The Brattle Group

Seams Cost Allocation:

A Flexible Framework to Support Interregional Transmission Planning

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SPP Southwest Power Pool

EXECUTIVE SUMMARY

The Brattle Group was engaged by the Southwest Power Pool ("SPP") Regional State Committee ("RSC") to develop a general approach to seams cost allocation so that SPP could utilize a consistent set of principles and guidelines to assess the needs, benefits, and cost allocation of transmission projects at each of its seams with its diverse set of neighbors.

Seams cost allocation is especially challenging given the number of barriers related to the planning and analysis of interregional transmission projects. Planning-related challenges often start with limited staff resources to evaluate and consider seams projects, which can be exacerbated by a lack of sufficiently-detailed and current multi-region planning data and models to conduct joint system analyses. Uncertainty as to how or when neighboring systems will evaluate and consider seams projects as part of their regular planning processes can cause significant delays in the development of seams project. Also a "gap" between top-down and bottom-up planning studies can lead to an inability to identify beneficial seams projects. Qualification criteria for a seams project often differ between neighbors, and transmission benefits and metrics are not articulated with enough detail to allow for cost allocation based on identified benefits to each entity. Moreover, individual seams projects may offer a very different mix of benefits (*e.g.*, reliability, market efficiency, and public policy) to each of the neighboring regions and its transmission owners, which complicates cost allocation efforts. Finally, the lack of sufficiently detailed, actionable but flexible cost allocation principles and guidelines creates yet another major barrier to the planning and cost allocation of seams projects. This barrier is magnified if cost allocation is not aligned with ownership interests and transmission rights.

Regional planning entities have been pursuing various efforts to address these barriers. SPP, for example, in collaboration with the SPP RSC, developed a draft whitepaper on seams cost allocation principles and has addressed interregional planning in joint operating agreements ("JOAs") with several seams neighbors. The Federal Energy Regulatory Commission ("FERC") recently released Order 1000, requiring regional transmission planning entities under its jurisdiction to develop interregional cost allocation methodologies based on FERC-approved principles.

As part of our engagement to develop a general approach to seams cost allocation, we collaborated with SPP and SPP RSC staff to pursue five major tasks: 1) review SPP's draft whitepaper; 2) evaluate cost allocation frameworks used elsewhere; 3) develop a general framework for the cost allocation of seams projects; 4) test the framework with case studies of seams projects; and 5) draft and present a final report with our recommendations and proposed framework to the SPP RSC. A "Joint Project Team" was formed with key RSC- and SPP-assigned staff to facilitate project flow and coordination.

We provide in this report comments on SPP's draft whitepaper and a review of seams cost allocation efforts in other markets to identify successful practices that may be considered by SPP and its seams neighbors. This survey of cost allocation approaches spanned both RTO and non-RTO regions in the U.S. and Europe and focused on cost allocation principles, seams planning, and benefit metrics as applied to a variety of seams project types to address reliability, market efficiency, and public policy objectives.

The framework we developed is based on clearly-identified cost allocation principles and a comprehensive set of benefit metrics, while also allowing for the flexibility needed to consider a wide range of different projects types and seams entities. Our review of relevant experience from other markets also strongly suggests that seams cost allocation needs to be designed as an integral part of the interregional planning process. In this context, SPP's existing JOAs with neighboring transmission entities serve as the logical starting point for developing a more comprehensive and actionable interregional planning and cost allocation framework.

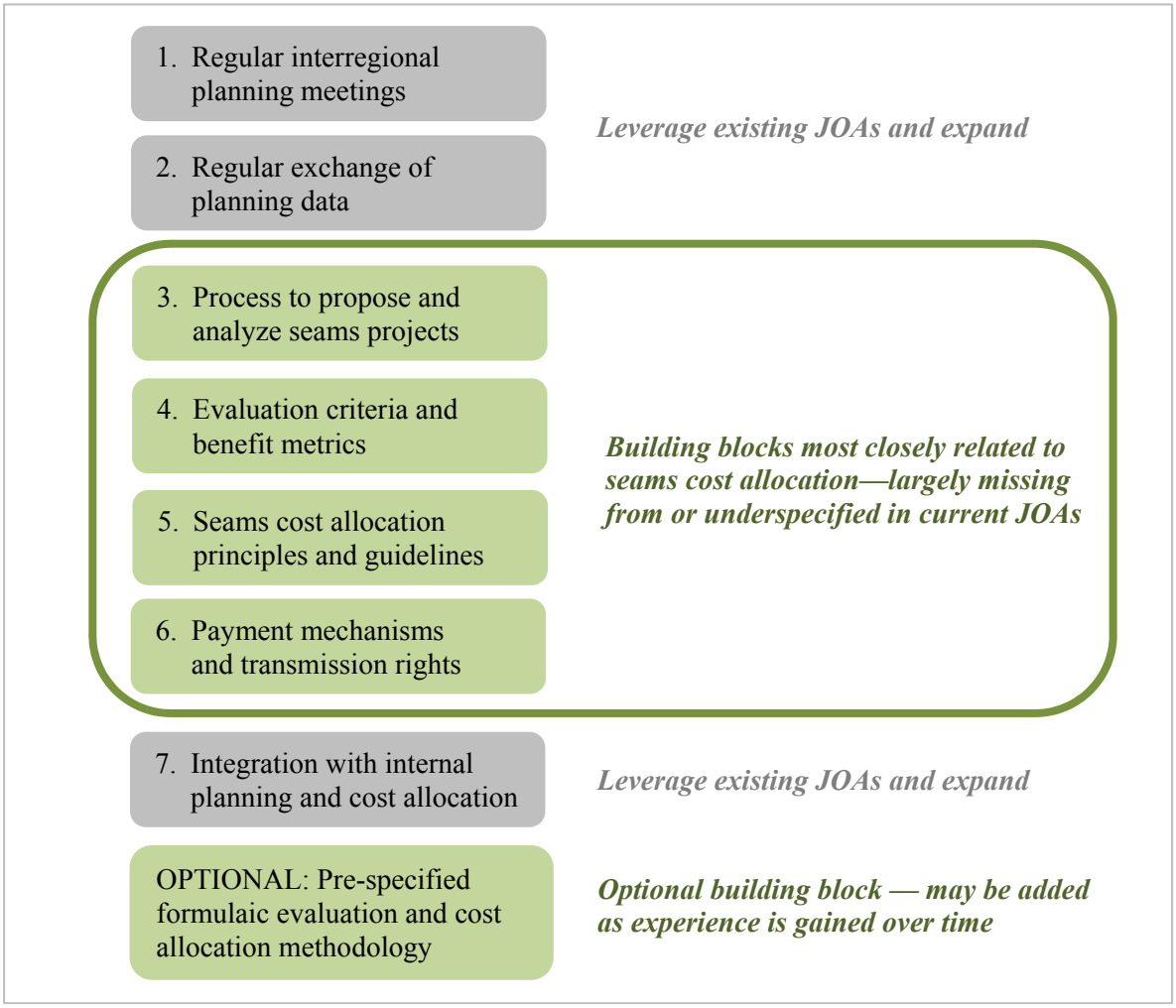
We identified seven "building blocks" needed to support interregional planning and cost allocation as shown in Figure 1 below. The first two building blocks already exist in SPP's JOAs but would need to be expanded to incorporate best practices. For example, with regard to building block No. 1, the JOAs already require a commitment to ***regular interregional planning meetings*** of the seams entities as well as coordination with state, federal, and multi-state entities. We recommend, however, more direct participation of regulatory commission staff from states affected by the particular seam in the planning and cost allocation discussions under the JOAs. Such involvement by state regulatory staff in the evaluation of proposed seams projects would likely facilitate the development of seams projects and cost allocations that will be acceptable to each of the involved state commissions in the permitting and (where applicable) retail rate recovery of the selected projects. In addition, while the JOAs may specify bilateral meetings between entities, they should be flexible enough to ***allow for participation by multiple seams entities*** if doing so can more effectively address challenges along seams between multiple transmission planning entities.

Building block No. 2 requires the timely ***exchange of planning data*** (as is already provided for in the JOAs). In addition, to facilitate planning of seams projects, we recommend that seams neighbors develop jointly-validated and endorsed load-flow cases and planning models for the combined footprint and planning horizon. This would allow each seams entity to accurately analyze the system of its neighbor to prepare credible initial cost-benefit evaluations of potential seams projects.

The third through sixth building blocks are most directly related to seams cost allocation. They are also largely missing from or underspecified in the existing JOAs. Building block No. 3

serves to define the parameters of a seams project and requires the specification of a ***process to propose and analyze seams projects***. The JOAs currently largely rely on the Joint Coordinated System Plan ("JCSP") process to identify seams projects. We propose to establish additional options under which seams entities could unilaterally or jointly propose seams projects outside the JCSP process. SPP will also need to specify how their transmission owners and other market participants can propose seams projects to SPP.

Figure 1
Building Blocks of Proposed Interregional Planning and Cost Allocation Framework



Building block No. 4 requires each seams entity to specify the ***evaluation criteria and benefit metrics*** that they will use for seams project evaluation. These criteria and metrics would not need to be identical across seams entities but would, *at a minimum*, need to include *all* the benefits and metrics each entity uses in its internal transmission planning process. In addition, we recommend the consideration of additional benefits and metrics, including some that are

unique to seams projects, such as increases in wheeling through and out revenues that can offset a portion of project costs.

Building block No. 5 consists of pre-specified ***seams cost allocation principles and guidelines***. Rather than resolve seams cost allocation on a case-by-case approach (as is provided for under the current JOAs), we recommend the inclusion of agreed-upon principles and guidelines to serve as the overarching framework for developing transmission cost allocation for seams projects. We specify a number of recommended principles and guidelines and provide case studies of how cost allocation shares might be derived for specific types of projects, consistent with the evaluation criteria and benefit metrics outlined in building block No. 4.

Building block No. 6 specifies ***payment mechanisms*** that allow for the actual sharing of project costs across the seam. Given the different characteristics of seams projects and limitations that certain entities may have in paying for transmission upgrades they do not own, we propose that seams agreements specify several options for payment mechanisms—such as shared ownership and financial transfers—that can be used to implement the agreed-upon cost allocations. We additionally recommend that physical or financial ***transmission rights*** are provided to each seams entity in exchange for their seams-related payments or investments.

Building block No. 7 addresses the ***integration of the interregional planning and seams cost allocation with each entity's internal planning and cost allocation processes***. This includes adding to the JOAs specific provisions that address who can propose a seams project, who can build and operate it, how planning analyses for seams projects are initiated, and how seams projects are integrated with internal planning processes and cost recovery, including planning in response to generation interconnection and transmission service requests, which can impact the overall benefits of seams projects.

Finally, we recommend that an optional building block allow for the inclusion of **pre-specified formulaic evaluation and cost allocation methodologies for specific project types.** Several seams cost allocation methodologies in other markets include such pre-specified formulaic approaches, such as those for interregional reliability and economic projects between the MISO and PJM. However, while such formulaic approaches can greatly streamline the evaluation and cost allocation of seams projects, many seams projects will not "fit" the pre-specified qualifications criteria. We thus recommend that seams projects that do not fit such pre-specified options still be evaluated under the general cost allocation framework as summarized above.

Stakeholders suggested five candidate seams projects that could be used as "test cases" for our proposed approach. We have developed case studies for three of these projects to illustrate the application of our proposed framework. We also developed "straw man" tariff language

(provided in Appendix C) to illustrate how the proposed framework might be implemented in the context of the existing JOAs.

SPP staff is actively working towards the Order 1000 compliance deadline, which is April 11, 2013 for interregional planning and cost allocation. We believe it is imperative that there be significant coordination between SPP and the RSC and hope that SPP and the RSC will be able to build on our proposed framework, including the straw man JOA language provided in Appendix C, to fully develop a robust interregional planning and cost allocation methodology that can be implemented through SPP's ongoing coordination efforts with its neighbors. We hope that this report can be used as the basis for this coordinated work to meet the Order 1000 mandate.

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- SPP (OGE)/Entergy – Proposed Danville Area EHV Station
- SPP (AEPW)/Entergy – Proposed Murfreesboro

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I. BACKGROUND

Southwest Power Pool ("SPP") established the Seams Steering Committee ("SSC") in early 2010 to identify and address seams-related issues, provide guidance on operational and planning coordination, and suggest improvements.[1] In the SSC's review of existing agreements, it noted that a variety of agreements exist between SPP and its neighbors ranging from basic NERC reliability coordination agreements which are focused on operations, to more sophisticated joint operating agreements which discuss long-term planning.[2] However, most existing documents did not adequately address or provide enough guidance on cost allocation for seams projects leaving the decision to be addressed on a case-by-case basis.

In an attempt to establish a more systematic approach to cost allocation, the SSC began developing a whitepaper, *Draft Cost Allocation Principles for Seams Transmission Expansion Projects* ("Draft Seams Cost Allocation Whitepaper" as provided in Appendix A and discussed in Section III below), in collaboration with the SPP Regional State Committee ("SPP RSC").[3] The whitepaper seeks to articulate a consistent set of overarching seams cost allocation principles and methodologies that could be applied to SPP and each of its neighbors. It could then be used by SPP as a starting point to discuss seams cost allocation, an especially challenging task as SPP's neighbors include market-based (MISO), non-market private (Entergy, AECI, CLECO), and non-market public power (Western, SWPA) transmission entities.

On June 17, 2010, the Federal Energy Regulatory Commission ("FERC") released its Notice of Proposed Rulemaking ("NOPR") on "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities" ("FERC NOPR").[4] With regard to interregional planning and cost allocation, the FERC NOPR proposed six principles cost allocation, which are discussed in greater detail in Section V.[5]

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1 Southwest Power Pool, Inc., "Seams Steering Committee Charter," April 22, 2010.

2 Southwest Power Pool, Inc., "Seams Steering Committee Meeting," June 15, 2010.

3 The SPP RSC is comprised of the retail regulatory commissioners in the SPP member states of Arkansas, Kansas, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. The SPP RSC provides state regulatory agency input on matters of regional importance related to the development and operation of the bulk electric transmission within SPP. In addition, the SPP RSC is charged with developing cost allocation methodologies for transmission upgrades within SPP.

4 Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23, June 17, 2010.

5 Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23, Notice of Proposed Rulemaking, June 17, 2010, pp. 97-99.

Though the FERC NOPR had not been finalized into a rulemaking and several of SPP's neighbors are non-FERC-jurisdictional, the Draft Seams Cost Allocation Whitepaper proactively included several aspects of the FERC NOPR. To assist SPP and the SPP RSC with further development of a seams cost allocation methodology, the SPP RSC issued a request for proposal ("RFP") in February 2011, seeking a qualified consulting firm to assist SPP, the SPP RSC, and SPP stakeholders in the area of cost allocation for seams transmission projects. *The Brattle Group* was engaged in June 2011 to provide our expertise and analysis on the matter. On July 21, 2011, the FERC issued its Order 1000, which retained the cost allocation principles that had been proposed in the NOPR.[6]

A. PROJECT ASSIGNMENT AND PURPOSE

The Brattle Group was engaged to undertake two phases of analyses as described in the RFP. The focus of the first phase was to develop a general approach to seams cost allocation so that SPP can use it to assess the needs and benefits at each of its seams with its neighbors. In doing so, we reviewed, documented, and reported to the SPP RSC and SPP SSC the benefit measurements that have been proposed and those that have been accepted for use by other jurisdictions to be applied to various types of transmission upgrades. We also reviewed the Draft Seams Cost Allocation Whitepaper to assess whether its proposed cost allocation principles were complete and consistent, whether the proposed cost allocations met those principles, and to recommend alternatives.

The second phase of this assignment, as originally specified in the RFP, was focused on leveraging the results and findings from the first phase to create a detailed recommendation report addressing SPP's seams.

B. APPROACH

After discussions with RSC and SPP staff, the two phases of this assignment as originally specified in the RFP were combined into five major tasks as summarized in Table 1 below.

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[6] Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23, Order No. 1000, July 21, 2011.

Table 1
Combined Phase One and Two Task List

Task	Description	Report Reference
1. Review of Draft Seams Cost Allocation Whitepaper	In-depth review of Draft Seams Cost Allocation Whitepaper	Section III
2. Evaluate Cost Allocation Frameworks Used Elsewhere	Identify and review proposed and/or accepted seams cost allocation and benefit measurements used elsewhere to see whether they are compatible with the principles outlines in the Draft Seams Cost Allocation Whitepaper	Section IV
3. Develop General Approach	Develop general approach and seams cost allocation framework with principles and methodologies and benefit measurements	Sections VI through XI
4. Test Approach Developed in Task 3	Test and demonstrate the robustness of the principles, framework, and methodologies developed in Task 3, and fine-tune or revise as necessary. Ideally the analysis would be based on specific transmission projects, involving the individual seams entities that are evaluated within the SPP transmission planning process to "troubleshoot" or "stress test" the considered approaches	Section XII
5. Draft and Present Report	Report and outline to be reviewed by RSC, SPP staff, other "Joint Project Team" members, and stakeholders. Deliver draft of detailed recommendations report to CAWG by March 2012, and a final report and presentation to the RSC by April 2012	Section I.C

As required by the RFP, Task 1 was an in-depth review of the Draft Seams Cost Allocation Whitepaper to check for completeness and consistency. This assessment is presented in Section III with the whitepaper included as Appendix A. We then researched and analyzed cost allocation frameworks used elsewhere (Task 2) as discussed in Section IV with key supporting documents provided in Appendix B. Based on the information gathered in Task 1 and Task 2 and discussions with SPP and RSC staff and stakeholders, we developed a general seams cost allocation methodology (Task 3), which included the cost allocation principles and methodologies as well as benefit metrics.

Throughout this process we worked closely with the RSC staff, SPP staff, and SPP stakeholder groups to leverage existing resources and work already completed on seams cost allocation. Tasks 1 through 3 largely address the requirements of the first phase described in the RFP. When developing a general framework, however, it is important to test and demonstrate its robustness or otherwise run the risk of developing methodology that cannot accommodate "real world" seams projects and complications. Therefore, Task 4 was designed specifically to "stress test" the proposed framework by applying it to existing or proposed seams projects. This allowed us to refine our proposed framework and present more concrete recommendations. As we discuss in Section XII, we received recommendations for specific candidate seams projects from SPP staff, RSC staff, and stakeholders, to which we could apply our proposed cost allocation framework. Lastly, Task 5 provides the presentations and reports required in both phases of the RFP and includes feedback from the RSC, SPP staff, stakeholders.

C. JOINT PROJECT TEAM AND STAKEHOLDER PROCESS

A Joint Project Team was formed to facilitate project flow and coordination. The Joint Project Team included key RSC- and SPP-assigned staff (*e.g.,* from the Seams Cost Allocation Task Force or "SCATF" and the Cost Allocation Working Group or "CAWG") and the *Brattle* project team. Team members participated in bi-weekly conference calls to discuss project status, data availability and needs, and coordination of logistical matters. For example, the Joint Project Team was responsible for reorganizing the project into the previously-discussed five tasks, developing a work plan, and agreeing on deadlines and deliverables. The SPP and RSC SCATF members of the Joint Project Team also provided introductions to access existing RSC- and SPP-internal experience, research, and data. The Joint Project Team further reviewed and provided feedback on draft research results, work products, and report drafts. Finally, the Joint Project Team provided guidance about the need and agenda for conference calls and meetings with other groups, such as the SPP SSC, the full RSC CAWG, the quarterly RSC meetings, and meetings adjacent seams entities. Table 2 summarizes the major meetings and conference calls with various groups and stakeholders to discuss the progress and present findings of the project.

Table 2
Key Meetings and Conference Calls

Date	Event	Description
July 19, 2011	Kick-off meeting (TX)	Kick-off meeting with RSC SCATF and SPP staff to revise schedule, scope, identify concerns, and discuss SPP Draft Seams Cost Allocation Whitepaper. Continued Joint Project Team discussions in bi-weekly status calls and ad-hoc calls.
August 11, 2011	SSC Monthly Meeting (KS)	Attended meeting to discuss the ongoing effort, interregional cost allocation examples, candidate seams projects on which to test framework, and examples from other markets.
September 30, 2011	SSC conference call	Conference call to discuss *Brattle's* first draft of a generic inter-regional planning and cost allocation framework and candidate seams projects.
October 21, 2011	SSC conference call	Follow-up conference call after receiving feedback on draft generic framework via email.
October 24, 2011	RSC Quarterly Meeting (NM)	Attended meeting to provide a progress update and presentation of draft framework and cost allocation principles
January 9, 2012	SSC Monthly Meeting	Participated in meeting via conference call to discuss cost allocation principles and methodologies, cost allocation guidelines based on illustrative examples, benefits, and metrics, and redlined joint operating agreements
January 26, 2012	Midwest ISO RECBTF Meeting	Participated via conference call to present draft framework to the Midwest ISO's Regional Expansion Criteria and Benefits Task Force ("RECBTF")
January 30, 2012	RSC Quarterly Meeting (TX)	Attended meeting to provide a progress update and presentation of cost allocation principles and methodologies, cost allocation guidelines based on illustrative examples, benefits, and metrics, and redlined joint operating agreement
February 3-28, 2012	Stakeholder Feedback	Individual conference calls with AEPW, Midwest ISO, Entergy, and AECI to discuss and receive feedback on draft framework and illustrative JOA inserts to implement framework
February 7, 2012	FERC Presentation	Presentation of draft framework to FERC staff members, including FERC's office of the general counsel
April 4, 2012	CAWG Monthly Meeting	Participated in meeting via conference call to present and discuss draft of the final report provided on 3/28
April 12, 2012	Order 1000 Interregional Coordination Meeting	Participated via conference call in SPP-MISO meeting to review the RTO's current thoughts on complying with the interregional aspects of Order 1000, incorporate stakeholder comments and develop consensus on concepts. Presented the proposed cost allocation framework.
April 23, 2012	RSC Quarterly Meeting (OK)	Attend meeting to present final report

D. REPORT STRUCTURE

The remainder of this report is structured as follows. Section II describes the barriers to interregional planning and cost allocation, which our proposed framework seeks to address. Section III includes our comments and feedback on the SPP RSC's whitepaper, "Draft Cost Allocation Principles for Seams Transmission Expansion." Section IV summarizes our survey of seams cost allocation efforts and issues outside of SPP, and Section V provides an overview of the FERC Order 1000 requirements for interregional cost allocation.

Sections VI through XI present our proposed interregional planning and cost allocation framework. In Section VI, we first present a case study of a seams project currently under construction, which we use to present our proposed framework for interregional planning and cost allocation and explain why cost allocation is an integral part of the overall planning process. We also introduce in this section our "building blocks," which serve as the foundation of our proposed framework. While some portions or versions of the building blocks already exist in SPP's processes and agreements with seams neighbors, others are insufficiently developed or missing entirely. We dedicate a section to each of these insufficiently-developed or missing building blocks.

The first of these insufficiently-developed or missing building blocks, presented in Section VII, defines a process to propose and analyze seams projects, including a process for unilaterally or jointly proposed projects and the responsibilities of each seams entity. Section VIII then discusses principles and examples for evaluation criteria and benefit metrics. Section IX presents our recommended seams cost allocation principles and guidelines that should be included in each interregional planning and cost allocation agreement. Section X discusses payment mechanisms that may be utilized by the neighboring entities to implement seams cost allocation. Lastly, Section XI presents an optional building block that allows for the development of pre-specified formulaic evaluation and cost allocation methodologies.

Section XII presents three case studies in which we apply and "stress test" the proposed approach. And, finally, a summary of our conclusions and next steps are presented in Section XIII.

II. BARRIERS TO INTERREGIONAL PLANNING AND COST ALLOCATION

To facilitate development of an effective seams cost allocation framework, we reviewed existing planning processes and obtained stakeholder input in an attempt to identify barriers to the development and cost allocation of seams projects. Interregional transmission planning is particularly challenging given a number of barriers in three broad categories: (1) interregional planning processes; (2) seams project evaluation and benefits; and (3) cost allocation.

Planning-related challenges often start with **limited staff resources** to evaluate and consider seams projects given the high work load of internal planning processes and operational seams efforts. Even if additional resources could be dedicated to seams planning, we found that there often is **limited exchange of sufficiently current data and inadequate joint planning models**. The emphasis here is not the sheer volume of data exchanged but the extent to which the available data and planning models would allow one seams entity to accurately model the impact of a proposed seams project on its neighbor's system. For example, jointly-developed and validated interregional power flow cases are not generally available for the combined footprint such that one seams entity would be in a position to credibly model the neighboring system. We also found that there is considerable **uncertainty as to how or when neighboring systems will evaluate and consider seams projects** as part of their regular planning processes. This creates mismatched timelines and missed opportunities to evaluate seams projects in a timely fashion. Finally, we identified a "gap" between top-down and bottom-up transmission studies, which can lead to an inability to identify beneficial seams projects. For example, SPP's "top-down" regional planning study, the Integrated Transmission Plan 10 ("ITP10"), identifies proposed transmission buildouts based on benefits provided by each configuration without fully considering projects that could be built and partially paid for in response to long-term transmission service requests ("TSRs"). At the same time, bottom-up planning efforts, like the evaluation of TSRs, only consider firmly-planned projects that already have a notice to construct but not other transmission projects that have been approved within the context of the ITP process. The disconnect is created because individual TSRs may benefit from the larger upgrades proposed in the ITP process but would not be able to fund such upgrades on an individual basis. Similarly, to the extent that an ITP project could address TSRs, payments received from TSRs would not be captured as a benefit in the ITP10 analysis.

When considering seams projects, we found that the **qualification criteria for a seams project often differ between neighbors**. These differences can create a gap that eliminates beneficial solutions even before a detailed analysis can be undertaken. This may be due to a requirement that a seams project that offers market efficiency benefits to one seams entity also needs to qualify as a market efficiency project in the neighboring seams entity. Other potentially beneficial seams projects may be eliminated by minimum voltage or project cost requirements or

the requirement that seams projects need to be physically located in both entities' footprint. The latter eliminates from consideration as a seams project any upgrades to flow gates that are entirely within one entity's footprint but constrain transactions within the neighboring seams entity.

Overall we also found that **many transmission-related benefits are not considered or lack specified metrics that could quantify or describe those benefits for seams projects**. There is also uncertainty about which types of transmission benefits are considered in the planning process of the neighboring seams entity. This can be a significant barrier to project selection and cost allocation, since costs can realistically be allocated to individual seams entities only based on benefits that are recognized by those entities. For example, would a seams neighbor consider a reduction in transmission loading relief ("TLR") events to be a reliability benefit? How would this benefit be monetized or what portion of a seams project's costs could be allocated to a neighbor who benefits from a reduction of TLR events? Moreover, **individual seams projects may offer very different types of benefits to each of the neighboring regions and transmission owners**. For example, a seams project that addresses a reliability concern within one seams entity may offer mostly market efficiency or economic benefits to the neighboring seams entity. As a result, a requirement that individual seams projects provide the same type of benefit (*i.e.,* reliability, economic, or public policy) to both seams neighbors will eliminate many potentially beneficial seams projects.

While robust planning and benefit considerations are essential to seams cost allocation, the **lack of sufficiently detailed, actionable, but flexible cost allocation principles and guidelines** makes it difficult to resolve seams cost allocation challenges. For example, FERC's requirement that costs be allocated so they are "roughly commensurate" with benefits is a good starting point, but does not provide quite enough guidance to be actionable by itself. On the other hand, while entities have attempted to develop detailed interregional evaluation frameworks for certain types of seams projects (*e.g.*, reliability or market efficiency projects), we found that such frameworks often are based on the "lowest common denominator" of the neighboring entities' planning processes and are insufficiently flexible to address many potentially attractive seams projects.

Finally, barriers to seams projects are created if cost allocation is not aligned with **ownership interests and transmission rights**. Transmission owners in non-market regions and non-jurisdictional transmission owners will be unable or hesitant to pay for seams projects without obtaining transmission rights (*e.g.*, a share of the upgrade's incremental flowgate capacity) in return for their payments.

To mitigate the identified barriers, a successful approach to cost allocation will need to be flexible enough to accommodate different types of seams projects (*e.g.,* reliability, economic, and public policy projects) for different types of neighboring regions and entities (*e.g.,* market

and non-market areas, FERC jurisdictional, and non-jurisdictional entities). Furthermore, the approach should recognize that a project may provide different types of benefits to each of the neighboring seams entities. To balance this flexibility, an effective framework also needs to be specific enough to be actionable without being overly restrictive and formulaic. In this regard, our proposed framework requires the joint development and validation of planning assumptions and models, comprehensive identification and explanations of all quantitative and qualitative benefits considered in each entity's transmission planning process, the identification of any additional benefits specific to seams projects (such as increased wheeling revenues), and specification of metrics by which to measure the identified benefits. Lastly, to address implementation-related barriers, assignment of transmission rights and specification of acceptable payment mechanisms to implement cost allocations will be necessary. The proposed framework for interregional planning and seams cost allocation presented in Sections VI through XI specifically builds on these considerations.

III. REVIEW OF SPP'S DRAFT SEAMS COST ALLOCATION WHITEPAPER

As noted earlier, in an attempt to establish a more systematic approach to cost allocation, the SPP's Seams Steering Committee developed a draft whitepaper—the *Draft Cost Allocation Principles for Seams Transmission Expansion Projects* ("Draft Seams Cost Allocation Whitepaper," provided in Appendix A)—in collaboration with the SPP Regional State Committee ("SPP RSC").[7] This Draft Seams Cost Allocation Whitepaper seeks to articulate a consistent set of overarching seams cost allocation principles and methodologies that could be applied to SPP and each of its neighbors. It begins with the recognition that SPP's seams agreements with its various neighbors "lack systemic requirements describing how costs for upgrades identified in these coordinated plans should be allocated between SPP and its neighbors."[8] The draft whitepaper also acknowledges that effective cost allocation will "promote improved transmission planning coordination at SPP's seams and facilitate more cost effective and efficient interregional solutions."[9] In order to develop a consistent approach to cost allocation, the Draft Seams Cost Allocation Whitepaper proposes principles to be considered in

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[7] The SPP RSC is comprised of the retail regulatory commissioners in the SPP member states of Arkansas, Kansas, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. The SPP RSC provides state regulatory agency input on matters of regional importance related to the development and operation of the bulk electric transmission within SPP. In addition, the SPP RSC is charged with developing cost allocation methodologies for transmission upgrades within SPP.

[8] SPP, *Draft Cost Allocation Principles for Seams Transmission Expansion Projects*, January 7, 2011, p.1.

[9] *Ibid*., p. 1.

five interrelated areas: (1) seams projects classification and applicability; (2) seams project designation criteria and OATT compatibility; (3) models and modeling assumptions; (4) metrics and criteria; and (5) cost allocation.[10] This section of the report discusses these areas and provides our thoughts on the completeness and consistency of the specified principles.

A. SEAMS PROJECTS CLASSIFICATION AND APPLICABILITY AND SEAMS PROJECT DESIGNATION CRITERIA AND OATT COMPATIBILITY

The first two topic areas are closely interrelated and will therefore be discussed together. The Draft Seams Cost Allocation Whitepaper notes that seams projects, or so called interregional transmission projects ("IRTPs"),[11] are generally identified as part of a coordinated system planning and modeling effort between SPP and the neighboring seams entity. It also acknowledges that IRTPs may be unilaterally identified but are still considered for seams cost allocation.

> **Observations:** We agree that this approach allows for some flexibility in how seams projects are identified and necessarily sets cost allocation within the context of interregional planning.

The draft whitepaper also specifies that an IRTP may physically cross a seams boundary or be wholly located within one seams entity.[12] To qualify as an IRTP, a project should be a minimum of 100 kV and have a total engineering and construction cost of at least $20 million.[13] While it is possible to consider lower voltages or costs, these minimum thresholds have been established so that time and resources are dedicated to projects that would be more likely to produce sufficient benefits to both seams entities.[14]

> **Observations:** We agree that IRTPs that provide benefits to both seams neighbors may or may not physically cross the seams boundary. We also agree that the availability of time and resources are significant constraints, but it does not necessarily follow that smaller or lower-voltage projects would not produce sufficient benefits to both parties in relation to allocated costs. In fact, smaller projects with significant benefits to both parties may be easier to validate and approve.

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[10] *Ibid*., p. 1.

[11] "Seams" and "interregional" are used interchangeably in the Draft Seams Cost Allocation Whitepaper.

[12] Draft Seams Cost Allocation Whitepaper, p. 1.

[13] *Ibid*., pp. 1-2.

[14] *Ibid*., p. 2.

The draft whitepaper classifies IRTPs based on three major drivers: 1) reliability needs ("IRTP-R"); 2) economic improvements ("IRTP-E"); and 3) public policy requirements ("IRTP-P").[15] To be considered an IRTP-R, the general principle notes that both seams entities should contribute to the need for a project by a "significant" amount so that there are sufficient benefits accruing to each party based on allocated costs. The seams entity not constructing the IRTP-R facility should contribute at least 5% of the loading on the constrained facility.[16] This approach is similar to the one used between PJM and the MISO for reliability-driven seams projects (see discussion in Section IV.A). For IRTP-Es, the main principle is that each seams entity should receive benefits from reduced congestion equal to or exceeding its allocated costs.[17] In addition, at least one generator in a seams entity's dispatch footprint should have a generation to load distribution factor of 5% or greater on one or more of the constraints being addressed.[18] This approach is also similar to the one used between PJM and the MISO for economically-driven seams projects (see Section IV.A). Public policy requirements are not specifically defined in the draft whitepaper but may include state or federal renewable energy standards or carbon caps.[19] To qualify as an IRTP-P, the project should be identified through the seams entities' coordinated system planning process, and determined necessary to meet the policy needs of at least one of the seams entities.[20] IRTP-Ps are not upgrades required to meet transmission service or a request for generation interconnection.

> **Observations:** We noted a potential inconsistency or at least a need for clarification in the consideration of project drivers. While it is helpful to classify projects based on reliability, economic, and public-policy drivers, few of SPP's neighbors consider each of these drivers in the same way as defined in the draft whitepaper. For example, economic benefits may be considered by a neighbor but are not necessarily quantified in terms of adjusted production costs or other metrics used by SPP. Importantly, other seams entities may not distinguish between reliability, economic, and public policy projects as is suggested in the whitepaper. In fact, SPP's own internal planning process does not categorize transmission projects based on these three drivers. Furthermore, it is not clear that seams entities will benefit from the project in the same way. This is recognized in the final section of the draft whitepaper, which notes that a project may provide benefits to a seams entity based on one driver but also provide benefits to its seams neighbor via a

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15 Draft Seams Cost Allocation Whitepaper, p. 1.

16 *Ibid.*, pp. 2-3.

17 *Ibid.*, p. 3.

18 *Ibid.*, p. 3.

19 *Ibid.*, p. 2.

20 *Ibid.*, p. 3.

different driver.[21] For example, a reliability project in one entity's footprint may provide economic benefits to the other seams entity. While this section notes that cost allocation of IRTPs should *consider* whether there are multiple benefits or drivers, it does not provide any guidance on how to do so. Furthermore, it is not clear if a project can qualify as an IRTP-R, IRTP-E, or IRTP-P (and thus be eligible for cost allocation) if the neighboring seams entity does not receive the same types of benefits. One approach may be to define an IRTP by a *major driver* but recognize that it can produce different or multiple benefits to each seams entity.

The Draft Seams Cost Allocation Whitepaper makes special mention of OATT compatibility for cost sharing and recovery. It notes that IRTP's should be identified via coordinated system planning and that each seams entity should have the appropriate cost recovery provisions to allocate the cost of IRTP's.[22] The draft whitepaper also notes that costs allocated for approved IRTP's will be recovered using SPP's then current regional cost allocation methodology, regardless of the IRTP's voltage.[23]

Observations: We agree with this provision and generally note that the allocated costs of IRTPs should be recovered by each seams entity in the same way as costs of other internal (regional or local) projects are recovered. It will, however, be important to specify the mechanisms defining how cost allocations are implemented (*i.e.*, payment methodologies) and to make sure that these mechanisms are acceptable to each entity.

B. MODELS AND MODELING ASSUMPTIONS

In terms of models and modeling assumptions, the Draft Seams Cost Allocation Whitepaper requires the use of the same tools and assumptions as those used in the coordinated planning efforts between seams entities.[24] The draft whitepaper notes that formulating similar assumptions within mutually accepted planning horizons will be essential to IRTP-R and IRTP-E screening, selection, and cost allocation solutions.[25]

Observations: Relying on consistent data inputs and models will foster a better understanding of the seams and seams-related needs between neighboring entities. However, the exchange of data in itself, even if consistent with existing coordinated

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[21] Draft Seams Cost Allocation Whitepaper, p. 5.

[22] *Ibid.*, p. 2.

[23] *Ibid.*, p. 2, footnote 2.

[24] *Ibid.*, p. 3.

[25] *Ibid.*, p. 3.

planning efforts, may still not produce agreeable results. We recommend that planning models are developed jointly for the combined footprint and validated by both seams entities. We also recommend that each pair of seams entities agree upon an explicit schedule for exchanging data, developing joint planning models, and validating the models. While the draft whitepaper does not go into much detail, a formal agreement between the seams entities should explicitly list the types of data, scenarios, and models used or developed for the analysis of seams projects.

C. METRICS AND CRITERIA

Metrics and criteria are not discussed in detail for IRTP-Rs or IRTP-Ps. Instead, the Draft Seams Cost Allocation Whitepaper offers seams entities the option to use metrics established by the SPP Economic Studies Working Group that represent reliability-, public policy-, and regulatory-driven needs.[26] For IRTP-Es, the Draft Seams Whitepaper lists three metrics that, at the minimum, should be used for benefits calculations: (1) adjusted production cost ("APC") savings; (2) project deferrals and/or displacements; and (3) reduced system losses. Additional metrics may be considered with the agreement of the seams entities. The Draft Seams Whitepaper also notes that IRTPs developed as a result of specific transmission service requests should allocate the costs to the transmission customers who submitted the request.

Observations: SPP has included in the draft whitepaper three metrics for IRTP-Es that it already considers in its own regional planning process. This is helpful because it recognizes that IRTPs will be considered in a manner consistent with SPP-internal projects. Though the three metrics for IRTP-Es are a useful starting point, non-market regions and non-jurisdictional transmission owners may not recognize or actively consider APC savings in their planning processes. In that case, it would be difficult to adopt the metric for seams planning as it would create an inconsistency with the entities' internal planning processes. Furthermore, the APC metric will understate the benefits of seams projects as it does not consider the potential that a portion of a seams project's costs could be offset by increased wheeling through and out revenues. The second IRTP-E metric, project deferrals and/or displacements, can be applied more broadly to all types of seams projects. In other words, any type of seams project can efficiently defer and/or displace any type of internal projects, including reliability and public policy-driven projects. As for system losses, it is not entirely clear if all of SPP's neighbors currently consider this benefit in their planning efforts, which would cause inconsistencies with their internal planning framework. Lastly, the draft whitepaper

[26] Draft Seams Cost Allocation Whitepaper, p. 4.

makes special mention of transmission service requests for energy transferred across a seams boundary. We propose to consider this a benefit that is specifically related to seams projects because increasing transmission capacity to accommodate service requests will generate revenues, which will offset a portion of the IRTP's costs.

The proposal to use specific metrics and criteria for IRTP-Es suggests that both seams entities would need to agree to use the same metrics and criteria. This may be difficult for some entities, as discussed above, and may result in much time spent on efforts to develop a common set of metrics, which may only reflect a "least-common-denominator" outcome. Such an outcome would not be able to recognize many potentially beneficial seams projects.

D. COST ALLOCATION

The draft whitepaper's final section on cost allocation establishes principles for each type of IRTPs. For IRTP-Rs, the proposed cost allocation principle is to reflect cost causation as measured by each entity's loading contribution to the constrained facility.[27] For IRTP-Es, the costs allocated to each entity are recommended to be based on the net present value of total *quantifiable benefits* for each entity. The Draft Seams Cost Allocation Whitepaper also notes that seams entities should be allowed to consider other arrangements, such as allocating costs based on allocation of physical transmission capacity rights if mutually agreeable to both entities.[28] For IRTP-Ps, the cost allocation principle simply notes that the project should cost-effectively meet each entity's public policy goals as compared to other options.[29] Therefore, cost allocation should follow the level to which public policy objectives are met with the new IRTP-P. The final paragraph of the Draft Seams Cost Allocation Whitepaper then notes that other drivers should be considered under each classification of IRTPs for the purposes of cost allocation.

Observations: We generally agree with assigning costs to "cost causers" but point out that the cost of IRTP-Rs (or any other type of IRTP) could be allocated either to the cost causers or beneficiaries. In fact, the entities may "cause" transmission investment needs differently than they receive benefits from an upgrade. Thus, we recommend that benefits also be considered to determine cost allocation for IRTP-Rs. For IRTP-Es, we assume the cost allocation principle (read consistently with the first two areas discussed

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[27] Draft Seams Cost Allocation Whitepaper, p. 4.

[28] *Ibid.*, p. 5.

[29] *Ibid.*, p. 5.

above) means that the costs allocated to each entity should be in proportion (but equal to or less than) the present value of quantifiable benefits calculated for each entity. An exclusive focus on the present value of benefits does not recognize non-monetized benefits that an IRTP-E may provide, such as additional reliability or public policy benefits. While the quantifiable and monetized benefits that a project may provide can serve as the foundation for cost allocation, other benefits should not be overlooked entirely even if they have not been monetized. Since transmission service across both RTO and non-RTO seams is still based on physical transmission rights, allocating costs in proportion to physical transmission capacity (and associated rights) may be a pragmatic and attractive option for many seams projects. Lastly, suggesting that IRTP-P costs should be allocated to *each entity* based on the "level" to which each entity is able to meet public policy goals is inconsistent with the proposed IRTP-P qualification criteria that requires only that an IRTP-P meet at a minimum *one* entity's public policy goals. This would not allow seams entities to consider needs different from its neighbors and poses particular problems for IRTP-Ps if state mandates vary or projects provide public policy benefit to only one of the seams entities, even though other benefits may accrue to the other neighbor.

IV. EFFORTS AT INTERREGIONAL PLANNING AND SEAMS COST ALLOCATION ELSEWHERE

This section of the report summarizes efforts to address interregional cost allocation and planning efforts in other markets. We identify successful or promising practices that may be considered by SPP and its seams neighbors. Our survey covered nine examples from RTO and non-RTO regions in the U.S. and Europe, which include cost allocation principles, seams planning processes, and benefit measurements as applied to a variety of project types such as reliability, economic, and public policy upgrades.

A. PJM-MISO SEAMS COST ALLOCATION FOR RELIABILITY AND MARKET EFFICIENCY PROJECTS

The PJM Interconnection, L.L.C. ("PJM") and Midwest ISO ("MISO") are the only two RTOs with pre-specified, FERC-approved interregional cost allocation methodologies. PJM and MISO offer such cost allocation methodologies for two types of projects: reliability driven and market efficiency (*i.e.,* economic) driven transmission upgrades (see Appendix B.1 for original tariff language). Both cost allocation methodologies rely on pre-specified qualification criteria (such as a minimum cost threshold) and pre-specified cost allocation formulas that are applied for projects that pass the qualification criteria.

For a transmission upgrade to qualify as a "***cross-border baseline reliability project***," the following criteria are applied: (1) the joint RTO planning committee must agree that the project meets applicable reliability criteria; (2) the project needs to meet the definition of a reliability project under at least one of the RTO's tariffs; (3) at least $10 million of the total project cost must be allocated to the RTO in which the project is not constructed; and (4) the neighboring RTO must contribute at least 5% to the total loading on the constrained facility. Costs are then allocated based on each RTO's relative contribution to the combined flow on the constrained facilities or defined interface. The costs allocated to each RTO will then be recovered according to the internal cost-allocation framework under each of the RTOs' respective tariffs.

"***Cross border market efficiency projects***" must meet a slightly different set of criteria: (1) the project must be evaluated as part of the RTOs' coordinated system planning process; (2) the project must quality as a market efficiency upgrade under both RTOs' tariffs; (3) total project costs must exceed $20 million; (4) the project must meet minimum benefit-cost ratios with benefits calculated based on 70% adjusted production cost savings and 30% load LMP savings to both RTOs; (5) the project must also meet each of the RTOs' individual cost-benefit criteria; and (6) the project must address at least one constraint that carries at least 5% of power flows from one generator in the adjacent market serving load in the adjacent market. Costs are then allocated based on the net present value of the total benefits calculated for each RTO. Allocated costs are then recovered through each of the RTOs' existing tariffs.

These cost allocation methodologies reflect an RTO-centric approach. For example, the evaluation criteria and benefit metrics used for seams cost allocation are based on the overlapping set of the two RTOs' existing benefits metrics. Furthermore, the approach assumes recovery of allocated costs via the RTO's existing internal cost allocation methodologies. And, consistent with the joint and common market principles shared between PJM and MISO, the methodologies do not include any physical rights to new or expanded transmission paths.

Observations: This is a valuable example because of the similarities between SPP's relationship to MISO. As is the case for PJM and MISO, SPP and MISO use similar metrics to estimate benefits. While this approach based on a fairly narrowly-defined, formulaic approach could similarly be applied to reliability and market efficiency projects between SPP and MISO, it would not be able to address many types of seams projects. The approach would also not be helpful as a seams cost allocation framework with SPP's non-RTO neighbors because many of these neighbors do not currently use similar benefit metrics. Though this approach provides significant clarity up front, it would be difficult to implement between market and non-market regions. Furthermore, neither of these two formulaic approaches would "fit" the types of candidate seams projects that have been identified by SPP staff and market participants. Even within MISO and PJM, no major cross border reliability or market efficiency projects have been

approved by the RTOs through this methodology—despite the fact that these options have now been available for several years.[30]

B. NORTHERN TIER COST ALLOCATION PROCESS AND PRINCIPLES

The Northern Tier Transmission Group ("NTTG") is a voluntary organization that coordinates transmission systems operations, products, business practices, and planning for its member utilities in the Pacific Northwest and Mountain states, serving customers in Oregon, Washington, California, Idaho, Montana, Wyoming, and Utah.[31] The utility members include Deseret Power Electric Cooperative, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, and Utah Associated Municipal Power Systems. They collectively serve 2.7 million customers and maintain over 27,000 miles of high-voltage transmission.[32]

Since NTTG is not an RTO, the boundary between each vertically-integrated utility member represents a seam similar to those of SPP and its neighbors. NTTG's Steering Committee oversees and directs initiatives undertaken by members and is comprised of representatives from regulatory utility commissions of the states where NTTG members operate, utility members, and state consumer advocacy groups.[33] NTTG has a set of cost allocation principles which it applies to proposed projects in its members' service territories (see NTTG cost allocation principles attached as Appendix B.2).

As part of FERC Order 890 compliance, the NTTG formed a Cost Allocation Committee ("CAC"), which includes staff from regulatory utility commissions, its utility members, and state consumer advocacy groups. The CAC developed four broad cost allocation principles based on the "beneficiaries pay" concept with an emphasis on consensus building and equity.[34] For example, costs cannot be allocated involuntarily and benefits received may include physical or financial transmission service rights.[35] These cost allocation principles are applied to a wide variety of transmission projects (not defined by a *de minimis* threshold), which include any

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[30] FERC approved the PJM-MISO tariff for cross-border reliability projects in an order released in FERC Docket No. ER05-6-044, *et al.*, on January 31, 2008 and the tariff for cross-border market efficiency projects in an order released in FERC Docket No. ER05-6-108, *et al.*, on November 3, 2009.

[31] Northern Tier Transmission Group, "Fact Sheet," available at: http://nttg.biz/site/index.php?option=com_content&task=view&id=122&Itemid=1. Accessed February 1, 2012.

[32] *Ibid*.

[33] *Ibid*.

[34] Northern Tier Transmission Group, "NTTG Cost Allocation Principles," May 29, 2007, p. 6. Available at: http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=193&Itemid=31.

[35] *Ibid.*, p. 7.

project that impacts one or more load serving entities in terms of supporting load growth, providing economic benefits, or meeting public policy goals.[36]

During the transmission planning process, market participants within NTTG will submit an application with details about their projects, including a proposed cost allocation methodology. The CAC will review these submitted materials and analyses of costs and benefits, check for consistency against NTTG's cost allocation principles, and provide a non-binding recommendation for cost allocation.[37] The CAC will first provide a preliminary cost allocation recommendation during the transmission study plan development and then a final written recommendation to be included in the annual or biennial transmission planning reports submitted to the Steering Committee for approval.[38] However, each project still needs approval from its applicable state commission.

Within the 2008-2009 planning cycle, for example, the CAC reviewed over $9 billion in proposed transmission projects and recommended (*i.e.,* reaffirmed) the cost allocation methodologies as proposed by project sponsors for over $7 billion of the projects.[39] One of these recommended projects, the "Energy Gateway" project, accounts for $6 billion and consists of nine segments.[40] Each of the nine segments is allocated differently to one or two transmission owners, with ownership or joint ownership of individual segments used as the tool to implement cost allocation. For example, five segments are wholly owned by each of the individual utilities, with costs recovered through their respective transmission tariffs from native load and wheeling customers. The remaining four segments are jointly-owned and cost allocation is aligned with ownership shares.

Observations: This is a helpful example because cost allocation is explicitly linked to the transmission planning process and is based on concrete cost allocation principles without being overly prescriptive. Project sponsors are encouraged to develop a cost allocation methodology for review by the CAC (which includes utility, state commission, and consumer advocate staff) to ensure adherence to the pre-specified NTTG cost allocation principles. The principles also

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36 *Ibid.*, pp. 4-5.

37 Northern Tier Transmission Group, "Cost Allocation Committee Charter," October 21, 2009, pp. 4-5.

38 Northern Tier Transmission Group, "NTTG Cost Allocation Principles," May 29, 2007, p. 12.

39 NTTG Cost Allocation Committee, "2008-2009 Cost Allocation Committee Final Report," December 1, 2009, pp. 2-4. Available at: http://nttg.biz/site/index.php?option=com_docman&task=cat_view&gid=220&Itemid=31. The sponsors for the remaining $2 billion in proposed projects did not submit sufficient information for the CAC to provide a recommendation.

40 The Energy Gateway project is comprised of 11 segments in total for a cost of over $7 billion. The sponsors for two of the segments did not provide enough information for the CAC to recommend a cost allocation.

provide for enough flexibility to allow for seams projects that benefit sponsors differently (*e.g.*, provide reliability benefits to one utility, provide market efficiency benefits to a second utility, and provide a combination of benefits to a third utility).

C. COLUMBIAGRID EXPANSION PLANNING PROCESS AND COST ALLOCATION GUIDELINES

ColumbiaGrid is a voluntary organization, which coordinates transmission systems operations and transmission planning, administers an OASIS portal, and provides corporate services for its member utilities in the Pacific Northwest and Mountain states serving customers in Oregon, Washington, Idaho, Montana, California, Wyoming, Nevada, and Utah. ColumbiaGrid has developed cost allocation methodologies for different types of projects that are analyzed during its transmission planning and expansion process (see Appendix B.3). Since ColumbiaGrid is not an RTO, the boundaries between each of its vertically-integrated utility members are similar to the boundaries between SPP and its neighbors. The utility members include Avista Corporation, Bonneville Power Administration, Chelan County Public Utility District ("PUD"), Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power.[41] They collectively own over 22,000 miles of high-voltage transmission.[42]

ColumbiaGrid's biennial transmission planning process starts with a regional needs assessment conducted over a 10-year planning horizon. "Study Teams" comprised of project sponsors, impacted system representatives, interested participants, and ColumbiaGrid staff then develop projects to address needs and impacts. While Study Teams are responsible for developing a cost allocation methodology for each project, ColumbiaGrid has already outlined guidelines and principles for the cost allocation of reliability, economic, and transmission-service-request driven projects, as well as so called "expanded scope" projects that are a combination of the previous types.[43] Table 3 below shows the drivers, project categories, and cost allocation guidelines ColumbiaGrid has developed.

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[41] ColumbiaGrid, "Participation Overview," available at: http://www.columbiagrid.org/participation-overview.cfm. Accessed February 10, 2012.

[42] ColumbiaGrid, "About the Power Grid," available at: http://www.columbiagrid.org/about-the-power-grid.cfm. Accessed February 10, 2012.

[43] ColumbiaGrid, "Planning and Expansion Functional Agreement," Appendix A: Planning Process, July 27, 2011.

Table 3
Summary of ColumbiaGrid Cost Allocation Guidelines

Driver of transmission need	Project category name	If no cost allocation agreement is reached, Staff may recommend:	Board action
Local reliability	Single System Project	N/A – costs allocated to the individual affected system	N/A
Regional reliability	Existing Obligation Project ("EOP")	Costs allocated to cost causer and/or those that may benefit from the EOP by delaying or eliminating the need for their own upgrade	Review and approve Study Team or ColumbiaGrid Staff recommendation with option to modify
Economics	Capacity Increase	New cost allocation or default allocation based on proportion of additional capacity received	Informational only, may not disapprove or modify
Transmission service and interconnection requests	Requested Service Project	Cost allocated to requesting customer and potentially to transmission owner if project can delay or eliminate needed upgrades	Review and approve Study Team or ColumbiaGrid Staff recommendation with option to modify
Combination of above	Expanded Scope Project	Cost allocation based on the category of the expansion(s)	Informational only, may not disapprove or modify

Sources and Notes: ColumbiaGrid, "Planning and Expansion Functional Agreement," Appendix A: Planning Process, July 27, 2011.

In the event that the Study Team cannot agree on a cost allocation methodology, the ColumbiaGrid Staff and Board may be called upon to provide a cost allocation recommendation. Ultimately, the final biennial transmission plan will need the approval of the ColumbiaGrid Board, comprised of three independent directors. The most recent 2012 update to the 2011 Biennial Transmission Expansion Plan included $2.4 billion of projects.[44]

[44] ColumbiaGrid, "2012 Update to the 2011 Biennial Transmission Expansion Plan," February 15, 2012, p. 6. Available at: http://www.columbiagrid.org/planning-expansion-overview.cfm.

Observations: Similar to NTTG, cost allocation in ColumbiaGrid is considered in conjunction with the transmission planning process. ColumbiaGrid, however, is more formally structured and provides specific guidance on cost allocation methodologies to be applied to projects meeting individual or a combination of needs but still allows seams projects to benefit sponsors differently. Unlike NTTG, there is more emphasis on general stakeholder rather than state representative involvement since a large portion of the ColumbiaGrid footprint consists of public power companies, such as the Bonneville Power Administration.

D. ISO-NE, NYISO, AND PJM'S NORTHEASTERN ISO/RTO PLANNING COORDINATION PROTOCOL

ISO New England ("ISO-NE"), the New York Independent System Operator ("NYISO"), and PJM are parties to the *Northeastern ISO/RTO Planning Coordination Protocol* ("Protocol"), approved by the FERC in 2004, which supports and enhances each ISO/RTO's separate planning processes by providing an overarching forum and process for coordinating system planning in the Northeast region (see Appendix B.4).[45] The Protocol develops a coordinated effort to ensure "on-going reliability and the enhanced operational and economic performance of the systems of the parties."[46]

The Protocol outlines two main responsibilities of the parties. The first responsibility is to coordinate the generator interconnection and long-term transmission service requests that may have cross border impacts. The second is to produce a Northeastern Coordinated System Plan ("NCSP") that integrates: "(1) the system plans of the parties, (2) on-going load growth and retirements or deactivations of infrastructure, (3) market-based additions to system infrastructure, such as generation or merchant transmission projects, (4) distributed resources, such as demand side and load response programs, and (5) transmission upgrades identified, jointly, by the parties to resolve seams issues or to enhance the coordinated performance of the systems."[47] The NCSPs are developed on a periodic basis for a 10-year outlook and are supported by two main groups: (1) the Joint ISO/RTO Planning Committee ("JIPC"), comprised of staff from the ISO/RTOs to conduct the analyses; and (2) the Inter-Area Planning Stakeholder Advisory Committee ("IPSAC"), which provides input from stakeholder groups such as market

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[45] ISO New England, New York ISO and PJM, "2009 Northeast Coordinated System Plan," p. 4.

[46] ISO New England, New York ISO and PJM, *Northeastern ISO/RTO Planning Coordination Protocol*, Section 1: Introduction. Available at: http://www.interiso.com/public/document/Northeastern%20ISO-RTO%20Planning%20Protocol.pdf.

[47] *Ibid*.

participants from each party, governmental agencies, regional state committees, and regional reliability councils.[48]

To develop the NCSP, the Protocol outlines the data requirements and format, timing of data exchange and verification, and processes for jointly developing the plan and incorporating stakeholder reviews. Although neighboring Canadian entities (Hydro-Québec TransÉnergie, the Independent Electric System Operator of Ontario, and the New Brunswick System Operator) are not signatories to the Protocol, they have agreed to participate on a limited basis to exchange data and other relevant information on a periodic basis.[49] Cost allocation is addressed through each party's own tariff.[50]

The most recently completed NCSP from 2009 reviewed a wide variety of topics of regional concern and impact such as proposed environmental regulations that may trigger significant retirements, transmission interconnection and operational integration of wind resources to meet state enacted RPS requirements, and demand side resource development.[51] It has also identified specific areas of improvement such as increasing the economic transfer capability between ISO-NE and NYISO, for further analysis in a separate economic study.[52]

Observations: The Northeastern ISO/RTO Planning Coordination Protocol is a helpful example of seams planning because the processes and committees have already produced several coordinated system plans, which have in turn identified seams-related upgrades. However, it is not clear how many of the identified seams projects are the direct result of the coordinated planning effort. The participating system operators believe that the protocol meets many of the interregional planning requirements of FERC Order 1000, but would need further modifications to develop a cost allocation methodology.[53]

E. UMTDI COST ALLOCATION PRINCIPLES

The Upper Midwest Transmission Development Initiative ("UMTDI") was created by the governors of Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin to "identify and

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48 *Ibid.*, Section 2.1: Inter-area Planning Stakeholder Advisory Committee and Section 2.2: Joint ISO/RTO Planning Committee.

49 *Ibid.*, Section 1: Introduction.

50 *Ibid.*, Section 4.4: Cost Allocation.

51 ISO New England, New York ISO and PJM, "2009 Northeast Coordinated System Plan."

52 ISO New England, *New York/New England Economic Study Process Report and Illustrative Results*, June 29, 2011. Available at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/reports/2011/ny_ne_eco_study.pdf.

53 Buechler, John P., "FERC Order 1000: Transmission Planning & Cost Allocation," presented at *IPSAC Webinar*, November 29, 2011, p. 8 and p. 11.

resolve regional transmission planning and cost allocation issues associated with the delivery of renewable energy from wind rich areas within the five-state footprint to the region's customers."[54] UMTDI has an Executive Committee—comprised of a utility commissioner and a governor's representative from each state—that worked with MISO staff to discuss legal issues, cost allocation, and regional planning.[55] Through this effort, UMTDI developed eight cost allocation principles for transmission investments needed to interconnect renewable generation (see Appendix B.5).

The UMTDI cost allocation principles are based on the concept that cost causers and beneficiaries should bear the cost of transmission investments.[56] The principles note that the methodologies used should be flexible and consider more than a single benefit metric and that, over time, the distinction between reliability and economic driven projects will tend to blur.[57] The principles also recognize the importance of regional planning to leverage resources throughout the region for effective transmission builds, which tend to be more efficient at higher voltages.[58] Some of these concepts have been included in the MISO's Multi Value Project ("MVP") evaluation criteria during the planning phases of the Regional Generation Outlet Study.

Observations: Somewhat similar to the RSC role in SPP cost allocation, UMTDI provided input to MISO's transmission planning and cost allocation process. MISO's adoption of the MVP evaluation criteria recognizes that regional transmission projects, especially those at higher voltages, can address a number of different drivers and provide benefits, which may vary by market participant over time. The example provides some insight into how a public policy-oriented scope was expanded to consider benefits more broadly within the transmission planning process.

F. NESCOE Draft Framework for Public Policy Projects and Associated Cost Allocation

In response to FERC Order 1000, the New England States Committee on Electricity ("NESCOE") developed a draft framework for considering transmission projects to meet public policy requirements and the associated cost allocation within the ISO-NE market (see Appendix

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[54] Upper Midwest Transmission Development Initiative, "Executive Committee Final Report," September 29, 2010, p. 1. Available at: http://www.misostates.org/files/UMTDISummaryReportFinal.pdf.

[55] *Ibid.*, p. 3.

[56] Upper Midwest Transmission Development Initiative, "Regional Electric Transmission Planning in the Upper Midwest to Support Wind Energy," June 30, 2009.

[57] *Ibid.*

[58] *Ibid.*

B.6).[59] NESCOE is a not-for-profit organization comprised of representatives from all six New England Governors to provide input and advance policies to promote reliable and economic electricity while maintaining environmental quality.[60]

ISO-NE's tariff currently addresses only reliability and economic (*i.e.,* market efficiency) transmission projects. According to the draft framework, NESCOE envisions a separate public policy-focused assessment. To start, NESCOE will review the laws and regulations of the six New England states and consider feedback from stakeholders (such as public officials) and other market participants. NESCOE will then provide to ISO-NE documentation of these public policy requirements and make them available to the public. Based on the identified public policy requirements, ISO-NE will conduct a two-step "Public Policy Study" which will follow the parameters of an Economic Study under ISO-NE's tariff. This study, which will be publicly available, will identify transmission and associated costs needed to meet the requirements. ISO-NE will perform more detailed analyses at NESCOE's request and according to parameters and assumptions identified by NESCOE.

If the ISO's studies find that public policy requirement needs align with reliability or market efficiency needs, ISO-NE will determine to what extent the proposed transmission solution addresses reliability needs. States which are determining if the proposed transmission project would meet their public policy objectives will need to agree with the ISO's identified allocation to reliability needs. The remaining portion will then be considered a public policy project for cost allocation. The framework does not provide a specific cost allocation approach but notes that (1) projects will only move forward if benefits outweigh the costs and (2) an evaluation of a project's benefits should include mechanisms for cost control, assurance of delivery of benefits (*e.g.*, RECs), whether or not PPAs have been signed, and other contractual arrangements or methods to satisfy the public policy requirement.

To qualify as a public policy project under the ISO-NE tariff, the draft framework requires that each state accepting an allocation of costs needs its state regulatory commission to approve both allocated costs and the PPAs that require the transmission investment. In a significant departure from ISO-NE's current tariff, cost allocation for public policy projects would thus be determined through agreement by the states on how to share costs for each particular project. This approach

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[59] New England States Committee on Electricity, "New England States' Draft Framework for Public Policy Projects & Associated Cost Allocation Under FERC Order 1000," January 9, 2012. Available at: http://www.nescoe.com/uploads/Order_1000_Framework_Jan_12_2012.pdf.

[60] New England States Committee on Electricity, available at: http://www.nescoe.com/. Accessed January 15, 2012.

may lead to costs shared broadly across all states, several states, or only a single state, depending on the agreed-upon scope of the identified benefits.

Observations: This is a potentially helpful example because NESCOE envisions greater state participation in defining the policy requirements that transmission planners need to meet. Furthermore, states are explicitly responsible for developing acceptable cost allocations for identified public policy projects. This approach reiterates the value of state input and participation in RTO planning, identification of benefits and metrics, and cost allocation processes—particularly for public policy projects. Nonetheless, the proposed framework is also limiting because (1) it will be difficult and contentious to determine which portions of a project specifically address public policy, reliability, and market efficiency needs; (2) the framework currently provides little guidance on how benefits should be measured and acceptable cost allocation shares could be derived; (3) the iterative study process and requirement that states individually pre-approve cost allocation will likely be very time consuming; and (4) the requirement that states approve PPAs for renewable resources utilizing the planned transmission facilities may create significant project development challenges because developers may not be able to find counterparties willing to sign PPAs until after transmission access has been secured.

G. SEAMS COST ALLOCATION FOR MICHIGAN PARS TO ADDRESS LAKE ERIE LOOP FLOWS

Persistent loop flows around Lake Erie have been negatively impacting the systems of MISO, NYISO, PJM, and the Ontario Independent Electricity System Operator ("Ontario IESO") for several years, causing excessive congestion.[61] One of the proposed solutions to better align actual flows with scheduled contract paths was the installation of several phase angle regulators ("PARs") in both the U.S. and Canada. The U.S.-based facilities are located in the MISO-portion of Michigan in ITC*Transmission's* ("ITC's") territory, but will impact the flows on all the other RTOs' systems. While all parties have highlighted the benefits of the PARs, cost allocation remains unsettled.

In a joint filing at the FERC, MISO and ITC proposed using a distribution factor ("DFAX") analysis to determine the percentage that each entity contributes to Lake Erie loop flows as a measure of cost causation (see Appendix B.7).[62] PAR costs would then be allocated in proportion to these power flows. The DFAX methodology is identical to that approved by FERC for the cost allocation of PJM-MISO cross border reliability projects (see Appendix B.1). Based on MISO's most recent analysis, the costs are proposed to be allocated 47.0% to MISO; 29.2%

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[61] Midwest Independent Transmission System Operator, Inc. and International Transmission Company d/b/a ITC*Transmission*, FERC Docket No. ER11-1844, October 20, 2010, p. 2.

[62] *Ibid.,* p. 15.

to NYISO; and 23.8% to PJM.[63] After the total costs of the PARs are allocated to each market, each of the U.S. RTOs would then decide how to recover its share of the costs from its own loads.[64] (There is no allocation to Canadian entities, as they are non-FERC jurisdictional and are already assuming the entire costs of the PARs on the Canadian side of the border.[65])

However, the RTOs have not come to agreement over the proposed cost allocation. In fact, after an unsuccessful year-long settlement process at the FERC, the case has now been set for a hearing, starting on July 30, 2012, with initial decisions due by November 13, 2012.[66]

Observations: Though cost allocation for the U.S.-based PARs is still unresolved, this is an instructive case as the facilities are wholly located within one market but clearly provide significant congestion relief benefits to neighboring markets. Despite its interregional impacts, this project would not fit the definition of an "interregional" project under FERC Order 1000, which defines interregional projects as those that physically cross the seams between regions (see Section V below). Moreover, despite the fact that the MISO's proposed cost allocation methodology has already been approved in the seams agreement with PJM for cross border reliability projects, PJM argues that it cannot accept the proposed cost allocation methodology because the PAR project does not meet the definition of a cross border reliability project under the seams agreement. This highlights the challenges that can be associated with narrow definitions of project types.

H. EUROPEAN "TRANSIT FLOW" COMPENSATION MECHANISM

The integrated European electricity system offers some parallels to the current U.S. market structure within the Eastern interconnection. For example, the European electricity system is highly interconnected but jurisdiction is split between members and non-members of the European Union (somewhat similar to FERC jurisdictional and non-jurisdictional entities). Furthermore, each European country has a national regulator (similar to separate state public utility commissions), which oversees a single or small number of government-owned or independent transmission system operators ("TSOs"). The TSOs ensure reliable operation of the high-voltage grid and facilitate non-discriminatory generation interconnection. In addition to

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63 *Ibid.*, p. 15.

64 *Ibid.*, p. 16.

65 Midwest Independent Transmission System Operator, Inc. and International Transmission Company d/b/a ITC*Transmission*, Prepared Direct Testimony of Digaunto Chatterjee, filed on behalf of the Midwest Independent Transmission System Operator, Inc., FERC Docket No. ER11-1844-002, January 31, 2012, p. 6.

66 Midwest Independent Transmission System Operator, Inc., "Order Establishing Procedural Schedule and Rules of Procedure for Hearings," FERC Docket No. ER11-1844-002, January 17, 2012.

system operations, some TSOs in Europe may also own the transmission infrastructure and be responsible for its expansion.[67] However, as in US RTO markets, the TSOs of the 27 member countries of the European Union are required to be independent of other market participants.[68]

In an effort to foster more cross border electricity trading, European Union regulation eliminated use-of-system charges for individual import/export transactions at national boundaries and for wheeling electricity through countries (collectively referred to as "transit flows"), thereby essentially de-pancaking the interconnected European system.[69] However, as cross border electricity flows have increased, so have congestion costs and the need for investment in additional national and cross border transmission capacity.[70]

Prior to 2002, cross-border capacity expansion and its cost allocation and recovery had been negotiated on a bilateral basis. Beginning in 2002, a voluntary European Inter-Transmission System Operators Compensation mechanism ("ITC mechanism") was introduced to compensate TSOs within the agreement for the infrastructure costs of hosting transit flows, which are based on actual power flows rather than assumed contract path flows, including loop flows.[71] Various compensation mechanisms had been debated and tried until a legally binding agreement became effective in March 2011, signed by the European Network of Transmission System Operators for Electricity ("ENTSO-E") and 41 TSOs from 34 countries, which includes both European Union members and non-members (see Appendix B.8).[72] ENTSO-E, an umbrella organization for

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67 European Network of Transmission System Operators for Electricity, "What is a Transmission System Operator – TSO?," available from: https://www.entsoe.eu/the-association/what-is-a-tso/.

68 *Ibid.*

69 European Commission, Commission Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity, published in the Official Journal of the European Union, July 15, 2003. Note, however, that market participants also face congestion charges that are determined by auctioning off reservations and scheduling rights to scarce cross-border intertie capacity. See Pfeifenberger, *et al.*, *Alberta's Intertie Challenges: A Survey of Market Design Options for Seams Between Power Markets*, prepared for the Alberta Electric System Operator, 2012 (forthcoming).

70 For example, congestion costs at national boundaries rose from €1.4 billion in 2006 to €1.7 billion in 2007. See Directorate-General for Energy and Transport, European Commission, *Consultation Document on the Inter-TSO Compensation Mechanism and on Harmonization of Transmission Tarification: Towards Fair and Non-Discriminatory Arrangements for Trans European Cross-Border Power Flows*, December 9, 2008, pp. 10-11.

71 European Network of Transmission System Operators for Electricity, "ENTSO-E puts in place an enduring inter-TSO compensation mechanism," March 24, 2011.

72 *Ibid.*

European TSOs, is responsible for establishing arrangements for the collection and disbursement of all payments from the ITC mechanism.[73]

The ITC mechanism establishes a fund which will compensate TSOs both for transmission losses and system costs caused by hosting cross-border flows. The fund was established by regulation[74] based on the forward-looking Long-Run Average Incremental Costs ("LRAIC") of transmission infrastructure needed to accommodate such cross-border flows of electricity.[75] The most recent fund for 2011 was set at €100 million and may be reassessed or refined based on experience.[76] Contributions into the fund are collected from each TSO based on its share of historical net flows onto and from its national transmission system compared to the other nations.[77] For "perimeter" countries which are not part of the ITC agreement, imports and exports are charged at €0.8/MWh and charges are added to the fund.[78]

Disbursements from the fund for such "cross border infrastructure compensation" are determined annually, starting with a calculation of transmission losses. The ENTSO-E is responsible for modeling each country in the interconnected European system with and without transit flows to calculate the net losses attributed to hosting transit flows on an hourly basis.[79] The cost of these calculated volumes of losses are then compensated based on rates or costs in each TSO's own national tariff.[80] The second type of disbursement is based on the incremental infrastructure costs each TSO is estimated to incur to accommodate the identified transit flows. Disbursements to each country are based on a formula, which includes consideration of each nation's transit flows compared to the total system-wide flows and a load factor.[81]

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[73] European Commission, Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, published in the Official Journal of the European Union, September 24, 2010.

[74] *Ibid*.

[75] *Ibid*.

[76] *Ibid*.

[77] *Ibid*.

[78] European Network of Transmission System Operators for Electricity, "ENTSO-E puts in place an enduring inter-TSO compensation mechanism," March 24, 2011.

[79] Referred to as the With and Without Transit ("WWT") methodology.

[80] European Network of Transmission System Operators for Electricity, "ENTSO-E puts in place an enduring inter-TSO compensation mechanism," March 24, 2011.

[81] European Commission, Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging, published in the Official Journal of the European Union, September 24, 2010.

Observations: The ITC mechanism was developed over several years of experimentation, largely driven by the depancaking of cross border transmission charges and liberalization of the European electric system. However, while the mechanism seeks to compensate countries for hosting cross-border and loop flows based on transmission losses and generic estimates of incremental system expansion costs, it does not specifically address transmission expansion nor does it seek to optimize flows between and across countries.

I. EUROPE-WIDE TRANSMISSION SYSTEM PLANNING

In 2009, the European Commission also enacted regulation to identify gaps in resource adequacy and transmission investments within and between the national markets.[82] The European Commission delegated to ENTSO-E the responsibility of developing a non-binding biennial Ten-Year Network Development Plan ("TYNDP") for the entire EU footprint.[83] A major driver of this effort is the European commitment to reduce carbon emissions (which has greatly increased the penetration of renewable generation), the need to coordinate resources for doing so, and the objective of fostering competition within the European electricity market.

The first TYNDP was published by ENTSO-E in 2010 as a pilot program with a full plan expected in 2012 (see Appendix B.9 for the Executive Summary of the TYNDP).[84] For this pilot effort, the final plan was an aggregate of the most recently available national and regional planned and projected transmission needs that were the result of regional, multilateral, or bilateral negotiations between TSOs (rather than the result of European Commission mandates or incentives).[85] Projects approved by each TSO and its national regulator typically will need to pass certain socio-economic cost-benefit analyses, which vary from country to country.

The 2010 TYNDP highlighted several criteria used by European TSOs to evaluate transmission projects against projected costs, such as the ability of the project to: (1) maintain system adequacy and operational security to meet demand growth and reduce outages; (2) integrate renewable energy; (3) foster competition and reduce prices; (4) produce environmental benefits such as CO_2 emission reduction; (5) garner social acceptance especially with regard to siting issues; (6) be technically feasible; (7) reduce production, operational, maintenance, or overall investment costs; and (8) reduce network losses and congestion.[86] This non-exhaustive list

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82 European Parliament, Regulation EC No 714/2009, July 13, 2009. Available at: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF.

83 European Network of Transmission System Operators for Electricity, *Ten-Year Network Development Plan 2010-2020*, June 28, 2010, p.8. Available at: https://www.entsoe.eu/index.php?id=232.

84 *Ibid*.

85 *Ibid.*, p. 163.

86 *Ibid.*, pp. 136-140.

considers both quantitative and qualitative criteria and is implemented differently by each TSO and nation.

While the 2010 pilot TYNDP did not rank projects or conduct economic analyses, it evaluated and included high-voltage transmission investments (new builds or upgrades) of "European significance" that addressed at least one of the three pillars of European Union energy policy: (1) security of supply; (2) tackling climate change by integrating renewable energy sources; and (3) market integration (lowering aggregate generation costs by increasing cross-border trading of power).[87] The 2010 TYNDP identified a potential investment need of 42,100 km of new and upgraded high-voltage AC and DC transmission lines (both within and between countries) over the next 10 years.[88] Over the next five years, the estimated cost of investments of "European significance" is between €23 billion and €28 billion.[89]

Lastly, the pilot program also focused on establishing and refining the processes and procedures that will be used in future TYNDPs, development of future scenarios, tracking resource adequacy, and identifying challenges to transmission development.

Observations: While *ad hoc* transmission upgrades have already occurred between countries, planning for European cross border investments, much like interregional transmission planning in the U.S., has only recently become more formalized and encouraged by the regulatory process. The 2010 pilot TYNDP provides some insights into the various benefits metrics considered in the European planning processes, which include a variety of quantitative and qualitative criteria. Given the similar policy goals throughout Europe, such as climate-change-related mandates, policy makers and national regulators have become important stakeholders in the TYNDP process. At this stage, however, cost allocation for cross border projects has not been formalized as part of the TYNDP process.

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87 *Ibid.*, p. 9.

88 *Ibid.*, p. 163. The members of ENTSO-E collectively operate 300,000 km of high-voltage transmission lines.

89 *Ibid.*, p. 16.

V. FERC ORDER 1000 REQUIREMENTS

As noted earlier, FERC issued its rulemaking on "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," as Order No. 1000 on July 21, 2011. As the title of Order 1000 suggests, the rule is as equally focused on transmission planning as it is on cost allocation. FERC Order 1000 requirements for interregional planning and cost allocation will need to be considered in the development of the proposed seams cost allocation framework for SPP.

With respect to interregional planning and cost allocation, Order 1000 recognizes that joint coordinated planning, as already discussed in FERC Order 890, "may identify solutions to… needs that are more efficient than those that would have been identified if needs and potential solutions were evaluated only independently by each individual transmission provider."[90] While previous FERC orders have been largely focused on regional planning—planning within an RTO region or within a pre-defined region as reported to FERC in Order 890 compliance—Order 1000 recognizes that "the lack of coordinated transmission planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers of transmission providers, which may result in rates that are unjust and unreasonable and unduly discriminatory or preferential."[91] Furthermore, the FERC noted that challenges associated with cost allocation are a major barrier to getting needed transmission built.[92]

Order 1000 establishes minimum requirements on interregional planning with the goal of identifying interregional projects[93] "that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities."[94] To do that, entities can leverage their existing regional planning processes by adding processes to accommodate interregional transmission planning. Order 1000 requires that the interregional transmission coordination procedures for each pair of seams neighbors be memorialized in each transmission provider's OATT and optionally in a separate coordination agreement filed with the Commission.[95] The FERC requires that interregional planning processes facilitate: (1) the articulation of

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[90] Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23, Order No. 1000, July 21, 2011, p. 274 ("Order 1000").

[91] *Ibid.*, P 350.

[92] *Ibid.*, P 485.

[93] Order 1000 refers to "interregional projects," while this report uses the slightly broader term "seams projects," which may be wholly located within one seams entity's footprint as discussed in Section VII.

[94] Order 1000, P 393.

[95] *Ibid.*, P 475.

transmission needs and potential solutions for each region; and (2) identification and joint evaluation of cost-effective interregional solutions to those regional needs.[96]

An important component of the interregional planning process is the exchange of data, with a description of the type of transmission studies to be conducted,[97] and transparency (including establishing websites or email lists to disseminate information).[98] Order 1000 requires that data be exchanged at least annually,[99] supported by a joint effort to harmonize differences in assumptions, models, and criteria used to evaluate proposed interregional projects.[100] Interregional project are defined as projects that are physically located in both regions.[101]

The order also requires that interregional projects must first be proposed as an interregional project in each region in which the project would be located, thereby triggering a process for the seams neighbors to jointly evaluate the proposed project.[102] While the FERC did not specify a timeline for interregional transmission coordination or a deadline for project proposals, Order 1000 notes that the time frame for an interregional process should be within the same general time frames as each region's consideration of intra-regional projects and to allow for coordination and joint evaluation.[103]

In terms of cost allocation, Order 1000 requires that regions develop a common method or methods for allocating the entire prudently-incurred costs of a new interregional facility among the beneficiaries of the transmission facility in which the facility is located.[104] However, rather than prescribe uniform methodologies, Order 1000 articulated broad principles to allow for flexibility and encourage direct negotiation between entities.[105] The six cost allocation principles that apply to interregional transmission projects are summarized in Table 4.

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96 Order 1000, P 396.

97 *Ibid.*, P 398.

98 *Ibid.*, P 458.

99 *Ibid.*, P 454.

100 *Ibid.*, P 437.

101 *Ibid.*, P 416.

102 *Ibid.*, P 436, P 442.

103 *Ibid.*, P 438, P 439, P 440.

104 *Ibid.,* P 578, P 640.

105 *Ibid.*, P 561, P 604, P 606.

Table 4
FERC Order 1000 Interregional Cost Allocation Principles

Principle 1	Costs allocated to each seams entity must be roughly commensurate with estimated benefits
Principle 2	A region that receives no benefit from an interregional facility must not be involuntarily allocated any costs of that facility
Principle 3	Benefit-cost thresholds, if used, cannot exceed 1.25 for purpose of interregional cost allocation
Principle 4	Costs cannot be assigned involuntarily to transmission planning regions in which the transmission facility is not located
Principle 5	The cost allocation method and data requirements for determining benefits and identifying beneficiaries must be transparent with adequate documentation to allow a stakeholder to determine how they were applied
Principle 6	Different entities may use different cost allocation methods for different types (*i.e.,* reliability, congestion relief, public policy) of projects as long as the methods are set out and explained in detail

Sources and notes:
Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23, Order No. 1000, July 21, 2011.

Principle 1 requires that allocated costs are at least approximately linked to the beneficiaries of an upgrade.[106] Specifically, for interregional projects the benefits to each entity should be roughly commensurate with the costs allocated to each. Though Order 1000 declined to specifically define "benefits" or "beneficiaries," it is clear that benefits may be related broadly to reliability, congestion relief, or meeting public policy goals.[107] Principle 2 requires that sufficient benefits exist, either at present or in a likely future scenario, before project costs are allocated to a region.[108] Principle 3 does not require the use of benefit-cost ratios but, to the extent that one is used, seeks to ensure that the threshold is not so high as to preclude projects that would provide "worthwhile" benefits.[109] In special scenarios, a benefit-cost threshold higher than 1.25 may be used, but seams entities will be required to justify the higher threshold and the

[106] Order 1000, P 622.
[107] *Ibid.*, P 624.
[108] *Ibid.*, P 637.
[109] *Ibid.*, P 646, P 647.

FERC will need to approve its use. Principle 4 is consistent with Order 1000's definition of an interregional project, which is limited to projects that are physically located in both regions, but does not preclude cost allocations to other regions as long as these regions voluntarily agree to such allocations.[110] Principle 5 reiterates cost allocation and data transparency requirements for determining benefits and identifying beneficiaries for an interregional facility to ensure that stakeholders are able to determine how cost allocation methods were applied to a proposed transmission facility. And, finally, Principle 6 recognizes that different cost allocation methodologies may be used by each seams entity and these methodologies may be different for each type of project.

Order 1000 also requires that developers of interregional projects first propose them through the regional planning processes of each region where the facility is located to trigger the interregional coordination process. The interregional project would only be eligible for cost allocation under the interregional cost allocation methodologies developed pursuant to Order 1000, if each portion of the interregional project ultimately is also approved by the corresponding seams entity's regional planning process.[111] This provision is intended to forge a closer alignment between transmission planning and cost allocation.[112] Lastly, Order 1000 does not require, but strongly encourages state agency participation in an open stakeholder process[113] as well as multilateral seams coordination.[114]

Compliance filings for the interregional aspects of Order 1000 are due on April 11, 2013—18 months after the effective date of the final rule.

VI. FRAMEWORK FOR INTERREGIONAL PLANNING AND COST ALLOCATION

This section presents our proposed framework for interregional planning and cost allocation. To make the individual building blocks of the proposed framework more tangible, we begin with a case study summarizing recent experience with the multi-party Acadiana Load Pocket project that resulted in a successful cost allocation. As we discuss the recommended interregional planning and cost allocation framework and the related principles and guidelines for benefit

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[110] Order 1000, P 657.

[111] *Ibid.*, P 436.

[112] *Ibid.*, P 582.

[113] *Ibid.*, P 402.

[114] *Ibid.*, P 417.

measurement and cost allocation, we will refer to this project and the "lessons learned" from this case study to make our recommendations more tangible. Section VI.B discusses key considerations for our framework, including the importance of integrating seams cost allocation with the interregional planning process. Section VI.C then presents an overview of the "building blocks" of our proposed framework and how each of them supports seams cost allocation.

A. CASE STUDY: ACADIANA LOAD POCKET PROJECT

To help develop a robust cost allocation framework, we closely reviewed experience with a recent "seams project"—the Acadiana Load Pocket ("ALP") Project. The approximately $200 million ALP Project is a series of new transmission lines and substations jointly developed by three transmission system operators—Cleco Power ("Cleco"), Lafayette Utilities System ("LUS"), and Entergy Gulf States Louisiana ("EGSL")—to address a variety of reliability and economic considerations related to serving a load pocket in south-central Louisiana.

While the ALP Project does not involve RTO seams, it specifically addresses transmission needs along the seam between three individual transmission service providers. The challenges encountered in developing the project and the associated cost allocation proved to be helpful in our effort to develop the proposed interregional planning and cost allocation framework. Specifically, the ALP Project is a helpful case study because: (1) it is a seams project involving multiple transmission providers; (2) it provides both reliability and economic benefits to the sponsors; (3) the reliability and economic benefits differ significantly for each of the sponsors; (4) cost allocation was implemented by aligning it with physical ownership of newly constructed facilities; (5) there was strong public utility commission involvement; and (6) the project has already been approved by the Louisiana Public Service Commission.

The ALP is defined as the electrical loads south of U.S. Highway 190 to the Gulf of Mexico, west of the Atchafalaya Basin, and east of the City of Jennings as shown in Figure 2 below.[115] The loads within the ALP area include Cleco, LUS, EGSL, South Louisiana Electric Cooperative Association, South Louisiana Electric Membership Corporation, and Louisiana Energy and Power Authority.[116] In 2008, load was approximately 1,700 MW while total generation capacity was only 965 MW.[117]

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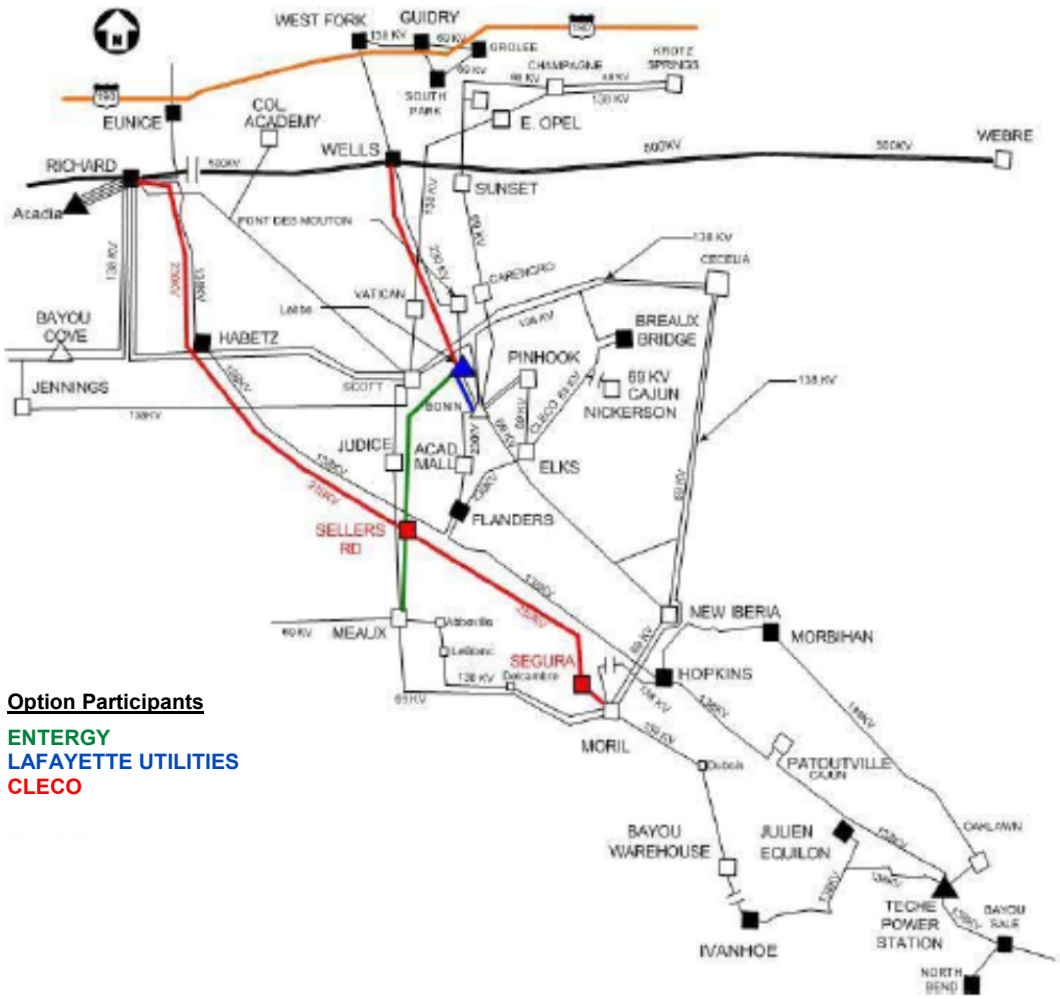
[115] Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008, p. 4 ("Whitmore Testimony, 7/14/08").

[116] *Ibid.*, p. 4.

[117] *Ibid.*, Exhibit TJW-2, p 1 and p. 5.

The ALP region had been experiencing several problems, including an increase in transmission loading relief ("TLR") procedures to curtail non-firm service, an over-reliance on inefficient generating units needed for voltage support, disconnects between modeling assumptions and actual operational limits, a lack of operational flexibility in the load pocket, and limitations to accommodate additional transmission service.

Figure 2
Acadiana Load Pocket Project



Sources and notes: Southwest Power Pool, Inc., "Cleco, Entergy, and Lafayette Utilities System to improve electric service in South Louisiana through joint transmission project," January 19, 2009.

The ALP area had been experiencing reliability problems since the early 2000's and a new substation was completed in 2005 to alleviate some of the TLR procedures that forced the

curtailment of non-firm transmission service and relied on more expensive generation within the load pocket.[118] Despite the new substation, conditions within ALP continued to worsen and a joint study effort, including SPP as the Independent Coordinator of Transmission ("ICT") for Entergy, identified the following major issues within the ALP:

- **Increase in TLR procedures and their severity** — Between November 2006 and November 2007, SPP reliability coordinators initiated 125 TLR procedures, primarily on EGSL's lines for the loss of Cleco's or LUS's lines. The TLR procedures included both firm and non-firm curtailments for importing energy from external generators and required re-dispatch of Cleco's Teche and LUS's Bonin Power plants (discussed below).[119]
- **Over-reliance on inefficient units** — Because of import constraints, two plants within ALP, Cleco's Teche Power plant and LUS's Bonin Power plant, were required to be online during moderate to high load conditions.[120] The Teche plants are described as "old, less efficient steam turbines" with units 1, 2, and 3 placed in service in 1953, 1956, and 1971, respectively.[121] Cleco's Teche Unit 3 is the **single largest generation contingency** in ALP[122] and provides both **load-serving capability** and **voltage support,** which may complicate any scheduled maintenance and cause reliability concerns if the unit was to be offline for an extended period of time.[123] If a solution such as the ALP Project was implemented, estimated fuel savings to Cleco would be $144.2 million between 2010 and 2016 and $905.6 million between 2010 and 2039.[124] LUS may also realize economic benefits such as fuel cost savings and increased generation flexibility.[125]
- **Disconnects between planning model assumptions and operation—**
    - Long-term modeling of flows versus operational realities — In the long-term model, only firm network resources were dispatched and confirmed long-term firm transmission transactions are modeled to meet each control area's load. However, the increase in (more efficient) merchant generation with short-term economic power sales causes a deviation in modeled power flows and actual use

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[118] Whitmore Testimony, 7/14/08, p. 7 and p. 11.

[119] *Ibid.*, p. 12.

[120] *Ibid.*, p. 10.

[121] *Ibid.,* p. 5.

[122] *Ibid.,* p. 10.

[123] *Ibid.,* p. 13.

[124] *Ibid.,* p. 25.

[125] *Ibid.,* p. 19.

of the transmission system.[126] The result was that the long-term model did not accurately capture how heavily the transmission system was being used to import into ALP.

  - Natural gas prices — Unforeseen increases in natural gas prices caused economic dispatch to favor imported energy, putting stress on the existing transmission system which was not designed for such significant reliance on imports.[127]
  - Power flow model correction — A smaller conductor used to "expeditiously" replace lines damaged by Hurricane Lili in 2002 was incorrectly recorded in the power flow model and caused a fault, forcing lines out of service.[128]
- **Lack of operational flexibility** — Increased reliance on imports means that it was more difficult to obtain scheduled outages on the transmission system to perform routine maintenance.[129]

In 2008, a joint study facilitated by SPP identified several upgrade options, one of which was the ALP Project, comprised of a reliability component to address TLRs and related concerns and an *additional* economic component as shown in Table 5 below.

While the reliability component addressed historical and current reliability concerns, the economic component was deemed valuable to the parties to create "optionality" by allowing the removal of must-run status for older units and increased operational flexibility.

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126 Whitmore Testimony, 7/14/08, p. 7.

127 *Ibid.,* p. 9.

128 *Ibid.*, p. 9.

129 *Ibid.*, p. 10.

Table 5
ALP Project Components, Benefits, and Estimated Costs

Component	Benefits	Total Est. Cost ($ million)
Reliability Component (Responsible Entity):		**$71.9**
• New 230 kV line from Labbe - Bonin (LUS) • 500/230 kV auto transformer at Wells (Cleco) • New 230 kV line from Wells - Labbe (Cleco/LUS) • New 230 kV line from Labbe - Meaux (EGSL) • 230/138 kV auto transformer at Meaux (Cleco)	• Relieves Entergy TLR procedures (allows for increased economic import) • Accommodates load growth and improves load serving capability[130]	Allocated roughly based on load ratio share and then matched with component ownership
Economic Component (Responsible Entity):		**$128.1**
• 500/230 kV auto transformer at Richard (Cleco/EGSL) • New 230 kV line from Richard - Sellers Road (Cleco) • New 230 kV substation at Sellers Road to connect Labbe-Meaux and Richard - Sellers Road (Cleco) • New 230 kV substation at Segura near Moril (Cleco) • New 230 kV line from Sellers Road - Segura (Cleco) • 230/138 kV auto transformer at Segura (Cleco) • New 138 kV line from Segura - Moril (Cleco)	• Allows removal of must-run designation for Cleco's Teche and LUS's Bonin • Economic benefits largely to Cleco (est. fuel cost savings of $906 million 2010-2039) • Additional generation dispatch flexibility and potential fuel cost savings for LUS	Approx. 70% allocated to Cleco (with smaller shares to EGSL and LUS) and then matched with component ownership
Total Estimated Cost *(as of 2008)*		**$200.0**

Sources and notes: Components from: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008. Benefits from: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008 and Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC, Louisiana Public Service Commission Docket No. U-31196, "Direct Testimony of Mark F. McCulla," November 13, 2009. Cost estimates from: Southwest Power Pool, Inc., Cleco Power - Lafayette Utilities System-SPP/SPPICT-Entergy Joint Transmission Planning Study, "Reliability and Economic Study for the 2008 Transmission Expansion Plan of the Acadiana Area Load Pocket," October 2008.

Cost allocation was developed by first determining which portion of the entire project addressed reliability concerns and which portion economic needs. For the reliability component, cost allocation was based on an adjusted load ratio share of Cleco, LUS, and EGSL as a proxy of received reliability benefits. (The adjustment was made to account for additional loads that each

[130] *Ibid.*, p. 19.

utility served under contract, using projected 2012 load.) The adjusted load ratio shares as applied to the estimated reliability component costs are shown in column [2] in Table 6.

Table 6
ALP Project Reliability Component by Adjusted Load Ratio Share

			Allocated ALP Project Reliability Component Cost ($ Million)		
Sponsor	Adj. Projected 2012 Load (MW)	Adj. Load Ratio Share (%)	Based on Adj. Load Ratio Share	Based on Ownership	Based on Revised Estimates
	[1]	[2]	[3]	[4]	[5]
EGSL	877	47%	$33.6	n/a	n/a
Cleco	732	39%	$28.0	$26.6	$30.1
LUS	270	14%	$10.3	n/a	n/a
Total	**1,879**	**100%**	**$71.9**		

Sources and notes:

[1]: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008, pp. 21-22.

[2]: Percentage of each utility's projected load as a share of total.

[3]: [1] x [2].

[4]: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, "Direct Testimony of Terry John Whitmore," July 14, 2008, p. 22.

[5]: Cleco Power LLC, Louisiana Public Service Commission Docket No. U-30689, Subdocket A, "Direct Testimony of Terry John Whitmore," November 4, 2008, p. 6.

According to filings made on behalf of Cleco, the $28.0 million share of the reliability component (as shown in column [3] of Table 6 above) was approximately aligned with the $26.6 million direct cost of constructing and owning the new transmission components interconnected to the Cleco system (as shown in column [4]). Therefore, in the first iteration of the Memorandum of Understanding ("MOU"), Cleco assumed $26.6 million in reliability-related ALP Project costs. In an updated MOU, Cleco and LUS each slightly expanded their projected buildouts with Cleco's total estimated reliability costs increasing by $3.5 million to $30.1 million (as shown in column [5]). Despite this revision, the underlying allocation does not change. In fact, the MOU is structured so that each utility is individually responsible for components of the ALP Project in a way that is *roughly commensurate* with benefits received. For the economic component, Cleco is the main beneficiary and therefore will own and construct the majority of those facilities at a total estimated cost of $87.1 million.[131]

[131] Whitmore Testimony, 7/14/08, p. 23.

There are at least five important "lessons learned" from the ALP Project case study, as summarized by SPP Staff.[132] First, there was general agreement that the various problems identified in the ALP had to be addressed and that **a seams solution could provide both individual and joint benefits**. Second, it was recognized that **needs and drivers were different for the parties involved**. The ALP Project provided both reliability and economic benefits, which accrued to parties differently. Third, **transmission planning and cost allocation was jointly considered** so that a solution and its associated costs produced equitable results. Fourth, **cost allocation via transmission ownership, not financial transfers, was easier to accomplish**. Especially for non-market regions and utilities, financial transfers may not even be possible or prove difficult to implement. For the ALP Project, each "seams entity" shared costs by building, owning, and maintaining a segment of the buildout. Similarly, each entity is responsible for recovering approved ALP Project-related costs through its own transmission tariff. Parties were also able to agree to the **approximate magnitudes of contribution rather than a strict matching of costs to benefits**. Cost allocation was determined by considering the approximate magnitude of the reliability and economic benefits to each party involved while also considering the geographic location of the future facilities and operational flexibility. And finally, **strong state-level participation** via Commissioner Jimmy Field of the Louisiana Public Service Commission and the ICT staff helped facilitate the process.

B. CONSIDERATIONS FOR THE PROPOSED COST ALLOCATION FRAMEWORK

We developed our cost allocation framework based on our review of barriers to seams cost allocation, the Draft Seams Cost Allocation Whitepaper, experiences elsewhere with interregional planning and cost allocation, FERC Order 1000, the ALP Project lessons, and discussions with SPP staff, SPP RSC staff, and stakeholders. Our framework also includes a set of cost allocation principles and methodologies to be used by SPP and its seams neighbors. Several objectives were identified by the Joint Project Team during the development effort, including that this framework:

1. Be compliant with FERC Order 1000;
2. Define a clear cost allocation methodology that provides enough guidance to be actionable;
3. Be flexible enough to be applied to all of SPP's neighbors, which consist of both FERC jurisdictional and non-jurisdictional entities;
4. Accommodate both bilateral and multilateral agreements to address multi-party seams;

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[132] Kelley, David, SPP Seams Steering Committee, "Acadiana Load Pocket," memo to Seams Cost Allocation Task Force ("SCATF"), September 12, 2011.

5. Be able to be applied to individual seams projects or groups of seams projects (identified either unilaterally or jointly);
6. Be robust enough to accommodate different types of seams projects and projects that offer different types of benefits to different seams entities; and
7. Allow for learning based on experience.

These objectives also ensure consistency among seams agreements with different entities, while allowing for variation amongst agreements to account for a range of different types of projects and seams entities.

While the focus of our report is on seams cost allocation, our review of relevant experiences strongly suggests that seams cost allocation issues cannot be successfully addressed without consideration of several related components of the overall interregional transmission planning process. In fact, ***cost allocation is an integral part of interregional planning***. For example, if costs are to be allocated based on benefits, there are fundamental requirements to calculating those benefits for each seams entity. These include availability of validated system data and planning models and a clear understanding of how transmission additions are planned and evaluated by each seams entity. Another consideration is state-level involvement in the planning process. As mentioned in the lessons learned from the ALP Project and interregional planning and cost allocation efforts elsewhere, state-level involvement during the planning and analysis stage more likely leads to an agreeable alignment of allocated costs and benefits to each of the seams entities.

Ideally, the cost allocation framework would be an integral part of a bilateral or possibly multi-lateral interregional planning agreement between the individual seams neighbors. It would include a process and timeline for proposing or identifying potential seams projects as well as commitments to meet regularly, develop jointly the models needed to accurately evaluate seams projects, and assess the benefits of the project to each entity consistent with (at minimum) each entity's internal planning process and cost allocation methodologies. The framework would also be flexible enough to consider additional benefit metrics and cost allocation methodologies that are not currently used in the entity's internal processes.

Through our discussions with SPP and SPP RSC Staff, we found that SPP's joint operating agreements ("JOAs") with Associated Electric Cooperative, Inc. ("AECI") and MISO were the most logical starting points in our efforts to develop a more robust interregional planning and cost allocation framework.[133] Each JOA is structured as a bilateral agreement and describes the

[133] In addition to the JOAs, SPP has a seams agreement with less detailed language with Entergy and three operating agreements with Southwestern Power Administration ("SWPA"), Tennessee Valley Authority ("TVA"), and Western Area Power Administration ("Western"), which are largely focused on the reliable
(footnote continued on next page)

process for the development of a Joint Coordinated System Plan ("JCSP") to be led by a Joint Planning Committee ("JPC", comprised of planning staff from both entities), with input from an Interregional Planning Stakeholder Advisory Committee ("IPSAC").[134]

As set out in the JOAs, the purpose of the JCSP is to identify transmission expansions or enhancements to maintain reliability, improve operational performance, provide an economic benefit, or enhance the competitiveness of electricity markets in the combined footprint.[135] The JOAs describe in some detail the types of models, studies, and updates (*e.g.,* planning models, load flow, short circuit, and stability studies) that would be required to develop the JCSP and the timing of such information exchange and planning meetings. The JOAs also note that "single party planning" (*e.g.*, for each entity's internal or regional system) and generator interconnection and long-term firm transmission service requests in one system which may impact the other system should be coordinated with the JCSP process. With respect to cost allocation for seams projects, however, the JOAs only state that it would be decided on a case-by-case basis.

Our proposal is to leverage the existing JOAs by expanding on the already-specified processes and committees, provide guidance on missing but critical components, and adding proposed cost allocation principles and benefits measurements. We discuss each of these points in the following sections and present illustrative "straw man" tariff language in Appendix C that could serve as the starting point to expand the existing JOA into a comprehensive cost allocation framework between SPP and its seams neighbors.

C. BUILDING BLOCKS OF THE PROPOSED INTERREGIONAL PLANNING AND COST ALLOCATION FRAMEWORK

We have identified seven "building blocks" needed to support the proposed interregional planning and cost allocation. These building blocks are shown in Figure 3 and discussed in this and the following sections of our report. We also provided in Appendix C a redlined version of and inserts to SPP's existing JOA to provide a "straw man" illustration of how these building

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(footnote continued from previous page)

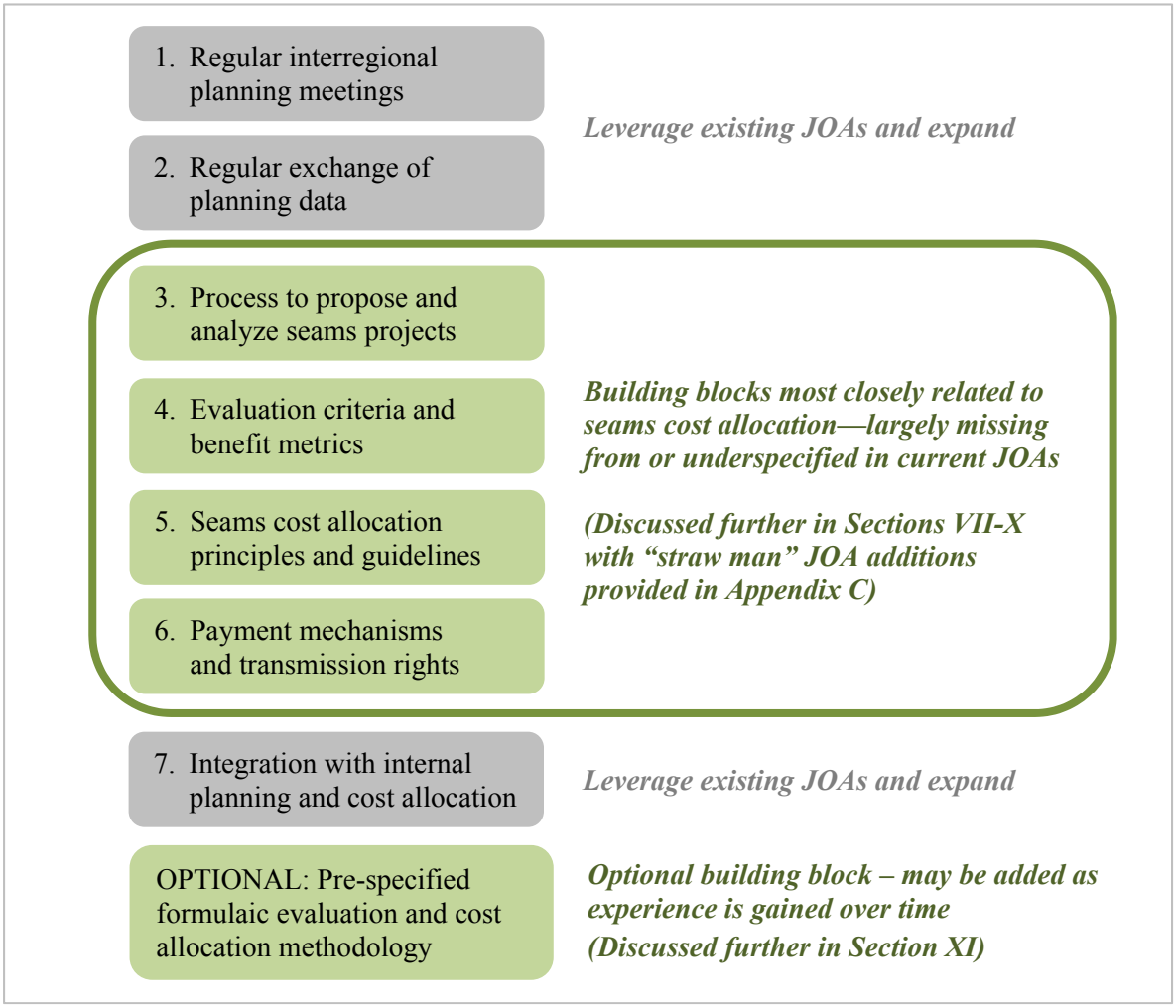
operation of interconnected facilities. SPP also has an additional operating agreement with ERCOT for the DC tie lines. SPP does not currently have a JOA or operating agreement with CLECO.

134 SPP and Associated Electric Cooperative, Inc., *Joint Operating Agreement*, "Article Seven," July 20, 2011 and SPP and Midwest ISO, *Joint Operating Agreement*, "Section IX," March 25, 2011.

135 SPP and Associated Electric Cooperative, Inc., *Joint Operating Agreement*, "Article 7.3: Joint and Coordinated System Planning," July 20, 2011 and SPP and Midwest ISO, *Joint Operating Agreement*, "Section 9.3: Coordinated System Planning," March 25, 2011. The SPP-AECI JOA refers to the identification of economic benefit whereas the SPP-MISO JOA refers to enhancing competitiveness.

blocks and our recommendations for the proposed cost allocation framework could be integrated into SPP's existing JOAs.

Figure 3
Building Blocks of Proposed Interregional Planning and Cost Allocation Framework



1. Building Blocks Nos. 1, 2, and 7

Building blocks Nos. 1, 2, and 7 already exist in some form in the JOAs but would need to be expanded. For example, ***building block No. 1*** requires a commitment to ***regular interregional planning meetings*** of the seams entities, as well as coordination with state, federal, and multi-state entities. While the current JOAs already provide for these commitments, we recommend more direct participation of regulatory commission staff from states affected by the particular seam in the planning and cost allocation discussions under the JOAs. Involvement by state regulatory staff in the evaluation of proposed seams projects, through a more prominent role of the IPSAC, for example, would likely facilitate the development of seams projects and cost

allocations that will ultimately be acceptable to each of the involved state commissions in their determination of needs, permitting, and, where applicable, retail rate recovery of the selected projects. As mentioned in our review of seams cost allocation elsewhere, Northern Tier Transmission Group's cost allocation framework emphasizes the importance of early involvement by state commissions.[136]

In addition, while the JOAs may specify bilateral meetings between entities, they should be flexible enough to ***evolve into agreements between multiple entities***, if doing so can more effectively address challenges along seams, such as on the eastern side of SPP that involve multiple entities.[137] In the WECC for example, there are several standing seams-related planning groups where all the transmission owners involved with certain seams (*e.g.*, the seam between Arizona, California, and Southern Nevada) meet periodically to coordinate transmission planning.

For ***building block No. 2***, we recommend that seams entities should commit to the timely ***exchange of planning data*** as already envisioned in the current JOAs, which provide detailed lists of data to be exchanged for the purpose of developing the JCSP. However, to further facilitate identification and analyses of seams projects, we additionally recommend that seams neighbors ***jointly develop and validate load-flow cases and other planning models*** for the combined footprint and their combined planning horizon. This would allow each seams entity to accurately analyze the system of its neighbor to develop potential seams projects and prepare credible initial system analyses and cost-benefit evaluations of the projects.

Building block No. 7 addresses the ***integration of the interregional planning and seams cost allocation with each entity's internal planning and cost allocation processes***. This includes adding to the JOAs specific provisions that address who can propose a seams project, who can build and operate it, how planning analyses for seams projects are initiated, and how seams projects are integrated with internal planning processes and cost recovery, including planning in response to generation interconnection and transmission service requests, which can impact the overall benefits of seams projects.

Illustrative redlines to the existing JOA that provide a "straw man" starting point for addressing our recommendations related to building blocks Nos. 1, 2, and 7 are found in Appendix C.1.

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[136] Northern Tier Transmission Group, "NTTG Cost Allocation Principles," discussion of Principle 3a, p. 10.

[137] This is mentioned in the JOA with MISO in Section 9.1.1 (j): "The JPC may combine with or participate in similarly established joint planning committees amongst multiple entities engaging in coordinated planning studies under tariff provisions or established under joint agreements to which the Parties are signatories, for the purpose of providing for broader and more effective inter-regional planning coordination."

2. Building Blocks Nos. 3, 4, 5, and 6

Building blocks Nos. 3 through 6 are most directly related to seams cost allocation. They are also underspecified and largely missing from the existing JOAs. We briefly describe these four building blocks below. Illustrative redlines to the existing JOA that could serve as the starting point to implement our recommendations for building block No. 3 are provided in Appendix C.1. In addition, Appendix C.2 provides straw man inserts to illustrate how building blocks Nos. 4, 5, and 6 could be added to the existing JOA.

Building block No. 3 serves to define the parameters of a seams project and requires the specification of a ***process to propose and analyze seams projects***. The JOAs largely rely on the JCSP process to identify seams projects. We propose to establish additional options under which seams entities (*e.g.*, through their participating transmission owners) could ***unilaterally or jointly*** propose seams projects outside the JCSP process. SPP will also need to specify how their transmission owners and other market participants can propose seams projects to SPP. Our recommendations as to building block No. 3 are discussed in more detail in Section VII immediately below.

To implement ***building block No. 4***, we recommend that each seams entity comprehensively specify the ***evaluation criteria and benefit metrics*** they will use for seams project evaluation. These criteria and metrics would not need to be identical across seams entities but would, at a minimum, need to include a comprehensive list of all benefits and metrics that each entity uses in its internal transmission planning process. In addition, we recommend the addition of benefits and metrics that are unique to seams projects, such as the value of wheeling through and out revenues. Our recommendations as to building block No. 4 are discussed in more detail in Section VIII of this report.

Building block No. 5 consists of pre-specified ***seams cost allocation principles and guidelines***. Rather than resolve seams cost allocation on a case-by-case approach, as is provided for under the current JOAs, we recommend the addition of principles and guidelines that would serve as the overarching framework for developing transmission cost allocation for seams projects. Section IX of this report specifies a number of recommended principles and guidelines and discusses our recommendations for building block No. 5 in more detail. We also provide case studies of how cost allocation shares might be derived for specific types of projects, based on the evaluation criteria and benefit metrics derived in building block No. 4.

Building block No. 6 specifies ***payment mechanisms*** that allow for the actual sharing of project investment costs or project revenue requirements across the seam. Given the different characteristics of seams projects and limitations that certain entities may have in paying for transmission upgrades they do not own, we recommend that the seams agreements specify

several options for payment mechanisms, such as ***shared ownership or financial transfers*** that can be used to implement the agreed-upon cost allocations. We additionally recommend that ***physical or financial transmission rights*** are provided to each seams entity in exchange for these ownership shares or payments. Our recommendations for building block No. 6 are discussed in more detail in Section X of this report.

3. Optional Building Block

Finally, we recommend an ***optional building block*** that could allow for the inclusion of ***pre-specified formulaic evaluation and cost allocation methodologies for specific project types.*** Several seams cost allocation methodologies in other markets include such pre-specified formulaic approaches (*i.e.*, those for interregional reliability and economic projects between the MISO and PJM). While such formulaic approaches have the potential to streamline the evaluation and cost allocation of seams projects, many seams projects will not "fit" the pre-specified qualifications criteria. We thus recommend that seams projects that do not fit such pre-specified options be evaluated under the general cost allocation framework as summarized above. Our recommendations for such an optional cost allocation building block are discussed in more detail in Section XI of this report.

VII. PROCESS TO PROPOSE AND ANALYZE SEAMS PROJECTS (BUILDING BLOCK NO. 3)

The current JOAs do not contemplate pre-defined thresholds for a project to qualify as a "seams" project. We recommend that seams agreements remain free of specific thresholds (other than the filing requirements discussed below). Specifically, we recommend that there be:

1. No pre-defined threshold limits — we advise against thresholds based on criteria such as voltage class, total cost, and total benefits, because even "small" seams projects may offer substantial benefits.
2. No strict configuration requirement — we recommend that "seams projects" can either be defined as single project (or even components of a larger regional project) or be comprised of a portfolio of seams-related projects grouped together.
3. No physical location requirement — we recommend that the definition of seams projects be more broad than the definition of "interregional projects" under FERC Order 1000, to include projects that either cross the seam (as interregional projects are defined in Order

1000) or be located wholly within one entity's footprint as long as the projects provide clear benefits to both seams entities.[138]

4. No limitation to specific project types — we recommend acknowledging that seams projects serve one or several purposes. Projects may be driven by reliability needs, operational and economic benefits, policy requirements, or a combination of these factors, and these factors may differ for each seams entity. Seams projects should also be able to include transmission upgrades that facilitate, expand, or provide an alternative to seams entities' internal transmission upgrades identified in their internal planning processes, including their evaluation of generation interconnection and transmission service requests.

We propose to start with a broad definition of seams projects because our discussions with SPP and other stakeholders indicated that seams-related challenges tend to cover a wide range of circumstances that makes it impractical to focus on specific thresholds. Any such thresholds or restrictive definitions can lead to sub-optimal solutions by prematurely disqualifying beneficial seams-related projects. For example, while the Acadiana Load Pocket had been identified as an area with a number of seams-related problems, the solution was a combination of upgrades to existing facilities as well as new substations, transmission lines, and capacitor banks.[139] Therefore, we recommend that the underlying qualification criteria should only be that a proposed seams project be able to address both seams entities' transmission needs and offer commensurate benefits to both.

We also recommend that seams projects must be proposed—jointly or unilaterally—through a predefined process that clearly establishes the responsibilities of both seams entities. In addition to specifying a seams proposal process through the JOA, SPP (and neighboring RTOs) will need to specify internal processes (*e.g.,* through the regional transmission planning process) under which individual transmission owners and other market participants can propose candidate seams projects to SPP. SPP can then further consider these candidate seams projects and then formally propose them under the interregional planning and seams cost allocation agreements with neighboring seams entities.

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[138] Note that only the latter is defined as an "interregional" project in FERC's Order 1000.

[139] SPP, "Cleco, Entergy, and Lafayette Utilities System to improve electric service in South Louisiana through joint transmission project," January 19, 2009.

A. PROCESS FOR UNILATERALLY PROPOSED SEAMS PROJECTS

The current JOAs are focused on coordinating data exchange and planning studies so that entities can jointly produce the JCSP, which may in turn identify beneficial seams projects. We recommend that the framework be expanded to include a process under which seams entities can propose potential seams projects unilaterally as long as the unilateral proposal meets certain criteria. The submission of such a qualifying unilateral proposal would obligate the other seams entity to participate in a joint study of the proposed project within a pre-specified, agreed-upon timeframe.

To facilitate the timely assessment of unilaterally-proposed seams projects, the seams entities will need to specify (*e.g.*, in their expanded JOA) how the evaluation of seams projects will be integrated into their existing transmission planning schedules and timeframes. This will allow the entities to define deadlines by which seams projects will need to be proposed for consideration in the next planning cycle. SPP's internal processes may also need to specify by when SPP staff, transmission owners, or other market participants will need to propose projects for further evaluation as a potential seams project.

To trigger the joint obligations under the recommended framework, the seams entity proposing a project unilaterally would be required to submit a formal proposal to its neighbor that meets all agreed-upon pre-specified requirements. Our proposed requirements are shown in Table 7. Clearly defining the requirements that need to be met for unilaterally-proposed seams projects helps prioritize resources and focus attention on those projects that are deemed sufficiently valuable.

As the table shows, a formal unilateral proposal would, first, need to include a detailed description of the proposed seams project and, second, a *qualitative* discussion of the project's needs, purpose, and benefits to both seams entities, which could differ on either side of the seam. Third, we recommend that such unilateral proposals include a preliminary *quantitative* analysis (*e.g.*, power flow and/or economic studies) of the project's benefits to both entities. This requires that the proposing seams entity has enough information about the neighboring system to undertake a preliminary quantitative analysis of seams-related impacts in the combined footprint and estimate benefits to both seams entities that, as discussed further below, are consistent with the metrics used by the neighboring seams entities in their transmission planning process. Finally, we recommend that seams project proposals also include a proposed preliminary cost allocation that is consistent with specified cost allocation principles and benefits identified in the preliminary analysis of the project.

Table 7
Recommended Requirements for Unilaterally-Proposed Seams Projects

Requirements for Unilaterally-Proposed Seams Projects	Notes and Comments
1. Detailed description of the project	Needs to provide necessary project information such as: • Geographic area • Seams entities impacted • Full technical description of the proposed project, including project costs
2. Qualitative discussion of the project's purpose and potential benefits to both neighbors based on agreed upon benefits and metrics	• Articulates drivers of the proposed seams project • Description of project benefits to both seams entities
3. Preliminary quantitative analyses of the project's potential benefits to both entities relying on the specified transmission benefits and metrics relevant to each seams entity or both. The proposing entity needs to include: (1) appropriate documentation, such as assumptions and data used in the analysis, and (2) analyses and results that are consistent (though not necessarily comprehensive in scope) with the planning methods and metrics of each entity	• Requires updated and jointly-validated planning models for combined footprint • Requires solid understanding of neighbor's benefit metrics used in transmission planning
4. Proposal for preliminary cost allocation consistent with specified principles and guidelines as a starting point for discussions	• Requires specification of cost allocation principles and guidelines • Requires seams entities to develop a shared understanding of how the specified cost allocation principals and guidelines would be applied (*e.g.*, through the joint development of case studies and "test projects")

The submission of a seams project proposal that meets these specified requirements would trigger the obligations under the proposed framework. For example, the neighboring seams entity would be obligated to conduct a joint study with the proposing entity within an agreed-upon timeframe (*e.g.*, 6-12 months or to include the project in the JCSP study process). This joint study would comprehensively assess the benefits that the proposed project provides to both seams entities, thereby confirming, refining, or expanding the preliminary analyses by the seams project proponent.

As noted, regional planning entities that cover the systems of several transmission owners, may need to modify internal processes to specify: (1) how seams projects can be proposed by internal planning staff, individual transmission owners, and other market participants; (2) how the nominated seams project would be evaluated internally to decide whether to proceed with a formal seams project proposal; and (3) the schedule and timeline under which internally-nominated projects would be evaluated and, if desirable, formally proposed as a seams project under the interregional planning and seams cost allocation framework

B. PROCESS FOR JOINTLY-PROPOSED SEAMS PROJECTS

Under the proposed framework, seams projects could also be proposed jointly based upon mutual agreement of the seams entities. Such joint seams project proposals could be made either (1) as the result of joint planning studies under the JCSP or (2) based on *ad hoc* agreements between the seams entities.

In this case, the seams entities would jointly prepare the project documentation and preliminary analysis and cost allocations specified in Table 7 above. After obtaining stakeholder input, the parties could then prepare the final seams project study either as a standalone analysis or, if timely enough, within the JCSP study effort.

VIII. EVALUATION CRITERIA AND BENEFIT METRICS (BUILDING BLOCK NO. 4)

A key building block and the foundation of any successful cost allocation framework is the detailed and comprehensive articulation of seams project evaluation criteria and benefit metrics. We refer to "benefits" as the obligations, goals, economic benefits, cost reductions, avoided costs, and other improvements and savings that the transmission investment may meet or achieve in the context of the transmission needs and drivers in each seams entity's internal (local and regional) transmission planning process. We refer to "metrics" as the means used to quantify, monetize, or more qualitatively describe each benefit. In Section VIII.A we first lay out the recommended benefit principles applicable to seams projects, followed by the benefit metrics that can be derived from SPP's and other seams entities' transmission planning process in Section VIII.B. In Section VIII.C, we describe additional benefits that seams projects may provide or can be added over time, which are not currently considered explicitly in internal planning processes.

A. BENEFIT PRINCIPLES APPLICABLE TO SEAMS PROJECTS

As the ALP Project experience clearly demonstrated, a single seams project can provide a range of different benefits to various seams entities. Had the ALP Project only been evaluated on reliability grounds, there may not have been "enough" individual benefits to justify even the cost of the reliability component. Furthermore, SPP is faced with a particular challenge in that certain commonly-used metrics within organized markets—such as adjusted production cost or "APC" savings—may not be used in the transmission planning effort of non-market or non-jurisdictional seams entities. Therefore, it is important that seams entities who are parties to the interregional cost allocation framework agree on a well-specified set of benefit principles and metrics. We therefore provide a recommended set of "benefit principles" that could be adopted by the neighboring seams entities within their JOAs as listed in Table 8. Illustrative JOA language is provided in Appendix C.2.

While these principles set the stage for defining benefits and metrics for all seams entities who are party to the cost allocation framework, we recommend that seams entities not be required to use the same exact benefits and metrics—though we expect there to be a significant degree of overlap, especially with regard to reliability-related benefits and metrics.

The JOAs only broadly mention benefits such as maintaining reliability, improving operational performance, providing an economic benefit, or enhancing the competitiveness of electricity markets.[140] However, there are no details within the JOAs that would define "reliability" or "economic" benefits or specify metrics that should be used to measure them. We recommend that the specified seams-related benefits and metrics for each seams entity include, at minimum, all benefits and metrics that the seams entity uses in its internal transmission planning efforts. We also recommend that each seams entity has the option, but not the obligation, to consider some or all of the benefits and metrics used by the other seams entity, even if these benefits and metrics are not currently used in its internal transmission planning process.

[140] SPP and Associated Electric Cooperative, Inc., *Joint Operating Agreement*, "Article 7.3: Joint and Coordinated System Planning," July 20, 2011 and SPP and Midwest ISO, *Joint Operating Agreement*, "Section 9.3: Coordinated System Planning," March 25, 2011. The SPP-AECI JOA only refers to economic benefit whereas the SPP-MISO JOA only refers to enhancing competitiveness.

Table 8
Recommended Benefit Principles

1. Seams projects (either as single projects or a group of projects) may offer combinations of different types of benefits;
2. It is possible that entirely different sets of benefits may accrue to each seams entity from a particular seams project;
3. The benefits and metrics used for the evaluation of seams projects by each entity will include all benefits and metrics considered in each seams entity's local and regional transmission planning process;
4. Each seams entity shall have the option, but not the obligation, to consider some or all of the benefits and metrics used by the other seams entity even if these benefits and metrics are not currently used in the entity's internal transmission planning process;
5. The seams entities recognize that seams projects may offer unique benefits beyond those currently considered in either entity's internal transmission planning process. If deemed significant, the entities agree to develop metrics to capture any such additional seams-related benefits;
6. The seams entities recognize that additional benefits may be documented as more experience is gained with the planning and evaluation of seams projects. If deemed significant, the seams entities agree to develop metrics to capture any such additional seam-related benefits; and
7. The seams entities recognize that seams projects may serve to avoid or delay the cost of (1) transmission projects in their existing regional and local transmission plans; (2) transmission upgrades that may be needed in the future to meet local or regional needs; and (3) transmission upgrades needed to satisfy generation interconnection and transmission service requests.

Additionally, as shown in the above table, we recommend that seams entities agree that seams projects can offer unique benefits beyond those currently considered in either seams entity's internal transmission planning process and that additional benefits may be documented as more experience is gained with the planning and evaluation of seams projects. If deemed significant, the seams entities would agree to develop metrics to capture any such additional seams-related benefits.

As addressed in our discussion of cost allocation principles and guidelines (Section IX), benefit principles Nos. 4-7 also help mitigate "fairness concerns" related to the potentially different scope of benefits that the proposed framework defines for different seams entities under benefit principle No. 3. In addition, one of the proposed cost allocation principles presented in Section IX.A requires that the allocated benefits of a seams project, when compared to its allocated costs, must be sufficient to support the project's approval based on the criteria that are used in each entity's internal transmission planning process. This means even if one seams entity (such as SPP) utilizes a more comprehensive definition of project benefits, the project will still be beneficial to the seams entity when considering both its share of benefits as well as its share of costs. This will ensure that the seams project and its cost allocation: (1) offers

acceptable net benefits to each seams entity; (2) is more attractive than pursuing the project without cost sharing; and (3) is more attractive than not pursuing the project (and thus not realizing any of its benefits).

B. BENEFITS AND METRICS USED IN ENTITIES' INTERNAL PLANNING PROCESSES THAT WOULD ALSO BE APPLIED TO SEAMS PROJECTS

As noted earlier, we recommend that the specified seams-related benefits and metrics for each seams entity include, at minimum, all benefits and metrics that the seams entity uses in its internal transmission planning efforts. To provide an illustrative example, we have summarized the benefits and metrics SPP currently uses to evaluate regional projects. By specifying the full set of these metrics in the JOA, including through references to relevant SPP-internal documents such as the Integrated Transmission Planning ("ITP") manual,[141] SPP's seams neighbors would be able to evaluate whether or not a potential seams project would meet SPP's planning criteria.

Table 9 summarizes the benefits currently considered by SPP in its internal evaluation of local and regional transmission projects and how those benefits are measured quantitatively, are monetized, or are only qualitatively considered.

To illustrate how the above list of benefits applied in SPP's internal transmission planning processes may differ from those of other seams neighbors, we provide as a purely illustrative example the benefits and metrics that a non-jurisdictional entity may be considering it its transmission planning efforts. This list, shown in Table 10, is based on our review of Western Area Power Administration ("Western") 2011 Strategic Plan. It has not been confirmed by Western and we use it solely as an illustration for the broad range of benefits that might be considered by non-RTO entities, even though their evaluation criteria and benefit metrics may be less formulaic or clearly stated than those in RTO markets.

The fact that seams neighbors may consider different benefits or analyze similar benefits differently has also been illustrated by the ALP Project case study discussed earlier in this report. Each of the sponsors of the ALP Project received either reliability or economic benefits (or both) but even similar benefits were categorized differently by the different sponsors and different metrics were used for similar categories of benefits. For example, Cleco found that the ALP Project would help reduce the cost of running one of its oldest and most expensive generators, thus providing an economic benefit. LUS also found that the ALP Project could help it avoid running more costly generators during summer peak, but considered that to be largely a

[141] The most recent ITP manual can be found at: http://spp.org/section.asp?pageID=128.

reliability benefit with only some economic impacts. On the other hand, Entergy quantified reliability benefits as a reduction in TLRs and firm curtailments. Therefore, while broad categories of benefits are a useful starting point for the analysis of seams projects, specific benefit descriptions and metrics are needed to produce actionable results.

Table 9
Summary of SPP Internally-Used Benefits and Metrics
That Would Also be Applied to Seams Projects

Benefit Category	Specific Benefits	Qualitative and/or Quantitative Metrics
Reliability benefits	Ability of project to avoid reliability violations	Quantified as number/duration of violations; monetized as avoided cost of regional/local upgrades
Reduced costs	Ability of project to produce adjusted production cost savings	Monetized through PROMOD or similar simulations
	Ability to replace or delay future or previously approved projects	Monetized as the avoided cost of replaced or delayed projects
	Energy value of reduced transmission losses	Monetized based on quantification through power flow simulations
	Capacity value of reduced transmission losses	Monetized as avoided capacity
	Reduced emissions costs	Monetized as allowances not purchased
Improved / increased ATC	Value of improved Available Transfer Capabilities	Quantified as incremental capacity (MW)
	Export/import improvements	Quantified as incremental capacity (MW)
	Ability to serve new load	Monetized as an offset to proposed seams project cost based on how much new load can pay for part of the project
	Access to beneficial services from other markets such as ancillary services or diversity exchange	Monetized value can be cost of additional generation in SPP footprint to supply those services
Improved / increased competition	Levelization of LMPs	Qualitative consideration
	Improved competition in SPP markets	Qualitative consideration

Table 10
Illustrative List of Benefits and Metrics Considered in a Non-RTO Seams Entities' Transmission Planning Process

Benefit Category	Specific Benefits	Qualitative and/or Quantitative Metrics
Reliability	Avoid reliability violations	Quantified as number/duration of violations and monetized as avoided cost of regional/local upgrade
	Reduce frequency and cost of supply interruptions during low-hydro years	Quantified as number/duration of likely events and monetized as cost of interruptions or replacement power
Load serving benefits	Reduce the dispatch of high-cost generation resources needed to serve load in presence of internal transmission congestion or import constraints	Monetized as reduced generation and emission costs
	Avoid cost of local transmission upgrades needed to support load growth	Monetized as avoided cost of regional/local upgrade
Increased off-system sales (to maximize value to electric service customers)	Increase in ATC and thus off-system sales	Monetized as incremental off-system sales profits and/or transmission rights
	Increase in sales of ancillary services to other systems (*e.g.*, for wind balancing)	Monetized as incremental off-system sales profits and/or transmission rights
Reduced transmission losses	Reduce transmission losses	Monetized as energy and on-peak capacity savings
Renewables integration benefits	Ability to avoid or delay local/regional transmission upgrades needed to integrate renewable resources for Western's strategic goals or RPS, if any	Monetized as revenue (or offset to costs) from accommodating multiple transmission service requests and/or generator interconnection requests
	Renewable integration benefit of CO_2 and other emission reductions	Quantified as tons of CO_2 avoided and measured as part of meeting Western's strategic goals and monetized for other emissions with allowance prices
	Proactively respond to a group of renewables interconnection requests rather than serially	Qualitative benefit for queue efficiency and may help to address chicken-and-egg issue for intermittent generation
Economic and renewable development	Ability of project to promote renewables and economic development consistent with policy objectives	Quantified as jobs created, economic impact on communities, potential fiscal benefits such as taxes or land-lease payments
Operational benefits	Ability of project to improve operating and maintaining flexibility and efficiency	Qualitatively described and monetized as must-run payments or cost of outage if maintenance is needed

In the context of how benefits can be defined for the purpose of cost allocation, it is also important to recognize that benefits can be considered both directly and indirectly. The definition of a direct benefit is the cost savings, efficiency gains, avoided costs, or revenue offsets provided by a seams project. Examples of this type of benefit are APC savings, additional wheeling revenues associated with ATC increases, or the avoided cost of other transmission projects. For the purpose of cost allocation, however, benefits can also be considered indirectly—such as through an entity's contribution to the need for a seams project or on a "cost causation" basis. For example, an entity's contribution to flows on a constrained facility that caused a reliability concern can be considered a proxy for the share of reliability benefits that the entity receives from a seams project which alleviates or eliminates the reliability concern.

C. BENEFITS APPLICABLE TO SEAMS PROJECTS

Internally-considered benefits and metrics are good starting points but may not comprehensively reflect the benefits of seams projects. For example, SPP quantifies APC savings calculated from PROMOD simulations, where imports are priced at the average internal load LMP and exports are priced at the average internal generation LMP. This leaves out wheeling revenues and other gains from trade due to differences in the load and generation LMPs between regions. Therefore, internally-considered benefits and metrics will need to be reviewed to see if they leave "gaps" that may be relevant for seams projects. This effort may identify additional benefits provided by seams projects that may not be applicable to region-internal transmission investments. Table 11 provides examples of such additional seams-project-related benefits and metrics that are not typically applicable to region-internal projects.

Table 11
Examples of Additional Seams Project-Specific Benefits and Metrics

Benefit Category	Specific Benefits	Metrics
Incremental wheeling through and out revenues	The ability of a seams project to increase export ATC, support transmission service requests and, as a result, generate incremental wheeling through and out revenues that offset a portion of the project's costs	Estimates of additional wheeling volumes derived from transmission service requests and/or PROMOD modeling
Benefits from increased reserve sharing capability	The extent to which increased intertie ATC with the neighboring system allows for a reduction of a seams entity's planning reserve requirement or the cost of planning reserves.	Quantified as a reduction in MW of reserve capacity

We recommend that the seams entities consider including these additional benefits and metrics in the evaluation process and cost allocation framework for seam projects. We also recommend that the seams entities agree that additional benefits and metrics can be considered on a project-specific basis upon mutual agreement of the seams entities. As noted earlier, illustrative "straw man" JOA language implementing these benefits and metrics recommendations for the proposed seams cost allocation framework is provided in Appendix C.

IX. SEAMS COST ALLOCATION PRINCIPLES AND GUIDELINES (BUILDING BLOCK NO. 5)

The fifth building block, and a main focus of this report, is the specification of general cost allocation principles and guidelines that build on the identified seams project-related benefits and metrics. The "cost allocation principles," as discussed in Section IX.A, serve as the overarching framework for the development of cost allocations for specific seams projects based on their identified benefits. We also additionally provide specific "cost allocation guidelines" in Section IX.B, which explain via examples how certain benefits and metrics can be used to derive cost allocations for seams projects that are consistent with the specified cost allocation principles. These principles and guidelines are then applied to illustrative case studies in Section XII.

A. COST ALLOCATION PRINCIPLES

The cost allocation principles of a comprehensive framework will, at minimum, need to be consistent with the six interregional cost allocation principles specified in FERC Order 1000 as discussed in Section V above.[142] However, based on our review of seams cost allocation principles and methodologies elsewhere we propose a broader set of cost allocation principles as shown in Table 12.

[142] As noted earlier, our recommended definition of a "seams project" is broader than in Order 1000, which defines as "interregional" only projects that physically cross the seam between regions. In our proposed framework, "seams projects" may be wholly located within one seams entity's footprint as long as both seams entities agree that the project justifies cost allocation because it provides meaningful benefits to both entities.

Table 12
Recommended Cost Allocation Principles

1. The cost of seams projects should be allocated to seams entities such that they are at least roughly commensurate with total benefits identified for each of the seams entities based on the benefits and metrics specified. Neither entity should be allocated a share of the cost of a seams project in which it receives no benefit.
2. The application of cost allocation methodologies and identification of benefits and beneficiaries must be transparent.
3. Different cost allocation methods can be applied to different types (*e.g.*, transmission needs driven by reliability, economic, or public policy requirements) or different portions of transmission facilities.
4. The seams entities will quantify and, if possible, monetize the identified benefits based on the metrics provided. The seams entities will also recognize non-monetized and non-quantified benefits in their assessment of the overall reasonableness of proposed seams project cost allocations.
5. The seams entities agree that the monetized reliability, load serving, public policy, or other benefit of a seams project will be at least equal to the avoided cost of achieving the same benefit solely through cost-effective local or regional transmission upgrades.
6. If benefit-to-cost ratios are used to assess the desirability of seams project to a seams entity or the seams entities as a group, the benefit-to-cost threshold must not exclude projects with significant net benefits. The threshold should not exceed 1.25.
7. Benefits to each seams entity need to be sufficient to support each seams project's approval through each entity's internal planning process considering the costs allocated to each seams entity; and
8. Seams project costs allocated to each seams entity will be recovered via the existing internal (local and regional) cost allocation process of each entity.

As shown in Table 12, many of the proposed cost allocation principles simply implement Order 1000 requirements. However, principles Nos. 4, 5, and 7 go beyond Order 1000 requirements. For example, the proposed principle No. 4 reflects the expectation that cost allocations be mostly based on quantifiable benefits and thus requires that the seams entities will attempt to quantify and monetize the identified benefits based on the metrics provided. It also states, however, that non-monetized and non-quantified benefits should still be considered at least qualitatively in the seams entities' assessment of the overall reasonableness of any proposed cost allocations. Principle No. 5 provides a framework for the monetization of reliability, load serving, public policy, and similar other benefits of seams projects by requiring that the monetized value of such benefits be at least equal to the avoided cost of achieving the same benefit(s) through cost-effective local or regional transmission solutions.

Finally, the proposed cost allocation principle No. 7 goes beyond Order 1000 requirements by specifically addressing "fairness concerns" related to the potentially different scope of benefits that the proposed framework defines for different seams entities. The principle requires that both

the allocated benefits of a seams project, when compared to its allocated costs, are sufficient to support the project's approval based on the criteria that are used in each entity's internal transmission planning process. This means even if one seams entity (*e.g.*, SPP) utilizes a more comprehensive definition of project benefits, the project will still be beneficial to the seams entity considering both its share of benefits as well as its share of costs.

While it is still possible that the broader scope of benefits will result in a larger share of allocated costs, the entity is not asked to approve a seams projects at terms that are any less attractive than the terms that would be considered for local and regional projects in the entity's internal planning process. In other words, while it is still correct that the seams entity with the broader scope of considered benefits will tend to share more of a projects' costs, the cost allocation outcome will (1) result in a project with acceptable net benefits; (2) be more attractive than pursuing the project without cost sharing; and (3) also be more attractive than not pursuing the project (and thus not realizing any of its benefits).

In addition, as noted in our discussion of benefits principles, the potential for greatly differing scopes of seams project-related benefits considered by each of the seams entities is mitigated by benefit principles Nos. 4 through 7 (see Table 8), which note that (1) each seams entity has the option to consider some or all of the benefits and metrics used by the other entity; (2) the seams entities will recognize benefits that are unique to seams projects even if they go beyond those considered in their internal planning processes; (3) additional benefits may be documented and considered as more experience is gained in the evaluation of seams projects; and (4) benefits will be at least as large as the cost of avoided cost-effective regional or local project alternatives.

B. COST ALLOCATION GUIDELINES

We recommend that seams agreements and associated business practice manuals include "cost allocation guidelines" that provide additional guidance on and illustrations of how benefit metrics would be applied in accordance with the cost allocation principles. This provides an opportunity for seams entities to memorialize how they weigh and prioritize the list of benefits detailed in the seams agreement. It also provides an opportunity for entities to explain the seams cost allocation framework through concrete (even if illustrative) examples. While an infinite number of guidelines and examples could be created, we suggest that entities focus on developing a core set of guidelines based on the benefit metrics most important to the entities involved, showing how the identified benefits would be considered in developing cost allocations.

We recommend an approach to developing guidelines under which the costs of a seams project allocated to each party can be based on one or a combination of several mechanisms. The first cost allocation mechanism would simply ***allocate seams project costs based on the share of monetized benefits***. In other words, costs would be allocated in proportion to the present value of project benefits received by each entity compared to the sum of the entities' present value of total benefits received.

In addition, cost allocation for some seams projects may also lend itself to consideration of more ***qualitative, non-monetized benefits and cost causation ratios***. For example, the seams entities could stipulate in their agreement that the cost of a seams project could also be shared based on:

- Each entity's relative ***contribution to the need*** for a project if the seams entities can agree that such contributions to need are either a reasonable proxy for the project's benefits (or roughly proportionate to the benefits) received by each entity. Examples of such allocations could be applying load-ratio shares or shares of power flows that contribute to the costs of a reliability-driven upgrade, or allocating the costs of a renewables-integration driven upgrade in proportion to PPAs signed by load-serving entities in their footprint or the entities' RPS requirements.
- Each entity's projected or allocated ***usage share*** of the project's added transmission capability (*e.g.*, allocated shares of increased flow-gate capacity) if the seams entities agree that such usage shares are either a reasonable proxy for the benefits (or roughly proportionate to benefits) received by each entity.
- Finally, the costs of seams projects could be allocated ***based on the project's physical location*** in each entity's footprint (*e.g.*, shares of circuit miles or direct assignment of project segments) if the seams entities agree that such footprint-based shares will be roughly proportionate to the benefits received by each party.

We provide in Section XII a recap of the ALP Project and two case studies which serve as an illustration for applying these cost allocation guidelines to seams projects.

X. PAYMENT MECHANISMS TO IMPLEMENT SEAMS COST ALLOCATION (BUILDING BLOCK NO. 6)

The final building block of our proposed seams cost allocation framework specifies the payment mechanisms that can be used to implement the agreed-upon cost allocations. We propose as a starting point the consideration of two types of payment mechanisms: (1) physical ownership shares; and (2) financial transfers. To facilitate such implementation of cost allocation, we also recommend that, to the extent feasible and practical, an entity sharing the cost of seams projects should also receive physical or financial rights for a commensurate share of the project's added transmission capability (*e.g.*, a share of increased flow gate capability).

Cost allocation based on ***physical ownership*** shares can be implemented through either (1) physical ownership of individual project segments or (2) co-ownership of the seams project or individual project segments. In either case, ownership of individual project segments would be assigned so that the investment and operating cost of each owned portion of the project is consistent with the determined cost allocations. Co-ownership of seams projects or individual project segments may be necessary where the project cannot be divided into fully-owned segments or if a proposed project (or project segment) is entirely within the service territory of only one of the seams entities. In other words, different shares of the seams project would be allocated to existing or new transmission owners within each of the two seams entities. The transmission owners would then simply recover the cost of their portion of the seams project as they would recover the cost of any other internal (regional or local) transmission project.

If the seams project is developed by a single corporate entity, the company could form a transmission-owning subsidiary in each of the neighboring seams entities, each of which would recover the costs associated with its ownership share of the seams project through the respective seams entity's existing regional or local cost recovery options. As discussed in Section VI.A, such an ownership-based approach was used to allocate costs of the ALP Project. It also is and has been used routinely for transmission cost allocation throughout the WECC, such as within NTTG.

Where ownership-based allocation of project costs is neither feasible nor practical, cost allocation can be implemented through ***financial transfers*** from one seams entity to the other. These payments would correspond to the determined share of the seams project's revenue requirements. We also recommend such payments be implemented in conjunction with the assignment of physical or financial rights for a commensurate share of the project's added transmission capability. The revenue requirements associated with payments to the neighboring seams entity would be recovered consistent with the cost recovery of the revenue requirements of local and regional projects in the transmission owner's regional footprint.

Examples of transmission rights provided under either the ownership or financial transfer options may be rights to a share of added flowgate capacity or rights to ATC increases provided by a seams project. In Day-2 markets, such rights may involve auction revenue rights or capacity transfer rights, similar to the rights that RTOs may already provide to the sponsors of "elected" or "participant funded" transmission upgrades.

Without obtaining any such transmission rights, many non-RTO and non-jurisdictional entities simply may not be able to assume the required ownership obligations or make financial payments to the neighboring seams entity. Most likely, only neighboring RTOs would be able to implement a financial transfer mechanism without obtaining rights to the transmission capability added by the seams projects for which they are paying. However, even for neighboring RTOs, the receipt of transmission rights in return for owning or paying for a portion of a seams project will increase the certainty of capturing project benefits and thus reduce inherent barriers to the joint pursuit of seams projects.

XI. OPTIONAL BUILDING BLOCK: PRE-SPECIFIED FORMULAIC EVALUATION AND COST ALLOCATION METHODOLOGY

As more experience with cost allocation of seams projects is gained, neighboring seams entities may find it helpful to specify more formulaic project evaluation and cost allocation options that would apply to specific types of seams projects. Examples of such pre-specified formulaic options are the frameworks that MISO and PJM have specified for cross border reliability and market efficiency projects (as summarized in Section IV.A). Ideally, such options would be created once it becomes clear that certain project evaluations and cost allocation formulas work well for specific types of seams projects that will likely be encountered periodically.

This option would allow seams entities to fully or partly pre-specify: (1) project qualification criteria; (2) the specific benefits and metrics used in the evaluation of seams transmission projects; and (3) a formula for cost allocation that relies on these benefits and metrics. Such pre-specified formulas could be developed for some or several types of projects, such as reliability, congestion relief, or public policy projects. Projects that do not "fit" any such pre-specified options will still be considered under the more general cost allocation framework described above.

A variation to this approach may be a less formulaic approach which would provide more specific guidelines for specific types of projects. For example, an agreement between SPP and

AECI might note that for reliability-only projects, acceptable cost allocations would be based on each entity's avoided costs of implementing their own solutions.

XII. CASE STUDIES: QUALITATIVE APPLICATION OF FRAMEWORK TO CANDIDATE SEAMS PROJECTS

As part of our effort to develop a robust seams cost allocation framework, we wanted to test it on actual or proposed projects. In Section XII.A we provide an overview of the feedback we received from stakeholders on candidate seams projects to evaluate. Based on this feedback and in discussions with the Joint Project Team, we apply our proposed framework to an actual seams project in Section XII.B and, on an illustrative basis, to two proposed seams projects in Sections XII.C and XII.D.

A. CANDIDATE SEAMS PROJECTS

We asked members of SPP Staff, RSC staff, the SPP Seams Steering Committee, and representatives of seams neighbors to provide candidate seams projects, including the following information:

- Why is the project needed from your company's perspective?
- What are the project's possible benefits?
- Have there already been any studies of the project?
- What are the barriers to the project (why has it not been pursued)?
- Are there lower cost projects that would be interesting to evaluate?

The following candidate seams projects were received (see Appendix D for more detailed descriptions of each):

- Acadiana Load Pocket ("ALP") Project involving seams entities Entergy/Cleco/LUS
- Branson Area Project involving seams entities SPP/AECI
- Quarry Project (Western Entergy Area) involving seams entities SPP (AEPW)/Entergy
- Danville Area EHV Station involving seams entities SPP (OGE)/Entergy
- Murfreesboro Project involving seams entities SPP (AEPW)/Entergy

As also discussed in Section VI.A, the ALP Project provides a case study of an actual "seams" project that has been under development for several years and provides particularly helpful lessons for the development of a robust framework. Except for the ALP Project, the remainder of the candidate seams projects are currently only in the early proposal stages. For some of the

projects, preliminary initial analyses have been conducted but are not conclusive and (to the best of our knowledge) seams cost allocation has not even been approached.

In addition to the ALP Project case study, we selected two of these proposed projects to illustrate the application of the proposed framework and its ability to consider different types of projects, benefits, cost allocation methodologies, and payment mechanisms.

The first of these two additional case studies, the Branson Area Project, highlights the need for closer integration of top-down and bottom-up transmission planning studies with seams coordination. It also illustrates the intrinsic value of seams projects, which often is not captured in internal planning processes. The Branson Area case study documents the ability of the proposed framework to consider projects between multiple market and non-market areas with potentially very different benefits considerations and physical ownership options of different project segments as a means to implementing cost allocation.

The second case study, the Quarry Project, is an illustrative example of a seams project that is wholly within one seams entity's footprint but may benefit both market and non-market seams neighbors by addressing reliability concerns in a load pocket as well as unfulfilled transmission service requests. These case studies also provide additional guidance on how to apply the cost allocation principles and guidelines discussed in Section IX.B.

B. ALP PROJECT

As described in Section VI.A, the ALP Project is a successful example of a multi-party cost allocation for a seams project. To test the robustness of our proposed framework, we compare the ALP Project experience against our benefit principles (Section VIII.A), cost allocation principles (Section IX.A), and payment mechanisms (Section X). Table 13 below reproduces the recommended benefit principles and highlights the principles (with a blue arrow) that apply to the ALP Project. (Those principles that that do not directly apply appear in grey font.)

Table 13
Recommended Benefit Principles as Applied to the ALP Project

1. Seams projects (either as single projects or a group of projects) may offer combinations of different types of benefits;
2. It is possible that entirely different sets of benefits may accrue to each seams entity from a particular seams project;
3. The benefits and metrics used for the evaluation of seams projects by each entity will include all benefits and metrics considered in each seams entity's local and regional transmission planning process;
4. Each seams entity shall have the option, but not the obligation, to consider some or all of the benefits and metrics used by the other seams entity even if these benefits and metrics are not currently used in the entity's internal transmission planning process;
5. The seams entities recognize that seams projects may offer unique benefits beyond those currently considered in either entity's internal transmission planning process. If deemed significant, the entities agree to develop metrics to capture any such additional seams-related benefits;
6. The seams entities recognize that additional benefits may be documented as more experience is gained with the planning and evaluation of seams projects. If deemed significant, the seams entities agree to develop metrics to capture any such additional seam-related benefits; and
7. The seams entities recognize that seams projects may serve to avoid or delay the cost of (1) transmission projects in their existing regional and local transmission plans; (2) transmission upgrades that may be needed in the future to meet local or regional needs; and (3) transmission upgrades needed to satisfy generation interconnection and transmission service requests.

As Table 13 shows, the ALP Project utilizes the majority of the benefits principles, which creates the foundation for considering cost allocation. The two principles not directly applicable to the ALP Project relate to the evolution of benefits based on project experience. Table 14 below follows the same format, but applied to the recommended cost allocation principles.

Table 14
Recommended Cost Allocation Principles as Applied to the ALP Project

1. The cost of seams projects should be allocated to seams entities such that they are at least roughly commensurate with total benefits identified for each of the seams entities based on the benefits and metrics specified. Neither entity should be allocated a share of the cost of a seams project in which it receives no benefit.
2. The application of cost allocation methodologies and identification of benefits and beneficiaries must be transparent.
3. Different cost allocation methods can be applied to different types (*e.g.*, transmission needs driven by reliability, economic, or public policy requirements) or different portions of transmission facilities.
4. The seams entities will quantify and, if possible, monetize the identified benefits based on the metrics provided. The seams entities will also recognize non-monetized and non-quantified benefits in their assessment of the overall reasonableness of proposed seams project cost allocations.
5. The seams entities agree that the monetized reliability, load serving, public policy, or other benefit of a seams project will be at least equal to the avoided cost of achieving the same benefit solely through cost-effective local or regional transmission upgrades.
6. If benefit-to-cost ratios are used to assess the desirability of seams project to a seams entity or the seams entities as a group, the benefit-to-cost threshold must not exclude projects with significant net benefits. The threshold should not exceed 1.25.
7. Benefits to each seams entity need to be sufficient to support each seams projects' approval through each entity's internal planning process considering the costs allocated to each seams entity; and
8. Seams project costs allocated to each seams entity will be recovered via the existing internal (local and regional) cost allocation process of each entity.

As Table 14 shows, the ALP Project utilizes all of the cost allocation principles except for (as far as we were able to determine) a specific benefit-to-cost ratio. This demonstrates that the benefit and cost allocation principles are flexible enough to consider such a complicated project and lead to successful cost allocation between the entities. Table 15 below follows the same format as applied to payment mechanism.

Table 15
Recommended Payment Mechanisms as Applied to the ALP Project

➡	1. Cost allocation may be implemented through physical ownership shares of either (1) individual project segments, or (2) co-ownership of the seams project or individual project segments; or
	2. Cost allocation may be implemented through financial transfers.
➡	3. Each entity will recover allocated costs consistent with cost recovery of local and regional projects within its footprint.
➡	4. To the extent feasible and practical, an entity sharing the cost of seams projects should also receive a physical or financial transmission right for a commensurate share of the project's added transmission capability.

The ALP Project cost allocation and payment mechanism was based on ownership of individual segments of the project and utilizes most of the payment mechanism guidelines listed in Table 15 above. Consistency with benefits and cost allocation principles and payment mechanisms shows that a seams project similar to the ALP Project could have been approved based on our proposed framework.

C. BRANSON AREA PROJECT

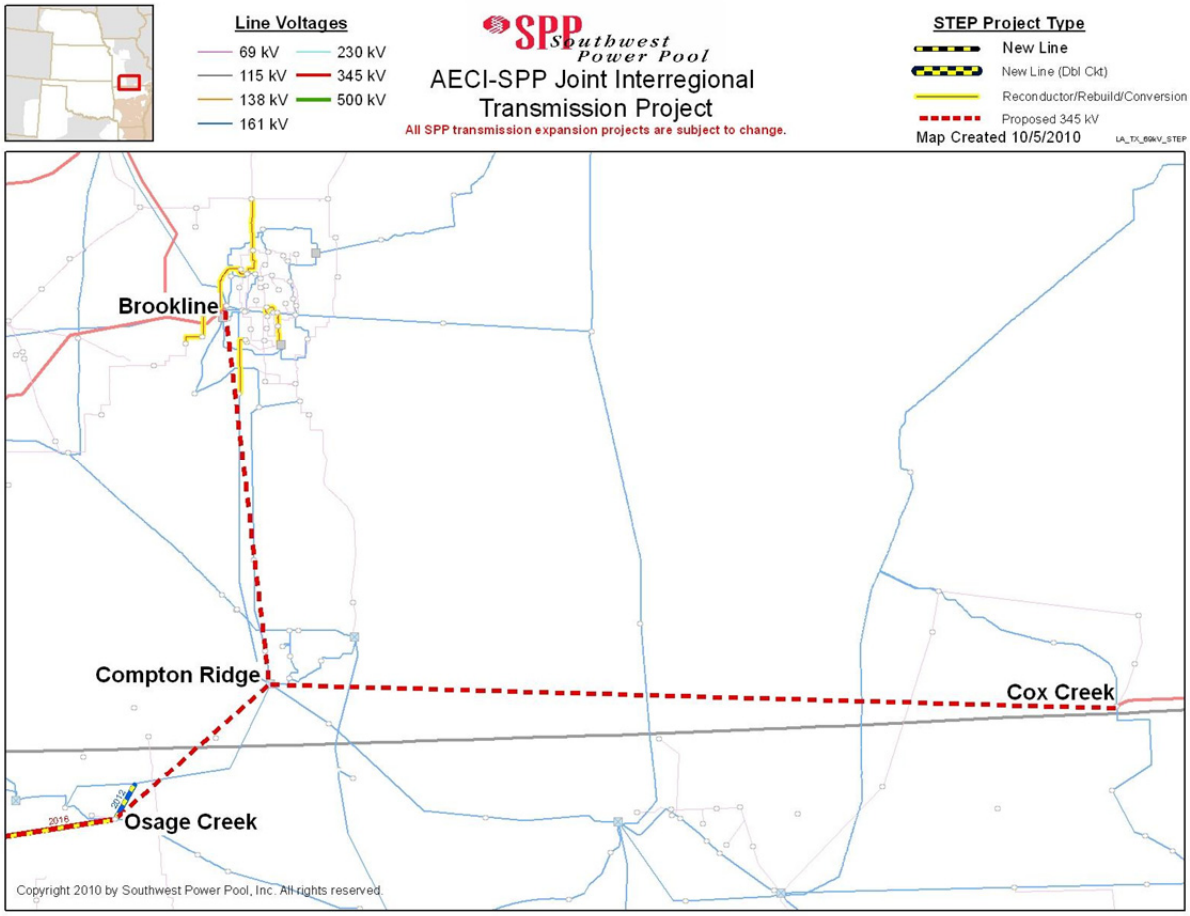
The Branson Area Project was suggested by both AECI and SPP as a candidate seams project that would address reliability concerns and load serving needs in the Branson area with additional potential economic benefits to the broader region. The 345 kV, $240 million project spans the Missouri-Arkansas border and has three main components as shown in Figure 4 below: a line from Brookline to Compton Ridge, one from Osage Creek to Compton Ridge, and a third from Compton Ridge to Cox Creek. Based on comments by AECI and SPP, the project would address the load serving needs of AECI (*e.g.,* to serve a potential 100 MW data server farm in the Branson area) and provide both reliability and economic benefits to SPP (*e.g.,* to prevent overloading of the 161 kV system and APC savings, respectively). The Project is also a component of various upgrades that have been identified in SPP's recent transmission service request study.

The Branson Area Project has been studied for several years, most recently in the *2011 Joint Project Study*, which tracked benefits to SPP, AECI, the Southwestern Power Administration ("SPA"), MISO, and Entergy through a preliminary high-level analysis of seams-related challenges.[143] However, the power flow and production cost analyses found only modest

[143] SPP, "Joint Project Study Results," February 22, 2011.

reliability benefits (*e.g.*, in terms of number of facilities overloaded or resolved, potential cost of outages in low hydro years, reducing the number of overloaded facilities under low hydro conditions) and economic benefits (APC savings and ATC increases) to SPP and AECI.[144]

Figure 4
Proposed Branson Area Project Components



Sources and notes: SPP, "Joint Project Study Results," February 22, 2011, p. 4

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However, while the high-level Branson Area Project study did not yet find compelling benefits, a 2011 "bottom-up" analysis of transmission service requests ("TSRs") appears to point to a different conclusion. In analyzing the TSRs and necessary related transmission upgrades in SPP's 2011 AG2 study, we found that the majority of the service requests (55% of total MWs requested) involved transfers from SPP to Entergy that required the Branson Area Project as well as many SPP-internal and other third party upgrades. In fact, the various components of the Branson Area Project were needed for 42 out of 57 TSRs.

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144 *Ibid*.

This suggests that the Branson Area Project may be a desirable project, but its benefits cannot be realized unless related SPP and third-party upgrades are implemented as well.

In the absence of a complete analysis of the Branson Area Project in combination with the SPP-internal and third-party upgrades identified in SPP's TSR study, we developed a hypothetical example of the total costs and benefits of the necessary upgrades. This example is summarized in Table 16 below.

Table 16
Illustrative Costs and Benefits of Integrated Seams Project Assessment, Including the Branson Area Project ($ Millions)

Illustrative Costs	All regions	$900 SPP-internal upgrades $240 Branson Area Project $60 Third-party upgrades	**$1,200 Total**
Illustrative Monetized Benefits	SPP	$210 Network service requests $550 Point-to-Point transmission service requests $200 Avoided ITP and reliability project costs $100 APC savings ***$1,060 subtotal (65%)***	**$1,640 Total**
	AECI	$80 Avoided cost of internal load serving projects ***$80 subtotal (5%)***	
	Entergy	$150 Transmission service requests (w/ SPP) $150 Avoided reliability project costs (w/ MISO) ***$300 subtotal (18%)***	
	MISO	$100 Transmission service requests (w/ Entergy) $100 70% APC/30% LLMP savings ***$200 subtotal (12%)***	

The accommodation of all TSRs in the 2011 AG2 study (and assuming none of the requests evaluated in earlier studies drop out) would require SPP-internal transmission upgrades costing $900 million,[145] as noted in the first row of the center column of Table 16. The cost of the

[145] Note, however, that any of the SPP-internal upgrades identified in the TSR study are transmission projects needed beyond existing projects and those that are already authorized to proceed with construction. The upgrades identified in this TSR study will thus overlap with any proposed transmission upgrades already
(footnote continued on next page)

Branson Area Project (estimated at $240 million) and other third-party upgrades (*e.g.*, in MISO and Entergy, assumed at $60 million) are assumed to bring seams-related project costs to a total of $1,200 million.

For illustrative purposes, the bottom portion of the table lists different types of hypothetical monetized benefits for SPP, AECI, Entergy, and the MISO. Starting with SPP, we hypothetically assumed that transmission revenues from additional SPP network service and point-to-point transmission service requests (*i.e.*, for wheeling out service) would pay for a significant portion of these upgrades. Based on estimates in the 2011 AG2 study, we assumed that $210 million of project costs would be recovered through the present value of incremental network service revenues (at existing rates). Wheeling out revenues from point-to-point transmission service requests (at existing rates) would provide approximately $110 million of incremental *annual* revenue requirements. Considering that the majority of these service requests are for five-year terms and assuming that many of them would get renewed or that other requests would take their place, these annual wheeling revenues may pay for at least $550 million worth of the identified upgrades (conservatively using a 20% charge rate).[146]

This suggests that SPP's incremental revenues associated with transmission service requests (and assumed renewals) would (at least hypothetically) pay for $760 million of the $1,200 million in identified upgrades. Furthermore, some of the $900 million in identified SPP-internal upgrades may overlap with projects identified in SPP's integrated transmission planning process ("ITP") and local reliability needs. As shown in Table 16 we hypothetically assumed $200 million in avoided costs of these other projects. Lastly, we have also assumed that, through the combination of these projects, SPP would realize APC savings of $100 million in present value terms. This means that under our hypothetical assumptions SPP would realize a total of $1,060 million in benefits from increased transmission revenue, avoided project costs, and production cost savings. (Additional benefits not included in our hypothetical example may relate to other SPP metrics such as reduced losses and increased competition.)

For AECI, the combined upgrades would allow for additional load-serving capability. We hypothetically assumed that the monetized benefit would be equal to $80 million in avoided cost

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(footnote continued from previous page)

identified in SPP's prior TSR studies and ITP studies but that have not yet received authorization to proceed with construction. It would thus be both helpful and necessary to analyze how many of the $900 million in SPP-internal transmission upgrades identified the 2011 AG2 TSR study are already planned through other means (*i.e.*, ITP or previous TSR studies).

146 As discussed below, it is possible to estimate incremental wheeling service revenues through PROMOD modeling, but that type of analysis has not been conducted. Some TSR customers will also be willing to pay more than the current transmission rate to obtain the requested service.

of an AECI-internal stand-alone project. For other entities such as Entergy and MISO, the $1,200 million of transmission projects is assumed to offer benefits from increased transfer capability amongst themselves and between SPP, AECI, and each of these entities. As shown in Table 16, the hypothetical increase in ATC is assumed to facilitate a present value of $150 million in additional transmission service revenue for Entergy (for service to SPP). In addition, similar to the monetized benefits for SPP, the upgrades are also assumed to avoid $150 million in hypothetical Entergy reliability projects (for service with MISO). The upgrades are also assumed to generate for MISO $100 million in transmission service revenue (for service with Entergy) and produce $100 million in adjusted production cost and load-LMP savings for MISO (consistent with MISO's own internal metric).

This illustrative example shows that capturing additional transmission service revenues (*e.g.*, estimated based on long-term wheeling out or through service requests) can be a significant "benefit" that should be considered in the evaluation of seams projects. The value of the incremental revenues can offset a substantial portion of project costs, but are not captured in any of SPP's monetized internal transmission planning metrics. Furthermore, it is also important to note that there may be customers who requested third-party service (*e.g.,* Entergy-to-MISO service) who may have to pay for some of the $900 million in SPP-internal upgrades.

The analysis of SPP's TSR study also showed that, while the Branson Area Project alone may not benefit SPP and AECI, closer coordination between TSR studies and ITP studies and interregional coordination of TSR studies can identify expanded project configurations that offer significantly higher benefits than the initially-identified seams project. Leveraging TSR studies may be an efficient way to identify promising seams projects as opposed to relying solely on top-down transmission studies such as the ITP or future studies to develop Joint Coordinated System Plans with neighbors.

Based on the hypothetical assumptions in this illustrative example, the total monetized benefits of $1,640 million outweigh total project costs of $1,200 million. The expanded seams project scope provides benefits to several seams entities—SPP, AECI, Entergy, and MISO. If SPP had seams agreements with each of them, then a four-way cost allocation may in fact be possible. As shown in Table 16, if the shares of the present values of monetized benefits would be used to determine cost allocations, SPP's share would be 65% of the $1,200 million in total project costs ($760 million of which would be offset directly by increased transmission service revenues even at existing rates), AECI would share 5% of total project costs, Entergy 18%, and MISO 12%. This cost allocation could be implemented based on physical ownership of individual project segments. With respect to the three lines of the Branson Area Project itself, for example, SPP could own the Brookline-Compton Ridge and Osage Creek-Compton Ridge (the two western lines) and AECI could own Compton Ridge-Cox Creek (the eastern line).

The fact that revenues associated with transmission service requests can offset a significant portion of total project costs even at current transmission rates also suggests that estimates of the long-term present value of such wheeling revenues would need to be calculated. Such estimates can be derived through a combination of approaches. For example:

- Starting with existing transmission service requests, experience-based "realization rates" could be derived to estimate how many of the submitted service requests will go forward at the standard (current of estimated future) wheeling rate. One would also estimate how many of these services requests would be extended or replaced with others after their initial term.
- The approximate magnitude and direction of TSRs can also be validated with historical market data. For example, if export ATC between SPP and Entergy is limited as suggested in SPP's TSR study and historical market prices show there would likely be significant trading opportunities (*e.g.*, average annual/seasonal on-peak/off-peak price spreads that exceed wheeling charges), then it would be reasonable to assume that incremental ATC would attract additional wheeling activity. This analysis based on historical price differences could also be used to validate that the TSRs are consistent with economic opportunities.
- Finally, the market simulations used to obtain estimates of adjusted production cost savings could be used to estimate changes in power transfers and associated wheeling revenues between and across individual regions. As noted earlier, adjusted production costs will not capture such wheeling revenues because SPP exports are priced at the SPP-internal average generation LMP, which does not include any wheeling out charges.

D. QUARRY PROJECT

The Quarry Project was suggested by America Electric Power West ("AEPW") as a candidate seams project with benefits to both SPP and Entergy. The "Western Region" of Entergy (in which the proposed project would be located) is a load pocket with limited import capability (*i.e.,* limited export capability from AEPW to Entergy) and a Local Area Procedure ("LAP") on the Mt. Zion-Grimes 138kV transmission line for the loss of the Grimes-Bentwater 138 kV transmission line. In SPP's *2010 ICT Strategic Transmission Expansion Plan* ("ISTEP") as the Independent Coordinator of Transmission ("ICT") for Entergy,[147] SPP documented that the Western Region had 1,117 non-firm and 1,455 firm available flowgate capability ("AFC")

[147] SPP, *2010 ICT Strategic Transmission Expansion Plan ("ISTEP")*, May 6, 2011, p. 31.

limiting events from January through September 2009, as shown in Figure 5 below. Similarly, the Western Region experienced 5,952 MWh of non-firm transmission loading relief ("TLR") curtailments during the same time. All events and curtailments listed in Figure 5 for Western are associated with the Mt. Zion-Grimes limitation.

Figure 5
2010 ISTEP-Studied AFC Events and TLR Curtailments

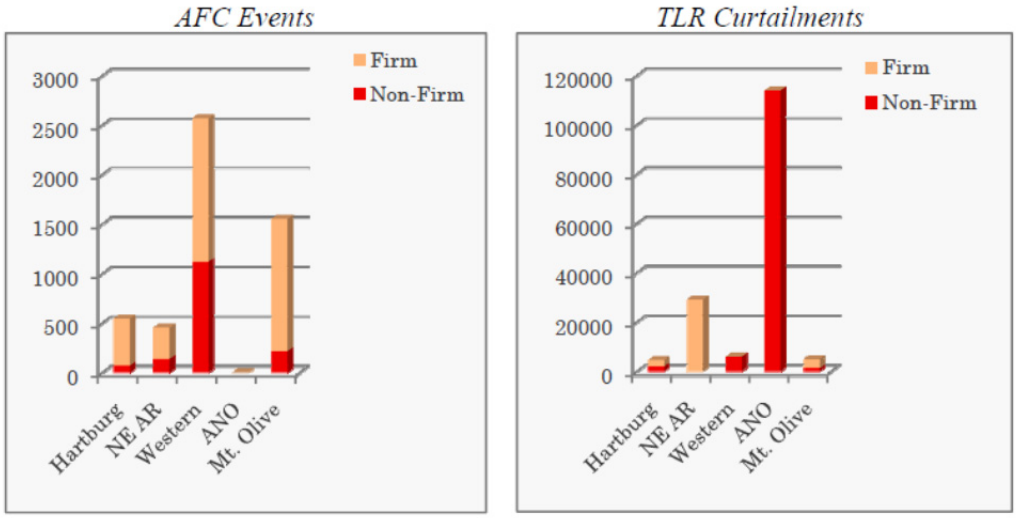

Figure 5.1: AFC Events **Figure 5.2: TLR Curtailments**

	Non-Firm Events	Firm Events
Hartburg	70	477
NE Ark	139	315
Western	1,117	1,455
ANO	0	0
Mt. Olive	216	1,338

Table 5.1: AFC Events (Non-Firm & Firm) January 2009 – September 2009

	Non-Firm Curtailment (MWh)	Firm Curtailment (MWh)
Hartburg	2,034	2,506
NE AR	0	29,207
Western	5,952	0
ANO	113,955	0
Mt. Olive	1,235	3,824

Table 5.2: TLR Curtailments (Non-Firm & Firm) January 2009 – December 2009

Source: SPP, 2010 ICT Strategic Transmission Expansion Plan, May 6, 2011, p. 31.

The proposed Quarry Project consists of a new 8.5 mile 345 kV line from Quarry to Rivtin with a substation and transformer for a total estimated cost of $53 million.[148] It would be wholly located within the Entergy's Western Region footprint in eastern Texas. Based on the 2010 ISTEP analysis, the proposed project could provide annual APC savings throughout Entergy of $4 million, reduce congestion costs, and "levelize" LMPs in modeled year 2016.[149] Other

[148] *Ibid.*, p. 23.

[149] *Ibid.*, p. 24.

benefits mentioned in the ISTEP, but not monetized, include increased transfer capability within the load pocket of approximately 300 MW (with a greater increase if constructed in coordination with other projects), and potential reductions in the number of AFC events and TLR curtailments.[150] Based solely on the APC savings, the project was estimated to yield a benefit-cost ratio of 0.41.[151] The left column of Figure 6 summarizes the major ISTEP findings.

The center and right columns in Figure 6 illustrate hypothetically-assumed total benefits to Entergy and SPP. For example, Entergy might consider APC savings as noted in the first light green box in the Entergy column. Another possible benefit of the proposed Quarry Project might include avoiding the cost of a smaller project to remove the Grimes-Mt. Zion line from LAP, as shown in the second light green box in the Entergy column. Indirectly, this may relate back to the 2010 ISTEP benefits (referred by the letters b, c, f, and g in grey boxes next to the light green illustrative Entergy benefits) by reducing congestion costs and congested hours across the Entergy footprint and specifically over Grimes-Mt. Zion. Since Entergy's Western Region is a load pocket, perhaps similar to the ALP, increasing Entergy's ability to serve load at lower cost could also be viewed as a reliability benefit. This may be related back to the 2010 STEP benefits noted in a, b, c, d, f, and g. Lastly, the increase in capacity (grey box e under the 2010 ISTEP benefits) may help increase off-system sales from the load pocket or conversely help accommodate additional transmission service requests ("TSRs"). These (hypothetical) Entergy benefits may be monetized and could be the first steps in considering cost allocation. It is also worthwhile to note that the non-monetized benefit of increasing transfer capabilities as analyzed by ISTEP (grey benefit box e) can influence both monetized and non-monetized benefits for Entergy. As in the ALP Project example, increasing access to load pockets also provides non-monetized (or more difficult to monetize) operational and maintenance benefits, reliability benefits via reduced TLR curtailments, increased transmission revenues from decreased AFC events, and synergies with other projects.

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[150] *Ibid.*, p. 22 and p. 31.

[151] 2010 ISTEP provides production cost savings in year 2016 of $4 million versus a total capital cost of $53 million for a benefit-cost ratio of 0.41. Based on these numbers, we infer that the carrying charge is $9.8 million.

Figure 6
2010 ISTEP and Hypothetical Benefits of the Proposed Quarry Project

	Benefits from ISTEP 2010 Analysis		Hypothetical Entergy Benefits	Hypothetical SPP Benefits
Monetary	a) $4 million in APC savings in 2016	a	APC savings	APC savings
	b) $11 million in congestion cost savings in Entergy in 2016	b, c, f, g	Reliability upgrades to remove Grimes-Mt. Zion from LAP	Increase in TSR revenue due to increased transfer capability
	c) $2.8 million in congestion cost savings over Grimes-Mt. Zion in 2016	a, b, c, d, f, g	Increased load serving capability by reducing cost to serve load (pocket)	
	d) -$2.01/MWh in LMP levelization	e	Increase in off-system sales and/or TSR revenue due to increased transfer capability	
Non-Monetary	e) Over 300 MW of additional transfer capability into load pocket	e	Increased operational and maintenance flexibility in load pocket	Synergies with other planned or proposed projects
	f) 1,215 fewer congested hours in Entergy in 2016	b, c, e, f, g	Decrease in AFC and TLR events	
	g) 786 fewer congested hours over Grimes-Mt-Zion in 2016	e	Synergies with other Construction Plan projects	
Benefit:	$4.0 million *(APC only)*		$8.5 million *(65%)* +	$4.5 million *(35%)*
Cost:	$9.8 million		$9.8 million	
B-C Ratio:	0.41		1.33	

Sources and Notes: SPP, *2010 ICT Strategic Transmission Expansion Plan ("ISTEP"),* May 6, 2011 for ISTEP benefits; all other data are illustrative.

Potential benefits to SPP were not analyzed in the ISTEP but Figure 6 above provides some hypothetical monetary and non-monetary benefits as illustrated in the last column. SPP also considers APC savings in its internal planning process and some may be attributable to the proposed Quarry Project. However, the likely greatest benefit to SPP may be the ability to fulfill TSRs to Entergy and consequently increase wheeling revenues, which provide an offset. Lastly, the non-monetary benefits to SPP may include synergies with other planned or proposed projects.

At the bottom of Figure 6 we show the 2010 ISTEP benefit, cost, and the 0.41 benefit-cost ratio under the ISTEP benefits in the left column. However, based on our hypothetical assumptions about other Entergy and SPP benefits, the combination of avoiding a smaller reliability upgrade, load serving savings, increased off-system sales, and additional TSR revenues (from both Entergy and SPP entities) produces a combined benefit of $13 million—65% of which accrues to Entergy and 35% of which accrues to SPP—and outweighs the estimated cost of $9.8 million. Based on these assumptions, the project would thus be cost effective for the combined Entergy-SPP footprint. While the benefits that Entergy may gain from its system (assumed to be $8.5 million) are not sufficient to offset Entergy's total cost of $9.8 million, after allocating 35% of total project cost to SPP, both Entergy and SPP will realize a benefit-cost ratio of 1.33.

XIII. CONCLUSIONS

We identified a number of significant barriers to seams cost allocation, which stem from challenges in planning for seams projects, how entities consider projects and calculate benefits, and the lack of workable cost allocation principles, guidelines, and mechanisms. We reviewed several approaches and developments that address these barriers, including the SPP's *Draft Cost Allocation Principles for Seams Transmission Expansion Projects whitepaper*, FERC's Order 1000, experience with a recent seams project, and examples from RTO and non-RTO regions in the U.S. and Europe—which included cost allocation principles, seams planning, and benefit measurements as applied to a variety of project types including reliability, economic, and public policy upgrades.

We found that a successful cost allocation framework requires well-specified benefit metrics and cost allocation principles, while allowing for flexibility to consider a wide range of different types of seams projects and seams entities. Our review experience from other markets also strongly suggests that a seams cost allocation framework needs to designed as an integral part of the interregional planning process.

Our proposed framework leverages SPP's existing JOAs with neighboring transmission entities as the starting point. The framework includes seven required (and one optional) building block, which address seams planning, data requirements and exchanges, project proposal processes and qualification, evaluation criteria and benefit metrics, seams cost allocation principles and guidelines, payment mechanisms and transmission rights, integration with internal processes, and optional formulaic cost allocation methodologies that could be developed as more experience is gained with specific project types. We applied the framework to proposed seams projects suggested by stakeholders to test its robustness in accommodating different types of projects with different benefits to both market and non-market entities. The framework is also consistent with the experience gained in the planning and successful cost allocation for the Acadiana Load Pocket project, a case study of a multi-utility seams project which is currently under construction.

In terms of next steps, we understand that SPP staff is actively working towards the Order 1000 compliance deadline, which is April 11, 2013 for interregional planning and cost allocation. We believe it is imperative that there be significant coordination between SPP and the RSC and hope that SPP and the RSC will be able to build on our proposed framework, including the straw man JOA language provided in Appendix C, to fully develop a robust interregional planning and cost allocation methodology that can be implemented through SPP's ongoing coordination efforts with its neighbors. We hope that this report can be used as the basis for this coordinated work to meet the Order 1000 mandate.