CAWG MEETING  
Nov. 1, 2006  
Embassy Suites Outdoor World  
Grapevine, TX  
1:00 – 5:30 pm  

AGENDA

1. Introductions  
   1:00 - 1:10

2. White Paper Discussion for Presentation to RTWG  
   Discussion lead by Mike Proctor  
   1:10 – 3:00

3. 15 minute break  
   3:00 – 3:15

4. Benefit Metrics for Economic Upgrades  
   Discussion lead by Mike Proctor  
   3:15 – 4:15

5. 15 minute break  
   4:15 – 4:30

6. Waivers methodology and MOPC issues  
   Discussion lead by Jay Caspary  
   4:30 – 5:30
CAWG WHITE PAPER ON ATTACHMENT Z

I. Background

Over the past year, the CAWG meetings have focused on Attachment Z from the perspective of what changes are needed to help promote investment in transmission upgrades that reduce congestion and result in lower cost, wholesale electricity supply to load-serving entities and ultimately to end-use consumers. For purposes of this white paper, transmission upgrades built to reduce congestion and lower the cost of electricity supply are considered Assigned Upgrades that are either directly assigned all or in part to the Transmission Customer or a Project Sponsor. The key component of Attachment Z is the ability of an entity that has been directly assigned the costs of a transmission upgrade (“Assignee” to the “Assigned Upgrade”) to receive revenue credits from additional use of these upgraded transmission facilities. Moreover, because it can be difficult and very costly on a per unit basis to construct small additions to the transfer capability of the transmission system, Attachment Z was initially designed to allow Transmission Customers not needing all of the capacity of the Assigned Upgrade to recover a portion of that cost through revenue credits.

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1 The CAWG recognizes that transmission upgrades that are built to meet reliability standards can also reduce congestion and lower electricity supply costs, but these upgrades are required irrespective of their economic benefit and are not called “economic upgrades.” Project Sponsor is definition 1.36a of the tariff; One or more entities that voluntarily agree to bear the cost of an Economic Upgrade. Transmission Customer is definition 1.45 of the tariff; Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff. Based on these definitions the Project Sponsor is NOT taking service and is NOT a Transmission Customer.

2 The portion of cost eligible for recovery is the amount directly assigned to the transmission customer in excess of the stated SPP rate.
A. Relationship of Revenue Credits to Investment in Economic Upgrades

In making a decision concerning investment in transmission facilities or accepting the direct assignment of the cost of upgrades to lower the cost of wholesale electricity supply, Transmission Customers and potential Project Sponsors would be comparing these costs to a stream of benefits they expect to receive from the expanded transmission capacity. These benefits could be in the form of either: 1) direct load benefits in the form of lower-cost purchases of power; or 2) direct generator benefits in the form of expanded sales of power. Both of these forms of benefits could reduce the cost of electricity supply for end-users.

Attachment Z provides an additional stream of revenues to be added to the cost/benefit calculation – revenue credits from others using the capacity of the facilities provided by the Assigned Upgrade. Having this additional stream of revenues available to the calculus of such decisions is critical to providing correct price signals and incentives.

B. Various Forms of Assigned Upgrades

Assigned Upgrades to the transmission system can be associated with either short-term (hourly, daily, weekly or monthly), mid-term (yearly up to 5 years) or long-term (5 years or longer) transactions for electricity supply.

Five years is used as a separation between long-term and mid-term because contracts for power supply that are 5 years or longer are eligible for regional cost allocation for new or changed designated resources to serve load. Even in the case of long-term contracts, if the cost of the upgrades needed to deliver power from a new or changed designated resource exceeds $180,000/MW, the excess that is not currently eligible for regional cost allocation would be considered an Assigned Upgrade and the Assignee would be eligible to receive revenue credits on that directly assigned cost.
To obtain transmission service for either long-term or mid-term contracts, a Transmission Customer would either be subject to “or” pricing if the transmission service requested is Point-To-Point (PTP), or to “and” pricing if the Transmission Customer is a network service customer not wanting to take additional PTP transmission service from the generation source. In either case, if the Transmission Customer pays more than the SPP transmission rate, as the Assignee, the Transmission Customer would be eligible to receive revenue credits on that directly assigned cost.

The CAWG was concerned about how Assignees using Assigned Upgrades for the purposes of short term transactions would be compensated. At one of the CAWG meetings a presentation was made regarding the flexibility a Transmission Customer taking long-term PTP transmission service would have under the SPP tariff. Assignees evaluating electricity cost savings associated with short-term transactions may want to reserve firm PTP transmission service for one-year or longer to protect their use of the Assigned Upgrade.

The CAWG also recognizes that assignees may not want to explicitly take PTP transmission service, but instead may simply want to sponsor the upgrade and participate in the SPP Energy Imbalance Market.

C. Structure of the Attachment Z White Paper

The remainder of this white paper is divided into two sections: Section II - Recommendation of the CAWG for changes to Attachment Z; and Section III – Alternative Resolutions for Unresolved Issues related to Attachment Z. In the

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3 That presentation is included as an attachment to this white paper.

4 Under proposed Order 888 reform, the FERC is requiring at least a 5 year reservation in order to be eligible for roll-over rights. If this change is implemented, it may be necessary to protect an investment in an economic upgrade designed for short-term electricity supply cost savings for the transmission customer to request a 5-year reservation for point-to-point transmission service.
recommendation Section II, a brief explanation of the reason for the recommendation will be presented. In Section III, details of discussion related to proposed alternative resolutions are presented.

II. Recommendations of the CAWG for Changes to Attachment Z

A. Project Sponsors

Project Sponsors are defined as those entities that request transmission upgrades be built, are willing to have the costs of the transmission upgrades directly assigned to them, but do not request transmission service to be taken from the Assigned Upgrade. Introducing the concept of a Project Sponsor not taking transmission service from the Assigned Upgrade requires some changes to be made to Attachment Z as it was originally drafted to provide an aggregate study process and revenue credits for Transmission Customers being directly assigned upgrade costs when such upgrades are needed in order to grant their requests for transmission service.

1. Absent any corresponding request for transmission service, should Project Sponsors be allowed to request and be directly assigned the costs of network upgrades? **CAWG Recommendation: YES.** This implies that Attachment Z should be divided into two distinct parts:

   Part II: Revenue Credits from Subsequent Transmission Use of an Assigned Upgrade for Assignees (both Transmission Customers and Project Sponsors).

2. Do any changes need to be made to Attachment Z regarding the aggregate study process? **CAWG Recommendation: YES,** there are several problems with the current aggregate study process that are listed
Below. Possible resolutions to these problems are presented in Section III.

a. With respect to the aggregate study process, the current version of Attachment Z only refers to requests for transmission service. This would exclude Project Sponsors that are not requesting transmission service from participation in the aggregate study process as a way to determine whether or not there are transmission service requests that would benefit from the upgrade and thereby share in the cost of the upgrade.

b. A concern was expressed about speculative projects being submitted into the aggregate study process by Project Sponsors. Whether speculative projects are submitted in the form of transmission service requests or by Project Sponsors, the CAWG recognizes that such requests tend to bog down the aggregate study process and there appears to be a need for a separate process for evaluating speculative or competing projects, e.g., transmission service for bids from competing resources. However, studying these projects separately may lead to erroneous conclusions.

c. The aggregate study process has required a significantly long time to reach a conclusion as restudy is required every time an additional transmission service request decides not to proceed.

3. Should the direction of the impact of subsequent requests for transmission service matter in determining the eligibility of the Assignee to receive revenue credits? **CAWG Recommendation: No.** Instead of using the direction of a request, the focus should be, “could the new service have been provided without the upgrade?” If it could, then no revenue credits should be received. If it could not, then revenue credits should be received by the Assignees. The overriding principle should be whether the upgrade makes it possible to provide the requested service. As with the current version of Attachment Z, this recommendation does not apply to the category 3 power devises.

4. Should Project Sponsors be allowed to subsequently request transmission service and receive revenue credits? **CAWG Recommendation: YES,** this should be a viable alternative. In this situation, the Project Sponsor
would receive revenue credits from the payments received by SPP for the Project Sponsor’s subsequent request for transmission service.

a. Short-term PTP transmission service can be used by the Project Sponsor for bilateral transactions that use the Assigned Upgrade.

b. Long-term PTP transmission service can also be requested by the Project Sponsor at a subsequent time that uses the Assigned Upgrade. For example, a later request for long-term PTP transmission service could involve a new or changed DR.

c. A Project Sponsor that is a NITS customer may subsequently request a new DNR that uses the Assigned Upgrade.

5. Should Project Sponsors be allowed to make a lump sum payment to the TO for the Assigned Upgrade? **CAWG Recommendation: YES**, the CAWG understands that, whatever the form of the payment (e.g., revenue requirements over the asset life or a lump sum payment), a multi-party agreement will be required, involving the Project Sponsor(s), the Transmission Owner(s) and the SPP. The CAWG recommends that the SPP include standard forms for such agreements in its Business Practices. However, the SPP should offer a standard payment such as revenue requirements over the asset life, and any alternative payment method should be a contractual arrangement negotiated between the Project Sponsor, SPP and the TO.

6. Should Attachment Z continue to place a limit on the revenue credits for which the Project Sponsor is eligible? **CAWG Recommendation: YES**

a. The current form of Attachment Z limits revenue credits to payments for that portion of directly assigned costs above the standard rates for transmission service; e.g., either through “or” pricing for PTP service or through “and” pricing for Network Integrated Transmission Service (NITS). A Project Sponsor would be entitled to receive the full amount of the Assigned Upgrade in revenue credits.
b. When a limit is placed on the amount of revenue credits received, the
tariff must also allow for accumulation of the difference between that
limit and revenue credits actually received, including interest. If this
occurs, it must be clear that this accumulated amount is still a limit,
not an amount due to the Project Sponsor at the end of some period of
time.

c. The tariff should also include a limit on the time over which revenue
credits can be received. This length of this period of time is an
unresolved issue that is discussed in Section III.

B. Subsequent Transmission Use of Assigned Upgrades in the Form of
Requests for New or Changed Designated Resources.

Subsequent transmission requests for new or changed Designated Resources
(DRs) that qualify for Base Plan Funding under Attachment J and that impact/use
Assigned Upgrades provide revenue credits to the original Assignee in the current
version of Attachment Z. Transmission requests involving DRs that qualify for
Base Plan Funding include both:

a) NITS requests for new or changed DNRs; and
b) PTP requests for new DRs.

However, the current version of Attachment Z does not separate out requests for
new or changed DRs from other transmission requests that impact Directly
Assigned Network Resources.

1. In revisions to Attachment Z, should subsequent transmission requests
involving new or changed DRs be set out as a separate category for
making payments to Assignees of Assigned Upgrades? **CAWG**

Recommendation: YES. This subsequent use of transmission directly
involves the application of Attachment J with the potential for Base Plan
Funding being used for revenue credits, and therefore needs to be kept
distinct from other forms of transmission service requests that impact
Assigned Upgrades. More specifically, Attachment J requires an
assignment of costs for upgrades to requests for a new or changed DR, and the manner in which this cost assignment applies to the requestor of the new or changed DR is unique toAttachment J.

2. For purposes of Attachment J determinations, what costs from Assigned
Upgrades should be included as attributable to subsequent requests for new or changed DRs? **CAWG Recommendation:** The costs from Assigned Upgrades that should be attributable to subsequent requests for DRs should include:

(a) \* (b) for Project Sponsor’s Assigned Upgrades; or
(a) \* (c) for Transmission Customer’s Assigned Upgrades

Both calculations are illustrated in Appendix A.

a. The original cost of the Assigned Upgrades. Whether or not accumulated depreciation over the period of time that these upgrades were in service should be subtracted from the original cost of the Assigned Upgrade is an unresolved issue that is discussed in Section III.

b. The MW impact of the new or changed DR associated with a Project Sponsor’s Assigned Upgrade that could not have been provided absent the Assigned Upgrade, as a percent of the smaller of the incremental MW transfer capacity created by the upgrade in either direction (denominator), greater of either:

(1) The incremental MW transfer capacity created by the upgrade in the direction of the increased transfer capability associated with the Assigned Upgrade; or

(1) The sum of absolute value of the incremental MW impacts on the Assigned Upgrade which could not have been provided without the Assigned Upgrade.

If the sum of MWs from new transmission service that could not have been provided absent the Assigned Upgrade exceeds the denominator calculated above, then the denominator would be adjusted to equal the sum of all MW impacts on the Assigned Upgrade from new transmission service.
c. The MW impact of the new or changed DR associated with a Transmission Customer’s Assigned Upgrade that could not have been provided absent the Assigned Upgrade, as a percent of the sum of the absolute value of the incremental MW impacts on the Assigned Upgrade which could not have been provided without the Assigned Upgrade.

The current Attachment Z applies (a) for all subsequent PTP use of the Assigned Upgrade and (b) for all subsequent network service use. However, the distinction should not be based on whether subsequent use is for PTP or network service use, rather the distinction should be based on whether or not, at the time of the original request, the Assignee of the costs of the Directly Assigned Network Upgrade requested and is now receiving transmission service from the Assigned Upgrade or not. If the Assignee did not take transmission service at the time of the original request (Project Sponsor), then it is impossible for the percent impact to be based on a share of the total incremental MW impacts from transmission service being taken from the upgrade as the Project Sponsor is not taking any transmission service and would have a zero impact. Using the incremental MW transfer capacity created by the upgrade is an alternative calculation that gives the same result as incremental MW impacts from transmission service sold when the total quantity of incremental MW impacts from transmission service sold are equal to the transfer capacity created by the transmission upgrade.

The primary reason for using percent of MW impacts from transmission service sold is to put all subsequent transmission service use of the upgrade on an equal basis with prior transmission service uses of that same upgrade. This will help to encourage potential co-sponsors not
to wait until after the upgrade is completed to request desired transmission service in hopes of obtaining such service at a lower cost than if they had co-sponsored the upgrade.

3. Do the revenue credits apply only to the Assignee of the Assigned Upgrade or do they also apply to subsequent Transmission Customers who are paying for a portion of the upgrade through revenue credits? **CAWG Recommendation:**

   a. If the original Assignee is a Transmission Customer, then revenue credits from subsequent Transmission Customers are shared among the original Assignee and all previous Transmission Customers paying revenue credits. The sharing of revenue credits is allocated on a pro-rata basis of their MW impacts on the Assigned Upgrade.

   b. If the original Assignee is a Project Sponsor, then all revenue credits are assigned to the Project Sponsor up to the point that

      1) the sum of assigned costs to subsequent Transmission Customers equals 100% (see Appendix A), or alternatively

      2) the Project Sponsor is fully compensated (discuss meaning).

   If there is subsequent transmission service that is responsible to pay revenue credits, then those revenue credits are shared among all previous Transmission Customers paying revenue credits on a pro-rata basis of their MW impacts on the Assigned Upgrade.

4. Should the costs from Assigned Upgrades attributable to new or changed DRs be subject to the safe-harbor provision of Attachment J? **CAWG Recommendation:** **YES.** The issue here is whether or not a request for long-term PTP service involving a DR should be directly assigned any costs associated with transmission facilities that are already in place. In
this context, keep in mind that any request for DRs that does not meet either the safe-harbor provision or the conditions of Attachment J and does not receive a waiver can be directly assigned costs associated with upgrades needed to grant the request. In its approval of Attachment Z, the FERC determined that Network Service that impacts the Assigned Upgrade should pay revenue credits to the Assignee of the costs of the Assigned Upgrade. Clearly such an impact from a NITS customer could occur through a request for a new or changed DNR. The CAWG recommendation is that new or changed DRs requested through PTP service should be treated in a comparable manner.

a. The $180,000/MW cap should apply to all requests for new or changed DRs, whether through NITS or PTP transmission service.

b. The cost from already constructed Assigned Upgrades should be included along with the costs of any additional upgrades needed to grant this transmission service.

c. If the $180,000/MW cap is exceeded and a waiver is not granted, then the amount of the excess should be distributed in proportion to the costs of each transmission upgrade assigned to the DR request, including both Assigned Upgrades and any new upgrades required.

5. Should “higher of” pricing apply to subsequent requests for a new or changed DR through PTP service? **CAWG Recommendation: YES.** If the costs directly assigned to a Transmission Customer requesting a DR through PTP service exceed the PTP rate, then that customer should be responsible for those costs.

a. Applying Attachment J in conjunction with Attachment Z determines the amount of cost going into Base Plan Funding and the amount of costs (if any) that would be directly assignable to the TC for PTP service.

b. Any cost directly assignable to the PTP TC would then be compared to the tariffed rate for PTP service by applying usual “or” pricing procedures.
- Customer will always pay at least the PTP rate.
- If costs (above those included in Base Plan funding) are lower than the PTP rate, then the TC pays the PTP rate.
- If costs (above those included in Base Plan funding) are higher than the PTP rate, then the TC pays the PTP rate plus an excess above that rate.

6. What should be the dollar flows related to subsequent DR through PTP service using an Assigned Upgrade? **CAWG Recommendation:** See Appendix B for examples of all the possibilities listed below.

The Assignee continues to pay for the cost of the Assigned Upgrade.

- Cost of Assigned Upgrades is assigned to subsequent PTP TC based on MW impacts.
- Revenues from subsequent PTP DR Service
  - Rates via Base Plan Funding for Assigned Upgrades go to SPP and are distributed to the Assignee. If Base Plan Funding covers all the costs, then the Assignee is not entitled to any additional revenue credits from the subsequent Transmission Customer. The subsequent Transmission Customer pays the PTP rate and the revenues are distributed to Transmission Owners.
  
  - If Base Plan Funding does not cover all the upgrade costs, then the subsequent Transmission Customer is directly assigned whatever costs are not covered, and the PTP “higher of” rate applies.
    - If the “higher of” rate is the PTP rate, then that portion of the PTP rate that covers transmission upgrade costs will be paid back to the Assignee’s share of upgrade costs not covered by Base Plan Funding. The remaining revenues are distributed to Transmission Owners.
    - If the “higher of” rate is above the PTP rate, then all of the “higher of” rate is applied to cover transmission upgrade costs which include the Assignee’s share of upgrade costs not covered by Base Plan Funding. There are no remaining revenues to distribute to Transmission Owners.
7. Should any change to Attachment J be made concerning a DNR request by a NITS customer that results in a form of “and” pricing? **CAWG Recommendation: NO.** Currently, under Attachment J, NITS customers requesting new or changed DNRs are subject to direct assignments of transmission upgrade costs as indicated below.

- When the assigned costs of the upgrades exceed the safe harbor limit of $180,000/MW a portion of the assigned costs of the upgrade above $180,000/MW are directly assigned to the NITS customer, unless a waiver is granted.
- To qualify for Base Plan funding, the DNR request must equal or exceed 5 years and total capacity cannot exceed 125% of forecasted peak demand. Otherwise, the NITS customer must either receive a waiver or pay for at least a portion of the cost of upgrades required to meet its DNR request.

8. What should be the dollar flows related to subsequent DNR through NITS service using a Assigned Upgrade? **CAWG Recommendation:** See Appendix C for examples of all the possibilities listed below.
• Assignee continues to pay TO for the cost of the Assigned Upgrade.
• Cost of Assigned Upgrades are assigned to subsequent NITS customer based on MW impacts.
• Revenues from subsequent NITS DNR Service:
  - Rate via Base Plan Funding for Assigned Upgrades go to SPP and are distributed to the Assignee.
  - Any Excess above Base Plan Funding paid by NITS customer also goes to the Assignee.

Diagram of Dollar Flows for New or Changed DNR through NITS

C. Subsequent Transmission Use of Assigned Upgrades by New or Changed System Load.

In the previous section subsequent use of Assigned Upgrades associated with new or changed Designated Resources was discussed separately from other uses because these subsequent transmission requests are eligible for Base Plan Funding which provides a source of revenues to pay the revenue credits. In addition, there are reliability upgrades included in the SPP transmission plan that are eligible for either Base Plan Funding or to be included in the Transmission Owner’s zonal rate. These upgrades do not involve subsequent requests for transmission service, but
are associated with reliably meeting system load from currently approved DRs. Since upgrades needed to support approved new or changed DRs are already taken into account through the transmission request process, the purpose of the SPP transmission plan is to ensure that the transmission system can continue to provide reliable transmission service to system load. In this context, new or changed system load refers to situations where load growth has occurred in such a way that additional upgrades are needed to meet ERO\(^5\) standards and SPP reliability criteria. In addition, Transmission Owners may have planning standards more stringent than ERO standards and SPP criteria, in which case upgrades may be required from new or changed load that results in associated costs being rolled into the Transmission Owner’s zonal rate. Thus, either through Base Plan Funding or through Transmission Owners’ zonal rates, there is a source of revenue to provide Assignees of Assigned Upgrades costs with revenue credits, where appropriate.

1. Should Assigned Upgrades that displace or defer reliability upgrades that would otherwise be needed result in reduced costs for the Assignees of the costs of the Assigned Upgrades? **CAWG Recommendation: YES,** to the extent that the reliability upgrades appear in the SPP Board approved plan at the time that the request for the Assigned Upgrades is approved. The cost of these reliability upgrades should be removed from the costs assigned to the Assignee. This is consistent with the current Attachment J that requires costs of reliability upgrades that are deferred or displaced by other transmission upgrades not be directly assigned, but instead are Base Plan funded.

2. Should subsequent use of Assigned Upgrades by “New Load” of a Transmission Customer result in revenue credits to the Assignees of the

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5 Electric Reliability Organization.
costs of the Assigned Upgrades? **CAWG Recommendation: YES.** It appears from the FERC Order on Attachment Z that if “New Load” associated with NITS impacts the Assigned Upgrade, the Assignee should receive revenue credits. A discussion of how SPP should make the necessary calculations to provide the revenue credits is included in Section III.

a. Clearly the addition of a large, new load would qualify, but there is no designated/arbitrary megawatt floor in the tariff.

b. In addition, it would appear that it shouldn’t make any difference whether there is only one customer or multiple customers that account for the new load.

c. In addition, it would appear that it shouldn’t make any difference whether the new load comes from existing customers or new customers.

**D. Subsequent Transmission Use of Assigned Upgrades by New PTP Transmission Service Other Than New or Changed Designated Resource.**

The previous two sections dealt with subsequent use of Assigned Upgrades associated with transmission requests for serving native load (i.e., new/changed designated resources or new/changed loads). In addition to these requests for transmission service to serve load from designated resources, there may be requests for PTP transmission service not related directly to serving load from designated resources. For purposes of this portion of the white paper, these subsequent requests for PTP transmission service are separated between short-term (less than one year) and long-term (more than one year).

Short-term requests for PTP transmission service are simply accepted or rejected by the SPP based on available transmission capability. There is no question of upgrades to meet these requests. This is not true of requests for long-term, PTP transmission service, where the length of term may require an upgrade
in order to meet the request. It appears that upgrades could also be required for
mid-term (over 1 year, but less than 5 years) requests for PTP transmission service
even if the FERC implements the recommendation to limit roll-over rights to
requests of 5 years or greater. At this time, it does not appear that limiting roll-
over rights to requests involving more than 5 years would impact the following
CAWG recommendations.

The current form of Attachment Z requires subsequent short-term PTP requests
for transmission that impact Assigned Upgrades to provide revenue credits to the
entities that have been directly assigned these costs. The requirements for
receiving such revenue credits and the form of these revenue credits are as follows:

- Must impact the Assigned Upgrades involved in the same direction as the
  initial overload.
- This MW impact is to be recalculated each month.
- The calculation for such revenue credits included in the existing
  Attachment Z is (MW impact)*(Applicable PTP rate)
  \[ MW \text{ Impact} = (% \text{ Distribution Factor}) \times (\text{MW Transmission Service}) \]
  \[ \text{PTP rate} = \text{the applicable rate paid by the subsequent TC} \]

1. Should any changes be made to Attachment Z regarding the calculation
   of revenue credits from subsequent short-term PTP requests for
   transmission that impact Assigned Upgrades? CAWG

   **Recommendation:** Yes, see Part II.A.3 and Part II.B.2.

2. Should any changes be made to Attachment Z regarding the calculation
   of revenue credits from subsequent long-term PTP requests for
   transmission that impact Assigned Upgrades? CAWG

   **Recommendation:** YES. It should be clear in Attachment Z that
   requests for long-term PTP service with and without a new or changed
   DR should be treated on a comparable basis.
a. A request for PTP service that does not include a new or changed DR should include a direct assignment of costs from the Assigned Upgrade that is then included in SPP’s calculation of “or”/“higher of” pricing for that request. While comparability is a strong argument in favor of this recommendation, there is another alternative to this issue that is discussed in Section III.D.

b. The calculations in the current Attachment Z require the SPP to recalculate the MW impact on the Assigned Upgrade for all PTP transmission service on a monthly basis. This is not consistent with the calculations made for long-term PTP service associated with a request for a new DR, where a one-time calculation of impact is made to determine the costs from the Assigned Upgrade that are, in essence, re-assigned to the subsequent request. In order to be consistent, the calculation of MW impacts for long-term PTP service should be made one time, whether or not the request involves a new or changed DR.

E. Revenue Credit Streams Versus Lump-Sum Credits

1. Should Attachment Z consider a lump-sum credit to the Project-Sponsor Assignee as an option in lieu of revenue credits when a portion of the revenue credits are coming from Base Plan Funding? CAWG

Recommendations: Based on the following situations.

NO when:

a. Project Sponsor is making payments for the Assigned Upgrade over the asset life (e.g., 30 years). For example, assume a new DNR is approved and a portion of the cost of the Assigned Upgrade is Base Plan Funded. The dollar flows for the revenue credit case are:
   - Project Sponsor pays SPP monthly payment for Assigned Upgrade costs. SPP transfers payment to Transmission Owner.
- SPP bills appropriate Transmission Customers for rates associated with new DNR. A portion of the revenues collected go to Project Sponsor.
- In net, SPP credits the Project Sponsor’s bill for revenues thereby reducing the Project Sponsor’s net payment. SPP makes up the difference to the Transmission Owner from revenues received in rates for new DNR. In effect, the Project Sponsor has received a lump-sum reduction to what is owed the SPP. But, this is different from receiving a lump-sum credit that would involve a one-time cash payment from SPP to the Project Sponsor.

b. The Network Transmission Customer funds the Assigned Upgrade when requesting a new DNR that exceeds the safe harbor limit of $180,000 per MW. The payment for the excess over the safe-harbor limit is made over the SPP standard payment period (e.g., 30 years). For example, assume a new DNR is approved and a portion of the cost of the Assigned Upgrade is Base Plan Funded. The dollar flows for the revenue credit case are identical to the previous example.

**YES, when:**

a. The Project Sponsor funds the Assigned Upgrade by paying the Transmission Owner the cost of the upgrade upfront. For example, assume a new DNR is approved and a portion of the cost of the Assigned Upgrade is Base Plan Funded. The dollar flows for the revenue credit case are:
- Project Sponsor pays SPP a monthly fee for operations & maintenance, including applicable payroll, payroll taxes, and property taxes of the Assigned Upgrade. SPP transfers payment to the Transmission Owner.
- SPP bills appropriate Transmission Customers for rates associated with new DNR. The appropriate portion of the revenues collected goes to the Project Sponsor.
- In net, SPP credits the Project Sponsor’s bill for the revenues, thereby resulting in a net cash payment to the Project Sponsor.

Alternatively, the dollar flows for the lump-sum credit case are as follows:
- SPP collects from the Transmission Owner a lump-sum amount for portion of the Assigned Upgrade that is included in Base Plan Funding.
- SPP transfers this lump sum payment to the Project Sponsor and the amount of revenue credits for which the Project Sponsor is eligible is reduced.
- SPP collects from the Transmission Customers for rates associated with the new DNR.
- Transmission Owner receives revenues from SPP for the lump-sum payment.
- The Project Sponsor continues to make monthly payments for operations & maintenance, including applicable payroll, payroll taxes, and property taxes.

b. The Transmission Customer funds the Assigned Upgrade by paying the Transmission Owner the cost of the upgrade through “higher of” pricing over the term of the transmission service contract. For example, assume a new DNR is approved and a portion of the cost of the Assigned Upgrade is Base Plan Funded.

1) If the term of the transmission service contract is completed and the TC is no longer taking transmission service, the dollar flows are the same as in the previous case except that if the TC is no longer taking transmission service, there are no maintenance fees.

2) If the initial term of the transmission service contract is completed, but the TC continues to take transmission service, the dollar flows for the revenue credit case are as follows:
   - The customer pays the PTP rate and receives back in revenue credits a portion of the rate based on the MW impact on the Directly Assigned Network Facilities. The remaining revenues are distributed among TOs.
   - SPP bills appropriate Transmission Customers for rates associated with new DNR. A portion of the revenues collected go as a credit to the Transmission Customer who has funded the Assigned Upgrade.
   - The sum of revenue credits received by the Transmission Customer may or may not exceed the PTP rate.

Alternatively, the dollar flows for the lump-sum credit case are as follows:
   - SPP collects from the Transmission Owner a lump-sum amount for the portion of the Assigned Upgrade that is included in Base Plan Funding.
   - SPP transfers this lump sum payment to the Transmission Customer and the amount of revenue credits for which the Project Sponsor is eligible is reduced.
   - SPP bills appropriate Transmission Customers for rates associated with new PTP service
   - Transmission Owner receives revenues from SPP for lump-sum payment.
   - The Project Sponsor continues to make monthly payments for the PTP rate absent revenue credits from the impact of the new DNR on the Assigned Upgrade.

3) If the initial term of the transmission service contract is not yet completed, the TC continues to take transmission service, and the dollar flows are the same as above without any revenue credits being received from the Transmission Customer’s own impact on the Assigned Upgrade.
III. Alternative Resolutions for Unresolved Issues Related to Attachment Z

A. Aggregate Study Issues

1. Proposals for evaluation of speculative or competing alternative transmission upgrade projects.
   a. The SPP should have a process separate from the aggregate study process that provides estimates of transmission upgrade costs for speculative or competing alternative transmission upgrade projects where it is understood that these estimates do not include any cost sharing possible from the aggregate study process. SPP could hire an outside consultant to perform these studies, and Transmission Customers requesting these studies be performed would pay the consultant fee.
   b. However, the results could be misleading. If three alternatives are studied and one is selected on a stand alone basis, there is no assurance that this is the best choice on an aggregate basis. This separate procedure could only serve as a screening procedure. It still might reduce the number of speculative requests.

2. Proposals for allowing Project Sponsors to benefit from the Aggregate Study process.
   a. Allow Project Sponsors to submit upgrades to which they are already fully committed to into the aggregate study process at any time prior to the in service date of the upgrade. Any transmission service request granted that requires the Project Sponsor’s upgrade to be in place would share in the cost of the upgrade.
   b. What should be the measure of commitment before Project Sponsors may submit proposed upgrades into the aggregate study process?

3. Proposals for complete the Aggregate Study Process.
   a. Only allow a fixed number of iterations by requiring anyone signing up for the last iteration to pre-commit to the project. This would require SPP to provide information on worst case scenarios to those included in the second to last iteration prior to their making a commitment to participate in the last iteration.
   b. Also consider a 180 day aggregate study process with a longer period for signing the letters of intent to encourage project commitment.
4. For purposes of determining the cost of an Assigned Upgrade that is assigned to a subsequent request for transmission service, should accumulated depreciation be subtracted from the original cost?

**YES.** Straight-line depreciation should be used in the calculation of accumulated depreciation and subtracted from the original cost of the Directly Assigned Network Resource. The reason for doing so is because the request for a new or changed DR may occur several years after the date at which the Assigned Upgrade is made, and there needs to be some mechanism to account for the age of the facilities in order that subsequent users are not overcharged for their use of older facilities. Straight-line depreciation is the most straight-forward method, and does not front load depreciation costs as would be the case for depreciation associated with levelized fixed charge rates.

**No.** While straight line depreciation maybe the most straight-forward method, it may not be consistent with the TO’s determination of its fixed charge rate. Any depreciation method used must be consistent with the TO’s method used to determine the payments being made by the Assignee or the credits paid to the Assignee.

5. Should eligibility to receive revenue credits be for a fixed period (and if so, how many years), or should eligibility to receive revenue credits be for the service life of the asset, or should eligibility to receive revenue credits be based on the fixed charge rate used to determine the Assignee’s Assigned Upgrade payment?

   a. **Fixed Period – 30 Years**

   The definition of “service life” in the draft Attachment Z2 reads as follows: “The time between the date electric plant is includible in electric plant in service, or electric plant leased to others, and the date of its retirement.” This definition adopts an accounting life concept, in contrast with other types of service life such as the actual physical life, an engineering projection of physical life, and the tax life used for accelerated depreciation. Whereas accounting life and tax life both play major roles in determining standard revenue requirements, the physical life determines the period over which the facility is available to create revenue credits. One advantage of using the accounting service life of a project to determine the maximum crediting period is that it gives the appearance of matching the potential credits with the period of time over which the Transmission Owner receives a return on the facility that is funded by the Project Sponsor or Transmission Customer. However, these time periods may not match in any event since the
amortization period for revenue requirements purposes can be shorter than the accounting service life. In addition, there are other issues related to the service life that must be resolved if it is to be used as the basis for defining the period in which credits are applied.

Most upgrade projects are likely to include equipment assigned to multiple FERC accounts, with each account having a different service life, a different net salvage value, and a different depreciation rate. In such cases, a determination has to be made as to which equipment component’s service life is used to determine the crediting period, and no single value may be accurate for the upgrade project in aggregate.

The service life used for accounting purposes can vary among companies, among regulatory jurisdictions, and among rate case orders. Should the crediting period vary depending on the Transmission Owner that constructs the project? Should the crediting period change if a rate order modifies the service life and the accompanying depreciation rate?

Both physical life and accounting life can be shortened by natural events, accidents, and technical obsolescence. Presumably, the crediting period must be shortened if a facility is retired early. In addition, the physical life sometimes can be extended by maintenance activity, capital additions, or both. These factors potentially create more uncertainty regarding the determination of service life.

As mentioned above, a possible alternative to utilizing service life as the maximum crediting period is to use a standard limit such as 30 years for all requested upgrades. A standard time limit would resolve some of the above questions associated with service life and would be simpler to administer. In addition, a standard crediting period may result in greater equity as a consistent time limit is applied to all upgrade projects, all Transmission Owners, and all Transmission Customers or Project Sponsors.

b. Service Life
Service life should be used for the period over which a Transmission Customer or Project Sponsor can receive revenue credits for the reasons below.

1) The Transmission Customer or Project Sponsor should receive revenue credits for all additional transmission service that could not be provided without the upgrade; therefore as long as the project is in service the Project Sponsor should be eligible to receive revenue credits.
2) The excess that the Transmission Customer or Project Sponsor will pay over and above the base rates will be based upon the revenue requirements of the upgrade which will represent a composite (dollar weighted) service life for the upgrade.

3) Transmission Owners do not use the same depreciation rates and choosing a standard term for revenue credits would be inconsistent with how the excess which is eligible for revenue credits is initially determined.

4) If an upgrade is removed from service earlier than originally anticipated that upgrade is no longer available to provide revenue credits whether service life or some other term is chosen.

5) The eligibility for credits should be consistent with the fixed charge rate used to determine the Assignee’s Assigned Upgrade payment.

B. Subsequent Transmission Use of Assigned Upgrades in the Form of Requests for New or Changed Designated Resources.

1. In Attachment J, if a DNR request results in the load-serving entities reserve margin exceeding the 125% limit in the first few years after the resource comes on line, how should the customer be directly assigned any of the costs associated with upgrades required by the request? The purpose of the 125% reserve margin limit on DRs is as an upper bound to prevent gaming with respect to an individual load-serving entity from in essence reserving significantly more transmission than is needed to serve its load.

ALTERNATIVES:

a. The MW level by which the DR exceeds the 125% level as a percent of the DR request is used to directly assign the engineering & construction costs of any upgrades (current practice).

b. The costs of required upgrades equal to $180,000 times the request DR capacity that brings the reserve level to 125% will be base plan funded subject to the DR term of 5 years or longer. The costs in excess of this amount will be directly assigned.

c. The Transmission Customer is initially assigned the percent of costs by which the DR request exceeds the 125% reserve margin (see a. above). If the actual reserve margin falls below the 125% level after an initial period where that limit was exceeded, then the payments for the upgrades that were directly assigned to the Transmission Customer should then be Base Plan
Funded through the cost allocation mechanism. Moreover, once the reserve levels fall below the 125% level, the issue of reserving significantly more transmission than is needed to serve load goes away.

C. Subsequent Transmission Use of Assigned Upgrades by New Network Load.

1. Would it make sense to include revenue credits from future reliability projects (those included at a later date in the SPP transmission plan) that would otherwise be needed “but for” the construction and availability of the Assigned Upgrades?

YES, this is a case where the “but for” condition makes sense, at least to the extent that this can be done in the SPP planning process.

a. One way to do this is to exclude all Assigned Upgrades from the SPP base case to identify criteria violations and needed upgrades.

b. Then answer the question: which of the needed upgrades are displaced by existing Assigned Upgrades.

NO. Making the “but for” calculations in the SPP planning process could require extensive additional modeling. RTWG should obtain SPP input before going forward with the types of calculations that could be required for including revenue requirements for older projects.

D. Subsequent Transmission Use of Assigned Upgrades by New PTP Transmission Service Other Than New or Changed Designated Resource.

1. Should the applicable PTP rate include “higher of” pricing via applicable cost from Assigned Upgrades?

YES

a. Comparability to PTP service that includes a new or changed DR - Should be the same as for a request for DR through a request for long-term PTP service that impacts an Assigned Upgrade, and both should include an assigned portion of the costs in the calculation of the “higher of” price.

b. A request for long-term PTP service may (and is likely to) require additional upgrades. If the Assigned Upgrades are excluded from the “higher of” calculations, then a proper allocation of revenue credits to Project Sponsors will not result.

NO
a. Discourages sales of PTP service and will result in lower revenues.
b. Could potentially result in gaming by customers taking short-term rather than long-term PTP service.
APPENDIX A
EXAMPLES OF CALCULATION OF
MW IMPACT FROM
NEW TRANSMISSION REQUESTS

Assumptions common to all examples:
Assigned Upgrade increased the capacity of the existing flowgate by 500 MW in
the A to B direction as well as in the B to A direction.
New transmission service request from Customer B has a 50 MW impact on the
same flowgate and in the same A to B direction.
The original cost of the Assigned Upgrade was $16,000,000.
The Assigned Upgrade has been in service for 10 Years with a depreciation life of
40 years.

Calculation common to all examples: The net plant value of the Assigned
Upgrade:
Original Cost – Accumulated Depreciation
$16,000,000 – (10/40)*($16,000,000) =
$16,000,000 - $4,000,000 = $12,000,000

Example A: MW Impact as a percent of Incremental MW Capacity
Additional Assumption: The Assignee that requested the Assigned Upgrade did so
without requesting any transmission service; i.e., is a Project Sponsor.
Percent of MW capacity from the new transmission service:
50 MW % 500 MW = 10%
Cost of Assigned Upgrade allocated to Customer B:
$12,000,000 * 10% = $1,200,000

Example A1: MW Impact from adding multiple new transmission service
In Example A, assume a customer C takes transmission service at the same time as
Customer B and the impact on the Assigned Upgrade is 450 MWs. The
cumulative impact of customers B and C now equals 500 MW, which is the
denominator in the calculation being used to determine the percent of costs being
allocated to new transmission service that impacts the Assigned Upgrade.
Customer B: $12,000,000 * 10% = $1,200,000
Example A2: MW Impact from adding subsequent new transmission service

Suppose a third Transmission Customer D takes transmission service subsequent to Customers B and C, and the impact on the Assigned Upgrade for Customer D is 100 MWs. The cumulative impact of customers B, C and D now equals 600 MW, which is greater than the denominator use in the calculations in examples A and A1. The question then, is what should Customer D be allocated in costs (for purposes of simplicity in the calculations, also paying in revenue credits), and who should receive those revenue credits?

First, the denominator used to calculate Customer D’s share of costs has increased from 500 MW to 600 MW, which is the sum of the MW impacts on the Assigned Upgrade:

Customer D: \( \frac{100 \text{ MW}}{600 \text{ MW}} \times 12,000,000 = 2,000,000 \)

Second, revenue credits from Customer B and C still go to A (the Project Sponsor), however, if A is fully compensated, revenue credits from Customer D would not go to A but instead would go to Customers B and C in proportion to their MW impacts to each.

Customer B: \( \frac{50 \text{ MW}}{500 \text{ MW}} \times 2,000,000 = 200,000 \)

Customer C: \( \frac{450 \text{ MW}}{500 \text{ MW}} \times 2,000,000 = 1,800,000 \)

Third, notice that this reduces the costs allocated to Customers B and C to the same level they would have been had their percent allocation been based on a denominator of 600 MW:

Customer B:
\[ 1,200,000 \text{ (to A)} - 200,000 \text{ (from D)} = 1,000,000 \]
Where: \( \frac{50}{600} \times 12,000,000 = 1,000,000 \)

Customer C:
\[ 10,800,000 \text{ (to A)} - 1,800,000 \text{ (from D)} = 9,000,000 \]
Where: \( \frac{450}{600} \times 12,000,000 = 9,000,000 \)

Example B: MW Impact as a percent of Incremental Transmission Service

Additional Assumption: The customer that requested the Assigned Upgrade (Customer A) did so through a request for transmission service; i.e., is a Transmission Customer, and that transmission service uses 100 MWs of the 500 MWs of increased capacity on the flowgate
Percent of incremental transmission service taken on the Assigned Upgrade by Customer B:

\[
50 \text{ MW} \% \left(100 \text{ MW} + 50 \text{ MW}\right) = \\
50 \text{ MW} \% 150 \text{ MW} = 33.3\%
\]

2. Cost of Assigned Upgrade allocated to Customer B:

\[
$12,000,000 \times 33.3\% = \$4,000,000
\]

**Example B1: MW Impact from adding subsequent new transmission service**

Additional Assumption: In example B, assume that after the first new customer (Customer B) was granted transmission service, a second new customer (Customer C) is granted new transmission service with a 25 MW impact on the Assigned Upgrade in the same direction, A to B.

1. Percent of incremental transmission service taken on the Assigned Upgrade by Customer C.

\[
25 \text{ MW} \% \left(100 \text{ MW} + 50 \text{ MW} + 25 \text{ MW}\right) = \\
25 \text{ MW} \% 175 \text{ MW} = 14.3\%
\]

2. Cost of Assigned Upgrade allocated to Customer C:

\[
$12,000,000 \times 14.3\% = \$1,714,286
\]

Example B2: MW Impact from adding multiple new transmission service

Additional Assumption: In example B, assume that at the same time both Transmission Customers request transmission service – Customer B for 50 MW and Customer C for 25 MW.

1. Percent of incremental transmission service taken on the Assigned Upgrade by the new customers:

   - Customer B: 50 MW % 175 MW = 28.6%
   - Customer C: 25 MW % 175 MW = 14.3%

2. Cost of Assigned Upgrade allocated to new Transmission Customer:

   - Customer B: $12,000,000 \times 28.6\% = \$3,428,571
   - Customer C: $12,000,000 \times 14.3\% = \$1,714,286

**Example B3: Compare Examples B1 to Example B2**
Notice that Customer B is paying less in example B2 than he would be paying in example B1, simply because of the sequencing of the service request. To correct this problem, in example B2 Customer B along with Customer A should be eligible for revenue credits from Customer C. Thus in example B2, the distribution of revenue credits from Customer C between Customers A and B is:

1. Percent allocation of revenue credits between Customers A and B:
   - Customer A: 100 MW % 150 MW = 66.7%
   - Customer B: 50 MW % 150 MW = 33.3%

2. Allocation of Revenue Credits (Revenue Credits are treated the same as costs for the sake of simplicity) from Customer C to Customers A and B:
   - Customer A: $1,714,286 * 66.7% = $1,141,857
   - Customer B: $1,714,286 * 33.3% = $571,429

   Notice that with this revenue credit from Customer C, Customer B is now paying in net the same amount as shown in Example D; i.e.,
   
   $4,000,000 (to Customer A) - $571,429 (from Customer C) = $3,428,571
APPENDIX B
EXAMPLES OF DOLLAR FLOWS
FOR VARIOUS APPLICATIONS OF
HIGHER OF PRICING FOR PTP SERVICE
ASSOCIATED WITH A DESIGNATED RESOURCE

Example 1: Basic Calculations

- The Attachment J assignment of costs to the new Transmission Customer from the Assigned Upgrade costs are less than the safe-harbor provision of $180,000/MW.
- There are no directly assigned costs to the new Transmission Customer.

<table>
<thead>
<tr>
<th>Example 1: Basic Parameters Assumed</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Customer A</strong></td>
</tr>
<tr>
<td>Upgrade Original Cost</td>
</tr>
<tr>
<td>Customer A: PTP - MW</td>
</tr>
<tr>
<td>A: PTP Service Charge</td>
</tr>
<tr>
<td>A: Higher of Pricing</td>
</tr>
<tr>
<td>Depreciation Life</td>
</tr>
<tr>
<td>Accum. Depreciation</td>
</tr>
<tr>
<td>Cost Included</td>
</tr>
<tr>
<td>PTP Reservation</td>
</tr>
<tr>
<td>Trans Serv Term</td>
</tr>
<tr>
<td>PTP Service Charge</td>
</tr>
<tr>
<td>% Distribution Factor</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Customer B</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Accum. Depreciation</td>
</tr>
<tr>
<td>Cost Included</td>
</tr>
<tr>
<td>PTP Reservation</td>
</tr>
<tr>
<td>Trans Serv Term</td>
</tr>
<tr>
<td>PTP Service Charge</td>
</tr>
<tr>
<td>% Distribution Factor</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Attachment Z Calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Included for B</td>
</tr>
<tr>
<td>Customer A MW Impact</td>
</tr>
<tr>
<td>Customer B MW Impact</td>
</tr>
<tr>
<td>Total MW Impact</td>
</tr>
<tr>
<td>% Customer B</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Attachment J Calculations</th>
</tr>
</thead>
<tbody>
<tr>
<td>B: Cost / MW</td>
</tr>
<tr>
<td>B: Safe Harbor Limit</td>
</tr>
<tr>
<td>B: Eligible for BPF</td>
</tr>
<tr>
<td>B: Direct Assign</td>
</tr>
</tbody>
</table>
Example 1: Dollar Flows

SPP Revenue Sources

- BPF upgrade costs are collected through zonal rates per the cost allocation in Attachment J.
- With no directly assigned costs to the new Transmission Customer, that Transmission Customer only pays the PTP rate.

<table>
<thead>
<tr>
<th>BPF Rate Calculations</th>
</tr>
</thead>
<tbody>
<tr>
<td>B: Eligible for BPF</td>
</tr>
<tr>
<td>B: Annual Revenues BPF</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>&quot;Higher of&quot; Rate Calculations</th>
</tr>
</thead>
<tbody>
<tr>
<td>B: Direct Assign</td>
</tr>
<tr>
<td>B: Fixed Charge %</td>
</tr>
<tr>
<td>B: Annual Cost</td>
</tr>
<tr>
<td>B: PTP Service Charge</td>
</tr>
<tr>
<td>B: Pays Higher of</td>
</tr>
</tbody>
</table>

SPP Revenue Payments

- The original Transmission Customer receives all the revenues from the BPF.
- The revenues collected from the PTP rate all go to other Transmission Owners (TOs) as the original Transmission Customer is fully compensated for the costs assigned out through Attachment J.

Dollar Flows

<table>
<thead>
<tr>
<th>Payments to SPP</th>
<th>$3,410,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>FROM</td>
<td></td>
</tr>
<tr>
<td>Cust A</td>
<td>$1,700,000</td>
</tr>
<tr>
<td>Cust B</td>
<td>$1,200,000</td>
</tr>
<tr>
<td>BPF</td>
<td>$510,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Payments by SPP</th>
<th>$3,410,000</th>
</tr>
</thead>
<tbody>
<tr>
<td>TO</td>
<td></td>
</tr>
<tr>
<td>Cust A</td>
<td>$510,000</td>
</tr>
<tr>
<td></td>
<td>$510,000</td>
</tr>
<tr>
<td></td>
<td>$0</td>
</tr>
<tr>
<td>TO Built Upgrade</td>
<td>$1,700,000</td>
</tr>
<tr>
<td>Other TOs</td>
<td>$1,200,000</td>
</tr>
</tbody>
</table>

Net Payments from A | $1,190,000 | Payments to - Payments by
Example 2: Basic Parameters Assumed

<table>
<thead>
<tr>
<th>Customer A</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Upgrade Original Cost</td>
<td>$65,000,000</td>
</tr>
<tr>
<td>Customer A: PTP - MW</td>
<td>200</td>
</tr>
<tr>
<td>A: PTP Service Charge</td>
<td>$2,400,000</td>
</tr>
<tr>
<td>A: Higher of Pricing</td>
<td>$11,050,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Customer B</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Depreciation Life</td>
<td>30</td>
</tr>
<tr>
<td>Accum. Depreciation</td>
<td>$6,500,000</td>
</tr>
<tr>
<td>Cost Included</td>
<td>$58,500,000</td>
</tr>
<tr>
<td>Customer B: PTP - MW</td>
<td>100</td>
</tr>
<tr>
<td>B: Trans Service Term</td>
<td>5</td>
</tr>
<tr>
<td>B: PTP Service Charge</td>
<td>$1,200,000</td>
</tr>
<tr>
<td>B: % Distribution Factor</td>
<td>20%</td>
</tr>
</tbody>
</table>

Example 2: Basic Calculations

- The Attachment J assignment of costs to the new Transmission Customer from the Assigned Upgrade costs exceeds the safe-harbor provision of $180,000/MW.
- The excess over the safe-harbor limit are directly assigned to the new Transmission Customer.

<table>
<thead>
<tr>
<th>Attachment Z Calculation</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Included for B</td>
<td>$58,500,000</td>
</tr>
<tr>
<td>Customer A MW Impact</td>
<td>40</td>
</tr>
<tr>
<td>Customer B MW Impact</td>
<td>20</td>
</tr>
<tr>
<td>Total MW Impact</td>
<td>60</td>
</tr>
<tr>
<td>% Customer B</td>
<td>33%</td>
</tr>
<tr>
<td>Customer B $</td>
<td>$19,500,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Attachment J Calculations</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>B: Cost / MW</td>
<td>$195,000</td>
</tr>
<tr>
<td>B: Safe Harbor Limit</td>
<td>$18,000,000</td>
</tr>
<tr>
<td>B: Eligible for BPF</td>
<td>$18,000,000</td>
</tr>
<tr>
<td>B: Direct Assign</td>
<td>$1,500,000</td>
</tr>
</tbody>
</table>
Example 2: Dollar Flows

SPP Revenue Sources

- BPF upgrade costs are collected through zonal rates per the cost allocation in Attachment J.
- The revenue requirements associated with these directly assigned costs to the new Transmission Customer are less than the PTP rate, resulting in the new Transmission Customer paying only the PTP rate.

<table>
<thead>
<tr>
<th>BPF Rate Calculations</th>
</tr>
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<tbody>
<tr>
<td>B: Eligible for BPF</td>
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<thead>
<tr>
<th>&quot;Higher of&quot; Rate Calculations</th>
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<tbody>
<tr>
<td>B: Direct Assign</td>
</tr>
<tr>
<td>B: Fixed Charge %</td>
</tr>
<tr>
<td>B: Annual Cost</td>
</tr>
<tr>
<td>B: PTP Service Charge</td>
</tr>
<tr>
<td>B: Pays Higher of</td>
</tr>
</tbody>
</table>

SPP Revenue Payments

- The original Transmission Customer receives all the revenues from the BPF.
- The revenues collected from the PTP rate are split between the original Transmission Customer (to cover the costs directly assigned to the new Transmission Customer) and the other Transmission Owners (TOs) per the standard SPP revenue distribution formula.

<table>
<thead>
<tr>
<th>Dollar Flows</th>
</tr>
</thead>
<tbody>
<tr>
<td>Payments to SPP</td>
</tr>
<tr>
<td>FROM</td>
</tr>
<tr>
<td>Cust A</td>
</tr>
<tr>
<td>Cust B</td>
</tr>
<tr>
<td>BPF</td>
</tr>
<tr>
<td>PTP Rate</td>
</tr>
<tr>
<td>Payments by SPP</td>
</tr>
<tr>
<td>TO</td>
</tr>
<tr>
<td>Cust A</td>
</tr>
<tr>
<td>$3,060,000</td>
</tr>
<tr>
<td>$480,000</td>
</tr>
<tr>
<td>TO Built Upgrade</td>
</tr>
<tr>
<td>Other TOs</td>
</tr>
<tr>
<td>Net Payments from A</td>
</tr>
</tbody>
</table>
Example 3: Basic Calculations

- The Attachment J assignment of costs to the new Transmission Customer from the Assigned Upgrade costs exceeds the safe-harbor provision of $180,000/MW.
- The excess over the safe-harbor limit are directly assigned to the new Transmission Customer.

**Example 3: Basic Parameters Assumed**

<table>
<thead>
<tr>
<th>Customer A</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Upgrade Original Cost</td>
<td>$100,000,000</td>
<td>Gross Plant</td>
</tr>
<tr>
<td>Customer A: PTP - MW</td>
<td>200</td>
<td>TSR (Trans Serv Request)</td>
</tr>
<tr>
<td>A: PTP Service Charge</td>
<td>$2,400,000</td>
<td>Assumed $1/kW/Month</td>
</tr>
<tr>
<td>A: Higher of Pricing</td>
<td>$17,000,000</td>
<td>17% Fixed Charge Rate over 30 years</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Customer B</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Depreciation Life</td>
<td>30</td>
<td>Years</td>
</tr>
<tr>
<td>Accum. Depreciation</td>
<td>$10,000,000</td>
<td>after 3 years</td>
</tr>
<tr>
<td>Cost Included</td>
<td>$90,000,000</td>
<td>Net Plant</td>
</tr>
<tr>
<td>PTP Reservation</td>
<td>100</td>
<td>MW</td>
</tr>
<tr>
<td>Trans Serv Term</td>
<td>5</td>
<td>Years</td>
</tr>
<tr>
<td>PTP Service Charge</td>
<td>$1,200,000</td>
<td>Assumed $1/kW/Month</td>
</tr>
<tr>
<td>% Distribution Factor</td>
<td>20%</td>
<td>Impact on Upgrade</td>
</tr>
</tbody>
</table>

**Attachment Z Calculation**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Included for B</td>
<td>$90,000,000</td>
<td>Net Plant</td>
</tr>
<tr>
<td>Customer A MW Impact</td>
<td>40</td>
<td>Impact from A's TSR</td>
</tr>
<tr>
<td>Customer B MW Impact</td>
<td>20</td>
<td>(B %DF)*(B MW Resrv)</td>
</tr>
<tr>
<td>Total MW Impact</td>
<td>60</td>
<td>Sum</td>
</tr>
<tr>
<td>% Customer B</td>
<td>33%</td>
<td>(B MW Impact) / (Total MW Impact)</td>
</tr>
<tr>
<td>Customer B $</td>
<td>$30,000,000</td>
<td>(%B) * (Cost Included for B)</td>
</tr>
</tbody>
</table>

**Attachment J Calculations**

| B: Cost / MW | $300,000 | (B TC %) / B (MW Resrv) |
| B: Safe Harbor Limit | $18,000,000 | (180,000/Mw) * (B MW Resrv) |
| B: Eligible for BPF | $18,000,000 | Min (B $, Safe Harbor Limit) |
| B: Direct Assign | $12,000,000 | (B $) - (Eligible for BPF) |
Example 3: Dollar Flows

SPP Revenue Sources

- BPF upgrade costs are collected through zonal rates per the cost allocation in Attachment J.
- The revenue requirements associated with these directly assigned costs to the new Transmission Customer are greater than the PTP rate, resulting in the new Transmission Customer paying more than the PTP rate.

<table>
<thead>
<tr>
<th>BPF Rate Calculations</th>
</tr>
</thead>
<tbody>
<tr>
<td>B: Eligible for BPF  $18,000,000 (180,000/Mw) * (B MW Resrv)</td>
</tr>
<tr>
<td>B: Annual Revenues BPF $3,060,000 (17% Fixed Charge times BPF Costs)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>&quot;Higher of&quot; Rate Calculations</th>
</tr>
</thead>
<tbody>
<tr>
<td>B: Direct Assign $12,000,000 (B$) - (Eligible for BPF)</td>
</tr>
<tr>
<td>B: Fixed Charge % 32% Calc for 5 yr. Trans Serv Resrv</td>
</tr>
<tr>
<td>B: Annual Cost $3,840,000 per year</td>
</tr>
<tr>
<td>B: PTP Service Charge $1,200,000 per year</td>
</tr>
<tr>
<td>B: Pays Higher of $3,840,000 Max (Annual Cost, PTP Serv Chrg)</td>
</tr>
</tbody>
</table>

SPP Revenue Payments

- The original Transmission Customer receives all the revenues from the BPF.
- The revenues collected from the PTP rate all go to the original Transmission Customer to cover the costs directly assigned to the new Transmission Customer. Other Transmission Owners (TOs) receive no revenues from the new Transmission Customer.

<table>
<thead>
<tr>
<th>Dollar Flows</th>
</tr>
</thead>
<tbody>
<tr>
<td>Payments to SPP $23,900,000</td>
</tr>
<tr>
<td>FROM</td>
</tr>
<tr>
<td>Cust A $17,000,000</td>
</tr>
<tr>
<td>Cust B $3,840,000 PTP Rate</td>
</tr>
<tr>
<td>BPF $3,060,000 Rolled into Zonal Rates</td>
</tr>
<tr>
<td>Payments by SPP $23,900,000</td>
</tr>
<tr>
<td>TO</td>
</tr>
<tr>
<td>Cust A $6,900,000 From BPF Rates</td>
</tr>
<tr>
<td>$3,060,000 Direct Assigned to Cust B</td>
</tr>
<tr>
<td>$3,840,000</td>
</tr>
<tr>
<td>TO Built Upgrade $17,000,000</td>
</tr>
<tr>
<td>Other TOs $0 From PTP Rate - New TC</td>
</tr>
<tr>
<td>Net Payments from A $10,100,000 Payments to - Payments by</td>
</tr>
</tbody>
</table>
CAWG: Measuring Benefits for Economic Upgrades

November 1, 2006
Mike Proctor

Two Basic Metrics

\[ \Delta \text{Adjusted Production Costs} \]

\[ = \Delta \text{Variable Production Costs} + \Delta \text{Revenues from Sales} - \Delta \text{Expenses from Purchases} \]

\[ \Delta \text{Load LMP} \]

\[ = \Delta \text{LMP} \times \text{Load} \]
\[ \Delta \text{Adjusted Production Costs} \]

- Reflects variable production costs to regulated loads.
- If congestion is reduced then,
  - Imports can increase, allowing the substitution of cheaper power for more expense own generation.
  - Exports can increase, allowing the sale of excess generation to others resulting in higher profits from off-system sales.

\[ \Delta \text{Load LMP} \]

- Reflects spot-market prices for purchasing power by competitive loads.
- To the extent that long-run forecasted changes in spot-market prices reflect what is likely to occur in long-term contracts for power, \[ \Delta \text{Load LMP} \] will estimate potential changes in long-term contract power costs.
SPP Expansion Plan Criteria

What metric is currently being used by SPP?

+ $\Delta$ MW * LMP

– $\Delta$ Dispatch Cost

Where these changes are calculated for each generator in SPP and added across all generators in the SPP region.

Explanation of SPP Metric

+ $\Delta$ MW * LMP

  √ LMP refers to the nodal price at the generator in the change case (with the upgrade in place).
  √ $\Delta$MW refers to either an increase or decrease in generator output.

+ $\Delta$Dispatch Cost

  √ Dispatch Cost refers to the variable cost of production.
  √ Another way to view this is as $\Delta$ MW * Inc $, where Inc $ is simply the $\Delta$ Dispatch Cost / $\Delta$ MW.

Benefit = $\Delta$ MW * (LMP – Inc $)$

  √ Increase = +50 MW * ($30 - $25) = + $250. This would be similar to an increase sales to the EIS market from a generator - associated with an increase in export capability.

  √ Decrease = -50MW * ($30 - $35) = + $250. This would be similar to reducing generator output and purchasing power from the EIS market - associated with an increase in import capability.
Comparison 1 Between Adjusted Production Cost and SPP

Closed System: No Exports or Imports for SPP - No Residual Congestion

<table>
<thead>
<tr>
<th>Component</th>
<th>Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen A: VC</td>
<td>-15,500</td>
</tr>
<tr>
<td>Gen B: VC</td>
<td>22,500</td>
</tr>
<tr>
<td>VC Savings</td>
<td>7,000</td>
</tr>
</tbody>
</table>

Conclusion

- SPP Metric excludes savings in congestion costs between market participants – BUT this is a reasonable exclusion (see next slide)
- Footnote:
  - SPP attempts to correct the congestion problem by adding a “Load Impact Sensitivity Equation” metric = (Δ Load LMP) * (X%)
  - This is actually meant to correct any congestion a market participant has in delivery of own generation to own load, not congestion between market participants.
Where Does the $6000 in Congestion Revenues for the Base Case go?

- The $6,000 in congestion revenues represents the difference between what A gets paid for 600 MW of sales and what B pays for 600 MW of sales.
  
  \[
  \begin{align*}
  A: & \quad 600 \text{MW} \times 30 \text{\$/MW} = 18,000 \\
  B: & \quad 600 \text{MW} \times 40 \text{\$/MW} = 24,000 \\
  \text{CR}: & \quad 600 \text{MW} \times (40-30) = 6,000
  \end{align*}
  \]

- SPP does not keep this $6,000, but instead must distribute it back to the market participants.
- This distribution of congestion revenues impacts the measure of benefits by $6,000.
- Does the SPP calculation of benefits correctly reflect this distribution of congestion revenues?

<table>
<thead>
<tr>
<th>SPP Implicit Allocation of Congestion Revenues</th>
<th>Adj PC</th>
<th>SPP</th>
<th>Congestion</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>$5,000</td>
<td>$2,000</td>
<td>$3,000</td>
</tr>
<tr>
<td>B</td>
<td>$8,000</td>
<td>$5,000</td>
<td>$3,000</td>
</tr>
<tr>
<td>Totals</td>
<td>$13,000</td>
<td>$7,000</td>
<td>$6,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Load Ratio Share Allocation of Congestion Revenues</th>
<th>Adj PC</th>
<th>Load</th>
<th>Congestion</th>
<th>Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>$5,000</td>
<td>$1,900</td>
<td>$2,150</td>
<td>$2,150</td>
</tr>
<tr>
<td>B</td>
<td>$8,000</td>
<td>$2,100</td>
<td>$3,150</td>
<td>$4,850</td>
</tr>
<tr>
<td>Totals</td>
<td>$13,000</td>
<td>$4,000</td>
<td>$6,000</td>
<td>$7,000</td>
</tr>
</tbody>
</table>

Should Congestion Revenue Savings Be Included as a Benefit?

NO

- Congestion revenues are distributed back to market participants and are therefore not a cost to load.
- The Adjusted Production Cost metric includes congestion revenue savings and these savings should be removed.
- Unclear that the SPP Benefit Metric (“Generator Benefits”) correctly accounts for the distribution of congestion revenues.
Does the SPP Benefit Metric Always Assume a 50-50 Distribution of Congestion Revenues?

**NO,** not when there is residual congestion after the upgrade.

See Comparison 2 on next slide.

---

### Comparison 2
**With Residual Congestion**

#### Closed System: No Exports or Imports for SPP - With Residual Congestion

<table>
<thead>
<tr>
<th></th>
<th>MW $</th>
<th>Inc $/LMP</th>
<th>MW $</th>
<th>Inc $/LMP</th>
<th>MW $</th>
<th>Inc $/LMP</th>
<th>Difference</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen A</td>
<td>2.500</td>
<td>$82,500</td>
<td>$25.00</td>
<td>3.000</td>
<td>$78,000</td>
<td>$26.00</td>
<td>$15,500</td>
<td>$31.00</td>
</tr>
<tr>
<td>Sales A</td>
<td>-600</td>
<td>-$18,000</td>
<td>$30.00</td>
<td>-1,100</td>
<td>-$38,500</td>
<td>$35.00</td>
<td>-$20,500</td>
<td>$35.00</td>
</tr>
<tr>
<td>Load A</td>
<td>1,900</td>
<td>$44,500</td>
<td>$23.42</td>
<td>1,900</td>
<td>$44,500</td>
<td>$23.42</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gen B</td>
<td>1.500</td>
<td>$52,500</td>
<td>$35.00</td>
<td>1,000</td>
<td>$30,000</td>
<td>$30.00</td>
<td>-$22,500</td>
<td>$45.00</td>
</tr>
<tr>
<td>Purch B</td>
<td>600</td>
<td>$24,000</td>
<td>$40.00</td>
<td>1,100</td>
<td>$39,600</td>
<td>$36.00</td>
<td>$15,600</td>
<td>$36.00</td>
</tr>
<tr>
<td>Load B</td>
<td>2,100</td>
<td>$76,500</td>
<td>$36.43</td>
<td>2,100</td>
<td>$66,600</td>
<td>$31.64</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>4,000</td>
<td>$115,000</td>
<td>$28.75</td>
<td>4,000</td>
<td>$108,600</td>
<td>$27.00</td>
<td>$44,400</td>
<td>$6,500</td>
</tr>
<tr>
<td>Congestion</td>
<td>$6,000</td>
<td>$1,100</td>
<td>$4,900</td>
<td>$7,000</td>
<td>Variable Cost Savings</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**SPP Implicit Allocation of Congestion Revenues**

<table>
<thead>
<tr>
<th>Adj PC</th>
<th>SPP</th>
<th>Congestion</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>$5,000</td>
<td>$2,000</td>
</tr>
<tr>
<td>B</td>
<td>$5,000</td>
<td>$3,000</td>
</tr>
<tr>
<td>Totals</td>
<td>$11,000</td>
<td>$5,000</td>
</tr>
</tbody>
</table>

**Load-Ratio Share Allocation of Congestion Revenues**

<table>
<thead>
<tr>
<th>Adj PC</th>
<th>Load</th>
<th>Congestion</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>$5,000</td>
<td>$1,900</td>
</tr>
<tr>
<td>B</td>
<td>$5,000</td>
<td>$2,673</td>
</tr>
<tr>
<td>Totals</td>
<td>$11,900</td>
<td>$4,573</td>
</tr>
</tbody>
</table>
Analysis of Residual Congestion

SPP Benefit Metric decreases benefits to B by $500 when B’s LMP ($36) does not drop to the same level as for A ($35). This represents a loss of $1 per MW that B is able to incrementally purchase from A after the upgrade (500 MW).

However, the SPP Benefit Metric does not properly take into account the distribution of congestion revenues before and after the upgrade.
- Before the upgrade $6000
- After the upgrade $1,100
- Difference is $4,900

But the SPP implicit adjustment is for $5,400 not $4,900.
- In essence, there is an additional $500 adjustment included in the SPP Benefit Metric, and making this adjustment is not consistent with congestion revenues being distributed back to market participants.

The true savings in Variable Production Costs is $7,000.

Conclusion

- When there is residual congestion occurring after the upgrade, the SPP benefit metric
  1. Does not properly measure congestion revenues; instead it
  2. Excludes some of the variable production cost savings from the benefits.
Consider Not So Much **Who** (allocations), but **What** (total benefits)

Assuming congestion revenues are distributed back to market participants, the *correct measure* of total benefits =

\[ \Delta \text{Adjusted Production Costs} \]

minus

Congestion Revenue Savings

= Savings in Variable Production Costs

---

**What About Exports?**

**Open System: Exports from SPP - No Residual Congestion**

<table>
<thead>
<tr>
<th>Component</th>
<th>Before</th>
<th>After</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen A</td>
<td>MW $</td>
<td>AVC/LMP $</td>
<td>MW $</td>
</tr>
<tr>
<td>Sales A</td>
<td>2,500</td>
<td>$62,500</td>
<td>$25.00</td>
</tr>
<tr>
<td>Exports</td>
<td>-300</td>
<td>-$9,000</td>
<td>$30.00</td>
</tr>
<tr>
<td>Load A</td>
<td>1,900</td>
<td>$53,500</td>
<td>$28.16</td>
</tr>
</tbody>
</table>

\[ \Delta \text{Exports} \]

<table>
<thead>
<tr>
<th>Component</th>
<th>Before</th>
<th>After</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen B</td>
<td>MW $</td>
<td>AVC/LMP $</td>
<td>MW $</td>
</tr>
<tr>
<td>Purch B</td>
<td>300</td>
<td>$12,000</td>
<td>$40.00</td>
</tr>
<tr>
<td>Load B</td>
<td>1,800</td>
<td>$64,500</td>
<td>$35.83</td>
</tr>
<tr>
<td>Total</td>
<td>4,000</td>
<td>$115,000</td>
<td>$28.75</td>
</tr>
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</table>

\[ \Delta \text{Cong} \]

<table>
<thead>
<tr>
<th>Component</th>
<th>Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen A: VC</td>
<td>-$18,100</td>
</tr>
<tr>
<td>Gen B: VC</td>
<td>$22,500</td>
</tr>
<tr>
<td>VC Savings</td>
<td>$4,400</td>
</tr>
<tr>
<td>$\Delta$ Exports</td>
<td>$5,000</td>
</tr>
<tr>
<td>Net Benefits</td>
<td>$9,400</td>
</tr>
</tbody>
</table>

\[ \Delta \text{Cong} \]

$3,000

\[ \text{Adj Prod Cst} \]

$12,400

---

15

16
What About Imports?

<table>
<thead>
<tr>
<th>Component</th>
<th>Savings</th>
<th>Variable Cost Savings</th>
<th>Import Cost Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen A: VC</td>
<td>-$7,725</td>
<td>$14,775</td>
<td>-$7,250</td>
</tr>
<tr>
<td>Gen B: VC</td>
<td>$22,500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>VC Savings</td>
<td>$14,775</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imports</td>
<td>-$7,250</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Benefits</td>
<td>$7,525</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Conclusions

- Using Adjusted Production Costs minus congestion costs savings gives the correct answer even when exports from SPP and imports into SPP are included.
- The SPP benefit metric does not correctly track exports and imports.
Next Meeting: What about benefits for competitively served load?

- We have addressed the correct metric to use for measuring overall benefits for regulated load.
- We have not addressed the correct metric to use for measuring overall benefits for competitively served load.

Additional Meetings:
Attempting to Answer *Who* (Allocations)
What level of aggregation?

- Load-Serving Entity (Assigned Costs)
  - Utilities serving regulated retail load
  - Wholesale customers
- Transmission Zones (Rolled into Rates)
  - SPP Transmission Pricing Zones
  - Use Weighted Measures of Benefits
- Sub-regions (Rolled into Rates: Sub-regional postage stamp rate)
  - Aggregates smaller Transmission Pricing Zones into larger areas; e.g., North SPP, Central SPP and South SPP.
  - What criteria should be used for aggregation?
- Region-Wide (Rolled into Rates: Region-wide postage stamp rate)
  - Eliminates the allocations question
Remaining White Paper
Issues
CAWG
November 1, 2006

KEY ISSUE

• CAWG proposed to eliminate the requirement that subsequent transmission service be in the same direction as the transmission request by the Assignee.
  – Problem with Project Sponsors not having a transmission request;
  – Desire to expand revenue credits as an incentive to get transmission built.
KEY Component

• The revised white paper (page 5) sets out as the principle: “could the new service have been provided without the upgrade?”
  – If it could not, then the Assignee should receive revenue credits.
• Practical Concern: How will SPP apply this principle?
• Philosophical Concerns:
  – If we want to provide incentives for economic upgrades, should we simply propose revenue credits for all new service that impacts the upgrade, irrespective of whether or not that service could or have been granted without the upgrade?
  – If transmission service could be provided in either direction without the upgrade, are we giving incentives for spurious investments in transmission?

Discussion
The “Denominator”

- At the last meeting the denominator used in the calculations of the cost assigned to subsequent use were changed to reflect elimination of the directional specification for revenue credits – see page 8.
- Language for Project Sponsors was unclear – alternate language gets rid of “direction” and accomplishes what was intended.
- Language for Transmission Customer did not need to be changed except to eliminate reference to direction.

Discussion
Sharing of Revenue Credits

- The white paper did not include any recommendations on the sharing of revenue credits by subsequent TCs that are paying for the upgrade.
  - Transmission Customer: revenue credits are shared among the original Assignee and all previous TCs paying revenue credits – allocated on a pro rata basis of MW impacts.
  - Project Sponsor: Special Case, see next slide.

What condition trips revenue credit sharing when Assignee is Project Sponsor?

1) The sum of assigned cost to subsequent Transmission Customers is greater than 100%;
   - See example shown in Appendix A

2) The Project Sponsor is fully compensated?
   - Due is the accumulated payments with FERC interest minus previous revenue credits.
Discussion
1. Introduction

In the Federal Energy Regulatory Commission (“FERC”) Order Granting RTO\(^1\) Status Subject to Fulfillment of Requirements issued February 10, 2004 (the “Order Granting RTO Status”), FERC directed the Southwest Power Pool (“SPP”) to be the Planning Authority and to plan for projects needed for economic reasons as well as those required to maintain compliance with reliability criteria. Pursuant to the SPP Open Access Transmission Tariff (“Tariff”), SPP is responsible for developing the SPP Transmission Expansion Plan (the “Plan”). To develop the Plan, SPP performs transmission planning studies to:

- Assess the reliability and economic operation of the SPP Transmission System;
- Identify Base Plan Upgrades; and
- Identify elective upgrades that have potential economic benefit to the SPP Region, but are not required for reliability reasons.

This protocol documents how models will be developed to identify upgrades that have potential economic benefit (“economic upgrades”) and how such economic upgrades will be evaluated.

1.1. Background

In the SPP planning process, the upgrades required to support the transmission system are categorized as either reliability upgrades or economic upgrades. Identification of reliability upgrades is based on power flow studies that are performed on the power system for snapshot hours, including seasonal on-peak and off-peak periods. The generation that is used in these studies takes into consideration the dispatch order for Designated Network Resources (“DNRs”) to meet the load of each Load-Serving Entity (“LSE”). However, the substitution of cheaper power from another LSE’s DNRs for more expensive power (economic transactions) is not taken into account in these reliability studies.

Identification of economic upgrades is based on modeling that includes both power flows and the substitution (re-dispatch) of lower-cost generation for more expensive generation where the secure limits of the transmission system allow such substitution to take place. These economic studies apply the same or highly similar network detail that is included in reliability studies. Moreover, the emphasis of economic upgrade studies is on present and potential flowgates; i.e., elements of the transmission system that are likely to be operated at or near their capacity limits.

1.2. Creation and Purpose of the SPP EMMTF

The SPP Economic Modeling & Methods Task Force (“EMMTF”) was established by the SPP Transmission Working Group (“TWG”) to advise and assist SPP Staff in the determination of the appropriate data, sources, models, timing, applications and economic

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\(^1\) Regional Transmission Organization (“RTO”).
parameters to be used in the development and evaluation of economic upgrade alternatives for the next increments of the Plan. As part of its scope, the EMMTF was also charged with reviewing the economic planning process used by SPP Staff and offering proposals for the improvement of the process. The EMMTF addressed the following:

1. Data requirements – Determination of the necessary data required to model, study, and evaluate economic upgrade alternatives.
2. Solution techniques – Review of the solution techniques used in the prior Plans and provision of recommendations for improvement and/or alternatives.
3. Definitions – Definition, as necessary, of any terms used in the economic planning process, data, or assumptions in a way that provides clear understanding.
4. Assumptions – Review and revision, as appropriate, of the economic assumptions to be used in the development of the economic phase of establishing the Plan.
5. Methodologies – Review and modification, if appropriate, of the methodologies for overall quantification of economic impacts and the breakout of such impacts to individual market participants.

The scope of the EMMTF included the following deliverables for which the task force was responsible:

1. Documentation describing the data necessary to conduct the economic studies.
2. Templates to be used in supplying the necessary data.
3. Recommendations regarding assumptions to be used by SPP Staff in future economic analyses.
4. A glossary containing the definitions of terms used in assumptions, data and the economic planning process.
5. Recommendations regarding improvements to modeling/solution techniques and the economic planning process.
6. Papers or other discussions describing methodologies applied.

Another responsibility of the EMMTF was to assist SPP Staff in the determination of the scope of individual economic upgrade alternative studies; i.e., SPP Staff will principally focus on SPP region-wide metrics, with the individual members continuing to evaluate and provide expertise on many of their own specific geographical areas of interest, as well as providing SPP with regional guidance.
1.3. Economic Upgrade Analysis Process Diagram

The following diagram provides an overview of the economic upgrade model development and analytical methods protocol process.

2. Transmission Planning Economic Upgrade Process Overview

2.1. Reliability & Economic Planning Process

As indicated in the Order Granting RTO Status, SPP is responsible for planning and directing or arranging transmission expansions, additions and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and to coordinate such efforts with the appropriate State authorities under Sections 2.1.5(b) and 2.1.1(j) of the Membership Agreement. Also, FERC recognizes that SPP is assigned the responsibility of designing a process to encourage open participation for market-motivated solutions to relieve long-term congestion; developing streamlined queuing process for both generation interconnection and transmission service requests; and developing a pro forma generation interconnection agreement.
2.1.1. Reliability Planning Process

Attachment O of the SPP Tariff covers the Transmission Planning and Expansion Procedures used for reliability upgrades and to respond to requests for new transmission service. Since this protocol is focused on economic upgrades, there is no additional detail on reliability upgrades provided in this protocol.

2.1.2. Economic Planning Process

Among the challenges of quantifying the economic benefits of transmission expansion projects is the estimation of the impact on overall regional congestion and identifying which specific sub-regional areas and market participants will likely benefit from the quantified congestion reduction.

SPP applies a set of multi-regional simulation models to estimate the impact of network expansion and upgrade projects on regional resource dispatch and congestion. A straightforward interpretation of the “societal impact” of reducing congestion is the ability to produce a “closer to optimal” dispatch of supply resources to serve electric loads, resulting in reduced dispatch costs within and across regions. In some situations the analysis might be expanded to include the potential impact on generating unit commitment and associated costs. Although SPP analyses focus on marginal-cost based assessments, specific assumptions regarding pricing during scarcity conditions will impact the likely distribution of these benefits to market participants.

The simulations used to conduct the economic analysis consist of a multi-step process with the following characteristics:

- The simulations represent sub-regional area-based unit commitment and regional security-constrained economic dispatch (e.g., a simultaneously feasible dispatch solution).
- The transactions reflected in the solution represent a mix of transaction types (e.g., firm, non-firm, “market”, etc.).
- There is no practical way to determine which transactions are of what type, and which unit output supports individual transactions.
- The economic upgrade simulations reflect incremental transmission upgrades and the resulting increase in economic transactions.
- The studies focus on the production cost difference between an economic upgrade case simulation and the base case simulation.

2.2. Screening Analysis

During the creation of each Plan, SPP Staff will analyze a wide variety of possible transmission upgrades identified by SPP Staff or suggested by market participants. The purpose of the screening analysis is to identify those potential upgrades that are most likely to produce positive benefits and which, therefore, will be subject to more detailed analysis as described in this protocol.
2.3. Quantification of Benefit-to-Cost

After performing the screening analysis, SPP will evaluate the top projects via detailed analysis. This detailed analysis includes quantification of benefit-to-cost which is a two step process. The first step is the determination of whether there are positive benefits to the market in total associated with the transmission upgrade. The second step is to break-out the expected economic benefits by sub-regional area or participant to provide to the stakeholders for informational purposes only. Details of these two steps are provided in Sections 7 and 8.

2.4. Sensitivity Analysis

Part of the analysis for each of the top projects will include an analysis of the sensitivity of the economics of the project to changes in assumptions. Examples of typical sensitivities include, but are not limited to, fuel prices, load growth rates, etc.

2.5. Reporting Requirements

Results will be published for the top projects that are evaluated using the detailed analysis described in this protocol. The published results will include:

- Study Input Assumptions, include data sources, including but not limited to:
  - Fuel price forecasts
  - Load and generation expansion/retirement forecasts
  - Generating unit parameters (heat rates, forced outage rates, start-up costs, ramp rates, variable O&M, must-run status, maintenance outages)
  - Operating reserve requirements
  - Hurdle rates used
  - Violation costs caps used
  - Transmission system topology
  - Modeling footprint

- Expected economic benefits (production costs + violation costs) over at least a 10 year period
- Break-out of expected economic benefits by sub-regional area or participant
- Shadow prices

In all reporting activities, SPP Staff will take all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the SPP Tariff (i.e., Sections 17.2(iv) and 18.2(vii); Attachment V (Section 13.1 and Article 22 of Appendix 6); Exhibit 1 (Section 2.3); Attachment AJ (Section 8); and Attachment C-One (Clause 7)).
2.6. Ongoing Economic Modeling and Methods Process

2.6.1. Interaction with Other SPP Data and Modeling Activities

The transmission network models applied to transmission project/upgrade economic analyses are derived from underlying seasonal power flow cases as constructed and managed by the SPP Model Development Working Group (“MDWG”). SPP has developed specific procedures for converting underlying MDWG power flow cases for interface with the simulation models applied for network economic analyses.

For efficiency of activities within SPP, the same or similar transmission network models and simulation models are also applied to other market simulation and analysis activities within the SPP organization.

2.6.2. Review of Modeling Assumptions with Generator Owners

As part of the process of performing the first economic upgrade analysis phase of establishing the Plan, SPP Staff made some initial assumptions regarding modeling data for generators. SPP Staff then worked with the individual generator owners to verify and refine the modeling data. The primary source of the initial modeling data was the database from Global Energy Decision, formerly Henwood. This modeling data was cross referenced against the limited data that SPP had in-house. In March 2005, as part of a data verification process, SPP provided each generator owner with the modeling assumptions for its generators; and requested verification of and corrections to the modeling data. In July and August of 2005, SPP Staff met with each generator owner to resolve any open issues.

Going forward, SPP Staff will review modeling assumptions for particular generators or generator types with the individual owners of the generators on a periodic basis as part of the process for the economic upgrade analysis phase of establishing future Plans. SPP will require the owners to provide updates to the generator modeling data via templates supplied by SPP. Also, at some point during the interconnection process for new generators, SPP will require the generator owner to provide modeling data for the new generator to be used in the economic upgrade analysis phase of establishing future Plans.

2.6.3. Ongoing Updates of Economic Models and Methods

SPP Staff will coordinate with the TWG to ensure that it is using the most appropriate economic models and methods in its analysis of economic upgrades.

3. Data Requirements

SPP Staff will periodically provide templates to be used in the provision of the data required to analyze potential economic upgrades in accordance with this protocol.

3.1. Confidentiality of Data

In addition to the treatment with respect to reporting requirements in Section 2.5, in all other activities SPP Staff will take all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the SPP Tariff (i.e., Sections 17.2(iv) and 18.2(vii); Attachment V (Section 13.1 and Article 22 of Appendix 6); Exhibit 1 (Section 2.3); Attachment AJ (Section 8); and Attachment C-One (Clause 7)).
3.2. Eastern Interconnection Network Representation

The network representation include detailed network transmission models as developed by the SPP MDWG and described in Section 2.6.1.

3.3. Eastern Interconnection Market Database

SPP Staff will start with market data from the Global Energy Decision databases, modified as described in subsequent sections of this protocol. In particular, all of the key generating unit modeling parameters as applied by SPP are periodically reviewed by specific generator owners for comment and possible revision in the modeling, as described in Section 2.6.2.

3.4. Load Forecast Assumptions

Control area peak load forecasts are based on the SPP Energy Information Administration (“EIA”) report 411 (“EIA-411”) and other information analyzed and documented by Global Energy Decision staff. SPP will, when capable, import database revisions based on the SPP EIA-411 reports and other filings recently published.

Peak loads are modeled based on total internal demand as reported by the utilities. Hourly load shapes are based on ‘typical year’ representations derived by Global Energy Decision from multiple years of historical data. This data inherently reflects a peak load coincidence factor of about 97% for the SPP region.

Direct load control and interruptible loads as reported in EIA-411 are modeled as dispatchable resources in PROSYM model from Global Energy Decision.

3.5. Generating Unit Characteristics and Representations

To the full extent identifiable, generators modeled in the underlying cases have been mapped to generating units\(^2\) represented in the MARKETSYM Locational Marginal Pricing (“LMP”) market model and database from Global Energy Decision. Most generator characteristics are as estimated by Global Energy Decision from analysis of publicly-reported data and other non-proprietary sources, but updated through the review process described in Section 2.6.2.

SPP has reviewed generating stations of the MARKETSYM databases\(^3\) against SPP EIA-411 reports and made identifiable revisions, such that more than 95% of total generating capacity of the underlying cases is explicitly identified and mapped across the models.

Thermal generator Equivalent Forced Outage Rates (“EFOR”) and Equivalent Scheduled Outage Rates (“ESOR”) are estimated for ‘classes’ of generators from North American Electric Reliability Council (“NERC”) Generator Availability Data System (“GADS”) data. SPP may adjust the EFOR and ESOR values to reflect most recent historic or actual performance data available.

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\(^2\) Generating units are referred to as ‘stations’ in the MARKETSYM database.

\(^3\) Plural here refers to the MARKETSYM modeling database and the so-called mapping file (the latter in MSAccess format).
A full Monte-Carlo modeling approach for evaluating the impact of generator forced outages would result in unacceptable run-time for the regional simulations. The PROSYM ‘converged Monte-Carlo’ technique is generally being applied, which constructs an outage forecast that is statistically similar at the control area level to what would result from a full Monte-Carlo simulation. The random outages exhibited at each specific location can still exhibit some bias on prices and other results relative to a detailed Monte-Carlo simulation, depending in part on how many total hours are simulated for each study. SPP may apply a ‘derate’ approach to modeling of forced outages in some future studies.

For scheduled outages, the PROSYM ‘distributed outage’ technique is being applied, whereby the outage hours for any specific generator are distributed across months of the year based on estimates of historical maintenance patterns for each region. This reduces the bias that may result at specific locations associated with fixed period outages (e.g., March 1-March 15 for unit X) that might be otherwise constructed and applied in the model.

Global Energy Decision generally estimates the full load heat rate of each generator from data reported by generator owners, including Continuous Emission Monitoring System (“CEMS”) data. For part-load heat rates, a generic profile as estimated for the associated class of generator (size and type) is applied. For some recently-installed simple-cycle and combined-cycle generating units, the database applies heat rate profiles obtained from vendors.

Generator annual and capacity seasonal ratings are generally defined in MARKETSYM based on data reported in EIA-411 reports and other sources.

The MARKETSYM database includes estimates of non-fuel Operations and Maintenance (“O&M”) costs (per MWh) for each generator from historical data and additional assumptions as applied by Global Energy Decision. The non-fuel O&M values can be characterized as ‘short-term variable’ cost estimates, based on explicit and implicit assumptions regarding the portion of overall O&M costs that are driven by hours of operation and associated MWh output. The Short Run Variable Cost (“SRVC”) values are generally higher than ‘instantaneous incremental costs’ often applied by modelers.

Additional generator characteristics such as minimum ‘up time’/‘down time’, ramp rates, startup fuel use, emission rates and others are also developed by Global Energy Decision for the MARKETSYM database, and impact the unit commitment and dispatch activities within the PROSYM model as well as the generator offer curves subsequently applied within the Simulator model of PowerWorld Corporation.

3.6. Generator Modeling Data

Generator modeling data is required in order to perform detailed analysis of economic upgrades. As indicated in Section 2.6.2, as part of the process for the economic upgrade analysis phase of establishing the Plan, SPP Staff will review modeling assumptions for particular generators or generator types with the individual owners of the generators on a periodic basis and may require the owners to provide updates to the generator modeling data via templates supplied by SPP. Data required to model generators may include, but is not limited to:
• Maximum MW Output, net of station load
• Minimum MW Output, net of station load
• Minimum Up Time
• Minimum Down Time
• Ramp Rate
• Annual Equivalent Forced Outage Rate
• Annual Equivalent Scheduled Outage Factor
• Full Load Heat Rate
• Start-Up Fuel Use
• Non-Fuel Start-Up Costs
• Short-Run Non-Fuel Variable O&M
• NOx Emission Rate
• SO2 Emission Rate
• Fuel Prices
• Emission Prices
• Historic Energy Output for Hydro Generators (Storage and Run-Of-River)
• Historic Energy Output for Wind Generators

3.7. Reliability/Must-Run Conditions

SPP is presently modeling estimated generator must-run conditions as provided by transmission system owners.

Commercial planning models presently have limited capability to internally address ‘recommitment’ of generating capacity to address local security requirements, and in general model developers are continuing to address and expand this type of capability in planning models. SPP is presently not designating any generating units as ‘fast start’ as currently applied by the Simulator model due to limitations of this modeling logic to realistically capture the costs associated with unit startup (i.e., the logic tends to ‘over-commit’), and because a practical means of de-committing capacity (mirror effect) has not yet been implemented.4

It appears the planning model simulations are not greatly compromised by the lack of more detailed security constrained commitment logic when conducting unit commitment with control area reserve requirements. Future analysis that includes modeling of region-wide unit commitment will clearly necessitate application of somewhat more sophisticated ‘local re-commitment’ logic in lieu of extensive manual modeling activity.

3.8. Fuel Prices

For natural gas and fuel oil, an estimated monthly market price is applied to all generators in the simulation footprint, adjusted for local prices adders as estimated by Global Energy Decision from historical data. The market price for natural gas is generally based on a forecast of short-run marginal prices indexed to the Henry Hub. Fuel oil prices are

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4 Logic is presently being developed by PowerWorld for Simulator to address de-commitment of generating units defined with minimum capacity levels greater than 0 MW.
similarly based on a forecast of short-run marginal prices. The EIA Annual Outlook report is applied as a source for deriving the natural gas and fuel oil prices.

For each coal-fueled plant, the MARKEYSYM database generally applies an inflationary increase to the most recent available annual per-unit fuel price reported by the generator owner to EIA/FERC.

3.9. Generator Offer Curves

The generator offer curves applied in the Simulator model are ‘energy-only’ ($/MWh) prices, that exclude start-up costs/prices and so-called ‘no-load’ costs/prices. SPP presently applies SRVC to construct these offer prices, which reflect the following parameters:

\[
\text{SRVC} = \text{Incremental Heat Rate} \times (\text{Fuel Price} + \text{Emission Cost}) + \text{Non-Fuel Variable O&M}
\]

For SO\(_2\) and NO\(_X\):

\[
\text{Emission Cost} = \text{Emission Rate [per unit of heat input]} \times \text{Emission Allowance Prices}
\]

A key aspect of the SRVC pricing is the underlying assumption that generators dispatching on the margin of an optimal dispatch (‘price-makers’) will not price significantly above their SRVC. Even in a relatively competitive market, this will not necessarily be so during periods of scarce capacity. Analysis of this situation is rather complicated and involves several key questions and issues, including appropriate price incentives to encourage new supply investment and market price mitigation. The techniques and implications of such analysis are beyond the scope of SPP’s immediate modeling activities, and would have relatively small impact on differential economic analysis across modeled cases.

Implicit in the assumption of SRVC pricing is that generators with dispatch costs lower than the marginal generators (‘price takers’) do not price above the expected price-makers. The price-takers could actually price anywhere between their own SRVC and that of the price makers with essentially no impact on the economic Optimum Power Flow (“OPF”) solution; i.e., the price takers are paid the same clearing price regardless. In this sense, the assumption that generators will submit SRVC offers is somewhat of a modeling convenience, in that the accumulation of offer prices across the dispatched generation is also an accumulation of variable dispatch cost, which is key to SPP’s economic analysis efforts.

The generator offer curves are constructed as piece-wise linear representations, generally with five dispatch segments for each generator.

As an initial approach to modeling possible energy production from generators that can inject to either SPP or the Electric Reliability Council of Texas (“ERCOT”), the offer curves for these generators are modeled with some portions of capacity being offered at energy prices significantly above their SRVC.

3.10. Transfer of Load & Generator MW Values to Simulator

The hourly control area loads and generator dispatch levels developed within the PROSYM simulation are forwarded to the Simulator model for network-level power
flow/OPF analysis. For all control areas of the simulations, loads are distributed to individual buses in proportion to the distribution represented in the underlying case, after accounting for area load losses and identified fixed-load (sometimes called ‘non-scalable’) buses. Hourly bus MVAR load values are estimated assuming non-varying load factor at each bus.

For control areas within SPP (or other simulated OPF areas), dispatch levels from the PROSYM model are forwarded to Simulator. To account for generating stations modeled in PROSYM that have not been mapped to specific generators of the underlying power flow case, a scaling factor is applied to the MW dispatch value and maximum MW (‘Pmax’) of each generator. The scaling factor also accounts for any controllable/interruptible load ‘resources’ dispatched by PROSYM in a given hour.

For control areas outside the simulated OPF footprint, generator dispatch levels of the underlying power flow case are scaled each hour to match the levels of the PROSYM simulation.5

3.11. Wind Farms

Daily wind farm profiles have been developed using actual data provided by the Alternative Energy Institute at West Texas A&M University, Canyon, Texas. An average hourly wind speed for each month was calculated from 1995-2000 data from three test sites: Amarillo, Dalhart, and White Deer. These wind speed values were then translated into MW values. The following monthly profiles are used to simulate wind farm impacts in economic analyses at SPP.

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5 For most control areas external to SPP, a detailed generator mapping between MARKETSM and Simulator generally does not exist.
3.12. Interaction with ERCOT & WECC

SPP has a total of 800 MW of DC ties with ERCOT and 600 MW of DC ties with Western Electricity Coordinating Council (“WECC”). The transfers modeled over the DC ties reflect historical data and recent patterns by time of day. There are also approximately 3,000 MW of dual grid generators that can feed into either the Eastern Interconnection or ERCOT. These generators are modeled as primarily feeding into ERCOT.

3.13. Modeling of Future Years

The cases used in the analysis of future years will model future year facilities as follows:

- Committed reliability and economic upgrades will be included;
- Generators known to be retiring will not be included; and
- New generators that have signed interconnection agreements will generally be included in future models with sensitivities to evaluate potential generation development scenarios.

4. Modeling Methods


4.1.1. Market Simulation Tools

The market simulation models being applied by SPP Staff are the combined MARKETSYM LMP model and the Simulator power flow/OPF model. The MARKETSYM model includes the PROSYM simulation engine and a market modeling database for the Eastern Interconnection.

4.1.2. Geographic Modeling Footprints

The SPP OPF modeling footprint is generally the overall SPP reliability region footprint. The modeling footprint for generating unit commitment/dispatch with PROSYM and AC/DC power flow solutions with Simulator extends out generally 3 control area tiers external to SPP. These modeling footprints are illustrated below:

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6 A few simulations have been conducted extending the OPF footprint one tier external to SPP excluding Entergy.
The SPP region is modeled with a break-out of 19 transmission areas encompassing the 17 actual control areas. American Electric Power (“AEP”) - West (“AEPW”) is represented by two transmission areas dispatched as a single control area, and there is also an explicit transmission area for Midwest Energy (“MidW”). Oklahoma Municipal Power Authority (“OMPA”) loads are distributed within the Oklahoma G&E (“OGE”), Public Service of Oklahoma (“PSO”)/AEPW and Western Farmers Electric Cooperative (“WFEC”) transmission areas. Arkansas Electric Cooperative Corporation (“AECC”) loads are aggregated with other loads at buses within the Entergy (“EES”) system, Southwestern Electric Power Company (“SOEP”) and Southwestern Power Administration (“SPA”).

4.1.3. Underlying Power Flow/Network Cases

SPP converts previous seasonal cases to support OPF/Security Constrained OPF (“SCOPF”) nodal price modeling of an entire one-year span as follows:

- Spring case (applied March-May)
- Summer Peak case (applied June-August)
- Fall case (applied September-November)
- Winter case (applied December-February)

SPP is effectively modeling a ‘fiscal’ year to simplify the construction of cases to represent a full year span.
Bus, branch, load and generator modeling detail are effectively driven by the representations in these underlying power flow cases.

4.1.4. AC/DC Power Flow/OPF Simulations

SPP has built out its modeling representations applying full AC analysis, and is presently applying full AC power flows within most OPF simulations. This has been done in part to evaluate the tools being applied and interpret results in the more stringent environment of full AC solutions. Increased volume of studies and other modeling parameters will necessitate applying DC solutions to some extent from time to time.

In conducting OPF modeling across a wide range of load and generator availability situations to represent a full year time span, and particularly when conducting full AC simulations, there are inevitably some number of simulation hours that do not successfully solve. SPP generally experiences a better than 90% successful OPF solve rate for the Summer season (which has been analyzed most heavily), and greater than 80% successful solve rates in the Spring season (which is the most challenging due to high generator maintenance and associated unique modeling circumstances).

4.1.5. Method to Represent a Full Year and Multiple Years of Results

If desired, the models can be applied to simulate a full 8,760 hours per year. However, the run-times for this modeling mode are generally unacceptably long, and at present the data handling would be overly slow/cumbersome. Therefore, many of the regional simulations will be conducted based on simulating every other hour of a ‘typical week’ representation for each month of the year; i.e., 12 hours per typical day, 84 hours per typical week (and for each month), or 1,008 simulated hours for a full year.

Initial comparisons made by SPP indicate that relatively little accuracy or consistency is lost at the regional level or control area level when applying the modeling mode described above. However, the approximations associated with reduced hour/probabilistic modeling techniques will inevitably be more pronounced at specific locations.

For economic upgrade studies that cover multiple years, not every year will be studied. SPP Staff will model selected years and then extrapolate to estimate the economics of intervening years.

SPP is still building out and evaluating its hardware and pre-/post-processing tools to support the overall modeling platform. The tools being applied are highly scalable, depending upon the number of processors applied to the simulations, status of the network server, and effort applied to development of post-processing techniques.

4.1.6. Generating Unit Commitment and Dispatch in PROSYM

PROSYM conducts an hourly generating unit commitment and dispatch, which is forwarded to Simulator for hourly power flow and OPF analysis. Prior to conducting a thermal unit commitment/dispatch, PROSYM estimates a peak shave hydro dispatch. The hydro dispatch applies energy values for each month of the year based
on up to 20 years of values as reported by generator owners. The model applies a Global Energy Decision estimate of the portion of energy that is ‘run-of-river’ hydro for each month, and applies a ‘peak-shave’ dispatch to the remainder of monthly hydro energy. Wind generation will be modeled in a manner similar to the treatment of ‘run-of-river’ hydro.

PROSYM then estimates a thermal generating unit commitment that minimizes the total cost\(^7\) for each weekly segment subject to modeling constraints applied by the user. SPP is applying operating reserve commitment constraints to each control area as listed in the table below. Operating reserves are presently not being assigned to specific generators – SPP will make such assignments as unit-specific information is received from SPP control areas. Operating reserves requirements are typically set in the range of approximately 7\% of load in the simulations. The following table reflects typical values used for operating reserve parameters. As indicated in Section 2.5, the actual values used in the analysis of a specific project will be published as part of the reporting requirements.

<table>
<thead>
<tr>
<th>Operating Reserve Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spinning Reserve Requirement</td>
<td>2% of Load</td>
</tr>
<tr>
<td>Regulating &amp; Load-Following “Up” Capacity Needed</td>
<td>3% of Load</td>
</tr>
<tr>
<td>Ready-Reserve (Non-Spinning) Requirement(^8)</td>
<td>2% of Load</td>
</tr>
</tbody>
</table>

PROSYM applies the following unit commitment equation for each control area, including identified firm interchanges from EIA-411 reports, FERC 715 filings or other identified sources.

\[
\text{Area Capacity Committed} \geq \left[\left(\%\right) \times \text{Area Demand} +/- \text{Net Firm Interchange}\right] \times \left[1 + \text{Spin Reserve} + \text{Regulation/Load-Following Up}\right]
\]

The SPP control areas are assumed to only commit owned generating resources or other resources that they have rights to against their internal load (again, net of firm interchanges). SPP generally models an area unit commitment target at about 80\% of Area firm Demand. The large generators owned by Independent Power Producers (“IPPs”) within SPP are excluded from the initial control area unit commitments, and are committed incrementally by PROSYM to the extent that the model estimates that committing these generating units would reduce total cost within the overall modeling footprint.

The unit commitment logic is also impacted by additional generator constraints such as minimum ‘up time’/‘down time’ values and hourly ramp rates as estimated for various groups of generators.

\(^7\) The PROSYM commitment can also minimize prices from offer curves constructed by the user.

\(^8\) To the extent that available ‘fast start’ capacity in the control area is less than this value, additional capacity must be spinning.
The PROSYM dispatch logic initially dispatches committed capacity within each control area to meet internal energy requirements, followed by a multi-area dispatch to equalize marginal cost (or price) as much as possible, subject to generalized area-to-area transfer limits estimated by Global Energy Decision from published sources and studies.

The hourly unit commitment and ‘initial’ dispatch values developed by PROSYM, along with hourly control area load levels and generator ‘offer curves’, are forwarded to the Simulator model for application to the OPF simulations.

4.1.7. Limit Monitoring and OPF Contingencies

Within the power flow and OPF simulations, all bus and branch elements >100 kV are monitored. Branch flows are limited to 100% of normal rating for each season, and buses are regulated to +/- 10% of nominal voltage.9

All flowgates within the SPP footprint are monitored within the OPF simulations, with monitored element post-contingency flows being limited to 100% of the total (firm plus non-firm) capacity rating of the flowgate.10

To gradually construct simulations that are verified to be fully consistent with ‘n-1’ SCOPF security analysis, SPP conducts contingency analyses to identify the branch outage contingencies most likely to constrain path elements within the market simulations, and applies this information to model additional post-contingency interfaces (i.e., ‘pseudo-flowgate’ representations).

The occurrence of branch flow limit violations necessitates the application of ‘slack costs’ in the Simulator OPF Linear Programming (“LP”) solution. The slack cost values are defined by the user, and effectively represent ‘caps’ on the redispatch cost the model will seek to clear violations. In any solution (short of setting the caps extremely and unrealistically high), there will be some small amount of un-cleared violations. The un-cleared violations can be thought of as unassigned dispatch costs. The change in slack cost across solved cases can represent a benefit of reducing un-cleared violations. The following table reflects typical values used for flow limit violation cost caps in the regional modeling. As indicated in Section 2.5, the actual values used in the analysis of a specific project will be published as part of the reporting requirements.

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9 Note that the PowerWorld Simulator OPF model does not presently have logic to explicitly clear bus voltage violations.

10 Consistent with SPP Criteria formula 4.5.10.4: Non-Firm Available Flowgate Capacity for Operating Horizon (NFAFC) = Total Flowgate Capacity – (b*TRM) – CBM – Non-Firm Base Loading; for most or all SPP Flowgates, b=0 and CBM=0 (total margin is incorporated within TRM), where TRM stands for Transmission Reliability Margin and CBM stands for Capacity Benefit Margin.
<table>
<thead>
<tr>
<th>Type of Element</th>
<th>Operating Range</th>
<th>Penalty</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPP Flowgate</td>
<td>0-2% Above Total Capacity</td>
<td>$100 per MW per Hour</td>
</tr>
<tr>
<td></td>
<td>&gt;2% Above Total Capacity</td>
<td>$200 per MW per Hour</td>
</tr>
<tr>
<td>Branch or Transformer</td>
<td>Above Normal Rated Capacity</td>
<td>$30 per MW per Hour</td>
</tr>
</tbody>
</table>

4.2. Quantifying Cost of Regional Network Congestion

Whenever the most economic resource cannot be dispatched to cover the next increment of load due to constraints on the transmission system, network congestion is present, and associated congestion costs are incurred. At a high level, the cost of congestion is represented by the amount of additional production costs incurred due to the presence of network constraints. This can include the cost impact of committing generating units out of merit order in order to avoid or minimize network loading constraints or violations.

Quantifying the total cost of congestion across a region is largely an academic exercise, in that one would need to simulate region-wide dispatches, and to at least some extent region-wide unit commitments, which would be totally unencumbered by network constraints or possibly even absent the energy losses associated with long transmission lines. Such a representation would certainly be well beyond any “break-even” or otherwise realistic level of transmission investment. For this reason, the comparative cases constructed by SPP address the change in the amount of congestion from the base case to the upgrade case resulting from the transmission upgrade.

At a high level, the shadow price of any flowgate or branch is the decrease in total system costs that would be achieved by increasing the rating of the flowgate or branch by 1 MW.

See Appendix B for an example of network congestion using an eight node model.

5. Base Case and Sensitivity Model Development

5.1. Base Case Model Development

5.1.1. Physical (vs. a Financial) Regional Simulation

The base case for economic upgrades is created from the reliability upgrade case. In other words, the economic upgrade base case starts with the same model of the system as used in the reliability upgrade case and includes any reliability upgrades identified.

The base case models reflect unit commitment primarily by control area and the SPP regional Energy Imbalance Service (“EIS”) market implementation, including real-time security-constrained economic re-dispatch. The base models are also set up for full AC power flow analysis.

The simulations reflect a physical commitment and dispatch of the regional bulk power system. The simulations in effect represent a large simultaneous feasible solution of regional dispatch subject to security constraints. In such a simulation, it is impractical to construct bilateral transactions to represent all or even most of the underlying transactions, in particular the “spot” market or other short-term transactions, that are inherently represented in the solution. More importantly, most
bilateral transactions do not affect the resultant physical dispatch solution, and are thus are not needed for SPP to estimate the impact on (physical) cost of production. An exception is owned/leased generation shares and other identified mid/long-term firm transactions, which can significantly impact the generating unit commitment simulations.

5.1.2. Incremental Dispatch Levels and Associated “Transactions”

The SPP simulations focus on the differential change between two compared cases – i.e., the “base case model” and a case model reflecting transmission upgrades. The changes to dispatch (and possibly hours of commitment) of individual generators inherently aggregate to changes in area dispatch levels and interchanges (i.e., transactions). However, as discussed more later in this document, SPP analysis focuses on changes in dispatch levels of individual generators, and thus inherently the incremental “sale” and/or “purchase” of energy by those generators at their respective locations, ultimately aggregating the results for generators owned (or controlled) by specific market participants. However, as mentioned above, there is no attempt to assign bilateral interpretations of the associated incremental transactions.

5.1.3. Physical Transmission Rights

The SPP transmission market applies physical transmission schedules and associated rights. At present -- i.e., prior to implementation of the EIS market described immediately below – scheduling or interchange “imbalances” are subject to various bilateral agreements as to price and other procedures. Under the emerging EIS market, all “imbalances” – real-time deviations from scheduled amounts -- will be subject to locational marginal prices, specifically defined and referred to as Locational Imbalance Prices (“LIPs”) in the SPP market protocols. Most deliveries (from generators to loads) both within a control area and across control areas will effectively be “hedged” by associated physical transmission rights. However, an indeterminate amount of energy will be subject to locational price uncertainty due to advertent or inadvertent imbalance of generation-to-load schedules. The re-dispatch of generators by the SPP regional SCED system is inherently defined as locational imbalance, priced at the LIP at each generator location.

5.1.4. Existing TLR Process for Reliability

Since Transmission Loading Relief (“TLR”) actions are undertaken for reliability, and not economic, purposes, TLRs are not used or reflected in the economic upgrade studies.

5.1.5. Operating Directives

SPP’s Operating Directives may allow higher loadings for short-term emergency operations. These Operating Directives provide non-firm capability that needs to be reflected in economic planning simulations to benchmark actual operations. These higher short-term emergency ratings can have a significant impact on the need for and savings associated with any transmission upgrades.
5.2. Specific Base Case Modeling Assumptions

5.2.1. Wheeling Rates

Because the SPP Tariff excludes the application of source-based wheeling rates within (most of) the SPP region, no explicit wheeling rates are generally modeled directly between SPP control areas. Because there are “through and out” wheeling rates for both imports to and exports from the SPP boundary, wheeling rates are applied to transactions which cross the SPP boundary.

5.2.2. Hurdle Rates

The modeling tools inherently attempt to model a highly efficient marketplace, subject to the constraints presented. The model’s underlying methodology is also consistent with the implicit assumptions of total price transparency and dispatch rationality (i.e., that market participants would not commit or dispatch resources higher in cost than other available resources within the modeling footprint).

One way that market inefficiency can be modeled is by applying ‘hurdle rates’ between SPP control areas. This approach effectively limits transactions to those that exhibit a price or cost differential higher than the hurdle rate. Since most market simulation models do not include a separate modeling variable for hurdle rates, they are applied via the wheeling rate variable; i.e., modeled “wheeling rate” = explicit wheeling rate + hurdle rate.

6. Base Case Model Benchmarking

Once the base model is built as described under Section 5 utilizing the assumptions and input data described under Sections 3 and 4, SPP makes several preliminary analysis runs for the first year of the study for the purposes of comparing the model output results against actual data from an historical year to ensure that the results that are being produced from the base case model are reasonable. The following sub-sections provide a description of the benchmarking process.

6.1. Long-Range Load & Resource Balance

SPP constructs the EIA-411 report for submittal to the U.S. Energy Information Agency in April of each year. This report includes a compilation of 10 year forecasts of electric load growth and existing/planned supply resources provided by each reporting electric utility within the SPP region. From this and additional related information, SPP constructs 10 year forecasts of regional demand and supply within the region, which are a source for construction and application of future year modeling representations.

6.2. Flowgate/Network Loadings

As part of base case model benchmarking, SPP compares the simulated flowgate loadings to the historical flowgate loadings of key flowgates. For example, below are graphs...
comparing the simulated flowgate loadings to the historical flowgate loadings for two flowgates: the Creswell to Kildare flowgate and the El Paso to Farber flowgate.

**Flowgate Loading Comparison**

<table>
<thead>
<tr>
<th>Creswell to Kildare Flowgate</th>
<th>El Paso to Farber Flowgate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Yr Simulated</td>
<td>2 Yr Historical</td>
</tr>
</tbody>
</table>

The Creswell-Kildare flowgate was the most constraining element within SPP for 2005. El Paso-Farber is another flowgate in SPP that is in series with Creswell-Kildare and can limit north to south transfers from Kansas to Oklahoma for an outage of the Wichita-Woodring 345 kV line. SPP analyses to date to benchmark the simulated loadings on these facilities compared to actual performance have been very encouraging. Actual flowgate loadings exceed Total Flowgate Capacity in recent history; and the SPP base model provides a very similar pattern. As expected, the simulated results provide slightly higher expected loadings that those experienced in actual operations. This is primarily due to conservatism in actual operations to provide margins above the theoretical optimum operating point in a simulation.

6.3. Area/Resource Energy Production

For each SPP control area, total generation production and the output of individual generators is compared to historical production figures. To the extent that significant differences exist, SPP will modify the base case input assumptions and address any differences.

6.4. Area Net Scheduled Interchange

In addition to Area/Resource Energy Production comparisons, SPP also compares net scheduled interchange values produced by the model against actual values for each SPP control area. These net scheduled interchange values are directly impacted by the results described under Section 6.3 along with modeling assumptions relating to firm scheduled transactions.

6.5. Review by Stakeholders

SPP provides preliminary Area/Resource Energy Production results and Area Net Scheduled Interchange results to the controls areas within SPP for review. SPP incorporates stakeholder feedback as to the reasonableness of results and makes
adjustments to the base assumptions, as appropriate, to correct any identified significant differences.

7. Calculation of Net Expected Economic Benefits

Once a particular transmission upgrade project has passed the screening analysis described under Section 2.2 (operating cost savings are expected to exceed construction cost of upgrade), more detailed economic benefits associated with that particular transmission upgrade are calculated based upon the expected reduction in operating costs within the SPP region that may be realized through reduction in re-dispatch costs and violation costs made possible by the particular transmission upgrade. Operating cost savings are generally estimated over a 10 year period to represent a desired 10 year payback of associated construction costs associated with a particular upgrade.

7.1. Operating Cost Reduction

The economic upgrade cases, when compared to the base case, will provide a measure of the economic benefit from a proposed set of transmission upgrades. Expressed as an equation, this would be as follows:

\[
\text{Expected Operating Cost Reduction} = \Delta \text{SPP Production Costs} + \Delta \text{Violation Costs}
\]

The change in production costs, as measured on an SPP region basis, represent an estimate of the reduction in true operating costs associated with generation operations since the assumptions built into the base case model and the upgrade case models assume that all generators would submit market offers that are equivalent to their true marginal operating costs.

Violation Costs are defined under Section 4.1.7. Removal of the violation costs through an economic transmission system upgrade is included in the overall benefit calculation.

7.2. Expected Economic Benefits and Net Benefits

Estimates of Operating Cost Reductions under Section 7.1 are calculated by SPP using the modeling methods described in this protocol for the base year of the analysis and one future year, generally 5 years out from the base year (i.e., model runs are not made for every year of a 10 year analysis period). Annual Operating Cost Reductions are then estimated for the remaining years within the 10 year analysis period through interpolation and extrapolation of the model run results. Once the Operating Cost Reductions of each year of the 10 year analysis period are obtained, SPP then calculates an Expected Economic Benefit over the 10 year analysis period, as reflected in current dollars, by discounting the Operating Cost Reduction values back to the base year of the analysis and summing the results. As a final step, the discounted 10 year Expected Economic Benefit is then compared to the projected construction cost of the particular upgrade to ensure that Expected Economic Benefit exceeds the expected construction cost.

8. Break-out of Expected Economic Benefits

Once the SPP regional economic benefits have been calculated as described under Section 7, the regional benefits are allocated, for informational purposes, to market participants based
upon the following allocation methodology. SPP provides this information to market participants to assist in the determination of their funding decision, if any.

8.1. Generator Benefits

The reduction in production cost calculated for the SPP Region is created through the removal of congestion costs resulting from the economic transmission upgrade which provides for a more efficient economic dispatch, allowing lower priced generation to further displace higher priced generation. This re-dispatch can be viewed as incremental transactions between generator owners. In order to determine which generator owners realize these benefits, SPP employs the following calculation to allocate the regional production cost benefits to generator owners:

\[
\text{SPP Congestion Impact Break-Out – Generation Re-Dispatch} = \sum_{\text{All Hours}} \sum_{\text{Each Area}} \sum_{\text{Each Area}} \left[ (\Delta \text{MW} \times \text{Nodal price}_F) - \Delta \text{Dispatch cost} \right]
\]

\(\Delta \text{MW}\) refers to the change in real output of each generator from the “Base Case” simulation (before expansion/upgrade) to the “Change Case” simulation. \(\text{Nodal Price}\) refers to the $/MWh locational price at each associated generator location of the Change Case solution, deriving from offer prices assumed in the modeling. The \(\Delta \text{Dispatch Cost}\) refers to the change in total dispatch cost ($) of each generator across the two cases.

This calculation addresses the economic impact of generator re-dispatch that is observed across comparable market simulation cases. These changes in dispatch implicitly represent incremental bulk power transfers that can be achieved as a result of removing or at least reducing certain congestion barriers. This component of the SPP Congestion Break-Out equation (see Section 8.2 for load component) should capture the direct economic impact of congestion reduction occurring from improved dispatch of generating resources across the modeled footprint and assumes distribution of the incremental scheduling rights to the owners of the re-dispatched generators.

Example: Application of Generation Re-Dispatch Equation

The following example represents an eight-node simplified OPF network model and the computations and one-line diagrams were constructed using Simulator. For the simplified examples presented here, it is assumed that generators offer into the market at marginal cost. As such, in these examples the only impediment to achieving the optimal or “least-cost” dispatch is network congestion.

The initial congested case is illustrated in Figure 1, reflecting a transmission network branch from Node 2 to Node 5 that is limited to 300 MW transfer. The generator output and network flows are consistent with an optimal achievable dispatch, showing that the network branch would become fully loaded, effectively creating an “export constraint” on the left side of the network and an “import constraint” on the right side of the network.

In Figure 1, the lowest-priced generator at Node 1 ($15/MWh) is fully dispatched. The next merit-order priced generator at Node 2 ($16/MWh) is capable of producing 440 MW, but is limited to 300 MW output by the transfer constraint. Conversely, the
A generator at Node 8 is producing megawatts only because the transfer constraint is present. A generator at Node 3 priced at $18/MWh is presently assumed to be out of service for maintenance. A generator at Node 5 is sufficiently high priced so as to not impact the situation. The LMPs range from $16/MWh at the left-most nodes, to a high of $21.50/MWh at Node 5.

Figure 1: Initial Congested Case

A visual perspective of removing the transfer constraint is shown in Figure 2, indicating that indeed in comparison to Figure 1, the generators have "re-dispatched" as reflected in the constructed schedules. Comparing the computed total dispatch cost of $15,994 shown on Figure 2 to the value of $16,541 shown on Figure 1, the saving is indeed $547 ($1 rounding error due to small loss factors). Also, Figure 2 shows that the marginal prices are now identical at all the nodes, consistent with the ability to now deliver the next megawatt of load anywhere on the network from the "merit order" generator at Node 2 (again $16/MWh).
Applying the Generator Re-dispatch portion of the congestion benefit break-out equation to the congested (“Base”) and non-congested (“Change”) cases shown on figures 1 and 2 results in the following:

“Benefit at” Gen Node 2 = \([137 \text{ MW} \times $16 \text{ (nodal price)}] - [137 \text{ MW} \times $16 \text{ (dispatch cost)}] = $0\)

“Benefit at” Gen Node 8 = \([-137 \text{ MW} \times $16\] - (-) \([137 \text{ MW} \times $20\] = +$548

Thus, in this example, the owner of the generator at Node 8 is effectively the beneficiary of the $548 benefit.

Please see Appendix B for a more detailed description of how the Generation Re-dispatch equation is applied and for additional examples.

8.2. Load Impact Sensitivity Equation

Within SPP, almost 90% of generating capacity is owned by vertically-integrated electric utilities. These utilities generally own sufficient transmission rights to deliver energy from affiliated generators to native loads and other obligated (firm) loads. These deliveries are scheduled via a combination of network transmission service within metered control areas and point-to-point service across control areas. Loads served by the scheduled deliveries are effectively “hedged” from the effects of changes in locational marginal prices beyond those inherent in the re-dispatch computations (i.e., these scheduled deliveries should not experience a nodal price charge or congestion cost charge in the marketplace).

However, some portion of loads will inevitably be “unhedged” in the markets. For example, in the upcoming SPP Phase I market, any load that is not scheduled beforehand
(Imbalance Energy) will pay a locational marginal price (called a Locational Imbalance Price or “LIP”). More generically, a certain amount of “unhedged” spot transaction activity is inevitable in any market due to uncertainties such as generator/transmission outages, weather conditions, and over time, load growth.

The second line of the congestion reduction benefit break-out equation is intended to capture the impact of changes in nodal prices on loads that not hedged in the marketplace, and is referred to herein as the “unhedged load” impact. The equation is:

\[
\text{SPP Congestion Impact Break-Out – Unhedged Load Impact} = \sum_{\text{Area}} \sum_{\text{Hours}} (\text{Load wtd price x Load x Pct load in mkt})
\]

The \( \Delta \text{Load-Wtd Price} \) refers to the change in load-weighted locational price for a specific area or participant. Multiplying this value by the associated \( \text{Load} \) is equivalent to aggregating the product of load and change of price at each location. The \( \text{Pct “Unhedged” Load} \) component refers to the portion of load that is not protected from nodal price fluctuations.

**Example: Application of Unhedged Load Impact Equation**

In the previous examples it was implicit that all load was hedged against “incidental” nodal price impacts via generation/transmission rights and associated scheduling to load. What if for the examples discussed in Section 8.1 assumed that 10 MW of load at Node 2 and also 10 MW of load at Node 5 were unhedged (i.e., no scheduled deliveries), and thus deliberately or incidentally experience the changes in nodal price as congestion in reduced?

Applying the Unhedged Load Impact portion of the congestion benefit break-out equation to the congested (“Base”) and non-congested (“Change”) cases shown on Figures 1 and 2 results in the following:

“Benefit at” Load Node 2 = \(-[\$16 \text{ (nodal price Figure 1)} - \$16 \text{ (nodal price Figure 2)}] \times 10 \text{ MW (load x Pct load in mkt)} = \$0\)

“Benefit at” Load Node 5 = \(-[\$16 – \$21.50] \times 10 \text{ MW} = +\$55\)

Thus, in this example, the owner of the load at Node 5 realizes a $55 benefit resulting from the 10 MW of unhedged load.

Please see Appendix B for a more detailed description of how the Unhedged Load Impact equation is applied and for additional examples.

8.3. Combined Allocation of Benefits to Generation and Load

For information purposes only, SPP estimates the combined generation and load benefits for each area with the SPP Region utilizing the equations specified under Sections 8.1 and 8.2. The combined formulation is shown below:
However, due to the challenges of estimating future levels of unhedged load relating to market activity, the percentage of load to apply in the equation is problematic. Therefore, SPP also calculates the allocation of benefits, again for informational purposes, utilizing on the Generation Re-dispatch portion of this equation, as describe under Section 8.1.

For both calculations, the equations are applied to each area within the SPP Region. Areas with positive results are summed and each areas percent contribution to this summation is calculated. These percentages are then used to calculate expected dollar benefits for each area based upon the total expected benefits for the SPP Region.

Please see Appendix A for an example of how these calculations were applied to develop results relating to an actual economic transmission expansion study.

9. Definitions/Glossary

[Once the protocol is in near final form, a review will be conducted to see if any terms are used that need to be defined and are different from those defined in the SPP Tariff and, if there are any, they will be entered here.]

Appendix A: Examples of Project Analysis & Results for Rose Hill-Sooner Using the ‘Base’ and ‘Sensitivity’ Models

Appendix B: Eight Node Model Example of Network Congestion
Appendix A

Examples of Project Analysis & Results for Rose Hill-Sooner
Using the ‘Base’ and ‘Sensitivity’ Models

Analyses of Rose Hill – Sooner 345kV Line

Jay Caspary
EMMTF WebEx
October 13, 2005
Transmission Expansion

- Minimum Transmission
- SPP Today
- Need for More Transmission
- Infinite Bus

Screening Process

- Ran MarketSYM base typical week July 2005
- Made change cases and reran MarketSYM run for the typical week July 2005
- Compared total production savings (dispatch savings + violation savings) to the base case
## Screening Process

- Estimated ten year savings based on total production savings
- Made ratio of estimated ten year savings to estimated construction cost
- Multiplied the ratio times 100

### Project Ranking

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Project Cost million $</th>
<th>Dispatch Savings 10 year Estimate Cost Savings</th>
<th>Ratio x 100</th>
</tr>
</thead>
<tbody>
<tr>
<td>N.E Oneta Tie N.E GRDA</td>
<td>8.0</td>
<td>9.4</td>
<td>117.50</td>
</tr>
<tr>
<td>Tolk-Potter</td>
<td>28.5</td>
<td>25</td>
<td>84.75</td>
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<tr>
<td>Cleveland-Sooner</td>
<td>18.0</td>
<td>14.57</td>
<td>80.94</td>
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<tr>
<td>Tuco-Tolk-Potter</td>
<td>44.5</td>
<td>25.23</td>
<td>56.74</td>
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<tr>
<td>Rose Hill-Sooner 345 kV</td>
<td>43.5</td>
<td>19.88</td>
<td>45.24</td>
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<tr>
<td>WPPS-Battlefield</td>
<td>3.0</td>
<td>1.947</td>
<td>34.90</td>
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<td>Fair Port-Sibley 345 kV</td>
<td>32.0</td>
<td>9.92</td>
<td>31.00</td>
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<td>Potter-Clovis</td>
<td>98.5</td>
<td>27.45</td>
<td>27.87</td>
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<td>Super X-Plan</td>
<td>491.5</td>
<td>136.844</td>
<td>27.74</td>
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<td>Pauline-Knodl-Spearville-0F 345 kV</td>
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<tr>
<td>Modified X-Plan</td>
<td>449.0</td>
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<td>Pauline-Knodl-Spearville 345 kV</td>
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<td>29.74</td>
<td>26.00</td>
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<td>Valiant Tie</td>
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<td>Original X-Plan (Plan-A)</td>
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<tr>
<td>Original X-Plan (Plan-B)</td>
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<td>Swissvale-JEC-Moore 345 kV</td>
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<td>16.97</td>
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<td>Tuco-Folk</td>
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<td>Flint Creek-SEES</td>
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<td>JEC-Moore 345 kV</td>
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<td>28.0</td>
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<td>9.57</td>
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<td>Chaves XFR 2</td>
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<td>9.57</td>
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<td>NW Texarkana-McNeil+Dolet Hills</td>
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<td>2.952</td>
<td>5.64</td>
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<td>Layne-Montrose-Collaway</td>
<td>100.0</td>
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<td>3.75</td>
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<td>Moore-Pringle</td>
<td>20.0</td>
<td>0.704</td>
<td>3.52</td>
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<td>SPS 115 Lines &amp; XFR</td>
<td>35.0</td>
<td>0.946</td>
<td>2.70</td>
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<td>Potter-Northwest</td>
<td>132.0</td>
<td>1.98</td>
<td>1.50</td>
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<td>Muskogee-Vili</td>
<td>36.3</td>
<td>0.389</td>
<td>0.99</td>
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<td>Dolet Hills Tie</td>
<td>24.3</td>
<td>0.051</td>
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<td>HalsCounty-PlantX</td>
<td>27.0</td>
<td>0.025</td>
<td>0.09</td>
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</tbody>
</table>
Rose Hill – Sooner 345 kV

Detail Market Analysis

- All four seasons
- Sensitivity to fuel cost and load growth
- Dispatch cost savings
- Generator benefits
- Load benefits
Rose Hill-Sooner Annual & 10 Year Savings

<table>
<thead>
<tr>
<th></th>
<th>Rose Hill-Sooner</th>
<th>Rose Hill-Sooner</th>
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<tbody>
<tr>
<td></td>
<td>2005</td>
<td>2010</td>
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<tr>
<td>Spring</td>
<td>$1,961,617</td>
<td>$1,630,577</td>
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<td>Summer</td>
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<td>Fall</td>
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<td>Winter</td>
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<td>$904,225</td>
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<tr>
<td>Total</td>
<td>$6,785,648</td>
<td>$5,427,176</td>
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<tr>
<td>Estimated 10 year Savings</td>
<td>$41,840,778</td>
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The 10-year savings calculates the net present value using an 8% discount rate. The calculation assumes annual savings of $6,785,648 for years 2005-2009 and annual savings of $5,427,176 for the years 2010-2014.

Production Cost Savings

- Production Cost Savings do not equal Generator Benefits
- Production Cost Savings equal expected economic dispatch savings plus violation cost savings
Generator & Load Benefits

Generator Benefits

\[ \sum_{\text{All Areas}} \sum_{\text{bus}} \sum_{\text{Gen}} \left[ (\Delta MW \times \text{Gen price}) - \Delta \text{Dispatch cost} \right] \]

Load Benefits

\[ \sum_{\text{All Areas}} \sum_{\text{bus}} \sum_{\text{Load\ Area}} \left[ \Delta \text{Load\ Area price} \times \text{Load} \times \% \text{unhedged load} \right] \]

Rose Hill-Sooner Annual Savings
The allocation of benefits was calculated two different ways. The first allocation is based on positive benefits for 10% load benefits plus positive generator benefit. The second allocation is based on just the positive generator benefits.
Sensitivity to Fuel Cost

- Benefits of Rose Hill-Sooner 345 kV Line increased 20% with higher natural gas fuel prices
- Almost linear correlation between natural gas price and economic value of potential 345kV interconnection between KS and OK

Violation Cost Reductions

- Benefits due to unloading key Flowgates
  - Creswell – Kildare
  - El Paso – Farber
- Be careful to not double count benefits of constraints in series
Key Factors for Market Projects

- Dispatch cost plus violation cost, key factor to determine if a project has a total market benefit
- Generation benefits plus load benefits used to allocate cost

Additional Factors to Consider Allocation of Benefits

- Reliability projects that are eliminated or deferred
- Additional benefits such as additional feeds into a load area
- Transmission service revenue
- Mitigation of Reliability Must Run (RMR) units
EIGHT NODE MODEL EXAMPLES – DECEMBER 2004 DRAFT

1. Introduction

Among the challenges of quantifying the economic benefits of transmission upgrades is the estimation of impact on overall regional congestion and identifying which specific sub-regional areas and market participants will likely benefit from the quantified congestion reduction.

SPP applies a set of multi-regional simulation models to estimate the impact of network expansion and upgrade projects on regional resource dispatch and congestion. A straightforward interpretation of the “societal impact” of reducing congestion is the ability to produce a “closer to optimal” dispatch of supply resources to serve electric loads, resulting in reduced dispatch costs within and across regions. In some situations the analysis might be expanded to include the potential impact on generating unit commitment and associated costs. Specific assumptions regarding pricing can impact the likely distribution of these benefits to market participants.

To help identify how much sub-regional areas and/or individual participants that might benefit from reduced congestion resulting from transmission expansion/upgrade projects, SPP has constructed the congestion reduction benefit break-out equation shown in Equation 1.

Equation 1: SPP Congestion Reduction Benefit Break-Out Equation

\[
\sum_{\text{All Hours}} \sum_{\text{Each Area}} \sum_{\text{Gen with } \Delta MW} [(\Delta MW \times \text{Nodal price}) - \Delta \text{Dispatch cost}] \\
- \sum_{\text{All Hours}} \sum_{\text{Each Area}} [\Delta \text{Load wtd price} \times \text{Load} \times (\text{Pct " unhedged" load})]
\]

The first line of Equation 1 is referred to herein as the “generator re-dispatch” portion of the equation, because it addresses the economic impact of generator re-dispatch that is observed across comparable market simulation cases. These changes in dispatch implicitly represent incremental bulk power transfers that can be achieved as a result of removing or at least reducing certain congestion barriers. This component the equation should capture the direct economic impact of congestion reduction occurring from improved dispatch of generating resources across the modeled footprint.

Application of the generator re-dispatch portion of Equation 1 can be thought of as implicitly quantifying incremental transactions made possible by removing or reducing “blockages” within the network. The nodal prices reflect the marginal value of injecting (exporting) or withdrawing (importing) energy at the respective generator locations. The impacts of
reducing congestion accrue to the owners of impacted generators and the load-serving entities receiving output from the generators.

Within SPP, almost 90% of generating capacity is owned by vertically-integrated electric utilities. These utilities generally own sufficient transmission rights to deliver energy from affiliated generators to native loads and other obligated (firm) loads. These deliveries are scheduled via a combination of network transmission service within metered control areas and point-to-point service across control areas. Loads served by the scheduled deliveries are effectively “hedged” from the effects of changes in locational marginal prices beyond those inherent in the re-dispatch computations (i.e., these scheduled deliveries should not experience a nodal price charge or congestion cost charge in the marketplace).

However, some portion of loads will inevitably be “unhedged” in the markets. For example, in the upcoming SPP Phase I market, any load that is not scheduled beforehand (Imbalance Energy) will pay a locational marginal price (called a Locational Imbalance Price or “LIP”). More generically, a certain amount of “unhedged” spot transaction activity is inevitable in any market due to uncertainties such as generator/transmission outages, weather conditions, and over time, load growth.

The second line of Equation 1 is intended to capture the impact of changes in nodal prices on loads that not hedged in the marketplace, and is referred to herein as the “unhedged load” impact. Due to the challenges of estimating future levels of unhedged/spot market activity, the percentage of load to apply in the equation is problematic, and should perhaps be thought of as akin to sensitivity analysis.

More specifically within the equation, ∆MW refers to the change in real output of each generator from the “Base Case” simulation (before expansion/upgrade) to the “Change Case” simulation. **Nodal Price** refers to the $/MWh locational price at each associated generator location of the Change Case solution, deriving from offer prices assumed in the modeling. The ∆Dispatch Cost refers to the change in total dispatch cost ($) of each generator across the two cases. As shown later, applying the Change Case nodal prices in the equation does not infer that Base Case prices are ignored – they are inherently reflected in the dispatch levels of the generators in the Base Case solution.

The ∆Load-Wtd Price refers to the change in load-weighted locational price for a specific area or participant. Multiplying this value by the associated Load is equivalent to aggregating the product of load and change of price at each location. The Pct “Unhedged” Load again component refers to the portion of load that is not protected from nodal price fluctuations.

2. Description of Eight Node Model

An eight-node simplified optimal power flow network model was developed to construct the examples in this Appendix B. The computations and one-line diagrams were constructed using the Simulator® model from PowerWorld Corporation. For the simplified examples presented here, it is assumed that generators offer into the market at marginal cost. As such, in these examples the only impediment to achieving the optimal or “least-cost” dispatch is network congestion.
3. Simplified Network Examples With and Without Congestion Present

The initial congested case is illustrated in Figure 1, reflecting a transmission network branch from Node 2 to Node 5 that is limited to 300 MW transfer. The generator output and network flows are consistent with an optimal achievable dispatch, showing that the network branch would become fully loaded, effectively creating an “export constraint” on the left side of the network and an “import constraint” on the right side of the network. For some of the examples which follow, it can be useful to think of the depiction as representing two utility control areas, each operated by vertically integrated utilities and with a border interface drawn right down the middle of the figure. However, a vertically integrated utility perspective is not necessary for the examples to be correct.

In Figure 1, the lowest-priced generator at Node 1 ($15/MWh) is fully dispatched. The next merit-order priced generator at Node 2 ($16/MWh) is capable of producing 440 MW, but is limited to 300 MW output by the transfer constraint. Conversely, the generator at Node 8 is producing megawatts only because the transfer constraint is present. A generator at Node 3 priced at $18/MWh is presently assumed to be out of service for maintenance. A generator at Node 5 is sufficiently high priced so as to not impact the situation. The locational marginal prices range from $16/MWh at the left-most nodes, to a high of $21.50/MWh at Node 5. It will become more obvious later why the marginal price at Node 5 exceeds the price of both the $16/MWh and $20/MWh “marginal” generators.

A visual perspective of removing the transfer constraint is shown in Figure 2, indicating that indeed in comparison to Figure 1, the generators have “re-dispatched” as reflected in the constructed schedules. Comparing the computed total dispatch cost of $15,994 shown on
Figure 2 to the value of $16,541 shown on Figure 1, the saving is indeed $547 ($1 rounding error due to small loss factors). Also, Figure 2 shows that the marginal prices are now identical at all the nodes, consistent with the ability to now deliver the next megawatt of load anywhere on the network from the “merit order” generator at Node 2 (again $16/MWh).

Figure 2: Effect of Removing the Congestion

4. Scheduling Examples with the Congestion Present

To help understand the scheduling perspective, simplified scheduling examples were constructed for the congested situation depicted on Figure 1.

The first set of schedules constructed as shown on Table 1 is consistent with a desired optimal dispatch of the lowest-cost resources, but is ignorant of the transfer limitation on the branch from Node 2 to Node 5. The prospect of overloading the branch makes this set of schedules infeasible. If these schedules were submitted to the transmission operator, a re-dispatch would be necessary to avoid overloading the transmission branch. The most efficient re-dispatch would again be consistent with Figure 1, effectively requiring that the output of the generator at Node 2 be dispatched 137 MW less than reflected in the schedules, and the higher-cost generator at Node 8 dispatched at 137 MW.
### Table 1: Initial Set of Schedules Ignorant of the Congested Transmission Branch

<table>
<thead>
<tr>
<th>Sched #</th>
<th>Transaction</th>
<th>Cumulative Loading on Branch</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>305 MW from Generator at Node 1 to Load at Node 7</td>
<td>89 MW</td>
</tr>
<tr>
<td>2</td>
<td>295 MW from Generator at Node 1 to Load at Node 8</td>
<td>189 MW</td>
</tr>
<tr>
<td>3</td>
<td>100 MW from Generator at Node 2 to Load at Node 2</td>
<td>189 MW</td>
</tr>
<tr>
<td>4</td>
<td>237 MW from Generator at Node 2 to Load at Node 5</td>
<td>300 MW (fully loaded)</td>
</tr>
<tr>
<td>5</td>
<td>100 MW from Generator at Node 2 to Load at Node 5</td>
<td>345 MW (OVERLOADED)</td>
</tr>
</tbody>
</table>

Assume that the parties submitting schedules #1 through #4 in Table 1 collectively hold the full scheduling rights to the 300 MW transfer capacity on the branch from Node 2 to Node 5. In this situation, the party submitting schedule #5 would bear the cost of the re-dispatch. In a nodal price market, the cost of congestion would be calculated consistent with Equation 2.

**Equation 2: Transaction-Based Congestion Cost Equation**

\[
\text{MW Transaction} \times (\text{Nodal Price at Withdrawl} - \text{Nodal Price at Injection})
\]

Applying the nodal prices from Figure 1 to this equation yields the following cost of congestion, resulting in a value equivalent to the incremental cost of the forced re-dispatch.

\[
100 \text{ MW} \times (\$21.50 - \$16) = 548
\]

(congestion cost calculation #1)

Other sets of schedules could be constructed to also yield the cost of congestion. For example, second set of schedules is shown in Table 2, with the further assumption that the parties submitting schedules #1 through #5 hold the scheduling rights to the congested transmission branch. The cost of congestion borne by the party submitting schedule #6 is quantified below, again yielding a consistent result.

\[
158 \text{ MW} \times (\$19.50 - \$16) = 548
\]

(congestion cost calculation #2)

### Table 2: Second Set of Schedules Ignorant of the Congested Transmission Branch

<table>
<thead>
<tr>
<th>Sched #</th>
<th>Transaction</th>
<th>Cumulative Loading on Branch</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>337 MW from Generator at Node 1 to Load at Node 5</td>
<td>157 MW</td>
</tr>
<tr>
<td>2</td>
<td>263 from Generator at Node 1 to Load at Node 8</td>
<td>246 MW</td>
</tr>
<tr>
<td>3</td>
<td>100 MW from Generator at Node 2 to Load at Node 2</td>
<td>246 MW</td>
</tr>
<tr>
<td>4</td>
<td>32 MW from Generator at Node 2 to Load at Node 8</td>
<td>257 MW</td>
</tr>
<tr>
<td>5</td>
<td>147 MW from Generator at Node 2 to Load at Node 7</td>
<td>300 MW (fully loaded)</td>
</tr>
<tr>
<td>6</td>
<td>158 MW from Generator at Node 2 to Load at Node 7</td>
<td>345 MW (OVERLOADED)</td>
</tr>
</tbody>
</table>

Any number of unique scheduling scenarios could be constructed to yield the cost of congestion in even this simplified network. However, consistent to each of them would be the underlying forced re-dispatch of the identified generators at Nodes 2 and 8 to avoid overloading the network branch. Thinking of it in this context, the cost of congestion reflected as a “direct transaction” between the affected generators would be calculated as follows:
5. Generator Re-Dispatch Equation

In a large network with multiple identified or potential congestion locations and associated re-dispatch at multiple generator locations, the scheduling scenarios that could be constructed to calculate the cost of congestion would be virtually infinite. However, consistent to each of them would be the underlying re-dispatch of generators as forced by the network congestion.

Implicit within a “Base Case” market simulation exhibiting congestion is an underlying set of schedules supporting the (sub-) optimal dispatch of that case. A “Change Case” with reduced network congestion would reflect incremental dispatch of low-cost/priced resources.

The generator re-dispatch calculation of the congestion reduction benefit break-out equation in effect assumes distribution of the incremental scheduling rights to the owners of the re-dispatched generators. In the context (most) of these generators being associated with integrated electric utilities, the scheduling rights would then effectively impact the price of scheduled deliveries to loads on those utility systems. This has the practical implication that incremental schedules made feasible by the elimination or reduction of congestion will most likely directly impact the “nearby” loads.

As an example of this, assume that Nodes 4 through 8 of Figure 1 or 2 (including the generator at Node 8) represent a small utility system, and the utility obtains the full scheduling rights associated with the improved (fully optimal) re-dispatch resulting from removal of the network congestion. The utility can then apply the scheduling rights to schedule lower-cost energy to effectively reduce congestion anywhere on the utility system, as shown within congestion cost computations #1 and #2 for scheduling to Node 5 or Node 7.

This break-out methodology does not represent a unique distribution of transmission scheduling rights, or even a “most appropriate” distribution (if there were one). However, the methodology should present a straightforward “initial” distribution of benefits based again on direct participation by owners of the generators impacted by the re-dispatch. Once again, to the extent the generators are part of a utility or control area network system, the benefit should effectively impact cost of delivery to loads within that system.

The congestion reduction benefit break-out equation should also appropriately capture the impact of re-dispatch that does not translate to scheduled transactions. For example, if a “must-run” constraint is impacted within a control area, the nodal prices of the changes in generation should capture the internal value of injecting/withdrawing energy at the impacted generator locations (e.g., no net impact if no congestion within the area), as well as the change in production costs.

6. Applying the Congestion Reduction Benefit Break-Out Equation to the Previous Examples

Applying the generator re-dispatch portion of Equation 1, the congestion reduction benefit break-out equation, to the congested (“Base”) and non-congested (“Change”) cases shown on Figures 1 and 2 results in the following:

“Benefit at” Gen Node 2  =  [137 MW  x  $16 (nodal price)]  -  $2,192 (dispatch cost)  =  $0

“Benefit at” Gen Node 8  =  [-137 MW  x  $16]  -  (-) $2,740  =  +$548
Thus, in this initial situation, the owner of the generator at Node 8 is effectively the beneficiary of the $548 benefit. One subtlety of this result is that the marginal price (marginal value of injecting generation) at Node 8 decreased, while the marginal price remained unchanged at Node 2.

Changing the situation slightly, assume that the generator at Node 2 has a “two-part piecewise linear” offer price as follows:

- First 400 MW is offered at (and the marginal cost is) $16/MWh
- Remaining 40 MW is offered at (and the marginal cost is) $18/MWh

The above change would not affect the congested case of Figure 1, but the non-congested result would now look like the depiction in Figure 3.

**Figure 3: Non-Congested Case with Two-Part Offer Curve for Generator at Node 2**

The (non-congested) marginal price at all nodes is now $18, and the re-dispatch impact of removing the congestion is as follows:

\[
[100 \text{ MW} \times 16] + [37 \text{ MW} \times 18] + [-137 \text{ MW} \times 20] = -474 \text{ (i.e., reduced congestion)}
\]

Apply the generator re-dispatch portion of the congestion reduction benefit break-out equation to the new situation depicted here, with the congested case again representing the Base and the non-congested case representing the Change, results in the following:

- "Benefit at" Gen Node 2 = \([137 \text{ MW} \times 18 \text{ (nodal price)}] - 2,266 \text{ (dispatch cost)} = +200"
- "Benefit at" Gen Node 8 = \([-137 \text{ MW} \times 18 \text{ (nodal price)}] - (-)2,740 = +274"
In this example about 58% of the benefit is assigned to the owner of the generator at Node 8. The marginal prices have changed significantly at both the exporting node and the importing node.

In both of the previous examples, the generator at Node 8 reduces output, and we state that “the owner of this generator … benefits”. Does it make sense that the owner benefits when generating less?

There are two perspectives on this question, depending on whether the generator is owned (or otherwise under the control of) a vertically-integrated utility, or is owned by an Independent Power Producer (“IPP”). When assuming utility ownership, it is clear in this simplified example the utility would benefit by importing energy at a lower price than the incremental cost of generating, as depicted in the example. It is not quite as straightforward to interpret this situation for IPP ownership. However, it would be expected that if the IPP owner could effectively replace a scheduled delivery from a high-cost source with equivalent delivery from a lower-cost source, an incremental margin could be achieved.

7. Unhedged Load

In the previous examples it was implicit that all load was hedged against “incidental” nodal price impacts via generation/transmission rights and associated scheduling to load. What if for the examples discussed earlier it was instead assumed that 10 MW of load at Node 2 and also 10 MW of load at Node 5 were unhedge (i.e., no scheduled deliveries), and thus deliberately or incidentally experience the changes in nodal price as congestion in reduced?

To interpret the impact of the unscheduled load, it is perhaps best to review the changes in both load charges and overall generator revenues between a congested case and a non-congested case. Table 3 shows the nodal price charges to the unscheduled loads for the comparative cases, based on the two-part price assumption for the generator at Node 2 as applied in the previous section. The unscheduled load at Node 2 experiences a $20 increase of charges with elimination of the congestion, due to the increase in nodal price at that location (from $16/MWh to $18/MWh). Conversely, and the unhedge load at Node 5 experiences a $35 decrease of charges due to the reduction of nodal price at that location (from $21.50/MWh to $18/MWh).

<table>
<thead>
<tr>
<th>Load at Node 2</th>
<th>Load at Node 5</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unscheduled</td>
<td>Charges</td>
<td>Serving</td>
</tr>
<tr>
<td>Congested Case</td>
<td>10.0 MW</td>
<td>$160</td>
</tr>
<tr>
<td>Non-congested Case</td>
<td>10.0 MW</td>
<td>$180</td>
</tr>
<tr>
<td>Change of Gen Revenue</td>
<td>$20</td>
<td></td>
</tr>
</tbody>
</table>

Table 4 shows in relative detail a calculation of the change in revenues and expenses for the two generators from the congested case to the non-congested case, with a break-out of portions attributable to both the scheduled and unscheduled loads. The change in revenue is calculated for both scheduled and unscheduled components as “ΔMW x nodal price”, since this is consistent with both the generator re-dispatch portion of the congestion reduction...
benefit break-out equation for scheduled loads, and how the “spot price” output would be priced. For the expense calculations, dispatch costs for the “final MW” of output were applied against the unscheduled loads, since this is consistent with how dispatch would effectively be impacted.

Table 4 yields net benefit for each generator consistent with the result for the example at the beginning of the previous section, including an overall saving of $474.

It is worthwhile to note that $15 of the overall benefit is identified with the unscheduled load. From this and other examples yielding a consistent result, it would appear the NET reduction in charges to unscheduled loads across simulated cases effectively overlaps with the quantification of benefit derived from the generator re-dispatch portion of Equation 1.

**Table 4: Generator Revenues and Expenses with 20 MW Unscheduled Load**

<table>
<thead>
<tr>
<th>Congested Case</th>
<th>Gen at Node 2</th>
<th>Gen at Node 8</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scheduled Load</td>
<td>$4,699</td>
<td>$2,466</td>
<td>$7,165</td>
</tr>
<tr>
<td>Unscheduled Load</td>
<td>$101</td>
<td>$274</td>
<td>$375</td>
</tr>
<tr>
<td>Non-congested Case</td>
<td>$6,706</td>
<td>$0</td>
<td>$6,706</td>
</tr>
<tr>
<td>Expense</td>
<td>$2,007</td>
<td>-$2,219</td>
<td>-$459</td>
</tr>
<tr>
<td>$259</td>
<td>$-2,219</td>
<td>-$274</td>
<td>-$15</td>
</tr>
<tr>
<td>$200</td>
<td>$274</td>
<td>$459</td>
<td>$474</td>
</tr>
</tbody>
</table>

There is another aspect to the impact of congestion reduction on the nodal prices paid by unscheduled loads. The examples applied herein exhibit the classic expectation that marginal prices on the exporting side of a congestion point are lower than would be observed in the non-congested situation or a “less-congested” situation, and prices on the importing side of a congestion point are conversely higher. **Figure 4** visually shows the perspective that the reduction of congestion is eliminating the differential impact imposed on unscheduled loads in the market.
8. Example with All Loads and Generators Exposed to Nodal Prices

The next set of examples applies the assumption that all loads incur charges based on their specific locational nodal prices and all generators are paid based on their specific locational nodal prices. These assumptions are consistent with assuming that no loads or generators effectively own or apply network transmission/transaction scheduling rights.

Table 5 summarizes generator revenues and load charges of the original congested case shown on Figure 1 assuming all loads pay the marginal nodal price and all generators are paid the marginal nodal price. The computed total charges incurred (by loads) exceed the computed total payments (to generators) by a significant amount (about 20%). This differential is a representation of the impact of congestion, based on the marginal prices of the particular solution state represented in Figure 1.

**Table 5: Load Charges and Generator Revenues Based Only on Nodal Prices**

<table>
<thead>
<tr>
<th>Node</th>
<th>MW</th>
<th>Nodal Price</th>
<th>Payment to Load</th>
<th>Payment to Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>100</td>
<td>$16.00</td>
<td>$1,600</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>337</td>
<td>$21.50</td>
<td></td>
<td>$7,242</td>
</tr>
<tr>
<td>7</td>
<td>305</td>
<td>$19.50</td>
<td></td>
<td>$5,935</td>
</tr>
<tr>
<td>8</td>
<td>295</td>
<td>$20.00</td>
<td></td>
<td>$5,900</td>
</tr>
</tbody>
</table>

Total Amount Paid by Loads: $20,677
Total Amount Paid to Generators: $17,140

Amount Paid by Loads less Amount Paid to Generators: $3,537
To understand the above effect, the first point to remember is that the marginal prices of a given “snapshot” are directly applicable only to the next increment of load at each location [1 MW in our models]. It should not be surprising that due to changing marginal prices at varying load levels, the application of a “single snapshot” of prices will inevitably produce a “mismatch” of charges paid in and revenues paid out if applied to all load and generation within the network. The larger the portion of overall network loads and generation to which the assumption is applied, the larger the transactional “mismatch” will almost certainly be.12

The type of unscheduled generator/load congestion $$ mismatch illustrated here does happen in real markets – although to a much lesser degree than exhibited in this example and undoubtedly with some offsetting impacts across hours. In actual markets, if a significant amount of “mismatch” accumulates over time, it will likely be distributed to all or a group of market participants by means of an “uplift” allocation mechanism.

Additional insight to the values calculated in Table 5 can be obtained by application of Equation 2, the transaction-based congestion cost equation.

Applying Equation 2, the transaction-based congestion cost equation, to the set of transaction schedules created in Table 1 of this document yields a computation of congestion costs shown in Table 6. It is worthwhile to note that the congestion cost for schedule #5 ($548) equals our earlier calculation for this scheduled transaction back in Section 4. Consistent with our earlier discussion, if schedules #1 through #4 all have scheduling rights to the loading of the transmission branch from Node 2 to Node 5, the associated congestion costs would be nullified, as indicated in Table 7. The only remaining congestion cost is that associated with schedule #5, which is not supported by scheduling rights.

### Table 6: Congestion Costs Computed from the Set of Schedules in Table 1

<table>
<thead>
<tr>
<th>Schedule</th>
<th>From</th>
<th>Load</th>
<th>Marginal Price Difference</th>
<th>Congestion Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>From Node 1 gen to Node 7 load</td>
<td>305</td>
<td>($19.5 - $16.0)</td>
<td>$1,056</td>
</tr>
<tr>
<td>2</td>
<td>From Node 1 gen to Node 8 load</td>
<td>295</td>
<td>($20.0 - $16.0)</td>
<td>$1,180</td>
</tr>
<tr>
<td>3</td>
<td>From Node 2 gen to Node 2 load</td>
<td>100</td>
<td>($16.0 - $16.0)</td>
<td>$0</td>
</tr>
<tr>
<td>4</td>
<td>From Node 2 gen to Node 5 load</td>
<td>237</td>
<td>($21.5 - $16.0)</td>
<td>$1,301</td>
</tr>
<tr>
<td>5</td>
<td>From Node 2 gen to Node 5 load</td>
<td>100</td>
<td>($21.5 - $16.0)</td>
<td>$548</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>1,037</td>
<td></td>
<td>$4,085</td>
</tr>
</tbody>
</table>

12 Referencing back to the previous example, with only 20 MW of unscheduled load (10 MW at each of two locations) the unscheduled revenue-charge “mismatches” were zero – i.e., in both the congested case and the non-congested case the charges incurred and revenues received matched (at $375 in the congested case and $360 in the non-congested case).
Table 7: Effect of Applying Transmission Rights to the Congestion Charges

<table>
<thead>
<tr>
<th></th>
<th>From Node 1 gen to Node 7 load</th>
<th>From Node 1 gen to Node 8 load</th>
<th>From Node 2 gen to Node 2 load</th>
<th>From Node 2 gen to Node 5 load</th>
<th>From Node 2 gen to Node 5 load</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>x ( $19.5 - $16.0 ) = $1,056</td>
<td>x ( $20.0 - $16.0 ) = $1,180</td>
<td>x ( $16.0 - $16.0 ) = $0</td>
<td>x ( $21.5 - $16.0 ) = $1,301</td>
<td>x ( $21.5 - $16.0 ) = $548</td>
</tr>
<tr>
<td>1</td>
<td>305</td>
<td>295</td>
<td>100</td>
<td>237</td>
<td>100</td>
</tr>
</tbody>
</table>
| 9. “Hidden” Dispatch Cost Savings

To illustrate a situation where congestion is being reduced but not eliminated, another set of cases was constructed. The congested case depicted in Figure 1 was revised assuming the network branch between Node 2 and Node 3 is rated 580 MW. It was also assumed the generator at Node 3 is available and priced at $18/MWh. These revisions had no impact on the generator dispatch or marginal prices of the original congested case.

The impact of upgrading the original congested branch (Node 2 to Node 5) such that it is no longer a congestion location is illustrated on Figure 5. We note that the transmission branch from Node 2 to Node 3 is now congested.

Very similar to the earlier example, eliminating the branch from Node 2 to Node 5 as a congestion location resulted in the generator at Node 2 ramping upward and the generator at Node 8 going off-line. However, in this newer situation the generator at Node 3 dispatches to 12.5 MW. The marginal price at Node 8 reduces to $17.50/MWh (rather than dropping to $16/MWh as previously observed). A total dispatch saving of $522 [$16,541 - $16,019] is observed from Figure 5 in comparison to Figure 1.13

---

13 It is worthwhile to note that the dispatch cost reduction of this example ($522) is almost as large as for the original example of Section 3 ($548).
Applying the generator re-dispatch portion of Equation 1, the congestion reduction benefit break-out equation, to these cases shows the following:

“Benefit at” Gen Node 2 = [124.5 MW x [$16 (nodal price)]] - $1,992 (dispatch cost) = $0

“Benefit at” Gen Node 3 = [12.5 MW x [$18]] - $225 = $0

“Benefit at” Gen Node 8 = [-137 MW x [$17.5]] - (-) $2,739 = $342

In this example, the equation is only capturing 66% of the net dispatch saving. Where is the other $180 dispatch saving hiding? Actually, this computation is a result of the “new” congestion location preventing the marginal prices from equalizing.

Applying Equation 2, the transaction-based congestion cost equation, to a pair of transactions consistent with the incremental transfers yields the following computations. These values were straightforward to calculate in this situation, since there are only two incremental “exporting” locations (generators at Nodes 2 and 3) and only one “importing” location (the generator at Node 8).

From generator at Node 2 to generator at Node 8: 124.5 MW x (17.5 - 16) = $187

From generator at Node 3 to generator at Node 8: 12.5 MW x (17.5 - 18) = $7

Although the above computed congestion cost should not negate any of the overall dispatch cost reduction observed ($522), it is still not obvious how this computation impacts the overall distribution of savings. To carry this example a step further, Table 8 lists a set of assumed schedules that are identical to those of Table 1 (except that the MW listed for
schedules #4 and #5 have been reallocated to emphasize the point at which the transmission branch from Node 2 to Node 3 would now congest).

### Table 8: A Set of Schedules Ignorant of the “Newly-Congested” Transmission Branch

<table>
<thead>
<tr>
<th>Sched #</th>
<th>Transaction</th>
<th>Cumulative Loading on Branch</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>305 MW from Generator at Node 1 to Load at Node 7</td>
<td>216 MW Node 2 -&gt; Node 3</td>
</tr>
<tr>
<td>2</td>
<td>295 MW from Generator at Node 1 to Load at Node 8</td>
<td>411 MW</td>
</tr>
<tr>
<td>3</td>
<td>100 MW from Generator at Node 2 to Load at Node 2</td>
<td>411 MW</td>
</tr>
<tr>
<td>4</td>
<td>316 MW from Generator at Node 2 to Load at Node 5</td>
<td>580 MW (fully loaded)</td>
</tr>
<tr>
<td>5</td>
<td>21 MW from Generator at Node 2 to Load at Node 5</td>
<td>591 MW (OVERLOADED)</td>
</tr>
</tbody>
</table>

Application of Equation 2, the transaction-based congestion cost equation, to the above schedules and nullifying the computations for schedules protected by available scheduling rights (schedules #1 through #4) yields a congestion cost of $24, as shown on Table 9. This value is consistent with that the dispatch cost penalty observed by comparing dispatch costs of Figures 2 and 5 ($15,994 and $16,019 respectively).

### Table 9: Congestion Costs Calculated from the Above Set of Schedules

| From Node 1 gen to Node 7 load | 305 x ( $17.6 - $16.0 ) = $489 |
| From Node 1 gen to Node 8 load | 295 x ( $17.5 - $16.0 ) = $440 |
| From Node 2 gen to Node 2 load | 100 x ( $16.0 - $16.0 ) = $0 |
| From Node 2 gen to Node 5 load | 316 x ( $17.2 - $16.0 ) = $382 |
| From Node 2 gen to Node 5 load | 21 x ( $17.2 - $16.0 ) = $24 |

1,037 $24

Unfortunately, the resultant impact on the ultimate distribution of benefits may not be resolved until reviewing which parties have rights at the newly-congested path. If these rights are not owned by the owner of the generator at Node 8, it would appear this participant would effectively be limited to the $384 benefit, and the remaining $180 would effectively accrue to one or more newly-identified participants.

### 10. Relevance of the Above Examples to Large-Scale Market Simulations Conducted by SPP Staff

The network congestion situations presented and examined herein are simplified representations of what is occurring in the large scale (8,000 network bus) optimal power flow simulations being conducted by SPP Staff. In particular, several specific observations can be noted and some key points reinforced from these examples in relation to the larger-scale cases.

A. In the examples of Sections 6 and 9, no “net benefit” is quantified for the exporting generator(s). In the small-scale cases, this is occurring because: 1) offer prices are implicitly modeled as being equal to incremental dispatch costs; and 2) the nodal prices are not changing at the exporting generator location(s). For essentially the same reasons, the large scale simulations recently conducted by SPP show relatively little “incremental
margin” for the generators that are dispatching more after a reduction of network congestion.

Within the large-scale simulations, SPP has been applying market offer prices equal to short-run variable cost for several reasons: 1) SPP has not conducted independent analysis of “offer price strategies” and possible impacts on prices and generator/participant profitability/margins; 2) A driving perspective when building the models was “cost-driven (i.e., societal) economic modeling”; 3) It is not clear how the application of specific “price markup” assumptions in SPP studies might be interpreted by market participants and others; and 4) from a more technical perspective, the PowerWorld Simulator model does not directly support separate computation or accumulation of costs and prices (although a reasonable work-around should be feasible).

Somewhat generic assumptions regarding price margin or markup would have a significant impact on the distribution of generator re-dispatch benefits. For example, if 100,000 MWh of area-to-area transfer were observed annually, a $2.00/MWh margin would result in about $200,000 additional benefit to exporters and an offsetting impact to importers (via higher purchased prices).

B. The “hidden” dispatch benefit observed in the example of Section 9 are also typically observed for large scale simulations conducted by SPP Staff when applying the generator re-dispatch portion of the congestion reduction benefit break-out equation. This is undoubtedly happening for the same reason discussed in that section (i.e., the computational impact of congestion that continues to exist in the Change case solutions).

An important point to draw from the example of Section 7 is that the appropriate measure of societal economic benefit of the reduced congestion is the region-wide reduction of dispatch costs, including reduced branch/interface limit violation costs. The portion of benefit that is not revealed in the net total of the generator re-dispatch portion of the congestion reduction benefit break-out equation can accrue to market participants if they own or receive sufficient transmission rights to nullify the congestion charges.

This discussion underscores the importance of consistency between the methodology of identifying/assigning quantified benefits for funding purposes and the ultimate assignment of incremental transmission/transfer rights. To the extent that the “hidden” benefits are allocated to specific market participants for funding purposes, it is important to verify that existing or new transmission rights accrue to the same participants.

However, any attempt to construct “incremental schedules” as applied in the example would be computationally challenging due to the amount of transactional activity inherent in the large-scale simulations, and in any event would not produce a unique or definitive result.

C. The unscheduled load example of Section 7 indicates there is a small overlap between the “generator re-dispatch” and “unhedged load” portions of the congestion reduction benefit break-out equation, to the extent that a net change in unscheduled load charges is applied. This seems intuitively correct from the perspective that unscheduled loads are then (in their aggregate) experiencing a portion of the economic impact of the generator re-dispatch that is occurring in the market.
D. The discussion at the end of Section 7 and highlighted by Figure 4 raises the perspective that perhaps it is reasonable to conclude that unhedged loads experiencing lower marginal prices due to network congestion are not truly being “penalized” when nodal prices rise toward the non-congested ideal as a consequence of the reduction of network congestion. This would imply the exclusion of some or all areas experiencing increased nodal prices in the “unhedged load” portion of the congestion reduction benefit break-out equation.

E. Applying the concepts discussed in paragraphs B-D above might result in detailed application of the congestion benefit break-out equation similar to that presented in Table 10.

Table 10: Possible Detailed Application of the Congestion Reduction Benefit Break-out Equation Components

<table>
<thead>
<tr>
<th>Area Calculation Part 1: Area Benefit Quantified from Generator Re-Dispatch Equation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1st Area = $\text{AGR}_1$</td>
</tr>
<tr>
<td>2nd Area = $\text{AGR}_2$</td>
</tr>
<tr>
<td>...</td>
</tr>
<tr>
<td>Last Area = $\sum \text{AGR}_X$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Area Calculation Part 2: Area Nodal Charges to &quot;Unhedged Load&quot; (each based on an assumed percentage of total load being unhedged)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1st Area = $\text{ANC}_1$</td>
</tr>
<tr>
<td>2nd Area = $\text{ANC}_2$</td>
</tr>
<tr>
<td>...</td>
</tr>
<tr>
<td>Last Area = $\sum \text{ANC}_X$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Application of Area Calculation Parts 1 &amp; 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>1st Area = $\text{AGR}_1 - \text{ANC}_1$(if &lt;0)</td>
</tr>
<tr>
<td>2nd Area = $\text{AGR}_2 - \text{ANC}_2$(if &lt;0)</td>
</tr>
<tr>
<td>...</td>
</tr>
<tr>
<td>Last Area = $\sum \text{AGR}_X - \sum \text{ANC}_X$(if &lt;0)</td>
</tr>
</tbody>
</table>

| Remaining Unassigned Portion of Benefit = $\text{DCR} + \text{VCR} - \sum \text{AGR}_X - \sum \text{ANC}_X$ |