Benefits for the 2013 Regional Cost Allocation Review

September, 13 2012

Approved by:

Metrics Task Force

Economic Studies Working Group

Revision History

Date	Author	Change Description	Comments
May 11, 2012	MTF	Initial Draft	
June 14, 2012	MTF	Added individual metric sections	for consideration by the Brattle Group
June 25, 2012	MTF	Significant edits	Distributed to the Metrics Task Force
July 5, 2012	SPP staff	Incorporated edits from the June 26, 2012 MTF meeting	Distributed to Economic Studies Working Group
Aug 24, 2012	SPP staff & MTF members	Incorporated comments from July 12, 2012 ESWG meeting and August 21, 2012 TWG meeting	Distributed to Metrics Task Force for formal approval
Aug 31, 2012	MTF call	In meeting edits	SPP legal is reviewing for clarity and style. Update will be provided to ESWG. Distributed to Economic Studies Working Group
Sep 7, 2012	SPP staff	Clarity and style edits	Distributed to Metrics Task Force
Sep 13, 2012	SPP staff	No changes	Approved by the Metrics Task Force
Sep 13, 2012	ESWG	Changes to recommendation language to include an evaluation of the metrics(p. 5), ancillary services section allocation to zones based on load-ratio share (p. 32), and other minor edits	Changes and report approved by the Economic Studies Working Group

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Executive Summary and Recommendations

The Metrics Task Force (MTF) presents this report to the Economic Studies Working Group (ESWG) as a completion of the benefit monetization effort undertaken during the spring and early summer of 2012. After consideration of a wide range of benefit metrics through multiple open and transparent stakeholder meetings, the MTF provides the following recommended benefit metrics that represent real dollar benefits for use in support of the principles laid forth by the Regional Allocation Review Task Force (RARTF) for the Regional Cost Allocation Review. The Regional Cost Allocation Review principles include: simplicity; acknowledgement of the "roughly commensurate" legal standard; the use of the best information available; consistency; transparency; stakeholder input; the use of real dollars values; consideration given to certain Board approved plans; more weight given to nearer term projects; and equity over time.

The MTF recommends thirteen (13) monetized benefit metrics be utilized in the Regional Cost Allocation Review. These benefit metrics include five (5) metrics that have been used in previous Integrated Transmission Planning (ITP) assessments and eight (8) new metrics that have been developed by the MTF.

The MTF also recommends that experiences in the application of these metrics, developments in market design, improvements in modeling tools, and increases in data availability be evaluated to ensure that these benefits are appropriately measured and quantified with a sufficient level of precision in the future.

<u>Traditional ITP metrics:</u>

- Adjusted Production Cost (APC)
- Reduced capacity expansion costs due to reduced transmission losses on peak
- Avoided or delayed reliability projects
- Reduction of emission rates and values
- Savings due to lower ancillary service needs and ancillary service production costs

<u>Newly developed metrics:</u>

- Marginal energy losses benefits
- Mitigation of transmission outage costs
- Capital savings due to reduction of minimum required capacity margin
- Reduced Loss of Load Probability (LOLP)
- Reducing the cost of extreme events
- Assumed benefit of mandated reliability projects
- Increased wheeling through and out revenues
- Benefit from meeting public policy goals

This report provides definitions, examples, data sources, and commentary on each of the newly developed metrics to ensure open and transparent communication of each metric's purpose and the elimination of any "double-counting" that might occur when calculating the benefit of transmission project(s) or portfolio(s).

The last section of this report is dedicated to metrics identified by the MTF but not recommended for use at this time:

- Increased competition and liquidity
- Unhedged zonal congestion benefits (due to limited zone-internal ARRs)
- Benefit of additional ARR availability to hedge imports from other zones
- Reduced cycling of base load units
- Value gap of transactions between SPP zones
- Mitigation of weather & load uncertainty
- Mitigation of renewables-uncertainty costs
- Economic benefit from cost-effective location of renewable resource to meet renewable energy targets
- Cost impact of emission savings, etc.

Section 1. Introduction

In January 2012, the RARTF Report made several recommendations with respect to SPP's approach to reviewing the Highway/Byway transmission cost allocation methodology. One of the recommendations stated:

> Through the work of the Economic Studies Working Group (ESWG) certain benefits be measured in the review. These benefits include: adjusted production costs; positive impact on capacity required for losses; improvements in reliability; remedy benefits in future reviews; reduction of emission rates and values; reduced operating reserves benefits; improvements to import/export limits; and public policy benefits.[1]

On February 9, 2012, the ESWG, under the direction of the Markets and Operations Policy Committee (MOPC), initiated the MTF with the specific purpose of developing tangible dollar-oriented measures and metrics for use in the economic evaluations identified by the RARTF Report.

1.1. RARTF Recommended Benefits

The RARTF Report provided an overview of SPP's research into various transmission cost allocation methodologies, as well as a broad range of approaches to measuring the benefits of transmission line projects. The RARTF iterated its belief that "to provide for a reasonable, fair, and acceptable review of the Highway/Byway, numerous methods should be used in this review as opposed to a single narrowly- focused method."[2] To establish a context for its recommendations, the RARTF included a descriptive list of a number of benefits that could be measured.[3]

In its report, the RARTF recommended the following eight (8) benefits be used in the Regional Cost Allocation Review:

- APC Benefits
- Positive Impact on Capacity Required for Losses
- Improvements in Reliability
- Remedy Benefits
- Reduction of Emission Rates and Values
- Reduced Operating Reserves Benefits
- Improvements to Import/Export Limits
- Public Policy Benefits

The RARTF Report further recommended the development of specific metrics that quantify the benefits in dollars by the ESWG. Additionally, the RARTF Report gave freedom to the ESWG to identify other metrics to be used in the Regional Cost Allocation Review. Each of the benefits listed above is addressed by this report.

[1] SPP Regional Allocation Review Task Force, "Regional Allocation Review Task Force Report," January 2012, p. 1.
[2] Ibid. p. 10.
[3] Ibid. pp. 11-16. The report explained that the inclusion of the detailed list was for "educational purposes" and that not all of the listed benefits should be used for the Regional Cost Allocation Review (RARTF Report, p.11).

1.2. Metrics Considered by the MTF

1.2.1. MTF Focus and Recommendations

The MTF considered methods to monetize a number of benefit metrics, but focused on the benefit metrics listed below. Each of these metrics are facets of the benefit types identified by the RARTF and multiple metrics may be categorized under the same type of benefit. This report contains recommendations regarding each of the following metrics:

- Marginal energy losses benefits
- Mitigation of transmission outage impacts
- Capital savings due to reduction of members' Minimum Required Capacity Margin
- Reduced Loss of Load Probability
- Reducing the cost of extreme events
- Assumed benefit of mandated reliability projects
- Savings due to lower ancillary service needs and production costs
- Increase in Available Transfer Capability
- Increased wheeling through and out revenues
- Benefit of meeting public policy goals

1.2.2. Other Benefits:

In addition to the benefits listed in Section 1.2.1, the MTF identified a range of additional benefits that deserve attention in the future, but require further development. These benefits include:

- Increased competition and liquidity.
- Unhedged zonal congestion benefits (due to limited zone-internal Auction Revenue Rights (ARRs))
- Benefit of additional ARR availability to hedge imports from other zones
- Reduced cycling of base load units
- Value gap of transactions between SPP zones
- Mitigation of weather & load uncertainty
- Mitigation of renewables-uncertainty costs
- Economic benefit from cost-effective location of renewable resources to meet renewable energy targets
- Cost impact of emission savings, etc.

While the MTF does not recommend the use of these "other benefits" in the Regional Cost Allocation Review at hand, monetization approaches for each are included for future consideration. The MTF also recommends that the developments in market design, modeling tools, and data availability be tracked to ensure that these benefits are measured and quantified with a sufficient level of precision in the future.

1.3. MTF Membership

SPP membership was represented at the MTF by the following individuals appointed by Alan Myers, Chair of the ESWG:

- Kip Fox, Chair American Electric Power
- Roy Boyer Xcel Energy – Southwestern Public Service Company
- Mike Collins Oklahoma Gas and Electric Company
- Paul Dietz Westar Energy, Inc.
- Tom Hestermann Sunflower Electric Power Corporation
- Greg Sweet The Empire District Electric Company
- Mitch Williams Western Farmers Electric Cooperative

In addition, Johannes Pfeifenberger and Kamen Madjarov of the Brattle Group were involved to give insight, suggest additional metrics and hypothetical examples, and finalize the MTF report.

Section 2. Approach to RARTF Recommendation

2.1. Metric Summary

The MTF approached its task as a brainstorming effort followed by refining the most promising alternatives. Members contributed ideas based on existing metrics from MISO, PJM, NYISO, ERCOT, member companies, and industry experience, as well as new ideas provided by the Brattle Group consultants. During the month of March 2012, the MTF identified 28 different ideas for metrics to be evaluated. After review and debate by the MTF, the list was narrowed down to approximately 13 metrics that would be reviewed, analyzed and further developed in order to provide a meaningful update to the ESWG and MOPC in July of 2012. Metrics that did not make it past the brainstorming phase were eliminated for one or more of the following reasons: the idea was not sufficiently developed to proceed further; there were no tangible dollars associated with the metric; the metric would be difficult, if not impossible, to calculate with current tools; or the metric was essentially a duplicate of an existing metric.

At the conclusion of the effort the MTF identified five (5) metrics that are currently used by SPP in the ITP process, eight (8) new metrics that the MTF recommends be calculated as part of the Regional Cost Allocation Review , and nine (9) other metrics that received significant consideration but have not yet gained enough consensus amongst the MTF or cannot currently be monetized for inclusion in the Regional Cost Allocation Review.

The most important aspect of the metrics to be developed is that the metrics should be able to provide "hard dollar" impacts of transmission to rate payers. In terms of this report, "hard dollar" means that each recommended metric must be able to provide incontrovertible evidence that a benefit will result in lowering of the overall cost to a rate payer. As part of this test, the MTF reviewed the metrics through the open SPP stakeholder meetings, transmission summits, and public postings, provided progress updates to the Cost Allocation Working Group (CAWG) to gather their feedback on the acceptability of the metrics being proposed, and sought feedback from the Chair and Vice-Chair of the original RARTF to reasonably assure that the MTF was addressing the metrics the RARTF recommended in the RARTF Report.

Due to the short amount of time before the Regional Cost Allocation Review will commence, the MTF concentrated on those metrics that could be reasonably implemented for the first Regional Cost Allocation Review. Section 9 of this report identifies additional metrics the Regional Cost Allocation Review team may want to consider especially after the Integrated Marketplace goes live in March of 2014 or in the second Regional Cost Allocation Review.

2.2. How to read this report

As the starting point for the discussions and analyses, the MTF relied on the benefit metrics recommended by the RARTF Report and has structured this report to provide metrics for each of the benefits recommended by the RARTF. Each of these benefits are discussed further in the report in the following sections:

- APC Benefits — Sections 3.1, Section 4, 9.2 through 9.6
- Positive Impact on Capacity Required for Losses — Section 3.2

• Improvements in Reliability	Sections 3.3 and Section 5
• Remedy Benefits[4]	
• Reduction of Emission Rates and Values	Section 3.4
• Reduced Operating Reserves Benefits	Section 6
• Improvements to Import/Export Limits	Section 7
• Public Policy Benefits	Section 8

Table 1 on the following page illustrates the connection between each of the metrics identified by the MTF and those recommended by the RARTF.

[4] Remedy benefits are a consequence of the Regional Cost Allocation Review. Since a review has not yet taken place this remedy is not addressed in this report.

RARTF Benefit	MTF Metric Name	Already Standard ITP Metric	MTF Recommended New Metric	Other Metric (Not Currently Recommended)	MTF Report Section
APC Benefits	Adjusted Production Cost (APC)	✓			3.1
	Marginal Energy Losses Benefits		✓		4.2
	Mitigation of Transmission Outage Costs		✓		4.3
	Unhedged Zonal Congestion Benefits			✓	9.2
	Reduced Cycling of Base Load Units			✓	9.4
	Value Gap of Transactions between SPP Zones			✓	9.5
	Mitigation of Weather & Uncertainty			✓	9.6
	Mitigation of Renewables Uncertainty Costs			✓	9.7
Positive Impact on Capacity Required For Losses	Reduced Capacity Expansion Costs Due to Reduced Transmission Losses on Peak	✓			3.2
Improvements in Reliability	Avoided or Delayed Reliability Projects	✓			3.3
	Capital Savings Due to Reduction of Members' Minimum Required Capacity Margin		✓		5.1
	Reduced Loss of Load Probability		✓		5.2
	Reducing the Cost of Extreme Events		✓		5.3
	Assumed Benefit of Mandated Reliability Projects		✓		5.4
Reduction of Emission Rates and Values	Reduction of Emission Rates and Values	✓			3.4

RARTF Benefit	MTF Metric Name	Already Standard ITP Metric	MTF Recommended New Metric	Other Metric (Not Currently Recommended)	MTF Report Section
Reduced Operating Reserves Benefits	Savings Due to Lower Ancillary Service Needs and Ancillary Service Production Costs	✓[5]			6.1
Improvements to Import/Export Limits	Increased wheeling through and out revenues		✓		7.2
	Benefit of Additional ARR Availability to Hedge Imports from Other Zones			✓	9.3
Public Policy Benefits	Benefit from Meeting Public Policy Goals		✓		8.1
	Economic benefit from cost-effective location of renewable resource to meet renewable energy targets			✓	9.8
Other	Increased Competition and Liquidity			✓	9.1

Table 1: Summary of Benefits & Metrics

[5] This metric has been previously monetized by the ESWG but the MTF provides recommendations for its improvement.

Section 3. Benefits Already Monetized through Metrics Specified in the ITP Process

The MTF observed that some of the RARTF recommended metrics are captured in the SPP Metrics Manual. As part of the SPP ITP process, the existing calculation of the monetized benefits included four key aspects: 1) calculated APC; 2) reduced capacity expansion costs due to reduced transmission losses on peak; 3) Avoided or delayed reliability projects; and 4) reduced emissions rates and values. This section recaps the monetization of those benefits.

3.1. Calculated APC

The standard APC metric currently used by SPP is a measure of the impact on production cost savings by considering Locational Marginal Price (LMP) for purchases and sales of energy between each area of the transmission grid. APC for an area (e.g., a utility) is determined using a production cost modeling tool that accounts for hourly commitment and dispatch profiles for one simulation year. The calculation, performed on an hourly basis, accounts for:

Production costs:	The fuel and non-fuel variable O&M costs of utility-owned or cost-of service-contracted generation.
Revenue from Sales:	MW Sold by Utility × Generation-Weighted Avg. Zonal Gen. LMP
Cost of Purchases:	MW Purchased by Utility × Load-Weighted Avg. Zonal Load LMP

This APC metric quantifies the monetary cost associated with fuel costs, generation dispatch, most grid congestion, energy purchases, energy sales, and other factors that directly relate to energy production by generating resources in the SPP footprint.

The APC calculation also captures the cost savings associated with reduced SO_2, NO_X, and CO_2[6] emissions by considering allowance prices for these pollutants. The quantified changes in SO_2, NO_X, and CO_2 emissions can be reported within the APC results in order to provide further insight into system expectations. (This emissions cost portion of the calculations is discussed further in Section 3.4).

APC estimates are usually performed for weather-normalized peak load (i.e., 50/50 peak load). In addition to hourly loads, they also include a pre-specified quantity of ancillary service requirements. Thus, to the extent the specific production cost software reasonably captures ancillary service costs, reductions in the cost of supplying ancillary service requirements are also captured in the standard APC metric for the simulated system conditions.

The APC metric as currently applied also has certain limitations, as discussed further in Section 4.1. This means that certain transmission-related benefits not captured in the standard APC metric can be quantified separately as discussed in Section 5 and 9.2 through 9.6.

[6] It should be noted that, to date, most Business as Usual scenarios using production cost simulations have not included a pricing mechanism for CO_2.

3.2. Reduced capacity expansion costs due to reduced transmission losses on peak

Reduced capacity expansion costs due to transmission losses on peak captures the value for the generation capacity that may no longer be required due to a reduction in losses during the system peak. This value can be monetized using the savings in capital attributed to the corresponding reduction in installed capacity requirements. These capital savings can be calculated by applying the estimated net cost of new entry ("Net CONE" as discussed in Section 5.1.4) to the reduction in installed capacity requirements.

3.3. Avoided or delayed reliability projects

Potential reliability upgrades are reviewed to determine if an upgrade with a greater economic or policy benefit could defer or replace an identified reliability solution. If such a larger project with economic or public policy benefits is pursued, the costs associated with the reliability projects that are replaced by the larger project represent the avoided or delayed reliability project benefit of the larger project.

The methodology by which reliability projects were replaced with economic projects follows these steps:

1. Reliability need identified.
2. Reliability mitigation provided and tested to ensure successful mitigation.
3. Congestion in the system identified.
4. Congestion near and related to reliability needs paired to compare alternative projects.
5. The value of resolving the congestion with an economic project that also mitigated the reliability need is measured and compared with the difference in costs between the projects.
6. Where cost-effective, the economic project was selected to mitigate the reliability need and relieve the congestion.

This benefit monetizes the reliability benefit as the avoided cost (or additional cost) of delaying or canceling (or accelerating) previously approved reliability projects.

The benefit should be allocated in accordance with the ratios of the allocation that would have been applied for the costs of the reliability project.

3.4. Reduced emission rates and values

As recommended in the RARTF Report, the benefit of reduced emission rates and values is already included in the APC benefit as previously noted in Section 3.1. The APC calculation captures the cost savings associated with reduced SO_2, NO_X, and CO_2 emissions, as scoped for each particular economic study, through the assumed allowance price for these emissions. The allowance prices are used as inputs to the production cost model simulations and are specific to the various generating technologies modeled.

The allowance market dynamics that take place separately from events in the energy market are not considered in this metric. Rather, a simplified approach that assumes allowances are sold and purchased at known market clearing price is applied and these allowance prices are included in the calculation of marginal production costs.

Section 4. APC Benefits Metrics

4.1. Limitations of the standard APC benefit

In the context of the discussion of the standard APC metric in Section 3.1, it is important to understand the limitations of this metric as it has been used in the ITP process. In particular, there are some production cost related savings that are not captured in the standard APC metric. This is because the standard APC results are typically based on production cost simulations for a base case and a change case that include a number of simplified assumptions, including:

- The simulations assume that the system experiences only weather-normalized peak load and energy conditions, thereby ignoring load variances during hotter or colder than normal weather conditions.
- The simulations assume that transmission facilities are available 100% of the time, thereby ignoring any maintenance and forced outages of transmission facilities
- The simulations assume that the MWh quantity of losses is fixed and does not change with transmission additions, thereby ignoring that transmission expansion may reduce the MWh quantity of losses that need to be supplied
- The simulations do not consider the likelihood of extreme events, such as infrequent, but possible, multiple major generation and transmission outages.
- The simulations tend to assume that hourly wind generation is perfectly known when generation units are committed for the next day, thereby ignoring the fact that the hourly level of wind generation is uncertain.
- The calculation of APC is based on a number of simplifying assumptions regarding the extent to which congestion costs can be hedged through ARRs in a day 2 market environment. For example, it assumes congestion between owned generations and load can be fully hedged while none of market-based purchases would be hedged.

However, as discussed further below, transmission-related benefits not captured in the standard APC metric due to these simplified assumptions can be identified and monetized through benefit metrics based on conducting additional analyses, such as the following:

- *Mitigation of Transmission Outage Costs*: While the standard APC metric does not capture production cost savings of new transmission during outages of other transmission lines, transmission outages can be simulated. Additional savings are generally realized due to expanded transmission capabilities during transmission outage events. This additional benefit metric is discussed in detail in Section 4.3.
- *Reducing the Cost of Extreme Events:* While the standard APC metric does not reflect the benefit of transmission expansion during extreme events, additional simulations of multiple generation or transmission outages can be used to quantify the additional benefit. The MTF classified this benefit under the category of reliability benefits, although it is monetized through production cost simulations. A detailed discussion of this metric is provided in Section 5.3.
- *Marginal Energy Losses Benefits:* While standard production cost simulations do not reflect that transmission expansion may reduce the MWh quantity of transmission losses, energy savings associated with this loss reduction can be estimated as a separate metric as discussed

in Section 4.2. (Reduced capacity expansion costs due to reduced transmission losses on peak are already monetized through an existing ITP metric as discussed in Section 3.2)

- *Unhedged Zonal Congestion Benefits.* The APC metric assumes that all congestion between a utility's owned (or cost-of-service based) generation and its load are fully hedged through an allocation of ARRs. If only a portion of these generation-to-load transactions can be hedged through an allocation of ARRs, the relief of generation-to-load congestion within a zone will provide additional benefits that can be quantified easily. This metric has been recognized as deserving further attention by the MTF as discussed in Section 9.2. However, given that SPP does not yet operate a day 2 market, the MTF does not recommend adding this benefit metric at this point.
- *Limited ARR Availability*. The APC metric values market-based purchases (e.g., imports) by each zone's at the zone's internal load LMP. This ignores the fact that even market-based purchases and imports may be from a new network resource for which the zone may be able to obtain ARRs. New transmission facilities may increase ARR availability and thus reduce the congestion exposure of the load-serving entity as discussed further in Section 9.3. However, given that SPP does not yet operate a day 2 market, the MTF does not recommend adding this benefit metric at this point.
- *Weather/Load Uncertainty*. The standard APC metric is calculated based on the load profile of a year that is scaled to reflect weather-normalized peak loads and energy consumption. However, the incremental value of transmission expansions during heat waves (e.g., under 90/10 peak load conditions) or geographically-diverse weather patterns (such as a hot southern and a cool northern portion of the service area), can be estimated with additional production cost simulations that reflect such load conditions. This is discussed in more detail in Section 9.6. The MTF has not been able to develop a sufficiently detailed proposal to include this metric at this point, but recommends that efforts to develop this metric continue.
- *Value Gap of Transactions between SPP zones*. Another drawback of the standard APC methodology is that market-based imports into a zone are priced at the zone-internal load LMP value, while market-based exports are valued at the zone-internal generation LMP. This leaves out any benefits (or costs) associated with the difference between the lower generation LMP of the exporting zone and the higher load LMP of the importing zone. For example, it would not capture the fact that an importing zone may be able to purchase power at the generation cost of the exporting zone (and obtain ARRs to hedge the congestion differentials). A simplified option to overcome this shortcoming is discussed in Section 9.5. However, because in a day 2 market this "value gap" depends in part on the treatment of ARRs and marginal loss refunds, the MTF recommends that this issue be explored in the future in combination with unhedged congestions and ARR availability metrics (Sections 9.2 and 9.3).

4.2. Marginal energy losses benefits

Standard production cost simulations used to estimate APC do not reflect that transmission expansions may reduce the MWh quantity of transmission losses. To simplify simulations and make run-times of the simulations manageable, load is "grossed up" for average transmission losses. The simulations then assume that the MWh quantity of losses is fixed and does not change with transmission additions. As noted above, this does not capture that transmission expansion may reduce the MWh quantity of losses that need to be supplied. However, the production cost savings due to such energy loss reductions can be estimated through post-processing simulation results. This energy cost benefit of reduced losses can be approximated as follows:

(1) Estimate the difference in energy cost of transmission losses within each zone for the base and change case as:

Energy loss cost = Generation MWh x (MLC_{load}-MLC_{gen}) x 1/2

In other words, use the production cost simulations' estimate of the Marginal Loss Component (MLC), calculate the weighted average MLC for generation and load nodes within each zone, and take into account that average losses are half the marginal losses between a zone's generation and load. This $/MWh value of energy loss costs is then applied to all MWh generated in each zone.

(2) Subtract the portion of loss-related energy cost benefit already captured in the standard APC metric (i.e., reductions in the cost of supplying the assumed level of transmission losses by which load has been grossed up for both the base and change case) to avoid double counting.

Energy loss cost captured in APC = (MWh of losses by which load has been grossed up)
x (average production cost of supplying these losses)

The $/MWh average hourly cost of supplying the fixed hourly losses already reflected in the standard APC metric can be estimated as the average zonal production costs for that hour.

4.2.1. Example

Actual load: 100 MW
Total transmission losses: 10 MW
Grossed-up load: 110 MW

BASE CASE (Production Cost Simulations)

Transmission
Gen ---------------------------> ***Load***
110 MW 110 MW
$50/MWh

Total Production Cost: $50/MWh x 110 MWh = $5500
Total cost of supplying losses: $50/MWh x 10 MWh = $500

CHANGE CASE (Production Cost Simulations)

Transmission
Gen =====================> ***Load***
110 MW 110 MW
$45/MWh

Total Production Cost: $45/MWh x 110 MWh = $4950
Total cost of supplying losses: $45/MWh x 10 MWh = $450
Simulated loss-related energy cost savings: $500-$450 = $50

BASE CASE (Actual)

Transmission
Gen ----------------------> ***Load***
110 MW 10 MW 100 MW
$50/MWh

Total Production Cost: $50/MWh x 110 MWh = $5500
Total cost of supplying losses: $50/MWh x 10 MWh = $500

CHANGE CASE (Actual)

Transmission
Gen =====================> ***Load***
105 MW 5 MW 100 MW
$45/MWh

Total Production Cost: $45/MWh x 105 MWh = $4725
Total cost of supplying losses: $45/MWh x 5 MWh = $225
Actual loss-related energy cost savings: $500-$225 = $275
Loss-related energy cost savings not captured in simulations: $275-$50 = $225

<u>Calculating Energy Loss Costs from Marginal Loss Revenues</u>

BASE CASE (Production Cost Simulations)

Marginal loss factor (marginal losses/load) = 0.2 (determined in simulation software based on line resistance data)

Marginal loss revenues = marginal loss factor x generation costs x load = 0.2x$50x100 = $1000
(determined directly by production cost simulation software)

Total loss cost = marginal loss revenues / 2 = $500

CHANGE CASE (Production Cost Simulations)

Marginal loss factor (marginal losses/load) = 0.1 (determined in simulation software based on line resistance data)

Marginal loss revenues = marginal loss factor x generation costs x load = 0.1x$45x100 = $450 (determined directly by production cost simulation software)

Total loss cost = marginal loss revenues / 2 = $225

Actual loss-related energy cost savings: $500-$225 = $275
Loss-related energy cost savings already captured in APC: $50 (from above)
Loss-related energy cost savings not captured in simulations: $275-$50 = $225

4.3. Mitigation of transmission outage costs

4.3.1. Definition

Standard production cost simulations assume that transmission lines and facilities are available during all hours of the year and that no planned or unexpected outages of transmission facilities will occur. In practice, however, planned and unexpected transmission outages impose non-trivial additional congestion costs on the system. Thus, the benefit of reducing this additional congestion is not captured in the standard APC metric. The availability of new transmission projects decreases congestion and increases the operational flexibility of the system to mitigate the impacts of transmission outages.

4.3.2. How to measure

To measure the savings due to transmission expansion during the outage of other transmission facilities, the production cost modeling analysis has to be augmented for a realistic level of transmission outages. There are two approaches that could be used to reflect transmission facilities outages in the production cost simulations:

1. A data set of normalized transmission outage schedules could be built and then introduced into the production cost simulations for both the base and change cases.
2. The constraint limits used in the production cost simulations could be reduced by a certain percentage in order to account for the forced and planned outage rate of the transmission facilities.[7]

The APC savings for the simulations reflecting transmission outages can then be compared to the APC savings for the standard simulations that do not reflect transmission outages. The cost mitigation benefit of transmission upgrades during transmission outages is the difference between

[7] This is not the preferred approach of the MTF since production cost simulations typically monitor only a select number of constraints the calculation of the reduction in rating will require the a recognition of the aggregate impact on constraints that are monitored. Transmission elements in series with individual outage probabilities must be considered in the use of the limited constraints. A production cost simulation with the actual outage patterns from a recent year (or a few years) is much easier.

the APC savings reflecting transmission outages and the APC savings without reflecting transmission outages.

4.3.3. How to monetize

This benefit metric is captured in the APC results from the augmented production cost modeling simulations, which are conducted as described above. Simply put, the benefits are measured by taking the difference between 1) the APC savings due to the transmission upgrades for a system considering transmission outages and 2) the standard APC savings due to the transmission upgrades which are calculated for a system without any transmission outages.

4.3.4. How is this benefit allocated to zones?

Because it is difficult to develop normalized transmission outage data that reliably reflects the outages that could affect each load zone, the MTF recommends that this benefit be calculated on an SPP-wide basis and allocated to zones based on a load ratio share. As more experience is gained with this metric, the calculation of the benefit could potentially be directly done on a zonal basis.

4.3.5. Where to get source data

The data set of normalized routine transmission outages can be compiled via an iterative process. As a starting point, historical data sets of transmission outages for several typical years (e.g., without any major storm outages) should be assembled. Then, the list can be normalized by combining information from several years supplemented by quantitative and qualitative inputs from MTF members and interested stakeholders.

The list of outages will exclude those from major storm events, but will include historical planned outages and a normal level of non-major forced outages. As a guideline, the included non-major forced outages must be at least those single-line outages or single transformer outages that are not included in the extreme events benefit metric analysis discussed in Section 5.3. Alternatively, the constraint limits would be modified to reflect the percentage of the original limit given by the transmission element's forced outage rate.

To enable the quantification of benefits under this section, the metric requires assistance from the Operational Reliability Working Group (ORWG) and the Transmission Working Group (TWG) in the compilation of a transmission outages dataset that is representative of transmission outages that member companies expect during typical operation of the grid (this set should exclude extreme events as defined in Section 5.3). This dataset would reflect the outage duration and time of year for planned outages. The transmission outage model should avoid bias towards one zone or another.[8]

4.3.6. Example

This calculation requires two simulations of the system's APC savings. The additional savings would be calculated by taking the difference between 1) the APC savings due to the transmission upgrades for a system considering transmission outages and 2) the standard APC savings due to the transmission upgrades which are calculated for a system without any transmission outages.

[8] In determining the final outage data set, the MTF believes it to be helpful if the outage data is reviewed by service area, by time, and by type in order to accommodate stakeholder consensus on the inputs used to calculate this metric.

1. Calculate base-case (without the transmission upgrades) SPP-wide APC savings (S_B) with simulations using the transmission outage dataset
2. Calculate change-case (with the transmission upgrades) SPP-wide APC savings (S_C) with simulations using the transmission outage dataset
3. Calculate the monetized SPP-wide benefit of mitigating transmission outage costs as the difference in APC savings considering transmission outages ($S_B - S_C$) and the standard APC savings calculated without considering transmission outages:

   $S_M = (S_B - S_C)$ less standard APC savings
4. For simplicity, assume there are three zones with corresponding load ratio shares:

   Z_1 (load ratio share = 30%)

   Z_2 (load ratio share = 60%)

   Z_3 (load ratio share = 10%)
5. Allocate the SPP-wide transmission outage cost benefit as follows:
   a. Z_1 benefit=30% × S_M
   b. Z_2 benefit=60% × S_M
   c. Z_3 benefit=10% × S_M

4.3.7. Recommendation

The MTF recommends that the transmission outage saving calculation is undertaken on a footprint basis and allocated by load ratio share to each zone. The MTF also recommends that the ORWG and TWG should determine the outage model to be used in the APC calculation representing a typical outage year.

Section 5. Reliability Benefits Metrics

The first two metrics discussed in Sections 5.1 and 5.2 are based on results and findings derived from loss-of-load probability analyses. The MTF proposes that for forward-looking benefit calculations, benefits under Section 5.1 be calculated only if there is either an actual change in the Minimum Required Capacity Margin or, alternatively, an explicit commitment on the part of SPP to reduce the Minimum Required Capacity Margin in a specific future year.

The assumed benefit of the mandated reliability projects metric described in Section 5.4 can be considered as the "default" reliability project metric. If a benefit is assigned to a project due to either of the metrics discussed in Sections 5.1 or 5.2, the assumed benefit as described in Section 5.4 should not be utilized. However, reducing the cost of extreme events as described in Section 5.3 represents the economic impact of the reliability benefit and is always additive to any of the other reliability metrics described within this section.

5.1. Capital savings due to reduction of minimum required capacity margin

5.1.1. Definition

According to SPP Criteria 2.1.9, each Load Serving Member's Minimum Required Capacity Margin shall be 12 percent. If a Load Serving Member's System Capacity for a Capacity Year is comprised of at least 75 percent hydro-based generation, then such Load Serving Member's Minimum Required Capacity Margin for that Capacity Year shall be nine percent. Reductions to the 12 percent requirement as a consequence of transmission expansion can be quantified as a transmission expansion benefit. In the event that SPP officially reduces the capacity reserve requirements (or officially commits to do so in a future year) due to the improved strength of the transmission system, the calculation for the hard dollar impact will be calculated as described below.

5.1.2. How to measure

Capital savings due to reduction of members' minimum required capacity margin due to transmission investments will be calculated as the MW difference between the capacity mandated under the initial Minimum Required Capacity Margin (in the absence of the new transmission project(s)) and the new (reduced) Minimum Required Capacity Margin.

A reduction to Minimum Required Capacity Margin due to transmission investments (e.g., as the result of increased intertie capacity with neighboring regions) will be identified by the ORWG and/or TWG and the SPP Criteria will be changed.

5.1.3. How to monetize

The MW value of Reduced Capacity Reserve requirement will be multiplied by the Net Cost of New Entry (Net CONE), assuming the new unit is a combustion turbine.

5.1.4. Where to get source data

Net CONE is the difference between the annualized cost of new entry (CONE) and the expected annual energy and ancillary service profits a unit of this type is expected to earn in the energy and ancillary service markets. The CONE value can be obtained by levelizing investment costs and fixed operating costs of a combustion turbine as reported in the latest version of the Department of Energy

Annual Energy Outlook report or another comparable public source. The following sources may be used to estimate the average annual energy and ancillary service profits for a combustion turbine:

- Historical market revenues net of fuel and variable non-fuel operating costs for combustion turbines in SPP or similar market(s)
- Revenues net of fuel and variable non-fuel operating costs for combustion turbines obtained from production cost simulations of the SPP or similar market(s)

Net CONE is then calculated as the difference between CONE and the estimated energy and ancillary service profits.

5.1.5. Example

If between the 2013 and 2016 Regional Cost Allocation Reviews, the capacity margin were reduced to 10% from a previous level of 12.3%, due to the addition of specific transmission projects, the dollar benefits would be calculated as follows:

> Zone 1 capacity requirement before was 200 MW; new requirement is 195 MW. Assuming a hypothetical Net CONE of \$100/kW-yr, the savings to Zone 1 would be: 5 MW × \$100/kW-yr × 1000kW/MW = \$500,000/yr.

This type of calculation would be done for each zone. The benefit would be attributed to the projects that precipitated the reduction in capacity margin. The benefit would apply in years where the forecasted capacity reserve margin is exceeded.

Whether that \$500,000 is a continual benefit for future Regional Cost Allocation Review analysis is the decision of those performing/approving the Regional Cost Allocation Review analysis.

5.1.6. Overlap with the Reduced Loss of Load Probability (LOLP) Metric

If between the 2013 and 2016 Regional Cost Allocation Reviews (or other future Regional Cost Allocation Reviews), the capacity margin in SPP is not reviewed and reduced, there would be no quantifiable benefit based on the Reduction of Members' Minimum Required Capacity Margin. However, the addition of transmission projects which would allow for a reduction in required capacity margins (if studied and updated) will nevertheless result in a reliability benefit by decreasing the likelihood that load will have to be shed during system emergencies. The reduction of load shed probabilities is directly captured by the Reduced LOLP metric discussed in Section 5.2.

Therefore, the two metrics are not additive. If the minimum required capacity margin is reduced, the system will have to hold a lesser amount of capacity reserves, which will translate into dollar savings. The LOLP, however, will remain unchanged since capacity reserves would be reduced to maintain the LOLP at the target level. Adding new transmission allows the system to maintain the LOLP reliability criteria with lower capacity reserve levels. On the other hand, if the mandated minimum required capacity margin is not reduced, the benefit of new transmission facilities will be captured through the Reduced LOLP metric—instead of savings realized from lower levels of capacity reserves, the benefit will be realized through improved reliability and be monetized through the reduction in the quantity and cost of unserved energy during loss of load events. This latter metric is discussed in detail next.

5.1.7. Recommendation

The MTF recommends that the ORWG and/or TWG specify the frequency and method by which the Minimum Required Capacity Margin will be revisited. The frequency of the calculation should be coordinated with the RARTF to ensure that the needs of the Regional Cost Allocation Review are met. The method should consider the effect of certain transmission upgrades in order to determine if the upgrades were responsible for the reduction in the requirement.

The MTF recommends that the ESWG set the value of the Net CONE for the Regional Cost Allocation Review and that the value be revisited every three years.

5.2. Reduced LOLP

5.2.1. Definition

Planned maintenance and unexpected outages can affect the ability of generation to reliably serve load. The system's ability to connect generation and load in a manner that ensures reliable service will increase with transmission expansion. The Reduced LOLP metric quantifies the incremental increase in system reliability as measured by the LOLH index, which translates into reduction in expected unserved energy, which is expressed in MWhs of lost load.

5.2.2. How to measure & monetize

System reliability studies generally rely on a Monte Carlo simulation framework to obtain a number of LOLP-related reliability measures such as Loss of Load Hours (LOLH), Loss of Load Expectation (LOLE), and Expected Unserved Energy (EUE). LOLH measures the expected number of hours in which load shedding will occur. LOLE is a metric that accounts for the expected number of days, hours, or events during which load needs to be shed due to generation shortages. EUE is calculated as the probability-weighted MWh that would be unserved during loss of load events.

To monetize the benefits under the Reduced LOLP metric, the MTF recommends that an estimate of the system-wide Value of Lost Load (VOLL) is applied to EUE. VOLL, measured in $/MWh of lost load, is the value assigned by various customer types to each MWh of unserved load. For example, a commercial customer might value lost load at $10,000/MWh while residential customers may have a VOLL of only $3,000/MWh. VOLL data are available from a number of publicly available studies. Conservative estimates for each of three principal customer classes—residential, commercial, and industrial—can be obtained from these studies. The MTF recommends relying upon a load-weighted SPP-wide average of residential, commercial, and industrial VOLL in the calculation of the monetary value of transmission-related reductions in EUE.[9]

As discussed in Section 5.1, caution should be applied in quantifying the system reliability benefits of new transmission projects. Due to the overlap between the benefit obtained from reduction in minimum capacity margin requirements and the benefit associated with the Reduced LOLP metric, double-counting of benefits needs to be avoided. Annual benefits should be monetized via a reduction in the minimum capacity requirement after such a reduction takes place. Prior to that, the benefits should be quantified through as a reliability benefit of a reduction in EUE.

Studies to determine Reduced LOLP metric in the following way:

1. Determine the reduction in the MWh of Expected Unserved Energy (EUE) between the base case and the change case;

[9] In selecting the VOLL estimates for each customer class, the MTF can utilize study estimates from the lower range of possible values to arrive at conservative assumptions or lower end of the band-width values.

2. Obtain the VOLL from existing literature and studies as the weighted average of VOLL estimates for different customer classes
3. Calculate the monetary benefit=EUE(MWh) *$VOLL_{SYSTEM\ WEIGHTED\ AVERAGE}$ ($/MWh)

5.2.3. Limitations in Reliability Simulations Tools

LOLE software modeling tools may be based on multi-area representation of the footprint with transmission limits (availability transfer capability) between control areas rather than reflecting the transmission topology within the SPP region. From an analytical perspective, the capture of benefits depends on the type of reliability modeling tool being used:

- If the reliability analysis tool models multiple zones within the system's footprint and recognizes major transmission links between zones, the LOLP benefit of these links can be captured on a zonal level and, thus, can be allocated to each zone. Furthermore, if the modeling tool represents the transmission topology in even greater detail, then the LOLP benefit of increased transmission capability can be captured fully.
- If the reliability modeling tool represents the footprint as a bubble surrounded by neighboring areas, then the internal transmission topology will not be modeled and, as a result, only the LOLP reliability benefit of increased transmission interties with neighboring regions would be captured. The LOLP benefit of additional internal transmission links will not be captured.

5.2.4. How is this benefit allocated to the zones?

Neither the LOLE nor EUE will be calculated specifically for each zone, but for the SPP footprint as a whole. Total monetized reliability benefit for the SPP footprint will be allocated to zones on a load ratio share basis.

5.2.5. Example

Consider the following hypothetical example:

a. The reliability analysis determines that the reduction of EUE between the base case (without the project(s)) and the change case (including the project(s)) is 1,000 MWh per year.
b. A survey of publicly-available studies yields the following conservative estimates of VOLL for each customer class:
   i. Industrial customers: $VOLL_{INDUSTRIAL}$=$10,000/MWh
   ii. Commercial customers: $VOLL_{COMMERCIAL}$=$7,000/MWh
   iii. Residential customers: $VOLL_{RESIDENTIAL}$=$3,000/MWh
c. The share of system load for each customer class is as follows:
   i. LOAD $SHARE_{INDUSTRIAL}$=50%
   ii. LOAD $SHARE_{COMMERCIAL}$=30%
   iii. LOAD $SHARE_{RESIDENTIAL}$=20%
d. As a result, the load-share-weighted system VOLL is:

$$
\begin{aligned}
VOLL_{SYSTEM\ WEIGHTED\ AVERAGE} = & (LOAD\ SHARE_{INDUSTRIAL} \times VOLL_{INDUSTRIAL}) + \\
& + (LOAD\ SHARE_{INDUSTRIAL} \times VOLL_{INDUSTRIAL}) + \\
& + (LOAD\ SHARE_{INDUSTRIAL} \times VOLL_{INDUSTRIAL})
\end{aligned}
$$

$VOLL_{SYSTEM\ WEIGHTED\ AVERAGE}$ = (50%) × ($10,000/MWh) + (30%) × ($7,000/MWh) +

+ (20%) × ($3,000/MWh) = $7,700/MWh

e. Calculate the monetized benefit:

Annual Benefit = REDUCTION IN EUE × $VOLL_{SYSTEM\ WEIGHTED\ AVERAGE}$ = 1,000 MWh × $7,700/MWh =$7,700,000 per year

5.2.6. Recommendation

The MTF recommends that the following rule applies: If there is an actual or proposed change in the Load Serving Member's minimum required capacity margin[10] then the metric from Section 5.1 will be used. During years where there is excess capacity available in the LSE, the metric from Section 5.2 should be used. If SPP has not authorized a change to this requirement, then metric from Section 5.2 is used.

5.3. Reducing the cost of extreme events

5.3.1. Definition

Extreme Events (e.g. severe weather, natural catastrophes, sabotage, regulatory restrictions, and similar events) can result in significant restrictions to the power system or result in simultaneous outages of several power system elements (generation or transmission facilities) that disrupt the regional energy supply. As a result, spikes in energy supply costs, disruption of service, and other adverse events will materialize. The transmission system's ability to reduce the effect of such events upon the cost to supply energy (e.g., through high-cost emergency imports, lengthy outages, negative regional economic impacts) will tend to increase with transmission expansion.

5.3.2. How to measure & monetize

The impacts from extreme events fall in two general categories:

1. *Reliability Impacts*: additional transmission capacity will help reduce the number of expected loss of load events caused by extreme events. If the extreme events are captured in the probabilistic reliability analyses, the resulting savings will be captured and monetized in the Reduced LOLP metric discussed earlier in Section 5.2. If the probabilistic analyses utilized to derive the Reduced LOLP metric do not adequately capture extreme events and their likelihoods, the analyses should be improved and augmented to reflect the likelihood of such events.
2. *Adjusted Production Cost Impacts:* additional transmission capacity will assist system operators with the mitigation of production cost impacts from extreme events. The resulting savings can be measured and monetized as the incremental APC savings obtained from production cost modeling analysis of selected extreme event scenarios by comparing APC savings from simulations of extreme events with and without the transmission upgrade to the APC savings (for the same period of time) from the standard base and change case simulations without the extreme event. This methodology is analogous to the approach estimating the mitigation of transmission outage related costs previously discussed in Section 5.3.

[10] Or, alternatively, if there is a firm commitment by SPP to change the minimum requirement in the future.

5.3.3. Where to get source data

Specification of extreme events, such as the simultaneous outage of multiple large generation units or storm related major transmission outages, and their probability of occurring in any particular year should be determined by the appropriate working group (TWG or ORWG) based on examples of historical events and approved by the working group. Specifically, the group should define what an extreme event is, how often it occurs, and its duration.

5.3.4. How is this measure conservative?

The specification of catastrophic events will be tempered by simulating the contemporary or future cost impact of historical events witnessed in the region. The analysis should focus on identifying between two and five examples of extreme events and their corresponding probabilities of occurrence. The probability of the events will be no more than once in five years; events that occur more often would be included in the metric discussion in Section 4.3. The potential reduction in insurance premiums paid by utilities for protection from catastrophic events will be ignored. However, the savings estimated in this analysis can be used as an approximation of the avoided insurance premium costs.

5.3.5. Example

- *Reliability Impacts*: Savings related to reliability impacts will be monetized as described in Section 5.2. Often when a catastrophic event occurs, load cannot be served, and generation is often shut down because there is no load to serve. This calculation will capture this part of the benefit due to the transmission.
- *Production Cost Impacts*: Saving related to production cost impacts will be captured in the same way as the transmission outage benefit metric discussed in Section 4.3. Correlation of this production cost with the loss of load noted above should be made in order to account for the reduction in production costs due to the reduction in load.

5.3.6. How is this benefit allocated to the zones?

Zonal production costs are highly sensitivity to the selection of the specific extreme event. Consequently, the MTF recommends that the benefit be assessed on an SPP-wide regional basis and then allocated to each zone based upon the load ratio share until zones that have excessive outages over time are identified and adjustments to the load ratio share methodology are reviewed.

5.4. Assumed benefit of mandated reliability projects

5.4.1. Benefits Equal to Costs for Mandated Reliability Projects

If part of the portfolio of transmission projects evaluated would to be built to meet transmission reliability standards (i.e. classified as "reliability project" by the ITP Manual), then the starting point in evaluating the benefit of such reliability project portion of the evaluated portfolio would be to assume its benefit-to-cost (B/C) ratio is at least 1.0. In other words, the benefit of fixing the reliability violation through the reliability portion of the evaluated portfolio should be assumed to be equal to its cost. This benefit would only be considered for projects that received NTCs under the category of "regional reliability" and will be mutually exclusive from any other reliability benefit applied to those same projects.

5.4.2. Allocation of Benefits Equal to Costs

All mandatory reliability projects have a SPP Regional State Committee and FERC-approved cost allocation that includes both a region wide and zonal component. These cost allocations are used to allocate the costs and therefore should be used to allocate the benefits set equal to the costs.

5.4.3. Inclusion of Other Economic Benefits

Treating benefits for mandated reliability projects equal to their costs avoids potential undervaluing of the portfolio value of reliability projects which are mandated and thus not justified solely by other economic benefits. The question then becomes: "how should the other economic (non-reliability) benefit metrics that might be associated with mandated reliability projects be treated?"

The most straightforward approach is to treat other economic benefits, such as APC savings, that might occur from the inclusion of the mandated reliability projects in the change case as additive or subtractive. The argument favoring this approach is that NERC reliability requirements are used to justify the need for these mandated reliability projects and the resulting allocation of benefits equal to costs minimally reflects the reliability benefits to customers. Any additional APC savings (or perhaps losses) would not have occurred absent the inclusion of these mandated reliability projects, and these benefits/losses are to be considered to the reliability benefits attributed to these projects.

Another approach considered the inclusion of mandated reliability projects in the base case and thereby excludes any measure of other economic benefits associated with these projects. However, in taking this approach there is a possibility that for some zones, the other economic benefits associated with these projects is greater than the allocation of their costs to those zones. Thus, this approach could result in undervaluing the benefits of the projects to those zones. In addition, if the other economic metric shows a loss to a zone, then this approach, which would set benefits equal to allocated costs, would result in overvaluing the benefits to that zone. Thus, this approach was rejected in favor of including mandated reliability projects in the change case and adding other economic benefits to the reliability benefits equal to costs. This approach is consistent with adding the costs of avoided or delayed reliability projects.

5.4.4. Example

The following table illustrates both methods discussed in Section 5.4.3. The only difference in benefits is shown in the APC Benefits column, where the total APC benefits go up by $50 when mandated reliability projects are included in the change case. However, there is a difference for each of the three zones in the example. Zone A's APC benefits go up by $75, zone B's APC benefits do not change, and zone C's APC benefits decrease by $25. The difference column at the end of the table shows that zone A's benefits are $75 lower and zone C's benefits are $25 higher when mandated reliability projects are included in the base case.

	Mandated Relibility Projects in Change Case				Mandated Relibility Projects in Base Case				
Zone	APC Benefits	Mandated Reliability	Avoided Reliability	Total Benefits	APC Benefits	Mandated Reliability	Avoided Reliability	Total Benefits	Difference
A	$200	$40	$25	$265	$125	$40	$25	$190	-$75
B	$100	$35	$10	$145	$100	$35	$10	$145	$0
C	$100	$25	$15	$140	$125	$25	$15	$165	$25
Totals	$400	$100	$50	$550	$350	$100	$50	$500	$50

Table 2: Assumed Mandated Reliability Benefit Example

Suppose the total portfolio cost for this illustration is $400 of which $100 are for mandated reliability projects, and the remaining $300 are for other economic projects. The B/C for mandated projects in the base case would be $500/$400 = 1.25, while for mandated projects in the change case the B/C would be $550/$400 = 1.35. Thus, by undervaluing zone A's benefits by $75 and overvaluing zone C's benefits by $25 the net result is a lowering of the overall B/C.

Avoided reliability projects were included in this example to illustrate the point that when the costs of these projects are included as a benefit, their treatment is equivalent to that of including mandated reliability projects in the change case. The costs of these projects are not included in the costs of mandated reliability projects, and are therefore not included in the overall cost of the portfolio. Their avoided cost is treated as a reliability benefit and the full APC benefits from the projects that displaced these avoided reliability projects are included in the calculation of APC benefits in both cases. Thus, avoided reliability benefits and APC benefits are treated separately and as additive, as are mandated reliability benefits and APC benefits when mandated reliability projects are included in the change case.

5.4.5. Recommendation

The MTF recommends that the reliability benefits of mandated reliability projects be set equal to their costs and allocated to zones in the same way as costs are allocated to the zones. Also, the MTF recommends that mandated reliability projects be included in the change case and other economic benefits be treated as additive or subtractive to their reliability benefits.

Section 6. Reduced Operating Reserves Benefits Metrics

6.1. Savings due to lower ancillary service needs and production costs

6.1.1. Definition

Ancillary Services (A/S) are essential to the reliable operation of the electrical system. A number of operating reserves and products fall into this category—spinning reserves, ramping (up/down), regulation, 10-minute quick start. Current production cost simulation tools account for energy costs on the system, but generally take a static approach to modeling sub-hourly A/S needs by setting aside an exogenously determined quantity of A/S reserves in each hour. However, new transmission projects can contribute to reduction in A/S system costs through either (1) a reduction in needed A/S quantities or (2) a reduction in the cost of procuring that quantity.

- *Quantity Impact*: At present, SPP A/S needs are determined according to the SPP Market Protocols with input from SPP staff. Findings from renewable integration studies and analyses suggest that improved transmission topology can contribute to reducing system A/S needs, which tend to increase as a function of renewable generation penetration. Therefore, system-wide A/S needs could be calculated as a function of transmission capacity and transfer capability among zones. While at present SPP A/S needs are not determined as a function of transmission, if SPP refines its A/S calculations in the future, MTF should track the implications. For example, additional wind might increase localized A/S needs, but additional transmission might reduce such localized A/S needs.
- *Procurement Cost Impact*: Conceptually, the cost of providing A/S should be captured in the APC metric if the simulation software can accurately capture and simulate A/S requirements and their deployment.

6.1.2. How to measure

The quantity impact will be captured as the formulaic determination of A/S needs evolves and transmission overlay begins to directly impact zonal or system-wide A/S needs. At such a point, the benefit from incremental transmission capabilities can be directly measured by calculating A/S needs in production cost simulations for the base and change cases.

Similarly, improved production cost modeling of sub-hourly A/S procurement and deployment can enable the measurement of the cost impacts directly within the APC calculations.

6.1.3. How to monetize

Monetization of the quantity and cost benefits will be reflected in the overall APC savings in two ways. First, the production cost simulation will be conducted using the initial A/S needs for the base case and the same (or possibly reduced) A/S needs for the change case. The difference in APC for the simulations will then reflect the reduced costs of procuring the specified A/S needs (e.g., lower procurement cost of the same A/S needs due to reduced transmission congestion that makes lower-cost resources available to provide ancillary services).

6.1.4. How is this benefit allocated to zones?

Benefits will be calculated in the production cost simulations and will be assigned to the SPP region as a whole and re-allocated to each of the zones on a load ratio share.

6.1.5. Example

- *Quantity Impact*
    - Spinning A/S quantity impact:
        - Consider a base case, where zonal congestion requires that 100 MW of spinning A/S be held system-wide. The 100 MW requirement is calculated based on a number of inputs, including transmission topology and ability to serve A/S needs among zones. The 100 MW need is provided to the production cost simulation software to be held as reserves in the hourly runs.
        - Alternatively, in the change case, the spinning A/S requirement modeled in the APC calculations has been reduced to 75 MW. The reduced A/S need is a function of improved transfer capabilities among zones. That is, local A/S resources do not need to be reserved due to the fact that assistance can be provided from other zones over the expanded transmission topology.
        - As a result, the spinning A/S quantity reduction from the base to the change case is 25 MW. The savings will be captured through the APC calculations.
    - Non-spinning A/S quantity impact: The reduction in non-spinning capacity need will be valued at the Net CONE value discussed in Section 6.1.4. For example, if non-spin requirements (system-wide or zone-wide) are reduced by 10 MW and Net CONE is \$100/kW-yr, the savings would be: 10 MW × \$100/kW-yr × 1000kW/MW = \$1 million/yr.
- *Procurement Cost Impact*
    - The amount of regulation and spinning reserves will be an input to production cost simulations. To the extent possible, the simulation software will "hold aside" an equal amount of committed (i.e., spinning) generating capacity to satisfy the specified quantity of regulation and spinning reserves. The costs of keeping committed capacity unloaded will be reflected in the simulations' production cost estimate. If transmission reduces A/S-related production costs, the change will be captured as part of the APC savings.

6.1.6. Recommendation

The MTF recommends that the A/S savings continue to be captured with the energy portion of the APC metric. At this point, the MTF does not see a need to estimate the A/S related portion of total APC savings. The MTF recommends, however, that the accuracy of ancillary service costs as reflected in production cost simulations be assessed and, if necessary, improved through software upgrades (i.e. Ventyx PROMOD™ ver. 10). Furthermore, MTF recommends that regulation MW requirements be added to the spinning reserves MW requirements in the production cost software simulations until the simulation software can more accurately capture the cost of holding regulation reserves.

Section 7. Improvements to Import/Export Limits Benefits Metrics

7.1. Increase in Available Transfer Capability (ATC)

An increase in ATC between zones within the SPP footprint and to neighboring regions allows the SPP transmission system to import and export more power across zonal and system-wide boundaries. This allows SPP to function more efficiently and provides a wide range of capacity and energy benefits. The majority of these benefits are already captured in specified benefits metrics as discussed below. For completeness, the full list of ATC benefits can be categorized as follows:

- *Increased Internal Congestion Relief*: this benefit is captured via APC savings calculated by the following metrics:
    - Standard APC metric (Section 3.1)
    - Mitigation of Transmission Outage Costs (Section 4.3)
    - Reducing the Cost of Extreme Events (Section 5.3)
    - Mitigation of Weather and Load Uncertainty (Section 9.6)
    - Marginal Energy Losses (Section 4.2)
- *Ability to Import lower Cost Energy from outside SPP*: this benefit is largely captured via APC savings in the production cost simulations (see internal congestion relief above). However, a "value gap" may exist due to how the APC metric is valuing exports and imports as discussed further in Section 9.5.
- *Increased Ability to Export Wholesale Power*: this benefit is monetized via two benefit metrics:
    - APC savings from the production cost simulations (see APC metrics discussion in Section 3.1)
    - Incremental wheeling out and through revenue—this is a benefit not yet captured by other benefit metrics and is discussed in Section 7.2.
- *Reduced Required Capacity Margins and Reduced LOLP Due to Tie-lines*: this benefit is captured through the Capital Savings Due to Reduction of Members' Minimum Required Capacity Margin or the Reduced LOLP metric (as discussed in Sections 5.1and 5.2)
- *Reduced Ancillary Service Costs*: this benefit is captured in APC savings as discuss in the Ancillary Services benefit metric in Section 6.1.
- *Increased Availability of ARRs and associated Transmission Congestion Rights (TCRs)*: This benefit can be captured through a shortcut/adjustment to the APC calculations in the production cost simulations. This is discussed in Sections 9.2 and 9.3 ("Other Benefit Metrics").
- *Risk Mitigation*: this benefit is captured in the following metrics:
    - Reducing the Cost of Extreme Events (Section 5.3)
    - Reduced LOLP (Section 5.2)

As noted in the above list, some of the monetary value of increased ATC is captured in the standard APC metrics, while the much of the rest is captured in additional benefit metrics specified by the MTF. The potential benefit associated with increased wheeling out and through revenues is discussed in Section 7.2.

7.2. Increased wheeling through and out revenues

Increasing ATC with a neighboring region improves import and export opportunities outside of the footprint. Increased inter-regional transmission capacity that causes increased through and out transactions will also increase SPP wheeling revenues. As noted above, while the energy revenue benefit of increased exports is captured by the APC metric (which values exports at the weighted average generation LMP of the exporting zone), the APC metric does not capture any increases in wheeling out or wheeling through revenues associated with increased transfer capability. These increased wheeling revenues are a benefit as they will offset part of the transmission projects' revenue requirements. Currently, SPP under collects wheeling out revenues through Schedules 7, 8, and 11. At MOPC's direction, the Regional Tariff Working Group (RTWG) is currently developing Tariff language to increase the Schedule 11 charges. However, with discounted rates for Schedule 7 and 8 benefits of transmission expansion, wheeling out rates will go to those entities wheeling power out of SPP rather than rate payers paying for the system and under collecting wheeling out rates.

7.2.1. How to measure

This benefit can be captured in one of two ways:

1. Post-processing of production cost modeling simulation results to measure annual increases in hourly MWh export flows over defined tie-line interfaces between SPP and neighboring regions, valued at the average $/MWh wheeling charge that SPP collected during the most recent historical year ; *or*
2. Review of actual historical data to identify increases in transmission reservations and associated revenues after inter-regional ATCs have increased.

Wheeling revenues calculations as proposed here will not result in double-counting of benefits with respect to APC calculations. The reason is that in the APC methodology, imports are priced at the importing region's internal load LMP, while exports are valued at the exporting region's internal generation LMP. As a result, even if part of the difference is payable as a wheeling charge, the revenues collected are not counted in either the exporting or importing region's APC.

In approach number 1, the sum of hourly power flows in the export direct will be used as a conservative proxy for transmission reservations. As a result, hourly power flows over interties in the export direction will be treated as export reservations and valued. Hourly power flows in import directly will not generate any SPP wheeling revenues.

In approach number #2 the average $/MWh wheeling charge should be calculated by dividing SPP-wide wheeling revenues collected during the most recent historical year by the total MWh of wheeling out and through transactions scheduled during the same year. The change in wheeling revenues can be found by comparing the real revenues before and after the transmission was energized.

7.2.2. How to monetize

To monetize the value of increased wheeling out and through transactions, MTF suggests relying on an average wheeling charge. The average SPP wheeling charge can be calculated by using the actual wheeling revenues divided by the MWh exports scheduled the previous year.

7.2.3. Example

Interchange through and out of the SPP footprint is measured for 8,760 hours in the production cost simulations in both a transmission base case and a transmission change case. The difference in interchange through and out between the two cases will be multiplied by the average wheeling charge and assigned to each of the zones on a load ratio share basis.

7.2.4. Recommendation

The MTF recommends that this benefit be initially estimated using the first of the two options (i.e., based on post-processing of export flows in simulations). As better historical information becomes available the process should then move to the second methodology. The benefits should be allocated based upon the load ratio share of the most up-to-date Schedules 7, 8, and 11 to accurately reflect the cost of wheeling charges out of SPP.

Section 8. Public Policy Benefits Metrics

8.1. Benefit from meeting public policy goals

8.1.1. Definition

At this time, the metric is limited to meeting public policy goals related to renewable energy supplies. Public policy can be met through state law, settlement agreement, or a regulatory determination made by a state regulatory authority. It does not include economic decisions made by individual utilities to acquire renewable energy supplies absent some form of legal requirement to do so. Note that for the purposes of this report, public policy mandates imposed by states and public policy goals announced by regulatory bodies or implemented by utilities may or may not be considered in the same manner. Any distinction should be addressed by the ESWG and/or MOPC.

8.1.2. Set Benefits Equal to the Costs of the Cost-Effective Transmission Upgrades Required to Meet the Public Policy Goal

In the instance that a certain goal is predetermined (e.g., set based on a public policy decision), the objective becomes one of finding the most cost effective method of meeting that goal. The benefit is in achieving the goal, and the monetization of that benefit is in the cost of achieving the goal. As with mandated reliability upgrades, the assumption is that public policy makers have made a decision that public benefit is at least equal to the cost of implementing a public policy.

8.1.3. Allocation of Benefit Equal Costs to Zones

The benefits are allocated to the participants based on their respective percentage participation in the overall goal. For renewable energy goals, this would be the quantity of renewable energy associated with the public policy goal. For meeting renewable energy goals with wind power, each zone will have an associated renewable energy (MWh) goal. The cost of the transmission upgrades necessary to most cost effectively achieve the sum of these renewable energy goals would then be allocated to each zone based on its percentage of the total renewable energy goal (MWh_{zone}/MWh_{total}). For those zones that are not required to participate in the public policy or have met their public policy requirement, no public policy benefits would accrue other than economic benefits captured in other metrics.

8.1.4. Distinction between Renewable Energy Targets and Renewable Energy Goals Related to Public Policy

When a distinction is made between a renewable energy “mandate” (goals related to public policy) vs. an economic choice for adding renewable energy, then the cost of the transmission system required to meet the renewable energy mandates must be determined separately from the transmission system required to meet total renewable energy (mandates plus economic choice). Because only renewable mandates are considered under public policy goals, the cost of the most cost effective transmission upgrades required to meet these renewable mandates would be included in setting benefits equal to costs.

8.1.5. Inclusion of Other Economic Benefits

As with reliability projects cost effective upgrades required to meet public policy goals (renewable energy mandates), there are two categories: 1) projects displaced by the portfolio of projects receiving NTCs; and 2) projects included in the portfolio of projects receiving NTCs. The treatment for these projects should be identical to reliability projects. Thus, the total costs of the cost effective upgrades required to meet public policy goals should be included as benefits, and are captured using other metrics identified.

8.1.6. Example

The example for public policy benefits equal to the costs of cost-effective upgrades required to meet the public policy goals is similar to the one used for Mandated Reliability Upgrades. The primary difference is the allocation of benefits for the cost effective upgrades required to meet the public policy goals is the same percentage for both upgrades included in the portfolio and upgrades displaced in the portfolio (i.e. if another project or projects displaced a public policy project the cost of the cost effective project would be deducted from the project that displaced it). In fact, the sum of these two columns in the following table would equal the total costs of these cost effective upgrades included as public policy benefits. Notice that, as was the case for the mandated reliability upgrades, the change in APC benefits from including the cost effective public policy projects in the portfolio in the base case is a decrease of $75 to zone A and an increase in APC benefits to zone C of $25.

	Cost-Effective Public Policy Projects in the Portfolio Included in the Change Case				Cost-Effective Public Policy Projects in the Portfolio Included in the Base Case				
Zone	APC Benefits	Included PP Upgrades	Displaced PP Upgrades	Total Benefits	APC Benefits	Included PP Upgrades	Displaced PP Upgrades	Total Benefits	Difference
A	$200	$40	$32	$272	$125	$40	$32	$197	-$75
B	$100	$35	$28	$163	$100	$35	$28	$163	$0
C	$100	$25	$20	$145	$125	$25	$20	$170	$25
Totals	$400	$100	$80	$580	$350	$100	$80	$530	$50

Table 3: Public Policy Benefit Example

As with the mandatory reliability upgrades, by placing the cost effective public policy upgrades that are include in the portfolio in the base case, benefits to zone A are undervalued by $75, and benefits to zone C are overvalued by $25.

8.1.7. Recommendation

The MTF recommends that the public policy benefits of cost-effective projects required to meet public policy mandates and/or goals be set equal to their costs and allocated to zones in proportion to each zone's share of renewable energy goals or mandate not already met. Also, the MTF recommends that cost effective public policy projects in the portfolio of projects receiving NTCs be included in the change case and other economic benefits be treated as additive or subtractive to their public policy benefits.

Section 9. Other Benefit Metrics

Based on its in-depth review and discussions of benefit metrics, the MTF acknowledges that, in addition to the capacity and energy savings discussed so far in this report, there are additional benefits metrics that deserve attention. While this section of the report focuses on such benefits, the MTF recognizes that their monetization is currently not possible. Instead, the MTF suggests that SPP monitor developments in market design, modeling tools, and data availability to ensure that these benefits be measured and quantified as it becomes appropriate in the future. At a later date, it may be beneficial for SPP staff to review the benefit metrics below and provide a recommendation that the specified metric be reconsidered by the ESWG.

The MTF identified the following benefit metrics as deserving further monitoring and for possible future consideration:

9.1. Increased competition and liquidity

At present, there are no obvious ways to quantify the monetary benefit of increased competition and market liquidity. But analysis in other regions have shown that increasing competition tends to reduce market prices and increases in liquidity tends to reduce the bid-ask spread of bilateral forward transactions, thus reducing the transaction costs of contracting and hedging.

9.2. Unhedged zonal congestion benefits (due to limited zone-internal ARRs)

The APC metric assumes that all congestion between a zone's generation and its load are fully hedged through an allocation of ARRs and the use of the Marginal Congestion Component (MCC). If only a portion of these generation to load transactions can be hedged through an allocation of ARRs (e.g., 85% as estimated in an analysis by American Transmission Company), the reduction of generation-to-load congestion within a zone caused by transmission expansion can be quantified for each zone as:

$$\text{Congestion relief benefit} = \min(\text{Load MWh, Gen MWh}) \times (MCC_{load} - MCC_{gen}) \times \text{unhedged portion}$$

The MTF recommends further developing and testing these calculations before possible introduction as an additional recommended metric at some point in the future.

9.3. Benefit of additional ARR availability to hedge imports from other zones

The APC metric values imports into each zone's at the zone's internal Load LMP. This ignores the fact that the increased imports may be from a new network resource for which the zone may be able to obtain ARRs. This will allow the zone to avoid the congestion charge between the source zone and the sink zone, thereby reducing the cost of the imports. Measuring the value of this benefit in production cost simulations is complicated as it is not clear which sources would likely be designated by sink zone as network resources for the purposed of this calculations. However, once actual experience with ARR allocations becomes available and it can be documented that, as a result of system upgrades, load zones are designating more external network resource and are able to obtain ARRs, a benefit metric that captures these circumstances may be developed.

As a proxy, it may be possible to assume (1) that ARRs would be available for all imports (or a portion, such as 50% of all imports); and (2) value them at the difference between the congestion components of each zone's internal load LMP and gen LMP (i.e., by using the internal MCC (difference a conservative lower limit of the MCC difference between external generation and load). This would be done as follows:

ARR availability benefit = import MWh x ($MCC_{load} - MCC_{gen}$) x hedged import portion

The MTF recommends further developing and testing these calculations before possible introduction as an additional recommended metric at some point in the future.

9.4. Reduced cycling of base load units

Currently, Phase 2 of the Western Wind and Solar Integration Study conducted by National Renewable Energy Laboratory (NREL) is analyzing the cycling cost impacts of accommodating renewable generation. According to a report prepared for NREL by Intertek APTECH, cycling costs can range between $131 per MW of capacity for each hot start to $286 per MW of capacity for each cold start for some types of coal plants.[11] The cost implication of additional cycling could thus be estimated by (1) counting the number of unit starts in production cost simulations, then (2) applying an average cost/start value from the NREL study. The MTF recommends further developing and testing these calculations before possible introduction as a recommended metric in the future.

9.5. Value gap of transactions between SPP zones

Currently, the SPP APC calculations result in zonal APCs, whose sum will tend to be less than the APC calculated for the entire SPP footprint. (In other words, $\Sigma(Zonal_{APC}) < SPP_{APC}$.) The reason for this imbalance is that some of the value of the interzonal transactions gets lost because exports get valued at the exporting zone's generation LMP while the import side of the same transaction is valued at the importing zone's higher load LMP. As a result, changes in the difference between the exporting zone's generation LMP and the importing zone's load LMP can be lost in the calculations.

This means that an entity may realize a ten dollar profit on the inter-zonal transmission transaction gets lost when calculating APCs on individual zonal level. This may also mean that negative APC savings values for some zones may be an artifact of how imports and exports are valued in the APC metric. If the analysis results in a negative zonal APC savings value, this might be an indication of missing ARR/TCR revenues and missing refunds of marginal load charges.

To at least partially address this issue, the following methodology could ultimately be adopted:

- Calculate: Δ (SPP_{APC}- $\Sigma(Zonal_{APC})$), that is, the change in the difference between the zonal sum and footprint-wide APC values between the base and the change case

The MTF recommends further developing and testing these calculations before possible introduction as a recommended metric in the future.

[11] "Power Plant Cycling Costs," Prepared by Intertek APTECH for NREL, April 2012, Table 1-1, p. 12. http://wind.nrel.gov/public/WWIS/APTECHfinalv2.pdf

9.6. Mitigation of weather and load uncertainty

9.6.1. Definition

Production cost simulations for the base and change case are based on normalized levels of peak loads and energy. As a result, the APC impacts of weather and load uncertainty are not readily captured in the default production cost simulation methodology. However, the region sometimes faces weather that is significantly hotter or colder, leading to higher or lower loads than the normalized values in the market simulations. Because the incremental cost of higher loads tend to exceed the decremental cost of lower load, the probability weighted average of production costs across the full spectrum on load conditions tends to be above the production costs for normalized conditions.

Weather and loads may also not be distributed uniformly across the footprint. This will tend to lead to additional power flows and transmission congestion that can increase the benefit of transmission additions relative to those captured in the normalized base and change case simulation. For example, cool summer weather in the northern part of SPP combined with hot weather in the southern part of SPP will lead to north-to-south power flows and associated transmission congestion that may increase the value of transmission investments.

9.6.2. How to measure & monetize

The benefits associated with this metric can be measured through the APC calculations in a production cost simulation analysis where the load profiles represent 90/10 and 10/90 load conditions as well as specific north-south scenarios. To monetize the savings, probability weighted average APC savings of these scenarios and the normalized base and change case simulations will be calculated. The benefit metric reflects the incremental APC savings that are equal to the difference between the probability weighted APC savings and the APC metric derived from the normalized base and change case simulations.

9.6.3. How is this benefit allocated to zones?

Zonal production costs may be sensitive to the selection of the specific weather pattern. Consequently, the MTF recommends that the benefit of weather and load uncertainty mitigation be assessed on an SPP-wide regional basis and then allocated to each zone based upon the load ratio share.

9.6.4. Example

Base could be considered for other load levels:

- Simulations with 10/90 load yields $90 million in APC savings (e.g., assigning a 20% weight)
- Simulations 50/50 load (i.e., the normalized base and change cases) yields $100 million in APC savings (e.g., assigning a 60% weight)
- Simulations with 90/10 load yields $200 million in APC savings (e.g., assigning a 20% weight)

Probability weighted average = $118 million (= 0.2x90 + 0.6x100 + 0.2x200)

Incremental APC savings = $18 million above APC savings derived with normalized base and change case conditions.

The MTF recommends further developing and testing this approach, including non-uniformly distributed weather patterns (such as a cool northern and unusually hot southern portion of the SPP region), before possible introduction as a recommended metric in the future.

9.7. Mitigation of renewables-uncertainty costs

Standard APC simulations tend to assume hourly wind generation is perfectly known during the generation commitment stage of system operations, which does not fully capture the energy and ancillary service costs related to the uncertainty of intermittent wind generation. Refinements in production cost modeling should allow capturing these energy and ancillary service costs and associated transmission related cost reductions as an add-on to the standard APC metric. However, the MTF does not offer specific recommendations at this point.

9.8. Economic benefit from cost-effective location of renewable resource to meet renewable energy targets

9.8.1. Definition

Renewable energy targets include both mandates and economic decisions to acquire renewable energy supplies. The concept is that by locating renewable energy resources in the most cost-effective manner, the generation costs of these energy supplies will be lower, but the transmission cost of delivering these energy supplies to the zones with renewable energy targets will be higher.

9.8.2. Measuring Economic Benefits:

Economic benefits from meeting renewable energy targets in the most cost-effective manner requires a detailed study of both generation capacity and transmission upgrades required to meet renewable energy supplies for two locations of the generation: 1) locating enough generation within each zone to meet the renewable energy targets for that zone; and 2) locating enough generation with the SPP region to meet the renewable energy targets for the region in the most cost effective manner. SPP has not performed such a study, but has instead assumed that the most cost effective manner of meeting renewable energy targets is through locating wind generation in areas that have the highest capacity factors.

Using SPP's assumption, both differences in capacity and energy costs must be taken into account to measure economic benefit from meeting renewable energy targets in a cost-effective manner.

- *Generation Capacity Savings: The reduced amount of generation capacity that is required to meet a renewable energy target by locating that capacity in a higher capacity factor region compared to locating that capacity within each zone.*
    - For example: by locating wind in a zone 4 region (e.g., with a capacity factor of 45%) rather than in a zone 2 region (e.g., with a capacity factor of 28%), a given level of installed generating capacity may be able to generate over 60% more energy (45/28=1.61). Stated differently, in order to generate the same amount of renewable energy, locating the capacity in a zone 2 region would require over 60% more generation capacity.
        - Capacity savings is calculated as the difference in the present value of annual revenue requirements associated with locating generation capacity required to meet the renewable energy target located in the local zone compared to being located in a higher capacity factor region.

- To implement this measure, the SPP will need to determine the wind capacity factors for locations within each SPP zone as well as the capacity factors for wind located in the best capacity factor locations within the SPP footprint.

- *Transmission Capacity Costs: The increased cost of cost-effective transmission upgrades required to meet a renewable energy target from resources located in the region compared to locating that capacity within the zone of the load having that renewable energy target.*
  - The would required a specific determination of where to locate renewable energy generation within each zone and the most cost-effective transmission upgrades required to deliver the energy from this generation to the load.
- *Energy Savings: The reduction in Adjusted Production Costs that occurs when the renewable resources required to meet a renewable energy target are located in a higher capacity factor region.*
  - For the wind example: irrespective of where the wind is located (in the utility's zone or in a higher capacity factor region) the energy from the wind must be the same in order to meet the renewable energy target. However, the savings in APC will vary by location.
  - To implement this, the base case would include the wind located within each zone and the change case would include the wind located at the higher capacity factor locations within the region.

9.8.3. Example

Base case is the local location of renewable resources within the zone. Change case is the regional location of renewable resource with the SPP region.

	Base Case	Change Case	Net Savings
Generation Capacity Costs	$1,000	$625	$375
Transmission Capacity Costs	$50	$150	-$100
Adjusted Production Costs	$250	$200	$50
Totals	$1,300	$975	$325

Table 4: Public Policy Savings Alternative Method

In this example, it is assumed that the renewable energy produced by the renewable generation is the same, but the generation costs for the base case (local location of renewable generation) are $375 (60%) higher than in the change case, the transmission costs are $100 lower, and the APCs are $50 higher, resulting in a net economic savings of $325 from locating the renewable generation more cost effectively within the SPP region.

9.8.4. Metric for Economic Benefits from Most Cost Effective Upgrades Required to Meet Renewable Energy Targets

Assume as a starting point that the most cost effective upgrades required to meet renewable energy targets make up the entire portfolio of approved projects receiving NTCs.

For the portfolio the APC savings are calculated as the difference in APC for the change minus the base case. Assuming the entire portfolio is the same as the cost-effective upgrades to meet the renewable energy targets, the change case is the same as in the cost-effective study. However, the base case is different from that of the cost-effective study as it includes no transmission upgrades for meeting renewable energy targets. In light of the differences, the question to be answered is what should be included as economic benefits from meeting renewable energy targets from the most-cost effective locations ($CERET_{benefits}$)? To answer this question, consider the calculation of Net Benefits = $APC_{savings}$ + $CERET_{benefits}$ – Portfolio Costs.

$$\text{Net Benefits} = (APC_{\text{change case}} - APC_{\text{base case}}) + CERET_{\text{benefits}} - \text{Portfolio Costs}$$

If Net Savings from CERET is used as $CERET_{benefits}$ the above becomes:

$$\text{Net Benefits} = (APC_{\text{change case}} - APC_{\text{base case}}) + \text{Capacity Generation Cost Savings} + (\text{Portfolio Cost} - \text{Local Transmission Costs}) + (APC_{\text{change case}} - APC_{\text{local case}}) - \text{Portfolio Costs}$$

$$= (2APC_{\text{change case}} - APC_{\text{base case}}) + \text{Capacity Generation Cost Savings}$$

$$- (\text{Local Transmission Costs} + APC_{\text{local case}})$$

First, notice the double counting of $APC_{change\ case}$ as contributing to net benefits. Next notice the absence of Portfolio Costs from this calculation as these costs are included as both benefits and costs if net savings are used as the metric for $CERET_{benefits}$. This leads to the following conclusions regarding the calculation of $CERET_{benefits}$.

- Since the costs of the cost effective transmission required to meet the renewable energy targets is included on the cost side, it should be excluded from the calculation of benefits for the most cost effective location of renewable resources.
- Since the APC of the cost effective transmission required to meet the renewable energy targets is included in the calculation of APC savings of the portfolio, they should be excluded from the calculation of benefits for the most cost-effective location of renewable resources.

The proper calculation of benefits from the cost effective location of renewable resources to meet renewable energy targets then becomes:

$$CERET_{\text{benefits}} = \text{Capacity Generation Cost Savings} - (\text{Local Transmission Costs} + APC_{\text{local case}})$$

Then the equation for Net Benefits becomes:

$$\text{Net Benefits} = (APC_{\text{change case}} - APC_{\text{base case}}) + \text{Capacity Generation Cost Savings} - (\text{Local Transmission Costs} + APC_{\text{local case}}) - \text{Portfolio Costs}$$

From the example calculation of net savings, the associated calculation of $CERET_{benefits}$ is illustrated in the following table.

	Base Case	Change Case	CERET Benefits
Generation Capacity Costs	$1,000	$625	$375
Transmission Capacity Costs	$50	NA	-$50
Adjusted Production Costs	$250	NA	-$250
Totals	NA	NA	$75

Table 5: CERET Benefits

9.8.5. Allocation to the Zones

For both the base case and the change case the renewable generation capacity must be assigned to each zone. For the base case and for zones where there is no difference in location for the change case, this assignment is straight-forward. However in the change case, the assignment of regionally located generation is unknown. The best assumption to make is that these zones would receive a pro-rata share of the regionally located generation not assigned to zones where there is no difference between locally and regionally located renewable generation resources. Once the renewable resources are assigned to each zone, the generation capacity costs and APC costs can easily be calculated for each zone.

While the regional transmission capacity costs would be assigned to the zones using the SPP highway/byway cost allocation, local transmission capacity costs would be assigned to each zone as if they were regional reliability upgrades required to reliably deliver the energy to the load.

9.8.6. Inclusion of Other Economic Benefits

As with assumed public policy benefits and mandated reliability benefits, it cannot be assumed that the most cost effective upgrades required to meet renewable energy targets will include the entire portfolio or all be included in the portfolio of projects receiving NTCs. Moreover, some of these upgrades may be displaced by other projects in the approved portfolio. As with mandated reliability upgrades and assumed public policy benefits, the upgrades from the most cost effective upgrades required to meet renewable energy targets should be included in the change case and other economic savings from the portfolio should be include. Notice that double-counting issues were taken care of in the specification of economic benefits from cost effective location of renewable resources for meeting renewable energy targets

If economic benefits from cost effective location of renewable resources for meeting renewable energy targets are included, assumed benefits from meeting public policy goals should not be added. First, renewable energy mandates are different from renewable energy targets. Second, including both would result in double counting.

One alternative considered to resolve double counting was to calculate assumed benefits for renewable mandates and economic benefits for renewable targets for each zone and take the maximum as the metric for meeting renewable targets.

At this time, the MTF needs to see more specific calculations of the economic benefit for most cost effectively meeting renewable energy targets before recommending this approach.

9.9. Cost impacts of emission savings, etc.

The MTF considered the inclusion of both the health costs due to emission reductions and the monetary benefit of reducing mercury (Hg) emissions based upon the possibility of further development of effluent markets and changes to environmental regulations. Due to the lack of any existing market pricing mechanism for mercury allowances and uncertainty regarding the future of related regulation the MTF recommends that the benefit of reducing mercury emissions be reconsidered at a later date. In an effort to identify hard dollar impacts that would result in direct ratepayers benefits that fall into the societal realm such as health impacts or job creation, the MTF would need more time to come to a consensus and identify data sources and studies that would be used as the proper reference.

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SPP Southwest Power Pool