 GW)
Dec-13	Complete PREZ study
Jan-14	Complete PREZ report

Scenario 1: System Upgrade Option



Ogallala – Windmill (SC, 27miles)
Windmill – Alibates(SC, 93miles)
Ogallala – Tule Canyon (SC, 47miles)
Ogallala - Long Draw(DB, 200 miles)
Condenser: WM (350 MVAr),
OG (350 MVAr)
Reactors: CW(150MVAr), OG(150MVAr),
LD(100MVAr)

Scenario 2: System Upgrade Option A

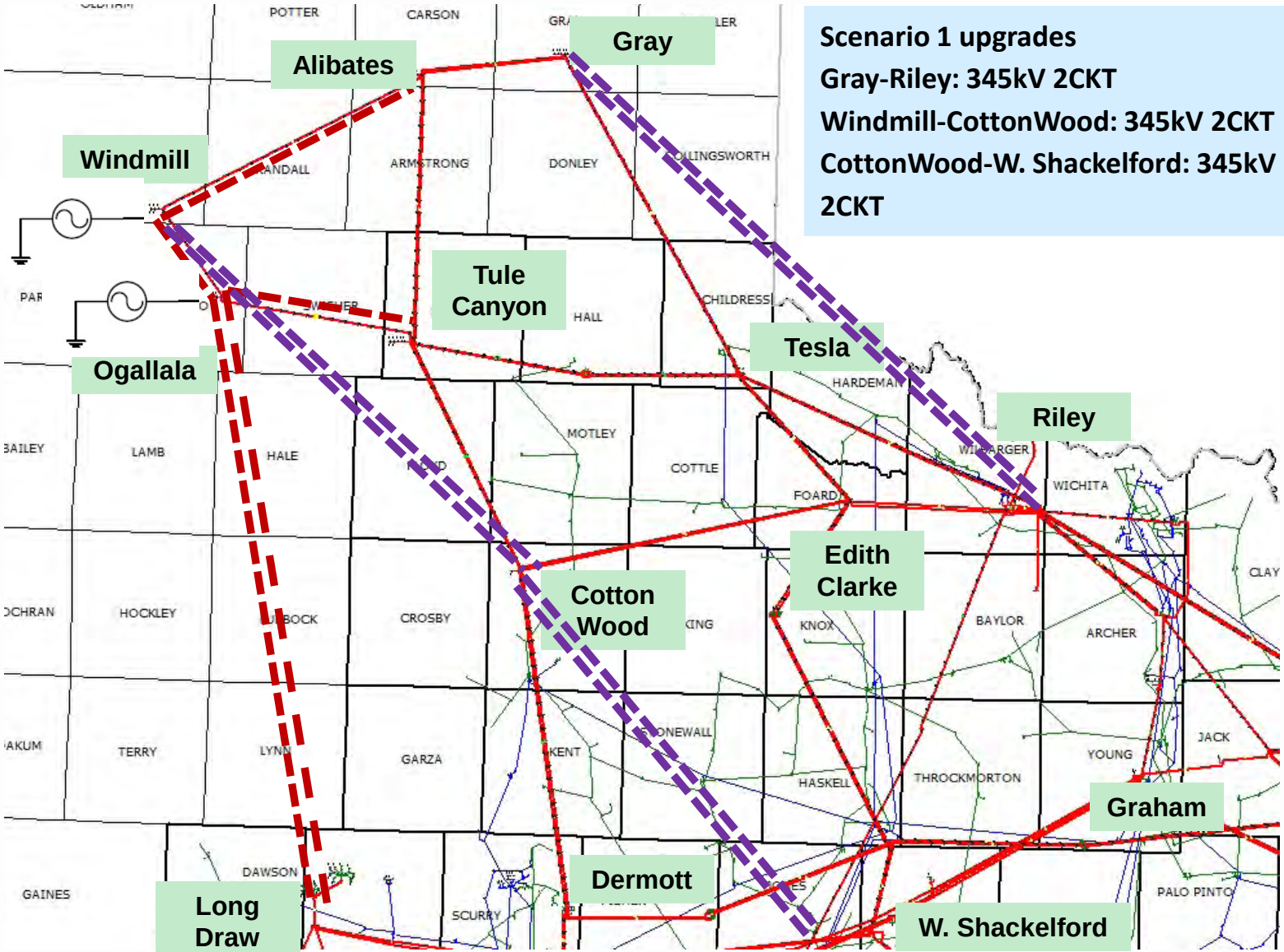


Scenario 1 upgrades

Gray-Riley: 345kV double ckts

Windmill-EdithClarke: 345kV double ckts

Scenario 2: System Upgrade Option B



Scenario 1 upgrades

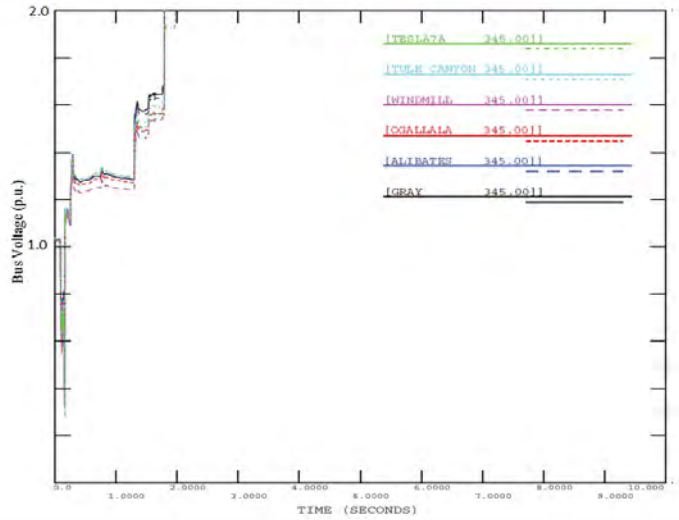
Gray-Riley: 345kV 2CKT

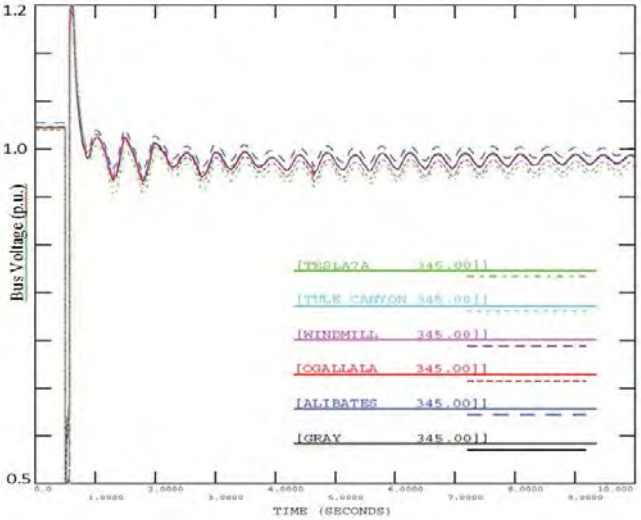
Windmill-CottonWood: 345kV 2CKT

CottonWood-W. Shackelford: 345kV 2CKT

Key Findings – Upgrade Needs

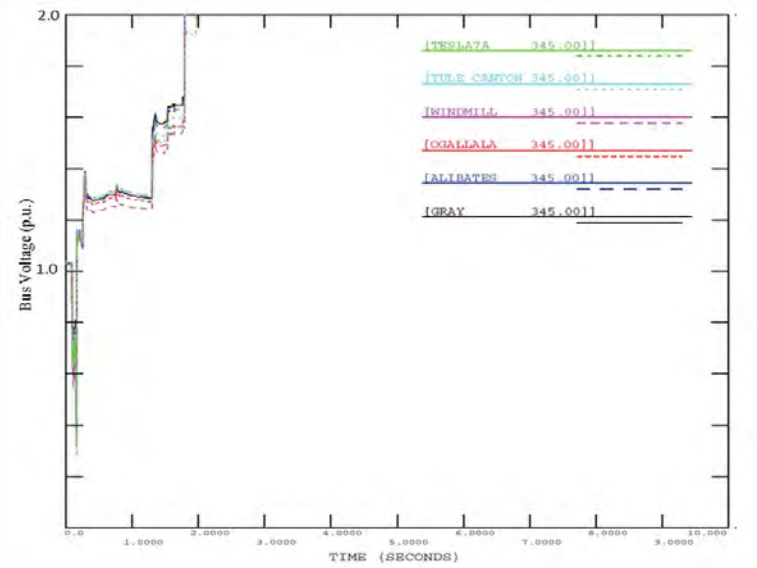
- Panhandle Upgrade Needs
  - Voltage Stability
  - System Strength (Short Circuit Ratio)
- Constraints in other region may limit the Panhandle export capability when Panhandle generation exceeds 6.5 GW. Other ERCOT regions may require further studies for potential thermal and stability challenges.



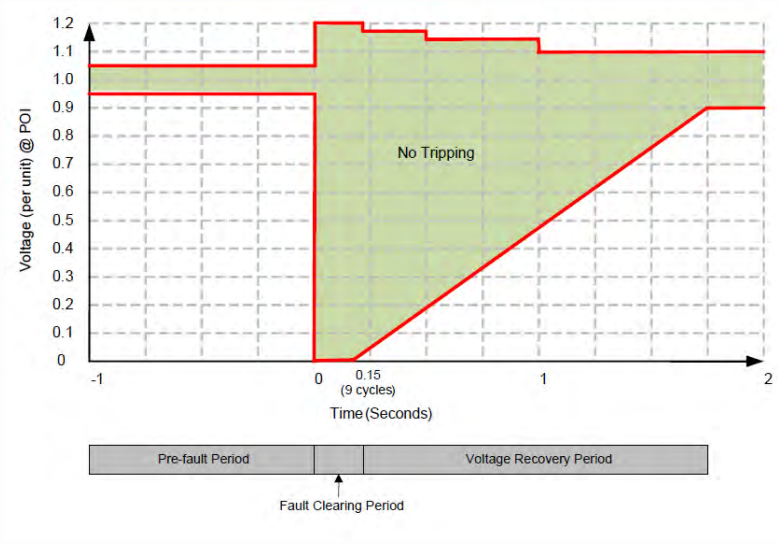


Key Findings – Overvoltage Cascading

- High Voltage Ride Through Capability in the proposed NOGRR 124 is needed to accommodate more wind generation in Panhandle

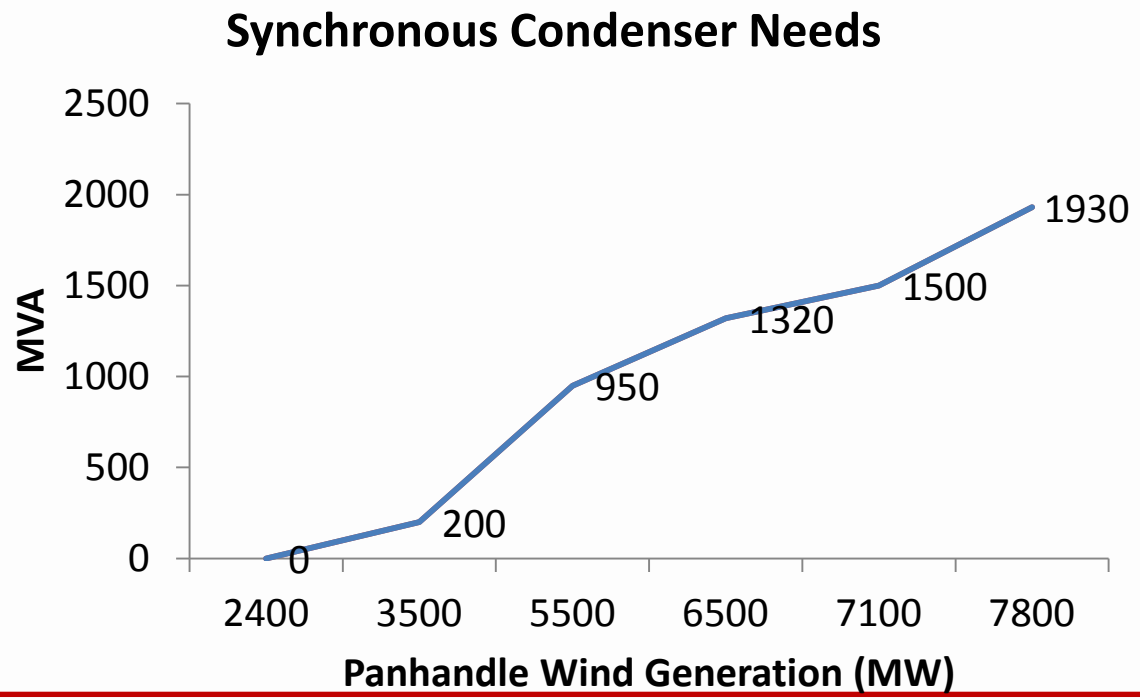


Potential overvoltage cascading



Proposed HVRT: NOGRR 124

System Strength Needs: Synchronous Condenser as an example

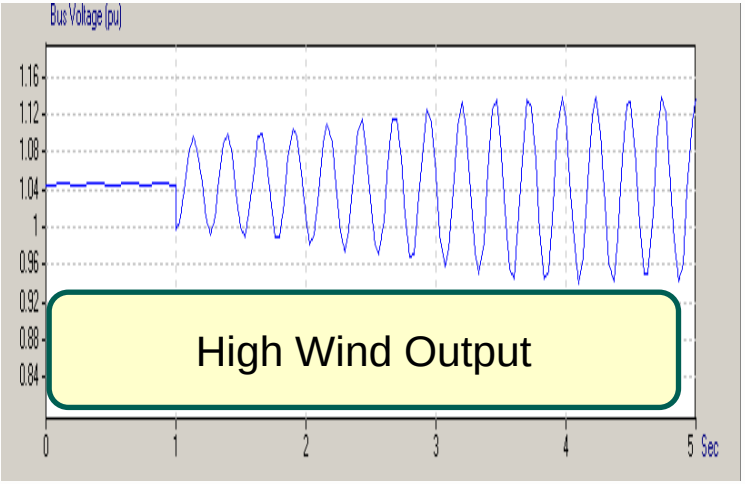


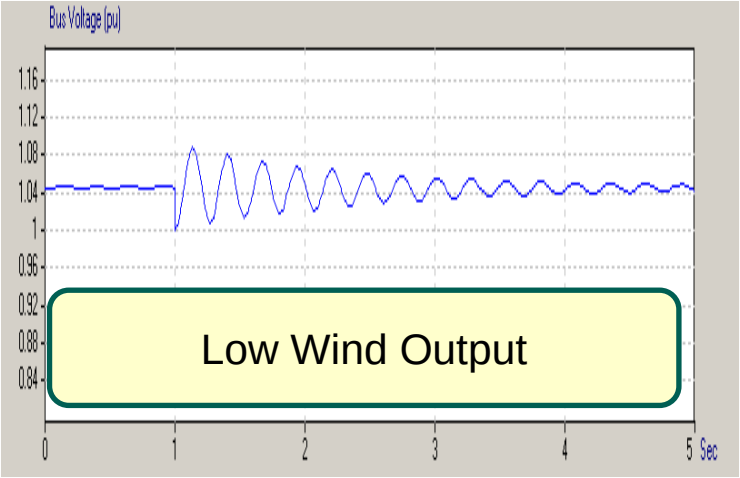
- Panhandle SCR target = 1.5
- Actual synchronous condenser needs will vary based on transmission line upgrades and wind generation projects.

- Is the need based on wind generation capacity or output?

Key Findings – System Strength Enhancement

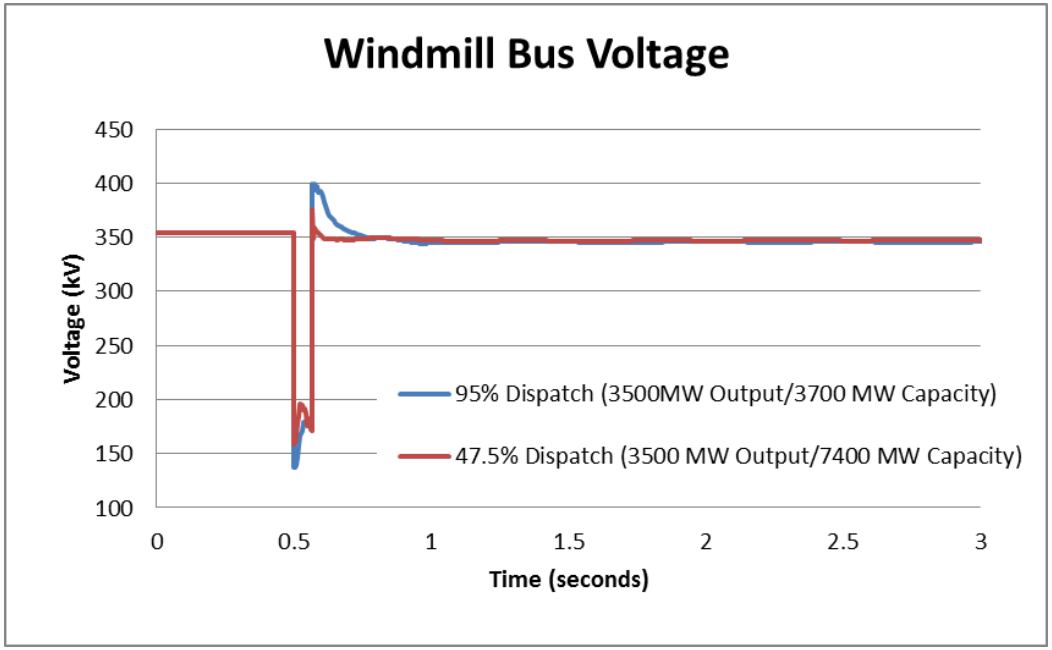
- The need of system strength enhancement in Panhandle is based on **<u>wind generation output</u>**.
- ERCOT and TSPs observed unstable responses from an existing WGR under a weak connection. A mitigation was developed to constraint the wind generation output to provide a stable operation of the WGR.





Key Findings – System Strength Enhancement

- PREZ Sensitivity Test:
  - Base case: 3,500MW output from 3,700MW capacity, SCR ~1.5
  - Test case: 3,500MW output from 7,400MW capacity, same system condition in the base case
- PREZ study results confirm the system strength enhancement is based on wind generation output.

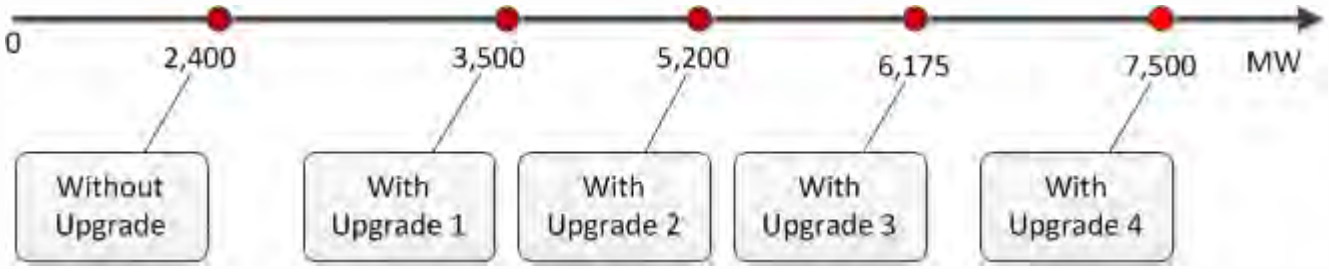


Roadmap

- Upgrades identified in scenario 1 and 2 are the reference for roadmap.
- The upgrade stage in the roadmap is identified to provide most reliability Panhandle export increase at a least upgrade cost.
- Perform economic cost analysis to find the triggers of upgrades
  - in terms of wind project capacity in Panhandle
  - Protocol 3.11.2 (5)

    …., the levelized ERCOT-wide annual production cost savings over the period for which the simulation is feasible is calculated and compared to the first year annual revenue requirement of the transmission project.….

Roadmap – Panhandle Export Limit



- Each upgrade also requires synchronous condensers and reactors
- Upgrade 1: add second circuit on the existing single circuit in Panhandle
- Upgrade 2: add new 345kV double circuits from Ogallala to Long Draw
- Upgrade 3: include one option from upgrade list below
- Upgrade 4: include one additional option from upgrade list below
- The final upgrade should include Gray-Riley option
- Upgrade list
  - Gray-Riley 345kV double circuits
  - Windmill—Edith Clarke 345kV double circuits
  - Windmill—Cottonwood—W.Shackelford 345kV double circuits

- Upgrades, project trigger points, and export limits may vary based on the assumed location of wind generation projects

Roadmap – Consider Operation Practice

Upgrades

Element	Description	Circuit #	Upgrade	Length/Size	Note	Estimated Cost ($M)	Total Cost ($M)
345kV Line	Alibates-Windmill	1	1	93 miles	On the existing tower		
345kV Line	Windmill-Ogallala	1	1	27 miles	On the existing tower	63	
345kV Line	Ogallala-Tule Canyon	1	1	47 miles	On the existing tower		
Synchronous Condenser	Windmill	--	1	200 MVA		43	115
Reactor	Alibates	--	1	50 MVAr		2.75	
Reactor	Ogallala	--	1	100 MVAr		5.5	
345kV Line	Ogallala-Long Draw	2	2	190 miles	New line	380	
Synchronous Condenser	Windmill	--	2	400 MVA		86	
Synchronous Condenser	Alibates	--	2	200 MVA		43	
Synchronous Condenser	Gray	--	2	150 MVA		32.25	560
Reactor	Windmill	--	2	50 MVAr		2.75	
Reactor	Ogallala	--	2	150 MVAr		8.25	
Reactor	Long Draw	--	2	150 MVAr		8.25	

- Upgrades, project trigger points, and export limits may vary based on the assumed location of wind generation projects

Summary -- Roadmap

Panhandle Grid	Panhandle Export Limit	Trigger for Upgrade (Panhandle Wind Capacity)	Upgrade Element	Estimated Upgrade Cost ($M)
Existing Grid	2,400 MW	-	-	-
Upgrade 1	3,500 MW	3,000 MW	• Add second circuits on the exisitng Panhandle grid • 200MVA synchronous condenser • 150MVAr reactors	115
Upgrade 2	5,200 MW	6,500MW	• Add one new 345kV double circuits -- (Ogallala-Long Draw) • 750MVA synchronous condenser • 350MVAr reactors	560
Upgrade 3	6,175 MW	-	• Add one new 345kV double circuits -- (Gray-Riley or Windmill-Edith Clarke or Windmill-Cottonwood-W.Shackelford) • 350MVA synchronous condenser • 300MVAr reactors	442
Upgrade 4	7,500 MW	-	• Add one additional new 345kV double circuits -- (Gray-Riley or Windmill-Edith Clarke or Windmill-Cottonwood-W.Shackelford) • 350MVA synchronous condenser • 450MVAr reactors	500

Conclusion

- ERCOT initiated study in early 2013 to determine roadmap for transmission improvements necessary to accommodate Panhandle wind development beyond initial 2.4 GW capacity
- Preliminary results show some near-term improvements may be able to be put in place to increase capacity relatively quickly but improvements for higher capacity may include longer lead time transmission lines

- Upgrades, project trigger points, and export limits may vary based on the assumed location of wind generation projects

Future Work

- Continue to work with TSPs for other alternative upgrade options proposed by TSPs and/or stakeholders

- Monitor the generation interconnection status for actual implementation of wind projects in Panhandle
  - The identified upgrades may be revised based on the actual implementation of wind projects in Panhandle
  - The impact of the proposed DC-tie connect to Panhandle may require further investigation

Alberta Electric System Operator

Fort McMurray West 500 kV Transmission Project

Project Information Brief

Date: May 9, 2013

2500, 330-5th Avenue SW, Calgary, Alberta T2P 0L4 Phone: 403-539-2450 Fax: 403-539-2949
www.aeso.ca www.poweringalberta.com

Contents

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1. BUSINESS OPPORTUNITY

1.1 Purpose of this Project Information Brief

This Project Information Brief (the "**Brief**") is intended to be a summary of: (i) the business opportunity, namely the opportunity to develop, design, build, finance, own, operate and maintain the Fort McMurray West 500 kV Transmission Project (the "**Project**"); and (ii) the anticipated competitive process for the Project. This Brief is not intended to be referred to in any way with respect to the interpretation of the tendering and commercial documents in respect of the Project (i.e. the Request for Qualifications ("**RFQ**"), Request for Proposals ("**RFP**"), Project Development Agreement or Project Agreement[1]) or to in any way define or describe any party's rights with respect to the Project.

1.2 Introduction

The Alberta Electric System Operator (the "**AESO**") intends to undertake its first competitive process (the "**Competitive Process**") to select a qualified proponent (the "**Successful Proponent**") to develop, design, build, finance, own, operate and maintain the Project described in this Brief.

The AESO is a not-for-profit statutory corporation governed by a board of Members comprised of individuals independent of the electric industry and appointed by the Alberta Minister of Energy. The AESO has responsibility for, among other things, planning the Alberta transmission system, obtaining "needs approval" for certain transmission enhancements from the Alberta Utilities Commission (the "**Commission**") and directing incumbent transmission facility owners to obtain "facilities approval" from the Commission to build and operate needed transmission system facilities.

Once facilities are placed into service they become part of the Alberta transmission system. The AESO provides non-discriminatory system access service to connect both load and generation customers to the Alberta transmission system. The AESO owns no transmission facilities. It directs operation of the transmission facilities exclusively made available to it, under legislation, by transmission facilities owners ("**TFOs**").

Electric transmission infrastructure development in Alberta has generally and historically occurred through the AESO's direct assignment of transmission projects to incumbent TFOs based on traditional service territories. The incumbent TFOs operate under a cost of service model in which their prudently incurred costs are paid by the AESO in accordance with a TFO tariff approved by the Commission. The AESO then recovers approved tariff amounts from users of the Alberta transmission system.

1.3 Alberta Government Energy Strategy

In December 2008, the Government of Alberta introduced the Provincial Energy Strategy, a comprehensive plan for Alberta's energy future. The strategy noted the importance of electricity as a "facilitator of prosperity" and a key contributor to economic development in Alberta. To aid in implementing the Provincial Energy Strategy, amendments to the *Electric Utilities Act* resulted in legislated "needs approval" for certain substantial upgrades to the Alberta transmission system referred to as "critical transmission infrastructure"[2].

In furtherance of the development of critical transmission infrastructure, the Government amended the Alberta *Transmission Regulation* to provide, among other things, that:

(a) the AESO develop a fair and open competitive process to determine the person who is eligible to apply for the construction and operation of the Project, and

[1] The Project Development Agreement and the Project Agreement are collectively referred to as the CP Project Agreements.
[2] Except in respect of critical transmission infrastructure, the determination of need for transmission infrastructure development is made by the Commission. Since the Project is critical transmission infrastructure, no Commission "needs approval" is required.

(b) the AESO obtain the Commission's approval of the competitive process prior to implementing it.

The AESO obtained approval from the Commission for the Competitive Process on February 14, 2013, subject to a number of conditions. In response to a letter filed by the AESO which sought clarification of condition nine contained in the Commission's approval, the Commission, on its own motion, initiated a review and variance process with respect to that condition. The Commission will review its findings and make its determination with respect to that condition. The AESO does not intend to commence the RFQ stage of the Competitive Process until the Commission has made its determination.

1.4 Project Objectives

Some of the AESO's objectives for the Project are to:

- minimize life-cycle costs through the use of competitive pricing;
- create opportunity for maximum innovation throughout the life cycle of the facilities;
- allocate risk to most efficiently and effectively mitigate risk and reduce costs;
- foster efficient investment, operation and maintenance of assets across the life cycle of the facilities;
- ensure facilities are designed to meet standards for performance and ensure the reliable operation of the Alberta interconnected electric system; and
- ensure timely completion of the Competitive Process and the Project.

1.5 Key Features of the Opportunity

The Project will span a distance of approximately 500 km and include: (i) a 500 kV AC single circuit transmission line of approximately 100 km from a 500 kV substation (to be built as part of the Project facilities) near Fort McMurray, Alberta to a 500 kV substation, to be built as part of the Project facilities and located at the site of the Livock substation in Alberta, and (ii) a 500 kV single circuit transmission line of approximately 400 km from the 500 kV substation located at Livock to a substation (not part of the Project facilities), near Edmonton, Alberta. Key features of the Competitive Process, the Project and this opportunity include the following:

- The AESO, through its competition, seeks to identify a Successful Proponent to develop, design, build and finance the Project, and to own, operate and maintain it for a term ending 35 years following a target in-service date (the "**Target ISD**"). Following the end of the term, it is anticipated that the Successful Proponent will transfer the Project to an AESO designate for the nominal amount of $1.00 (Cdn).
- The capital cost of the Project is estimated to be $1.6 billion (Cdn).[3]
- In addition to obtaining all other federal and provincial permits and approvals, the Successful Proponent will be responsible for preparing and filing a facilities application with the Commission under the *Hydro and Electric Energy Act* and obtaining, from the Commission, a permit to construct and a license to operate the Project ("**Facilities Approvals**"). The Commission's oversight of public consultation, route selection, environmental and other

[3] This Project estimate is a planning estimate with an expected accuracy of +/-50%, as is consistent with the AESO's transmission planning process.

factors, and the Commission's ultimate decision on whether to issue a permit to construct and a license to operate is a part of that process.

- At the RFP stage, two routes for the Project will be proposed by each proponent but the Successful Proponent's final route determination will be the subject of Commission approval through the Facilities Approvals application. The Commission may approve, or require amendments to, the routes proposed by the Successful Proponent and may hold public hearings on the Facilities Approval application, including the proposed routes, at which affected stakeholders may intervene.

- Though the Successful Proponent will own the resulting facilities during the term of the CP Project Agreements, it will be required, like incumbent TFOs, to make them exclusively available for the AESO to provide system access service to Alberta electricity market participants.

- The Successful Proponent will be entitled to fixed monthly payments[4] from the AESO which will commence upon the Project facilities being determined available (whether this date is before or after the Target ISD) and which will end 35 years following the Target ISD. The monthly payments will be subject to adjustments over time as well as reductions for non-compliance with such things as availability and other performance requirements. The monthly payments will also be subject to potential adjustments for other matters including changes in scope, changes in law, force majeure and relief events.

- The Successful Proponent will be, pursuant to legislation, a TFO in respect of the Project and will be subject to all provisions applicable to a TFO under the ISO Rules, Alberta Reliability Standards and all legislation applicable to TFOs.

- The Successful Proponent, pursuant to the *Electric Utilities Act*, will be required to file a TFO tariff with the Commission setting out as its rates, the amounts to be paid to it as established in the CP Project Agreements. The Commission must approve these tariff rates as filed since it is required by the *Transmission Regulation* to consider the resulting arrangements of the Competitive Process to be prudent.

- The payments to be made to the Successful Proponent under the CP Project Agreements will be recovered by the AESO through its tariff. The AESO is rated AA-/Stable by Standard & Poor's Rating Services.

- The AESO has no responsibility to reimburse or compensate anyone for considering the Competitive Process or the Project or for participating in the RFQ stage or RFP stage of the Competitive Process.

2. THE COMPETITIVE PROCESS

2.1 Project Competitive Process

(a) Fair and Open Competitive Process

The AESO was mandated by legislation to develop a fair and open competitive process to determine the person eligible to apply for the construction and operation of the Project. On February 14, 2013, the Commission approved the AESO's proposed Competitive Process with ten conditions.

[4] Note: It is expected that the operations and maintenance portion of the monthly payment will escalate over time.

(b) Anticipated Steps and Schedule

The AESO may engage interested parties in a process consisting of the following:

- A Request for Expressions of Interest ("**REOI**") stage and pre-RFQ information session;

- An RFQ stage for the submission of qualifications by parties interested in the Competitive Process for the Project, and to short-list up to five (5) respondents as proponents to move forward into the RFP stage of the Competitive Process; and

- An RFP stage, which identifies a Successful Proponent which will enter into the CP Project Agreements for the Project.

If proponents are selected to participate at the RFP stage, they will be required to post financial security at the time they submit their technical submissions and indicative financial submissions. Such security will be returned to the proponent if the proponent is not the Successful Proponent.

Both RFQ submissions and RFP submissions will be evaluated in accordance with set evaluation criteria by external independent evaluation panels which will make recommendations to the AESO. The process will be subject to oversight by an independent fairness advisor retained by the AESO.

If the AESO determines to proceed with the Project, then set out below is an indicative timeline for the Competitive Process and the Project:

AESO issuance of REOI	May 9, 2013
REOI Information Session	June 11, 2013
REOI concludes	June 19, 2013
AESO issuance of RFQ to interested parties	July 2013
RFQ Submissions Due	September 2013
AESO evaluation of RFQ Submissions and selection of short-listed respondents (who become proponents in the RFP stage)	November 2013
AESO issuance of RFP to proponents	December 2013
Technical RFP Submissions due, evaluation by AESO	October – November 2014
Financial RFP Submissions due, evaluation by AESO	December 2014
Selection of preferred proponent and execution of Project Development Agreement	December 2014[5]
Target ISD	2019

[5] The schedule for submission of the application for Facilities Approval, receipt of Facilities Approvals and corresponding execution of the Project Agreement will be determined by the Successful Proponent; however, the AESO will set the Target ISD.

3. The PROJECT

3.1 Project Description

The purpose of the Project is to increase electric transmission transfer capacity into and out of the Fort McMurray, Alberta area to accommodate load and generation growth. The Fort McMurray area has a significant number of large industrial customers. These customers will be contracting with the AESO for both demand transmission service (transmission service for consumers) and supply transmission service (transmission service for generators) with varying degrees of usage to satisfy industrial process requirements and for electric supply reliability.

The specific facilities planned for the Project, spanning a distance of approximately 500 km, are a 500 kV AC single circuit transmission line from a 500 kV substation in the Fort McMurray, Alberta area to a 500 kV substation at the site of the Livock substation in Alberta and then to the Sunnybrook substation near Edmonton, Alberta, with the following configuration:

- A 500 kV AC single circuit transmission line of approximately 100 km in length from a 500 kV substation to be built as part of the Project in the Thickwood Hills area approximately 25 km west of Fort McMurray (the "**Start Point**") to the existing Livock 939S substation, the 500 kV portion of which is to be built as part of the Project; and

- A 500 kV AC single circuit transmission line of approximately 400 km in length from the new Livock 500 kV substation to the Sunnybrook 510S substation (not part of the Project) near Edmonton, Alberta (the "**End Point**").

At the RFP stage, two routes for the Project will be proposed by the Successful Proponent but final route determination will be the subject of approval from the Commission as part of the Facilities Approvals. The AESO will provide Start Point to End Point route coordinates only. Following the selection of proponents under an RFQ and prior to receiving RFP Submissions, the AESO, to the extent it can reasonably do so, may help to coordinate and facilitate initial proponent consultation with affected landowners and other impacted stakeholders so that each proponent is able to conduct due diligence regarding the routes the proponent will be required to include in its submission in response to the RFP.

The CP Project Agreements will require the Successful Proponent to undertake responsibility to develop, design, build and finance the Project, and to own, operate and maintain it for a term ending 35 years following Target ISD. Following the end of the term, the AESO intends for the Successful Proponent to transfer the Project to the AESO's designate for the nominal amount of $1.00 (Cdn.).

3.2 Summary of Successful Proponent Responsibilities

The scope of the Successful Proponent's responsibilities in relation to the Project will be outlined in the CP Project Agreements and in legislation which is applicable to all TFOs. Development and initial design of the Project and the work necessary to apply for and receive the Facilities Approvals as well as processes for adjustments to the payments to be made to the Successful Proponent will be governed by the Project Development Agreement which will be executed when the Successful Proponent is selected. The Project Agreement will govern the final design, construction, ownership, operation and maintenance of the Project until the end of the term and will be executed immediately prior to financial close and following receipt of the Facilities Approvals. What follows is a general summary, only, of the responsibilities set forth in those agreements.

Apart from the AESO's initial coordination and facilitation of proponent consultation with potentially affected stakeholders during the RFP stage, the Successful Proponent for the Project will be responsible for all other aspects of the Project including the following:

(a) Route Development, Environment, Consultation and Stakeholder Relations Responsibilities

The Successful Proponent will be responsible for all development work including such things as First Nations, Metis, landowner and other stakeholder consultation, engagement and accommodation, environmental and geotechnical assessment and obtaining Facilities Approvals from the Commission. The Successful Proponent will also be responsible for acquiring all rights-of-way and other land entitlements required for the Project and the route approved by the Commission.

The Successful Proponent will be responsible for the Facilities Approvals - a permit to construct and a license to operate a transmission line. The Commission may hold public hearings on the Facilities Approvals application, and is entitled to deny, approve or provide variances for the application, including in respect of the routes proposed by the Successful Proponent. The Successful Proponent will be responsible for the development and prosecution of the Facilities Approval application to ensure substantive and timely approval. The *Hydro and Electric Energy Act* provides, among other land acquisition provisions, that the holder of a permit to construct a transmission line which requires an interest in freehold or Alberta Crown land along an approved route may acquire it by negotiation or, failing that, by expropriation proceedings under the *Surface Rights Act*. If such interests are required in First Nations lands, Metis settlement lands or Canadian Federal Crown lands, then such interests must be negotiated in accordance with the terms of the *Indian Act*, *Metis Settlements Act* and applicable Canadian Federal legislation and common law.

The AESO recognizes that the Commission approved route for the Project may vary from the routes proposed by the successful Proponent and that adjustment to the Project pricing may be required. Such adjustment is explained in Section 3.4 below.

The Successful Proponent will also be responsible for applying to all other regulatory agencies and approving authorities for environmental and all other approvals.

The Successful Proponent will be responsible for all communications and consultations relating to the development and later construction and operations stages of the Project, including community relations, consultation, media relations and public information as well as for the proceedings associated with the Facilities Approvals.

(b) Design & Construction

The Successful Proponent will be responsible for ensuring that all aspects of design, engineering and construction (including the procurement and delivery of all professional and other services, all procurement, installation and construction of equipment and materials, all labour, all permits and all other aspects of the design, engineering and construction of the Project) accord with the functional and other specifications outlined in the CP Project Agreements as well as all applicable laws, regulations and rules and policies applicable to all aspects of the Successful Proponent's responsibilities under the CP Project Agreements and as a TFO.

(c) Operations, Maintenance and Major Maintenance

The Successful Proponent will be responsible for the operation and maintenance of the Project during the entire term. The Successful Proponent is also responsible for term-end handover of the Project facilities to the AESO's designate in a condition to be specified in the Project Agreement. The scope of the operations and maintenance activities will include all services associated with the management, planning and delivery of such activities to ensure compliance with all reliability and performance measures and

standards in the Project Agreement and with all applicable electricity, environmental, health, safety and other legislation, and will include all maintenance and other obligations under all land ownership and use entitlements held by the Successful Proponent for the Project route approved by the Commission.

(d) Financing

The Successful Proponent will be responsible for arranging and delivering all financing to develop and complete the Project and to perform its obligations under the CP Project Agreements, for the term.

(e) Filing a Tariff

The Successful Proponent, pursuant to Section 37(1) of the *Electric Utilities Act*, will file with the Commission a tariff setting out the rates established through the CP Project Agreements to be paid by the AESO for its use of the Project facilities as required under the *Electric Utilities Act.* The Commission, pursuant to Section 24.2(4) of the *Transmission Regulation*, is required to find those rates to be prudent.

3.3 Key Risk Allocations

The CP Project Agreements will include details with respect to the allocation of risks between the Successful Proponent and the AESO. A high level summary of the proposed Project risk allocation is set out in Table 3.3 below.

Table 3.3 - Anticipated Risk Allocation

	AESO	**Successful Proponent**	**Shared**
Development Risks – Project Development Agreement Period			
Inflation/Deflation	X		
Foreign Exchange	X		
Route Change Arising From Commission Decision			X
Financial and Economic Risks – Project Development Agreement Period			
Change in Financial Markets[6]	X		
Base Interest Rate on Debt	X		
Financial and Economic Risks – Project Agreement Period			
Refinancing		X	
Construction Risks – Project Agreement Period			
Inflation/Deflation		X	
Early/late Completion[7]		X	
Operation Risks – Project Agreement Period			
Inflation/Deflation	X		

[6] The AESO will share financing cost savings if the Successful Proponent demonstrates that an alternative financing structure will result in a reduction of financing costs.
[7] The Successful Proponent receives additional monthly payments for those months which precede the Target ISD and for which the facilities are determined available. Conversely, the Successful Proponent will not receive monthly payments for those months during which the availability of the facilities is delayed beyond the Target ISD

Route Change Arising From AUC Decision	X		
Availability or Performance Standards		X	
End of Term Asset Condition		X	
Business Risks – All Periods			
Insurance costs	X		
Force Majeure	X		
Relief Events[8]	X		
Change in Law	X		
Scope Change	X		
Technical Cost Savings Proposals[9]			X
Default - AESO	X		
Default - Contractor		X	
Termination – AESO Default	X		
Termination – Contractor Default		X	
Termination – Force Majeure or Extended Relief			X
Uninsurable Risks	X		

3.4 Key Price Adjustments - Project Development Agreement

The Project Development Agreement contemplates that since Commission approval of the Successful Proponent's Facilities Approvals application will significantly post-date delivery of the RFP Submission, certain adjustments to the Successful Proponent's financial proposal may be required. The adjustment provisions expected to be proposed in the Project Development Agreement can be summarized as follows:

(a) Inflation/Deflation

Adjustments to payments will be made based on pre-determined indices to account for changes in commodity, labour and other construction related component costs, including changes in foreign exchange rates, during the period commencing on the date of the Successful Proponent's RFP submission and ending after receipt of Facilities Approval and on a date immediately prior to financial close.

(b) Route Changes Approved by the Commission

Adjustments to payments will be made for route changes resulting from the Facilities Approvals application process in accordance with pre-determined formulas based on changes to the quantity of major project components and the unit prices for such components, subject to a cap which limits the overall price adjustment.

During the RFP stage of the Competitive Process, the AESO will hold meetings with proponents at which proponents will be able to propose alternative adjustment mechanisms for consideration by the AESO.

Once Project costs have been updated and adjusted as contemplated by the Project Development Agreement, the Successful Proponent may be required to run a funding competition to obtain committed financing and update debt financing costs prior to execution of the Project Agreement. The updated financing costs will adjust the pricing of Project debt to reflect the then current market conditions.

[8] The first $50,000 is intended to be at the Successful Proponent's risk.
[9] Must be initiated solely by the Successful Proponent and acceptable to the AESO.

The financial proposal of the Successful Proponent will be based upon the financial markets at the time of the RFP Submission. The details of the financing will be outlined in the financial model in the RFP Submission and will include the rate of return and the financing structure (including debt/equity ratio). For the funding competition, the Successful Proponent must maintain the credit quality for the Project and no changes will be permitted to the financing structure and rate of return. Changes to the debt financing structure in the Successful Proponent's financial model will only be permitted if:

(a) the Successful Proponent can demonstrate to the AESO's satisfaction that its debt financing structure is unacceptable to financing sources because of market condition changes, or

(b) an alternative debt financing structure will result in a reduction in the updated financing costs and correspondingly, a reduction in the payments to be made by the AESO.

In the event that the AESO approves such a change, the AESO will be entitled to share in the benefit of the financing cost reduction as set out in the Project Development Agreement.

3.5 No Obligation to Proceed

This Brief does not constitute an offer of any kind, including an offer to enter into any contract with any person. This Brief does not in any way commit the AESO or make the AESO responsible for anything whatsoever, including proceeding with an RFQ stage or RFP stage, or any other part of the Competitive Process.

Final Rule on

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

Briefing on Order No. 1000 Presented by

Federal Energy Regulatory Commission Staff

The statements herein do not necessarily reflect the views of the Commission

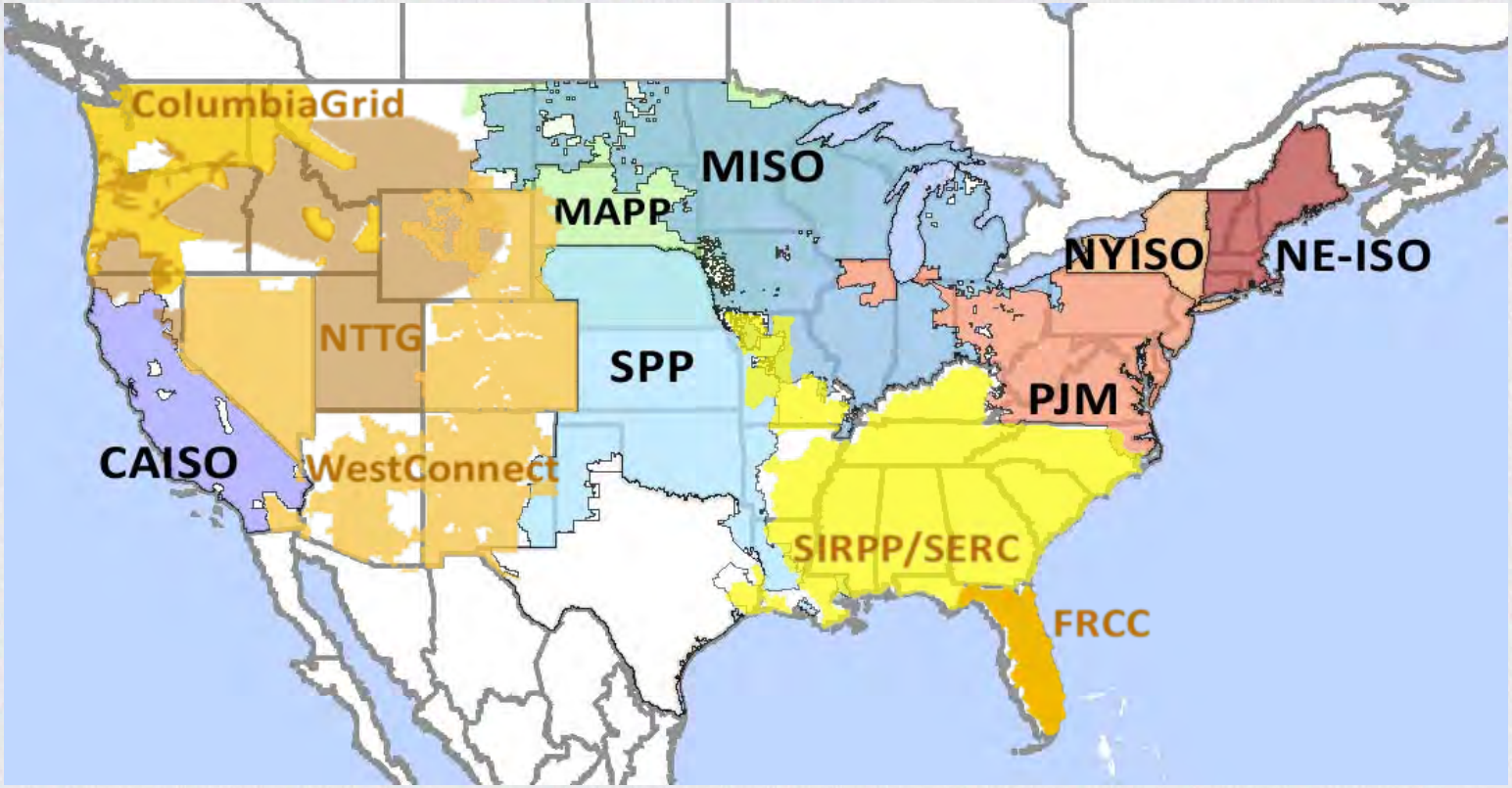
Timeline

- Order No. 888 in 1996
  - Requires open access to transmission facilities to address undue discrimination and to bring more efficient, lower cost power to the Nation's electricity consumers
- Order No. 890 in 2007
  - Requires coordinated, open and transparent regional transmission planning processes to address undue discrimination
- Order No. 1000 in 2011
  - Requires transmission planning at the regional level to consider and evaluate possible transmission alternatives and produce a regional transmission plan
  - Requires the cost of transmission solutions chosen to meet regional transmission needs to be allocated fairly to beneficiaries

Order No. 1000

- Planning Requirements
- Cost Allocation Requirements
- Nonincumbent Developer Requirements
- Compliance

Current Transmission Planning Regions *



- This map is for illustration purposes only. This map generally depicts the borders of regional transmission planning processes through which transmission providers have complied with Order No. 890. Those borders may not be depicted precisely for several reasons (e.g., not all transmission providers complying with Order No. 890 have a defined service territory). Additionally, transmission planning regions could alter because transmission providers may choose to change regions.
- Source: Derived from Energy Velocity

Important Terms

- Rule distinguishes between a transmission facility "in a regional transmission plan" and "selected in a regional transmission plan for purposes of cost allocation"

- Rule's requirements apply to "new transmission facilities," which are those subject to evaluation or reevaluation within local or regional transmission planning processes after the effective date of compliance filings

PLANNING REQUIREMENTS

Planning Requirements

1. Public utility transmission providers are required to participate in a regional transmission planning process that satisfies Order No. 890 principles and produces a regional transmission plan
2. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations
3. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if more efficient or cost-effective solutions are available

Regional Planning

- Each transmission planning region must produce a regional transmission plan reflecting solutions that meet the region's needs more efficiently or cost-effectively
- Stakeholders must have an opportunity to participate in identifying and evaluating potential solutions to regional needs

Planning for Public Policy Requirements

- Each public utility transmission provider must establish procedures to:
  - Identify transmission needs driven by public policy requirements
  - Evaluate potential solutions to those needs
- Public policy requirements are defined as enacted statutes and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level
- No mandate to include any specific requirement

Interregional Coordination

- Each pair of neighboring transmission planning regions must:
  - Share information regarding the respective needs of each region and potential solutions to those needs
  - Identify and jointly evaluate interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs
- Interregional transmission facilities are those that are located in two or more neighboring transmission planning regions
- No requirement to produce an interregional transmission plan or engage in interconnectionwide planning

COST ALLOCATION REQUIREMENTS

Cost Allocation Requirements

1. Regional transmission planning process must have a regional cost allocation method for a new transmission facility selected in the regional transmission plan for purposes of cost allocation
   - Cost allocation method must satisfy six regional cost allocation principles
2. Neighboring transmission planning regions must have a common interregional cost allocation method for a new interregional transmission facility that the regions select
   - Cost allocation method must satisfy six similar interregional cost allocation principles
3. Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method

Cost Allocation Principles

- Costs allocated “roughly commensurate” with estimated benefits
- Those who do not benefit from transmission do not have to pay for it
- Benefit-to-cost thresholds must not exclude projects with significant net benefits
- No allocation of costs outside a region unless other region agrees
- Cost allocation methods and identification of beneficiaries must be transparent
- Different allocation methods could apply to different types of transmission facilities

Cost Allocation

- The rule does not require a one-size fits all method for allocating costs of transmission facilities
  - Each region is to develop its own proposed cost allocation method(s)
- If region can't decide on a cost allocation method, then FERC would decide based on the record
- No interconnectionwide cost allocation

NONINCUMBENT DEVELOPER REQUIREMENTS

Nonincumbent Developers

- Rule promotes competition in regional transmission planning processes to support efficient and cost effective transmission development
- Rule requires the development of a not unduly discriminatory regional process for transmission project submission, evaluation, and selection

Nonincumbent Developers

Rule removes any federal right of first refusal from Commission-approved tariffs and agreements with respect to new transmission facilities selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:

- This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation
- This does not apply to upgrades to transmission facilities, such as tower change outs or reconductoring
- This allows, but does not require, the use of competitive bidding to solicit transmission projects or project developers
- Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities

Compliance

- Each transmission provider is required to make a compliance filing within twelve months of the effective date of the Final Rule

- The compliance filings for interregional transmission coordination and interregional cost allocation must be filed within eighteen months of the effective date

Outreach

FERC plans 3 webinars (early Fall) to aid compliance:

- RTO regions
- Eastern (non-RTO)
- Western (non- RTO)

For updates, please follow us:

Twitter twitter.com/ferc

Facebook facebook.com/ferc.gov

RSS ferc.gov/xml/whats-new.xml

July 21, 2011

Order No. 1000

Docket No. RM10-23-000

FEDERAL ENERGY REGULATORY COMMISSION FACTS

Order No. 1000
Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

Order No. 1000 is a Final Rule that reforms the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers. The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods.

Background

- On June 17, 2010, FERC issued a Notice of Proposed Rulemaking seeking comment on potential changes to its transmission planning and cost allocation requirements. Industry participants and other stakeholders provided extensive comment in response to the Notice of Proposed Rulemaking. The Commission received more than 180 initial comments and more than 65 reply comments.

Planning Reforms

The rule establishes three requirements for transmission planning:

- Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
- Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.
- Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

Cost Allocation Reforms

The rule establishes three requirements for transmission cost allocation:

- Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.
- Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.
- Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.

Nonincumbent Developer Reforms

- Public utility transmission providers must remove from Commission-approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:
    - This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.
    - This does not apply to upgrades to transmission facilities, such as tower change outs or reconductoring.
    - This allows, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.
    - Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.

- The rule recognizes that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

Compliance

- Order No. 1000 takes effect 60 days from publication in the *Federal Register*.
- Each public utility transmission provider is required to make a compliance filing with the Commission within 12 months of the effective date of the Final Rule.
- Compliance filings for interregional transmission coordination and interregional cost allocation are required within 18 months of the effective date.

139 FERC ¶ 61,090
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group,

v. Docket No. EL11-66-000

Bangor Hydro-Electric Co.; Central Maine Power Co.; New England Power Co. d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corp.; Northeast Utilities Service Co.; The United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Co.; Vermont Transco, LLC; and ISO New England Inc.

ORDER ON COMPLAINT AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued May 3, 2012)

1. On September 30, 2011, pursuant to section 206 of the Federal Power Act (FPA),[1] Complainants[2] filed a complaint against the New England Transmission Owners (New England TOs or Respondents),[3] contending that the current 11.14 percent base return on equity (ROE) for New England TOs recovered through ISO New England Inc.'s (ISO-NE) Open Access Transmission Tariff (OATT) is unjust and unreasonable. Complainants contend that the ROE should be set to no more than 9.2 percent (a reduction of 194 basis points). In this order, we establish hearing and settlement judge procedures. Further, we set a refund effective date of October 1, 2011.

I. Background

2. The New England TOs recover their transmission revenue requirements through formula rates included in the ISO-NE OATT. The Regional Network Service (RNS) and Local Network Service (LNS) revenue requirements for all the New England TOs are calculated using a single base ROE. In the Opinion No. 489 proceeding, the going-forward base ROE was established at 11.14 percent, consisting of a base ROE of 10.4 percent with an upward adjustment of 74 basis points to account for changes in capital market conditions—specifically, the yield of 10-year U.S. Treasury bonds—that

[1] 16 U.S.C. § 824e (2006).

[2] Complainants include: Martha Coakley, Massachusetts Attorney General (Mass AG); Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; the Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group.

[3] Respondents include: Bangor Hydro-Electric Co.; Central Maine Power Co.; New England Power Co. d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corp.; Northeast Utilities Service Co.; United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Co.; and Vermont Transco, LLC. Because, as discussed below, we grant ISO-NE's motion for dismissal as a party to this proceeding, we do not include ISO-NE in the phrase "Respondents."

took place between issuance of the Administrative Law Judge's initial decision in the case and Opinion No. 489.[4]

II. The Complaint

3. Complainants state that, due to changes in capital market conditions occurring since October 31, 2006, when Opinion No. 489 issued, the 11.14 percent base ROE for New England TOs as currently reflected in the ISO-NE OATT formula rates is unjust and unreasonable.[5] Further, Complainants cite the recent financial crisis as a changed economic circumstance, inclusive of the Lehman Brothers bankruptcy and the resulting "flight to quality" in the capital markets.[6]

4. Complainants state that their expert witness's discounted cash flow (DCF) analysis shows that the zone of reasonableness is now 7.0 percent to 11.4 percent, with a midpoint of 9.2 percent. Based on this analysis, Complainants argue that a just and reasonable base ROE for the New England TOs should not exceed 9.2 percent, which is 194 basis points lower than the current base ROE.

5. According to Complainants, their DCF analysis, which uses a national proxy group of 28 companies, conforms to the Commission's current precedent.[7] Their

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[4] *See ISO-New England Inc.*, 106 FERC ¶ 61,280, at PP 232-250 (2004); *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006) (Opinion No. 489), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarification*, 124 FERC ¶ 61,136 (2008) (Opinion No. 489 Rehearing Order).

[5] Complainants' expert witness asserts that the monthly yields on 10-year U.S. Treasury bonds have fallen from 4.98 percent to 2.88 percent, a decline of 210 basis points. Complainants state that 10-year U.S. Treasury bond yields directly correlate to the yields of utility bonds and their common stocks, and, therefore, the decline should be reflected in a downward adjustment to the ROE. Complaint, Ex. C-1 at 6-12 (Woolridge Testimony).

[6] "Flight to quality" refers to the action of investors moving their capital away from riskier investments to the safest possible investment vehicles.

[7] Complainants state they selected the proxy group using the following screening criteria for utilities: (1) listed as an electric or combination gas and electric company in *AUS Utility Reports*; (2) listed as an electric utility in *Value Line*; (3) has at least 50 percent regulated electric revenues; (4) has paid dividends for at least three years, with no dividend cuts; (5) is not involved in a merger or acquisition; (6) has an investment grade bond rating by Moody's or Standard & Poor's; and (7) has published analysts' earnings per share (EPS) growth rate from at least two different online financial information services (e.g., Zacks, Yahoo, or Reuters).

analysis eliminates two low-end ROE outliers (including these companies' high-end ROE values),[8] which Complainants state is consistent with the 100 basis point utility bond yield test.[9] Complainants' analysis also eliminates Hawaiian Electric Industries, Inc. (Hawaiian Electric),[10] which Complainants contend has a high-end ROE estimate of 13.7 percent, exceeding the next highest ROE in the proxy group by 190 basis points, and should therefore be excluded as an extreme outlier.

6. Complainants argue that, even though the current base ROE of 11.14 percent falls within the top of their zone of reasonableness, the Commission should nonetheless find it to be unjust and unreasonable. Complainants posit that the Commission has found that not every point within the DCF range would necessarily result in just and reasonable rates.[11] Complainants assert that transmission customers are overpaying the New England TOs by $113 million annually, which overpayment will increase to $206 million annually by 2015 due to expansion of the New England transmission system. Complainants request that the Commission: (1) institute a paper hearing proceeding to investigate the New England TOs' base ROE; (2) establish the earliest possible refund date; and (3) direct ISO-NE to make refunds.

III. Notice and Responsive Pleadings

7. Notice of the complaint was published in the *Federal Register*, 76 Fed. Reg. 62,396-97 (2011), with interventions and protests due on or before October 20, 2011. On October 4, 2011, ISO-NE filed motions for dismissal as a party, to postpone the answer date, to request expedited action, and that any refund effective date be established as the first day of a calendar month. On October 6, 2011, Complainants responded to ISO-NE's motions.

8. The following parties filed timely motions to intervene: Public Service Electric and Gas Co.; New England Power Pool (NEPOOL) Participants Committee; and Dynegy Marketing and Trade, LLC.

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[8] Utilities eliminated due to low-end ROE outliers were Entergy Corporation (5.6 percent) and Great Plains Energy (6.2 percent).

[9] Complaint at 22 (quoting *S. Cal. Edison*, 131 FERC ¶ 61,020, at P 55 (2010) (*SoCal Edison*) (excluding any company whose low-end ROE fails to exceed average bond yield test by about 100 basis points or more).

[10] Complainants list several more reasons why Hawaiian Electric does not have comparable risks (e.g., non-jurisdictional status and banking operations).

[11] Complaint at 26 (citing Opinion No. 489 Rehearing Order, 124 FERC ¶ 61,136 at PP 10-16).

9. The New Jersey Board of Public Utilities submitted a notice of intervention. The Maine Public Utilities Commission (Maine Commission) submitted a notice of intervention and comments, joined by a timely motion to intervene and comments by the New England Conference of Public Utility Commissioners (NECPUC) (together, Maine Commission and NECPUC).

10. The following parties filed timely motions to intervene and comments: NEPOOL Industrial Customer Coalition (NEPOOL Industrials); New Hampshire Electric Cooperative, Inc. (New Hampshire Coop), and New England States Committee on Electricity (NESCOE).

11. On October 20, 2011, ISO-NE and Respondents each filed answers. On November 4, 2011, Complainants filed an answer to Respondents' answer. Respondents submitted a response to Complainants' answer on November 21, 2011, and Complainants filed an answer to that response on December 6, 2011.

12. ISO-NE moves for dismissal as a party to this proceeding. ISO-NE principally contends that it is not the beneficiary of any ROE and, instead, is simply the billing agent for the New England TOs. ISO-NE maintains that it has purely an administrative role and that the New England TOs are the real parties in interest. In its response to ISO-NE's October 4, 2011 motion, Complainants do not object to ISO-NE's requested October 1, 2011 effective date.

13. The Maine Commission and NECPUC agree that, because of substantial changes in the financial markets, an investigation into the reasonableness of the base ROE is appropriate. They cite Complainants' witness testimony that the average 10-year Treasury yield for the period from April to September 2011 was 2.88 percent, which they state is significantly lower than the 5.0 percent average previously relied on by the Commission to adjust the ROE. They aver that "[t]here is every reason to believe, for example, that the composition of the proxy groups, the yields, and the growth rates that comprise the inputs to the DCF calculations have changed in significant ways since the Commission last evaluated the base ROE."[12]

14. NEPOOL Industrials support Complainants' request for an investigation, arguing that there is compelling evidence that the 11.14 percent base ROE is no longer just and reasonable.

[12] Maine Commission and NECPUC Comments at 7.

15. New Hampshire Coop supports the complaint, because the data underlying the current base ROE are more than five years old and "predate the dramatic capital market changes that have occurred in recent years."[13]

16. NESCOE agrees that the current base ROE of 11.14 percent does not meet the just and reasonable standard, because "economic conditions in New England and the rest of the United States are significantly altered from what they were [when the ROE was determined]."[14] Such a change, in NESCOE's view, justifies the initiation of an inquiry.

IV. Answer

17. In its answer, ISO-NE explains that it takes no position regarding the merits of the complaint because it is merely the billing agent for others: "the rates at issue are not the ISO's rates." ISO-NE states that it has no ROE and therefore, any order to change the base ROE should be directed at the New England TOs, not at ISO-NE.

18. In their October 20 answer, Respondents assert that Complainants have failed to meet the requirement under section 206 of the FPA,[15] namely, to show that the existing base ROE is unjust and unreasonable, because Complainants' DCF analysis does not conform to Commission precedent. Respondents submit witness testimony of Dr. William E. Avera with a DCF analysis that they assert shows the existing ROE is just and reasonable. Respondents state that Dr. Avera's DCF analysis relies on the use of a national proxy group in a manner consistent with Commission policy.[16] Among other things, Respondents calculated the growth rate used in the Commission's one-step DCF methodology for electric utilities,[17] excluding companies "that fail fundamental tests of reasonableness and economic logic as defined by the Commission."[18] They explain how such logic was applied to outliers. Specifically, Respondents excluded 11 low-end DCF results, ranging from 3.57 to 6.82 percent, as well as a high-end outlier of

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[13] New Hampshire COOP Comments at 3.

[14] NESCOE Comments at 4.

[15] 16 U.S.C. § 824e (2006).

[16] Respondents October 20 Answer at 15 (citing *id.*, Attachment A at 10-29 & n.5 (Avera Testimony)).

[17] Respondents October 20 Answer at 17.

[18] *Id.* at 18; *see also id.* at 18 n.37.

20.15 percent.[19] Respondents' DCF calculations retained the next highest cost of equity at 15.32 percent (Integrys Energy Services, Inc. (Integrys)), stating that this is well under the 17.7 percent threshold set in Opinion No. 489, and the 9.4 percent growth rate underlying this ROE estimate is significantly less than the 13.3 percent benchmark the Commission has continued to apply.[20]

19. In support of their position that Complainants' DCF analysis is inconsistent with Commission precedent, Respondents contend that Complainants use inappropriate proxy group screening criteria. For example, Respondents point out that Complainants exclude electric utilities from the proxy group which are not listed in AUS Utility Reports, whereas Commission precedent uses listing in Value Line Investment Survey (Value Line) as the criterion. Moreover, Respondents state that Complainants exclude electric utilities that do not have at least 50 percent regulated electric revenues, which criterion is also inconsistent with Commission precedent that requires all members of the proxy group to be electric utilities, without setting minimum revenue levels.[21] Respondents also take issue with Complainants calculation of the DCF growth rates, averring that they use the wrong sources. Respondents state that, while under Commission policy such growth rates are derived from Value Line and Institutional Broker Estimate Services (IBES), Complainants replace IBES with a composite of IBES and two other sources.

20. According to Respondents, this "combination of using the wrong proxy group and the wrong growth rates resulted in an obviously downwardly biased DCF analysis that understated the New England TOs' cost of equity."[22] Respondents further contend that Complainants inappropriately excluded Hawaiian Electric, whose high-end DCF result of 13.7 percent satisfied Complainants' proxy group screening criteria. They maintain that the Commission's policy is to exclude high-end DCF results above 17.7 percent.[23] In their view, this exclusion "appears to be entirely results-oriented."[24]

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[19] *Id.* at 18-19 (referring to *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008), which found that a 17.7 percent cost of equity was extreme and should be excluded).

[20] *Id.* at 20.

[21] *Id.* at 24 (referring to *SoCal Edison*, 131 FERC ¶ 61,020 (2010), *order on reh'g and clarification*, 137 FERC ¶ 61,016 (2011)).

[22] *Id.* at 29.

[23] *Id.* at 30 (citing *SoCal Edison*, 131 FERC ¶ 61,020 at P 57); *see also id.* at 31 (evaluating Commission policy in case law).

[24] *Id.* at 32.

V. Discussion

A. Procedural Matters

21. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

22. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2011), prohibits an answer to an answer unless otherwise ordered by the decisional authority. We are not persuaded to accept the answers following ISO-NE's and Respondents' October 20, 2011 answers to the complaint and will, therefore, reject them.

23. We will grant ISO-NE's motion for dismissal as a party to this proceeding. In doing so, we note that Complainants do not protest the motion,[25] and, we agree with ISO-NE that, with regard to the ROE at issue, ISO-NE is the billing agent for the New England TOs, not the beneficiary. The New England TOs are the true parties in interest for purposes of this proceeding.

B. Determination

24. We find that the complaint raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures ordered below. Accordingly, we will set the complaint for investigation and a trial-type evidentiary hearing under section 206 of the FPA.

25. While we are setting these matters for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their dispute before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[26] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[27] The settlement judge

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[25] Complainants October 6 Answer to Motion.

[26] 18 C.F.R. § 385.603 (2011).

[27] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges available for settlement proceedings and a summary of their background and experience (http://www.ferc.gov/legal/adr/avail-judge.asp).

shall report to the Chief Judge and the Commission within 30 days of the date of the appointment of the settlement judge, concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

26. In cases where, as here, the Commission institutes an investigation on complaint under section 206 of the FPA, section 206(b), as amended by section 1285 of the Energy Policy Act of 2005, requires that the Commission establish a refund effective date that is no earlier than the date a complaint was filed, but no later than five months after the filing date. Consistent with our general policy of providing maximum protection to customers,[28] we will set the refund effective at the earliest date possible, i.e., October 1, 2011, as requested.

27. Section 206(b) also requires that, if no final decision is rendered by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to section 206, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. Based on our review of the record, we expect that, if this case does not settle, the presiding judge should be able to render a decision within nine months of the commencement of hearing procedures, or, if the case were to go to hearing immediately, by January 30, 2013. Thus, we estimate that if the case were to go to hearing immediately, we would be able to issue our decision within approximately six months of the filing of briefs on and opposing exceptions, or by July 31, 2013.

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R., Chapter I), a public hearing shall be held concerning this complaint. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (B) and (C) below.

(B) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2011), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this

[28] *See, e.g.*, *Seminole Elec. Coop., Inc. v. Fla. Power & Light Co.*, 65 FERC ¶ 61,413, at 63,139 (1993); *Canal Elec. Co.*, 46 FERC ¶ 61,153, at 61,539 (1989), *reh'g denied*, 47 FERC ¶ 61,275 (1989).

order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

(C) Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(D) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Commission, 888 First Street, NE, Washington, DC 20426. Such a conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission. Commissioner Moeller is dissenting with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group,	Docket No. EL11-66-000

v.

Bangor Hydro-Electric Co.; Central Maine Power Co.; New England Power Co. d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corp.; Northeast Utilities Service Co.; The United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Co.; Vermont Transco, LLC; and ISO New England Inc.

(Issued May 3, 2012)

MOELLER, Commissioner, *dissenting*:

The majority finds that there are material issues of fact that cannot be resolved based on the record, and therefore, this matter should be set for hearing and settlement judge procedures. However, this finding is not compelling for the following reasons.

Complainants argue that the approved 11.14 percent base return on equity (ROE) in ISO-NE's tariff is unjust and unreasonable and should be reduced to no more than 9.2 percent (a reduction of 194 basis points). To support their conclusion that the base ROE should be no higher than 9.2 percent the complainants rely on a discount cash flow (DCF) analysis from an expert witness. However, the 9.2 percent ROE is based on a DCF analysis that departs from Commission precedent in several ways that are identifiable and thus able to be resolved based on the record.

Specifically, the Complainants' DCF analysis, which is the basis for the proposed ROE uses an average of growth rate data from several financial services instead of IBES alone.[1] In support, Complainants cite *Pepco Holdings*.[2] However, in that case, the Commission used the Value Line (br+sv) [3] growth rate and IBES growth rate, consistent with its long-term DCF methodology, rather than Value Line and a composite forecast of multiple sources, including IBES. Complainants have cited no Commission precedent that uses an average of multiple investor forecasting services. In fact, the Commission has consistently used a single investor service such as IBES for the investment analysts' growth rate estimate.[4]

Complainants' DCF analysis also eliminates companies whose sales are less than 50 percent electric.[5] For example, Complainants argue that Integrys should be eliminated from the proxy group, because Integrys derives less than 50 percent of its revenues from regulated electric utility operations. They cite several cases to support their position that the Commission regularly applies screening criteria to eliminate utilities primarily acting

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[1] *See Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, at PP 83-84 (2008) (rejecting the averaging of IBES with other comparable growth rate forecasts).

[2] *See Pepco Holdings, Inc.*, 124 FERC ¶ 61,176, at P 92 (2008); *but see id.* P 124.

[3] Briefly, "br+sv" is the sustainable growth rate determined by the Value Line inputs, where "b" is the expected retention ratio, "r" is the expected earned rate of return, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion ratio.

[4] *See, e.g.*, *RITELine Ill., LLC*, 137 FERC ¶ 61,039, at P 68 (2011); *N. Pass Transmission LLC*, 134 FERC ¶ 61,095, at P 46 (2011); *S. Cal. Edison Co.*, 92 FERC ¶ 61,070, at 61,263 (2000).

[5] *See Atlantic Grid Operations A LLC*, 135 FERC ¶ 61,144, at P 96 (2011) (reiterating policy to consider those companies as electric companies which are classified as such by independent investor services).

as natural gas companies.[1] Complainants' reliance upon these cases is misguided. The Commission eliminates companies from the proxy group that are not regarded by investors as an electric utility rather than use such revenue sources as part of its screening criteria.

Complainants DCF analysis also eliminates the high-end ROE of Hawaiian Electric (13.7 percent), as an outlier compared to the other companies in the proxy group. Complainants argue that they exclude Hawaiian Electric as a high-end outlier based on the 190 basis point "gap" between its high-end DCF result of 13.7 percent and the second highest ROE value of 11.8 percent. The Commission does not use the "gap" between the high-end DCF results in order to determine outlier values; rather, the Commission generally screens a proxy group for companies with unsustainable growth rates. Moreover, Complainants do not demonstrate that Hawaiian Electric's growth rate of 8.1 percent is unsustainable. When using its IBES growth rate of 8.60 percent, Hawaiian Electric's high-end DCF value is 14.24 percent. For similar reasons, Integrys, with a high-end DCF value of 15.32 percent, should not be excluded as a high-end outlier because Complainants do not demonstrate that its growth rate of 9.4 percent is unsustainable.

Complainants also propose in their DCF analysis to eliminate Integrys from the proxy group so as not to include companies involved in merger and acquisition (M&A) activity. Complainants have misapplied Commission precedent, which is to remove utilities from a proxy group only when the M&A activity is significant enough to distort the DCF inputs (inclusive of stock prices and estimates for earnings and growth rates).[2] Integrys's recent acquisition of two small companies, representing less than one-half of one percent of Integrys's asset base, is not the type of M&A activity that would distort its DCF inputs.

An existing rate is not rendered unjust and unreasonable merely by showing the possibility of a second just and reasonable rate.[3] Moreover, if Complainants had adhered

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[1] Complainants November 4 Answer at 6 (citing *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176, at P 113 (2008); *Va. Elec. and Power Co.*, 123 FERC ¶ 61,098, at P 61 (2008); *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 95 (2008)).

[2] *See* Opinion No. 489, 117 FERC ¶ 61,129 at PP 67-68.

[3] *See, e.g.*, *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 703 (D.C. Cir. 2007). *Cf. Oxy USA, Inc. v.* FERC, 64 F.3d 679, 691 (D.C. Cir. 1995); *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (Commission-approved proposal need not be the only just and reasonable proposal or even the most accurate).

to Commission precedent in developing their DCF analysis, the resulting zone of reasonableness, with a high-end exceeding approximately 15 percent, would have been wider than that proposed in the complaint, and the existing base ROE would have been well within the middle of that range.

Finally, Complainants generally assert that, due to changed economic circumstances, the New England transmission owners' cost of capital has declined and therefore the base ROE should be lowered. However, this assertion is not well-supported. Utility bond yields are one-half of a utility's cost of capital. The other half is a utility's cost of equity, which can only be estimated using a financial model, such as the DCF analysis. Complainants have not convincingly proven that the New England transmission owners' cost of equity has declined as much as bond yields to warrant a hearing in this case.

For all of the foregoing reasons, I would have rejected this complaint based on the record and described the areas where the Complainants' DCF analysis differs from the Commission's precedent accordingly.

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Philip D. Moeller
Commissioner

146 FERC ¶ 61,100
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Acting Chairman;
Philip D. Moeller, John R. Norris,
and Tony Clark.

Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California	Docket No.	EL14-15-000
v.		
Trans Bay Cable L.L.C.		
Trans Bay Cable L.L.C.	Docket No.	ER13-2412-000
		(Consolidated)
Trans Bay Cable L.L.C	Docket No.	ER13-2412-001

ORDER ON COMPLAINT, MOTION TO CONSOLIDATE,
AND REQUEST FOR REHEARING

(Issued February 20, 2014)

1. On December 17, 2013, the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities) filed a complaint (Complaint) against Trans Bay Cable L.L.C. (Trans Bay) and a motion to consolidate the Complaint with the ongoing hearing and settlement proceedings established in Docket No. ER13-2412-000 regarding Trans Bay's Transmission Revenue Requirement (TRR). On December 20, 2013, Six Cities filed a limited request for rehearing (Rehearing Request) of the Commission's order on Trans Bay's TRR.[1] In this order, we set the Complaint for hearing and settlement judge procedures, grant the motion to consolidate and deny Six Cities'

[1] Order Accepting and Suspending Proposed Tariff Changes and Establishing Hearing and Settlement Judge Procedures, *Trans Bay Cable LLC*, 145 FERC ¶ 61,151 (2013) (Trans Bay TRR Order).

Rehearing Request, as discussed below. We also establish a refund effective date of December 17, 2013.

I. Background

2. Trans Bay owns a 53-mile, 400 MW high-voltage, direct-current submarine transmission line buried beneath the San Francisco Bay, with converter stations at each end (Project) that provides direct electric transmission between Pacific Gas and Electric Company's (PG&E) Pittsburg and Potrero substations, both located in San Francisco, California.[2] Trans Bay is a participating transmission owner in the California Independent System Operator Corporation (CAISO), and recovers its transmission revenue requirement (TRR) through CAISO's open access transmission tariff. While the Project was under development, the Commission accepted a proposed operating memorandum setting forth the rate principles and operational responsibilities pursuant to which Trans Bay would undertake the development, financing, construction and operation of the Project upon its completion.[3] In an offer of settlement accepted by the Commission on December 30, 2011,[4] Trans Bay committed to file another rate case by September 20, 2013, with an effective date of November 23, 2013.[5]

3. Prior to the termination of the three-year rate moratorium that was included in the 2011 settlement, on September 20, 2013, Trans Bay proposed to increase its annual TRR from $132.5 million to approximately $139.1 million, which included a continuation of its previously authorized 13.5 percent incentive return on equity (ROE).[6] On November 21, 2013, the Commission accepted Trans Bay's proposed TRR, subject to refund, suspended the proposed TRR for the maximum five-month suspension, to become effective April 23, 2014, and set the proposed TRR for hearing and settlement judge procedures.[7]

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[2] A more detailed discussion of the background of this proceeding can be found in the Trans Bay TRR Order.

[3] *Trans Bay Cable LLC*, 112 FERC ¶ 61,095 (2005) (Operating Memorandum Order).

[4] *Trans Bay Cable LLC*, 137 FERC ¶ 61,258 (2011) (Settlement Order).

[5] *See Trans Bay Cable LLC*, Offer of Settlement and Stipulation, Docket No. ER10-116-000, at art. 5 § 5.1 (filed Nov. 8, 2011) (2011 TRR Settlement).

[6] Trans Bay Cable L.L.C., Docket No. ER13-2412-000 (September 20 Filing).

[7] Trans Bay TRR Order, 145 FERC ¶ 61,151 at P 18.

4. The Commission also dismissed Six Cities' and the California Public Utilities Commission's requests for a Commission-initiated investigation under section 206 of the Federal Power Act (FPA)[8] to determine whether the rates that Trans Bay would charge during the five-month suspension period from November 23, 2013, to April 23, 2014, were just and reasonable. In its Trans Bay TRR Order, the Commission stated:

> Neither the Operating Memorandum Order nor the Settlement Order state that the rate principles approved in the Initial Rate Order would terminate on November 23, 2013. Instead, the Commission found that Trans Bay was entitled to receive those rates for three full years and that Trans Bay would be required to file revised rates by September 20, 2013, which Trans Bay has done. Therefore, we find that Trans Bay has complied with the Commission's directives and a further investigation into previously settled rates is unwarranted.[[9]]

Hearing and settlement procedures began on December 17, 2013, in Docket No. ER13-2412-000.

II. Complaint and Motion to Consolidate

5. Six Cities argues that Trans Bay's current TRR, which is the continuation of the settlement rate during the five-month suspension period from November 23, 2013, through April 22, 2014, is not just and reasonable. Six Cities contends that the Period I data Trans Bay submitted as part of its September 20 Filing demonstrates that Trans Bay's current TRR of $132.5 million is excessive.[10] Six Cities explains that this data supports a TRR of $124.9 million, $7.6 million lower than its current TRR.[11] In addition, Six Cities asserts that Trans Bay's use of a 13.5 percent ROE to calculate its Period I and II TRR further inflates its actual cost of service because a 13.5 percent ROE falls outside of Trans Bay's range of reasonable returns. Instead, Six Cities states that its own analysis supports a range of reasonableness of 6.56 to 11.92 percent.

6. Six Cities requests that the Commission find that Trans Bay's current TRR is unjust and unreasonable, set it for hearing and settlement procedures, and order refunds with interest for the difference between the current TRR and the TRR resulting from the

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[8] 16 U.S.C. § 824e (2012).

[9] Trans Bay TRR Order, 145 FERC ¶ 61,151 at P 21.

[10] Trans Bay calculated its cost of service for Period I (July 1, 2012 to June 30, 2013) and Period II (January 1, 2014 to December 31, 2014), consistent with the requirements of the 2011 settlement. *See* September 20 Filing at P 17.

[11] Complaint at 7-8.

hearing as of the date of the Complaint. Six Cities also requests that the Commission consolidate the Complaint with the ongoing hearing and settlement procedures concerning the September 20 Filing in Docket No. ER13-2412-000. Six Cities argues that consolidating the two proceedings will increase efficiency because the Complaint and the September 20 Filing concern the same issues, i.e. establishing a just and reasonable TRR and ROE for Trans Bay.

III. Rehearing Request

7. Six Cities requests rehearing of the Commission's Trans Bay TRR Order regarding the rate moratorium applicable to Trans Bay's current TRR. Six Cities contends that the Commission erred in concluding that the Operating Memorandum Order and Settlement Order preclude an investigation into Trans Bay's current TRR at the end of the three-year rate moratorium. Six Cities asserts that the operating memorandum specifically states that, following the expiration of the three-year rate moratorium, "a change in the Company's [TRR] proposed by a [p]arty, a non-party, or the [Commission] acting *sua sponte* shall be reviewed under the 'just and reasonable standard' under [s]ections 205 or 206 of the [FPA]."[12] Therefore, Six Cities requests that the Commission reverse its findings in the Trans Bay TRR Order to the extent that the Commission purported to rule that the Operating Memorandum Order or Settlement Order prohibits a reduction in Trans Bay's TRR upon the expiration of the three-year rate moratorium.

IV. Notice and Responsive Filings

8. Notice of Trans Bay's complaint was published in the *Federal Register*, 78 Fed. Reg. 78,349 (2013), with interventions and protests due on or before January 6, 2014. The City of Santa Clara, California and the M-S-R Public Power Agency; DATC Path 15, LLC; Modesto Irrigation District; Northern California Power Agency; PG&E; and Southern California Edison Company filed timely motions to intervene. The California Department of Water Resources State Water Project (SWP) filed a timely motion to intervene and comments. Trans Bay filed a motion to dismiss, answers to the Compliant and to the motion consolidate the proceedings, and a request for attorneys' fees. Separately, Trans Bay filed a motion for leave to file an answer and an answer to Six Cities' rehearing request. Six Cities filed an answer to Trans Bay's motion to dismiss, answers to the Compliant and to the motion consolidate the proceedings, and a request for attorneys' fees. Trans Bay filed a motion for leave to answer and answer to Six Cities' response.

9. SWP supports both Six Cities' Complaint and motion to consolidate the proceeding with the ongoing hearing and settlement proceedings in Docket No.

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[12] Rehearing Request at 6.

ER13-2412-000. SWP agrees with Six Cities that, as demonstrated by the September 20 Filing, Trans Bay's current TRR is excessive and should be reduced.

10. Trans Bay argues that the Commission should summarily dismiss Six Cities' complaint with prejudice as an impermissible collateral attack on the Trans Bay TRR Order. Trans Bay explains that, in the Trans Bay TRR Order, the Commission considered and denied Six Cities' request for a section 206 investigation into Trans Bay's current TRR. Moreover, since Six Cities filed a request for rehearing of the Trans Bay TRR Order, Trans Bay adds that the Complaint is a collateral attack on an order pending on rehearing, which also constitutes grounds for dismissal.[13]

11. In addition, Trans Bay asserts that Six Cities' Complaint is barred by the doctrines of *res judicata* and collateral estoppel. First, Trans Bay claims that Six Cities' Complaint raises the same issues that it raised in its protest to the September 20 Filing. Second, Trans Bay contends that the issue of whether its TRR is just and reasonable was litigated and accepted in the Settlement Order and recently confirmed in the Trans Bay TRR Order. Thus, Trans Bay argues that the issues Six Cities raises in its Complaint are barred as *res judicata* and by collateral estoppel and should be dismissed with prejudice.[14]

12. Further, Trans Bay claims that the Complaint is facially deficient because Six Cities failed to satisfy the procedural requirements of Rule 206 of the Commission's regulations.[15] Trans Bay argues that Six Cities failed to quantify both the financial impact and the practical, operational, or other nonfinancial impacts caused by Trans Bay's current TRR, as required by Rule 206(b)(4) and (b)(5). Trans Bay also contends that Six Cities failed to explain why the timely resolution of the Complaint cannot be achieved through participation in the ongoing hearing and settlement proceedings in Docket No. ER13-2412-000, as required by Rule 206(b)(6). Trans Bay argues that the Commission has dismissed complaints for failure to satisfy the basic requirements of Rule 206 and should do so here.[16]

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[13] Trans Bay Motion to Dismiss, Answer to Complaint, and Answer to Motion to Consolidate Proceedings (Trans Bay Answer) at 7-10 (citing *Pac. Gas & Elec. Co.*, 116 FERC ¶ 61,004, at P 36 (2006) (having previously determined in an earlier order that the subject agreements permitted respondent market participants to change their cost methodology, the Commission dismissed the complaint against them as "no more than a collateral attack on that [prior] determination")).

[14] *Id*. at 10-12.

[15] 18 C.F.R. § 385.206 (2013).

[16] Trans Bay Answer at 12-15.

13. Should the Commission choose not to dismiss the Complaint, Trans Bay requests that the Commission deny the Complaint on its merits, arguing that Six Cities failed to establish a *prima facie* case under section 206 of the FPA. Trans Bay claims that Six Cities failed to provide evidence to show that Trans Bay's current TRR or ROE is unjust and unreasonable or that Six Cities' proposed TRR or ROE is just and reasonable. Trans Bay contends that it is inappropriate to use Period I data to establish its current TRR because Period I reflects its cost of service from July 1, 2012, to June 30, 2013, whereas the period during which the current TRR will apply begins on or after December 17, 2013, and ends on April 22, 2014. Thus, Trans Bay argues that an analysis of its current cost of service conditions based on Period II data would more accurately represent costs for the 2014 calendar year, which include the construction of nine significant additions to the Project.[17]

14. Trans Bay requests that the Commission also deny Six Cities' request to consolidate the Complaint with the ongoing proceedings in Docket No. ER13-2412-000. Six Cities argues that requiring the Commission to investigate and the parties to relitigate "previously settled rates" would unduly delay the matters already set for hearing.

15. Finally, Trans Bay asserts that the Complaint is so "clearly frivolous" that the Commission should require Six Cities to pay Trans Bay's legal fees incurred in defending itself against the Complaint.[18]

V. Discussion

A. Procedural Matters

16. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2013), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

17. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d)(1) (2013), prohibits an answer to a request for rehearing. Accordingly, we reject the answer filed by Trans Bay.

18. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2013), prohibits answers to answers. We are not persuaded to accept Six Cities' answer to Trans Bay's motion to dismiss, answer to the Complaint and to the motion to consolidate the proceedings, and the request for attorneys' fees, nor Trans Bay's answer to Six Cities' response and will, therefore, reject them.

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[17] *Id.* at 16-17.

[18] *Id.* at 21-22.

B. Commission Determination

1. Complaint

19. We find that the Complaint contains information sufficient to raise issues of material fact that cannot be resolved based on the record before us and that are more appropriately addressed in the hearing ordered below, and we establish a refund effective date of December 17, 2013. Also, Six Cities' complaint concerning Trans Bay's current TRR is based on similar facts and arguments at issue in the ER13-2412-000 proceeding covering Trans Bay's proposed TRR increase. Due to the common issues of law and fact, we will consolidate the Complaint with the hearing and/or settlement judge procedures currently pending in Docket No. ER13-2412-000.[19] Consistent with our instructions in the Trans Bay TRR Order, we direct the presiding judge to determine the appropriate range of reasonable returns and the appropriate ROE applicable for the current TRR at the upper end of this range, not to exceed 13.5 percent ROE.[20]

20. We deny Trans Bay's motion to dismiss because we find that the Complaint is not an impermissible collateral attack on the Commission's Trans Bay TRR Order. In the Trans Bay TRR Order, the Commission, exercising its discretion, declined to initiate its own FPA section 206 investigation as to the justness and reasonableness of the current TRR.[21] The Commission, however, made no finding that other parties were precluded from initiating their own FPA section 206 complaints.[22] Thus, we find that the Complaint is not an impermissible collateral attack on an order pending on rehearing.

21. Further, we find that the Complaint is not barred by the doctrines of *res judicata* and collateral estoppel. The Commission has previously explained that:

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[19] The Commission will consolidate proceedings where there are common issues of law and fact or if greater administrative efficiency will result from consolidation. *See, e.g., So. Cal. Edison Co*., 129 FERC ¶ 61,304, at P 26 (2009); *ISO New England, Inc*., 124 FERC ¶ 61,013, at P 36 (2008); *Ameren Servs. Co*., 121 FERC ¶ 61,205, at PP 22-23 (2007).

[20] Trans Bay TRR Order, 145 FERC ¶ 61,151 at P 19.

[21] The Commission may, within its discretion, determine not to initiate an investigation under FPA section 206. *Port of Seattle, Wash. v. FERC*, 499 F.3d 1016, 1027 (9th Cir. 2007).

[22] *See, e.g., PJM Interconnection, LLC*, 135 FERC ¶ 61,198, at P 66 (2011) (declining to establish a Commission investigation but stating that if a party believes a rate is unjust and unreasonable that party may file a complaint pursuant to FPA section 206).

> *Res judicata* applies . . . where a second suit or proceeding is brought on the same cause of action between the same parties or those in privity with them. The original judgment on the merits is conclusive not only as to matters actually raised but also to matters which could have been raised and litigated. Collateral estoppel . . . forecloses a party from relitigating the same question decided adversely to him by a prior judgment on another cause of action.[[23]]

Critical to the application of these doctrines is that there was, in fact, an "original judgment on the merits" so as to foreclose relitigation of a "question decided." Trans Bay contends that the issue of whether its current TRR is just and reasonable was litigated and accepted in the Settlement Order and recently confirmed in the Trans Bay TRR Order. This contention is not correct. As Six Cities correctly states, the 2011 settlement covered November 23, 2010 through November 30, 2013; however, the Settlement Order was not a judgment on the period beginning December 1, 2013, which is the subject of the Complaint. Similarly, as discussed above, when the Commission exercised its discretion and elected not to open a section 206 investigation in the TRR Order, this did not constitute a judgment on the merits that would preclude Six Cities from filing a section 206 complaint. Thus, the Complaint is not barred by the doctrines of *res judicata* or collateral estoppel.

22. Further, we deny Trans Bay's motion to dismiss the Complaint as facially deficient for failure to satisfy a strict application the procedural requirements of Rule 206 of the Commission's Rules of Practice and Procedure. We find that Six Cities has substantially complied with the Commission's complaint regulations in good faith.[24] Implicit in Six Cities' testimony and exhibits are the impacts that an excessive current TRR would have on Six Cities during the suspension period. Further, given the Commission's decision not to initiate its own FPA section 206 investigation of the current TRR, it is evident why the timely resolution of the Complaint could not be achieved through participation in the ongoing hearing and settlement proceedings in Docket No. ER13-2412-000.

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[23] *See Brian Hamilton v. El Paso Natural Gas Co.*, 141 FERC ¶ 61,229, at P 37 & n.44 (2012) (citing *McCulloch Interstate Gas Corp.*, 9 FERC ¶ 61,152, at 61,305 (1979), quoting *Gulf Oil Corp. v. F.P.C.*, 563 F.2d 588, 602 (3rd Cir. 1977)).

[24] *See La. Pub. Serv. Comm'n v. Entergy Corp.*, 129 FERC ¶ 61,205, at P 26 n.20 (2009) (denying a request to dismiss a complaint when the complaint "substantially complies" with Rule 206(b)'s requirements); *E.ON U.S. LLC*, 131 FERC ¶ 61,025, at P 41 n.60 (2010) (same).

23. Six Cities has established a *prima facie* case under section 206 of the FPA, and we will not dismiss it on that basis.[25] Trans Bay contends that Six Cities should not have used Period I data to establish its current TRR because Period I reflects its cost of service from July 1, 2012, to June 30, 2013, whereas the period during which the current TRR will apply begins on or after December 17, 2013, and ends on April 22, 2014 and that Period II data would more accurately represent costs for the 2014 calendar year. Trans Bay is welcome to present this and other evidence and arguments in the settlement and hearing proceedings, but we will not make a determination on this issue in this order.

24. Trans Bay also requests that the Commission deny Six Cities' motion to consolidate the Complaint with the ongoing proceedings in Docket No. ER13-2412-000 because doing so would amount to relitigation "previously settled rates." We disagree. As noted, the specific issue of the appropriate current TRR has never been litigated. Furthermore, consolidation will prevent the potential for duplicative discovery and allow the parties to more effectively utilize their resources in addressing issues common to both dockets.

25. Finally, for the reasons discussed above, we do not view the Complaint as "clearly frivolous," and we deny Trans Bay's request for legal fees.

26. While we are setting these matters for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their dispute before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance. The settlement judge or presiding judge, as appropriate, designated in Docket No. ER13-2412-000, shall determine the procedures best suited to accommodate the consolidation ordered herein. The settlement judge shall report to the Chief Judge and the Commission within 30 days of the date of this order concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

27. In cases where, as here, the Commission institutes an investigation on complaint under section 206 of the FPA, section 206(b) requires that the Commission establish a refund effective date that is no earlier than the date a complaint was filed, but no later than five months after the filing date. Consistent with our general policy of providing

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[25] As set forth in the Commission's regulations, a complainant establishes a *prima facie* case if the complainant: (1) clearly identifies the action or inaction which is alleged to violate applicable statutory standards or regulatory requirements; and (2) the complainant explains how the action or inaction violates the applicable statutory standards or regulatory requirements. *See* 18 C.F.R. § 385.206(b)(1)-(2) (2013). To that effect, the Commission requires that the complainant provide the Commission with evidentiary materials, including documents that support the facts in the complaint. *See* 18 C.F.R. § 385.206(b)(8) (2013).

maximum protection to customers,[26] and consistent with Complainants' requested relief, we will set the refund effective date at December 17, 2013.

28. Section 206(b) also requires that, if no final decision is rendered by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to section 206, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. Based on our review of the record, we expect that, if this case does not settle, the presiding judge should be able to render a decision within nine months of the commencement of hearing procedures, or, if the case were to go to hearing immediately, by November 30, 2014. Thus, we estimate that if the case were to go to hearing immediately, we would be able to issue our decision within approximately six months of the filing of briefs on and opposing exceptions, or by July 31, 2015.

2. Rehearing Request

29. Six Cities requests that the Commission grant rehearing of the Trans Bay TRR Order to the extent that it determined that the 2011 TRR Settlement or the 2005 Operating Memorandum precludes either the Commission acting *sua sponte* or any party from seeking a reduction in Trans Bay's TRR following the expiration of the initial three-year rate moratorium. As clarified herein, the Commission made no such determination in the Trans Bay TRR Order. The Commission exercised its discretion not to initiate its own investigation of the current TRR in that case. The Commission did not, based on the 2011 settlement or the 2005 Operating Memorandum, make any determination that other parties could not initiate their own FPA section 206 complaint regarding the current TRR. Therefore, we deny the Rehearing Request.

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and the Federal Power Act, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held in Docket No. EL14-15-000 concerning Trans Bay's TRR, as discussed in the body of this order.

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[26] *See, e.g.*, *Seminole Elec. Coop., Inc. v. Fla. Power & Light Co.*, 65 FERC ¶ 61,413, at 63,139 (1993); *Canal Elec. Co.*, 46 FERC ¶ 61,153, at 61,539 (1989), *reh'g denied*, 47 FERC ¶ 61,275 (1989).

(B) Six Cities' motion to consolidate is hereby granted and this proceeding is consolidated with the ongoing hearing and settlement judge proceedings in Docket No. ER13-2412-000.

(C) The refund effective date established in Docket No. EL14-15-000 pursuant to section 206(b) of the Federal Power Act is December 17, 2013.

(D) The settlement judge or presiding judge, as appropriate, designated in Docket No. ER13-2412-000 shall determine the procedures best suited to accommodate the consolidation ordered herein.

(E) Trans Bay's motion to dismiss is hereby denied, as discussed in the body of this order.

(F) Trans Bay's request for attorneys' fees is hereby denied, as discussed in the body of this order.

(G) Six Cities' Rehearing Request is hereby denied, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)