Regional Cost Allocation Review

October 8, 2013

SPP Regional Cost Allocation Review Report

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EXECUTIVE SUMMARY

This report contains the results of the Regional Cost Allocation Review (RCAR) of Southwest Power Pool, Inc.'s (SPP) Highway/Byway transmission cost allocation methodology in accordance with Attachment J, Section III.D of SPP's Open Access Transmission Tariff (OATT).

The analyses contained in this RCAR Report (the RCAR Report) were conducted based upon the recommendations of the Regional Allocation Review Task Force (RARTF) approved by SPP stakeholders in January 2012 (the RARTF Report). These analyses included the calculation of eight out of thirteen benefits approved by SPP's Metrics Task Force (MTF), Economic Studies Working Group (ESWG), Markets and Operations Policy Committee (MOPC), as well as the Members Committee and Board of Directors in September and October 2012.

When conducting the RCAR, SPP staff applied the ten principles contained in the RARTF Report. These principles include: simplicity, acknowledgment of the "roughly commensurate" legal standard, equity over time, the use of the best quantifiable information available, consistency, transparency, stakeholder input, the use of real dollars values, and the inclusion in the review of Board-approved transmission plans with more weight being given to nearer-term projects.

Applying these principles the RCAR Report shows:

- The overall benefit to cost (B/C) ratio for the region for projects that have been issued a Notification to Construct (NTC) since June 2010 under the Highway/Byway cost allocation methodology is a 1.39, and the overall B/C ratio for projects that have been issued an NTC since June 2010 plus Board-approved transmission projects with in-service dates of ten years or less under the Highway/Byway cost allocation methodology is a 1.42.

The assessment shows that for projects that have been issued an NTC since June 2010 a total of six zones were below the .80 threshold established by the RARTF, five zones were greater than the .80 threshold but below 1.0, and the remaining five zones were above a 1.0 B/C ratio. For projects that were issued an NTC since June 2010 plus Board-approved transmission projects with in-service dates of ten years or less a total of five zones were below the .8 threshold, five zones were between the .8 and 1.0, and six zones were above the 1.0 B/C ratio. Additionally, the RARTF Report contains three additional recommendations on next steps. These include:

- That the results contained in the Report showing that five zones are below the .80 threshold for NTC projects and projects with in-service dates within ten years or less (City Utilities of Springfield, The Empire District Electric Company, Grand River Dam Authority, Lincoln Electric System, and Sunflower Electric Power Corporation) be incorporated in SPP's current ITP10 assessment to consider whether the "[a]cceleration of planned upgrades" or the "[i]ssuance of NTCs for selected new upgrades" can provide these five zones with remedies to raise their B/C ratio above the threshold.

- That a second RCAR process [RCAR II] be commenced and work in parallel with the current ITP10 assessment which is expected to be completed in January 2015. Through this process, SPP staff can follow the directions contained in Sections 4.2 and Section 5.1 of the RARTF Report by utilizing the current ITP10 assessment and a RCAR II study as a means to understand whether any proposed remedies approved in the ITP10 will provide remedies to zones below the .80 threshold. If RCAR II does not show that adequate remedies exist, SPP staff can use the results of a RCAR II Report to analyze additional potential remedies for any zone below the threshold. The report will be completed either (i) shortly after the ITP10 is completed, if cost estimates are to be used in the RCAR II analysis; or (ii) shortly after the completion of the competitive solicitation process, if the RFP results are to be used in the RCAR II analysis

That the RARTF begin a process to evaluate “lessons learned” from SPP’s first RCAR Report and finalize “suggested improvements” to the RCAR process by the January 2014 stakeholder meeting cycle. This recommendation will allow any improvements to be incorporated into the RCAR II process and will be in accord with Section 7.1 of the RARTF Report.

BACKGROUND

In approving the Highway/Byway cost allocation methodology for the Southwest Power Pool, Inc. (SPP) Regional Transmission Organization (RTO), the Federal Energy Regulatory Commission (FERC) also approved a requirement that SPP conduct a review of the "reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every three years."[1] This review is required to "determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct (NTC) issued after June 19, 2010 to each pricing Zone within the SPP Region."[2] Thus, the purpose of this analysis is to measure the "cost allocation impacts" of SPP's Highway/Byway methodology by zones. The review is hereinafter referred to as the "Regional Cost Allocation Review" or "RCAR".

SPP's Open Access Transmission Tariff (Tariff or OATT) specifically requires that "the Markets and Operations Policy Committee (MOPC) and Regional State Committee (RSC) will define the analytical methods to be used" in conducting the Regional Cost Allocation Review.[3] As a result, the Regional Allocation Review Task Force (RARTF) was created as part of the SPP stakeholder process to develop the "analytical methods" used for the review.

The RARTF membership is composed of three representatives from the RSC, three SPP Members, and one member from the independent SPP Board of Directors. The members of the RARTF were jointly appointed by then RSC President Jeff Davis and then MOPC Chairman Bill Dowling who were serving in these capacities at the time of the creation of the RARTF. The appointed members of the RARTF are:

RARTF Members	
Chairman Michael Siedschlag	Nebraska Public Review Board
Vice-Chairman Richard Ross	American Electric Power
Commissioner Thomas Wright	Kansas Corporation Commission
Commissioner Olan Reeves	Arkansas Public Service Commission
Bary Warren	The Empire District Electric Company
Philip Crissup	Oklahoma Gas and Electric Company
Harry Skilton	SPP Board of Directors

Pursuant to the mandate in the RARTF Charter, the RARTF prepared a Report that included a recommendation as to how to define the "analytical methods" to be used in the Regional Cost Allocation Review. In January 2012, the RARTF Report was approved unanimously by the RARTF, the RSC, the MOPC, and SPP's Members Committee. The RARTF Report was also approved by the SPP Board of Directors.

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[1] Attachment J, Section III.D.1 of SPP's OATT.
[2] Attachment J, Section III.D.2 of SPP's OATT.
[3] Attachment J, Section III.D.4(i) of SPP's OATT.

SECTION 1: OVERVIEW OF THE RARTF AND RCAR REVIEW

1.1 Overview of SPP Tariff Requirements to Perform the RCAR Review

Attachment J, Section III.D to the SPP OATT establishes a four-step process for the Regional Cost Allocation Review. These steps are:

Step 1: One year prior to each three-year planning cycle (starting in 2013) the MOPC and RSC will define the analytical methods to be used to report under this Section III.D and suggest adjustments to the RSC and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint.[4]

Step 2: For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades with NTCs issued after June 19, 2010 to each pricing Zone within the SPP Region. The Transmission Provider in collaboration with the RSC shall determine the cost allocation impacts utilizing the analysis specified in Section III.8.e of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of this Attachment J to the SPP OATT.[5]

Step 3: The Transmission Provider shall review the results of the cost allocation analysis with SPP's Regional Tariff Working Group (RTWG), MOPC, and the RSC. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website.[6]

Step 4: The Transmission Provider shall request the RSC provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.[7]

1.2 Overview of RARTF Charter

In addition to the requirements contained in the SPP's OATT, the RARTF's Charter contained additional work and deliverables for the RARTF. Specifically, the Charter states:

> The RARTF will make final recommendations to the MOPC and the RSC regarding the analytical methods to be used to review the

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[4] *Id.*
[5] Attachment J, Section III.D.2 of SPP's OATT.
[6] Attachment J, Section III.D.3 of SPP's OATT.
[7] Attachment J, Section III.D.4 of SPP's OATT.

> reasonableness of the regional allocation methodology for the approval of both the MOPC and RSC. In addition to developing the analytical methods to be used in the analysis, the RARTF will provide SPP Staff guidance as to the Task Force's expectation for the threshold for an unreasonable impact or cumulative inequity. The RARTF shall prepare and issue the report by December 20, 2011.

Additionally, the Charter contained a list of key deliverables for the RARTF which states:

> <u>The RARTF scope of work and key deliverables include the following:</u>
>
> 1. Development of and recommendation for a methodology to be used to determine the current and cumulative long-term equity/inequity of the currently effective cost allocation for transmission construction/upgrade projects on each SPP Pricing Zone and/or Balancing Authority.
>
> 2. Develop a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority.
>
> 3. Develop a list of possible solutions for SPP staff to study for any unreasonable impacts or cumulative inequities on an SPP Pricing Zone or Balancing Authority.
>
> 4. Final report containing such recommendations to be prepared and issued by December 20, 2011.

1.3 Overview of Legal Standards

Pursuant to the RARTF Charter, the RARTF has been tasked to "[d]evelop a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority." In researching and discussing how to establish a threshold, SPP staff and the RARTF reviewed and considered the legal significance and relevance of the Seventh Circuit decision in the *Illinois Commerce Commission (ICC) v. FERC*.[8]

In this review, the RARTF found that the term "roughly commensurate" was used for the first time by the Seventh Circuit in the *ICC v. FERC* case. Other than the *ICC* case, the term "roughly commensurate" has never been used in an appellate case reviewing a FERC order, nor has FERC ever used the term prior to the *ICC* remand. Since the *ICC* opinion was issued, FERC

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[8] 576 F.3d 470 (7th Cir. 2009).

cited the Seventh Circuit's roughly commensurate standard in approving SPP's Highway/Byway cost allocation methodology,[9] Mid-continent Independent Transmission System Operator, Inc's (MISO) multi-value project ("MVP"), and California Independent System Operator Corporation's convergence bidding proposal, although none of these orders elaborates on the exact meaning of "roughly commensurate." Additionally, FERC, subsequent to the establishment of the RARTF, used the term in Order No. 1000,[10] as well as FERC's Orders on Rehearing for SPP's Highway/Byway cost allocation methodology[11] and on MISO's MVP cost allocation methodology. Specifically, as quoted by FERC in its October 20, 2011 Order on Rehearing, in the Seventh Circuit stated that the legal standard is that "an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities."[12]

The RARTF noted a couple of important aspects of the orders from the Seventh Circuit and FERC dealing with the "roughly commensurate" standard. First, it appears that "roughly commensurate" is not "cost-beneficial" so that something less than a 1.0 B/C ratio may comply with the standard and that FERC has said that "the question becomes not whether the Highway/Byway methodology matches cost to the benefits on a utility-by-utility or zone-by-zone basis, but whether it will provide sufficient benefits to the entire SPP region to justify a regional allocation of costs."[13]

Additionally, the RARTF notes that the *ICC* case and the precedent on which the Seventh Circuit relied in its decision did articulate certain principles that a cost allocation method must satisfy. These include:

- A cost allocation mechanism may track costs less than perfectly.
- A cost allocation mechanism need not calculate benefits to the last penny or, for that matter, to the last million or ten million or perhaps hundred million dollars.
- A pricing scheme may not require payments from those that derive no benefits or benefits that are trivial in relation to the costs.
- Rates must reflect, to some degree, the costs actually caused by the customer who must pay them.
- Benefits do not necessarily need to be quantified, but there must be an articulable and plausible reason to believe that benefits received by customers are at least roughly commensurate with the costs allocated to customers.
- FERC must compare the costs assessed against a party to the burdens imposed or benefits drawn by that party.

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[9] *Southwest Power Pool, Inc*., 137 FERC ¶ 61,075 (2011).
[10] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* 136 FERC ¶ 61,051 (2011).
[11] *Southwest Power Pool, Inc*., 137 FERC ¶ 61,075 (2011).
[12] *Southwest Power Pool, Inc*., 137 FERC ¶ 61,075 at P 22 (2011).
[13] *Southwest Power Pool, Inc*., 137 FERC ¶ 61,075 at P 26 (2011).

The RARTF considered the *ICC v. FERC* and related cases, as well as subsequent FERC orders citing the 7th Circuit's "roughly commensurate" standard, in the task force's deliberation and conclusions found in the RARTF's report. The RARTF's consideration of the "roughly commensurate" standard is reflected in the RCAR Report as well.

1.3.1 Legal Rulings Subsequent to the Overview of Legal Standards

Since the RARTF finalized its report, the Seventh Circuit issued an opinion that further clarified its earlier decision.[14] In the decision, the court upheld FERC's approval of MISO's cost allocation for "MVP" projects, which allocates costs "in proportion to each utility's share of the region's total wholesale consumption of electricity,"[15] because the projects "involve high-voltage lines that transmit electricity over long distances, will benefit all members of MISO and so the projects' costs should be shared among all members."[16] The court noted that there are "limitations on calculability [of benefits] that the uncertainty of the future imposes,"[17] and that some benefits of the MVP projects (the need for fewer local running reserves because power can be more readily obtained from elsewhere) are such that "[i]t's impossible to allocate these cost savings with any precision across MISO members."[18] The court found that the long-distance lines will make moving cheaper power easier, and "[t]here is no reason to think these benefits will be denied to particular subregions of MISO, and "[o]ther benefits of MVPs, such as increasing the reliability of the grid, also can't be calculated in advance, especially on a subregional basis, yet are real and will benefit utilities and consumers in all of MISO's subregions."[19] Finally, responding to arguments that FERC's analysis of benefits was crude, the court said that "if crude is all that is possible, it will have to suffice."[20] Quoting its earlier decision, it said that FERC simply needs "an articulable and plausible reason to believe that the benefits are at least roughly commensurate" with utilities' shares of regional energy consumption and "[f]or that matter it can presume [as it did in this case] that new transmission lines benefit the entire network by reducing the likelihood or severity of outages."[21]

In short, the Seventh Circuit's recent decision indicates that its previously articulated requirement that FERC demonstrate that cost allocation is "roughly commensurate" with benefits is tempered by "limitations on calculability" and the inability to determine benefits with precision over long time horizons given the "uncertainty of the future."

Just as the RARTF acknowledged in its January 2012 report that difficulties exist in calculating benefits, so did the Seventh Circuit in its June 7, 2013 opinion. Although, the Seventh Circuit

[14] *See Illinois Commerce Commission, et al. v. FERC,* No. 11-3421, slip op. (7th Cir. June 7, 2013).
[15] *Id.* at 7.
[16] *Id.* at 9.
[17] *Id.* at 11.
[18] *Id.* at 12.
[19] *Id.* at 12-13.
[20] *Id.* at 13.
[21] *Id.* at 13 (quoting *Illinois Commerce Commission, et al. v. FERC,* 576 F.3d, 470, 477 (7th Cir. 2009).

acknowledges that the calculation of benefits for transmission facilities has "limitations on calculability" given the "uncertainty of the future" and even went so far as to say that "if crude is all that is possible, it will have to suffice," the RCAR Report attempts to go beyond a mere crude analysis. Instead, the RCAR analyses as conducted per the direction given to SPP staff by the RARTF as well as the input from SPP's stakeholder process – including the work of the Metrics Task Force (MTF) – attempts to calculate the costs and benefits of SPP's Highway/Byway with the most up-to-date information.

1.4 Cost Allocation Challenges for Transmission Upgrades

The allocation of costs for public projects with significant and widespread public benefits is very challenging and difficult. This is particularly true for electric transmission projects, as has been stated by the FERC:

> Determining the costs and benefits of adding transmission infrastructure to the grid is a complex process, particularly for projects that affect multiple systems and therefore may have multiple beneficiaries. At the same time, the expansion of regional power markets and the increasing adoption of renewable energy requirements have led to a growing need for transmission projects that cross multiple utility and RTO systems. There are few rate structures in place today that provide the allocation and recovery of costs for these intersystem projects, creating significant risk for developers that they will have no identified group of customers from which to recover the cost of their investment.[22]

The RARTF noted the difficulties of implementing cost allocation methods for transmission projects. Because of these challenges the RCAR Report reflects the reasoned, sound, and well established methods established by the RARTF and endorsed by SPP Stakeholders in January 2012.

SECTION 2: SPP'S HIGHWAY/BYWAY COST ALLOCATION METHODOLOGY

2.1 Highway/Byway Summarized

The SPP RSC established the Highway/Byway cost allocation methodology that was subsequently approved by FERC.[23] The Highway/Byway methodology assigns 100% of all 300 plus kV transmission upgrades' Annual Transmission Revenue Requirement (ATRR) to the SPP zones on a regional basis using the Load Ratio Share (LRS), as a percentage of the whole of regional loads, of each zone multiplied by the total ATRR of the new upgrade. New upgrades

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[22] *Transmission Planning Processes Under Order No.* 890, Notice of Request for Comments at 5, Docket No. AD09-8-000 (Oct. 8, 2009).
[23] *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 (2011).

with a voltage rating between 100 kV and 300 kV are allocated 33% to all zones in the region on a LRS basis and 67% to the host zone's Transmission Customers (TCs). New upgrades under 100 kV are allocated 100% to the TCs of the host zone.

Figure 2.1
Highway/Byway Cost Allocation Overview

Highway Byway Cost Allocation Overview		
Upgrade Voltage	**Region Pays**	**Local Zone Pays**
300 kV and above	100%	0%
above 100 kV and below 300 kV	33%	67%
100 kV and below	0%	100%

The ATRRs assigned to the zones are collected from their respective TCs using the previous year's 12 month Coincident Peak LRS.

Cost allocation of new construction is the focus of Attachment J of the SPP OATT. The recovery of the ATRR is through Schedule 11 of the SPP OATT and booked by each zone in Attachment H of the SPP OATT. Additionally, these costs are offset by Point to Point (PTP) revenues collected by SPP for transmission service sold on the SPP system. Once these PTP revenues are collected, these revenues offset the amount zones pay under the Highway/Byway as provided for in Attachment L of the SPP OATT.

SECTION 3: RECOMMENDED REVIEW METHODOLOGY

3.1 Principles that Guided How SPP Staff Conducted the RCAR Review

Following research, stakeholder input and extensive discussion, the RARTF's Report contained 10 key principles for SPP staff to follow when conducting the RCAR analyses. The 10 principles adopted by the RARTF are as follows:

(1) Simplicity – The Regional Cost Allocation Review should be as simple as possible so that the report has a distinct understandability.

(2) Roughly Commensurate – The Regional Cost Allocation Review should use the principle of "roughly commensurate" as the legal framework and a guidepost when evaluating the reasonable and long-term equity of SPP regional transmission upgrades under the Highway/Byway cost allocation methodology.

(3) Use Best Information Available – The Regional Cost Allocation Review should use the most up to date and best available information for the review.

(4) Consistency – The Regional Cost Allocation Review should be consistent.

(5) Transparency – The assumptions, inputs, and data used in the Regional Cost Allocation Review should be transparent to SPP stakeholders.

(6) Stakeholder Input - The assumptions, inputs, and data used in the Regional Cost Allocation Review should be vetted through SPP's open and transparent stakeholder process.

(7) Real Dollars – The Regional Cost Allocation Review Analysis and Report should use dollar values of the year in which the report will be issued.

(8) Consideration Given to Certain Plans – The Regional Allocation Cost Review should give considerations to certain plans that have been approved by the SPP Board of Directors. This includes projects that have been issued an NTC since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.[24]

(9) More Weight Should be Given to Nearer Term Projects than Future Projects – Although the Regional Cost Allocation Review should give consideration to certain plans approved by the SPP Board of Directors, less weight should be given to plans which have been given an ATP as opposed to an NTC.

(10) Equity Over Time – The Regional Cost Allocation Review should adhere to the long term view of the Highway/Byway cost allocation methodology to strive toward regional cost allocation equity over time.

3.2 Regional Cost Allocation Review Methodologies

Because the RCAR is for projects that will be built under SPP's Highway/Byway cost allocation methodology, the RARTF recommended that certain projects and plans which are approved by the Board of Directors be evaluated. However, due to the less certain nature of the some projects, the RARTF recommended that emphasis of the review be placed on Board of Director approved plans that have in-service dates of ten years or less.

Since both a too conservative approach and a too broad approach to analyzing benefits of transmission projects can be problematic, the RARTF proposed using a single methodology for assessing the benefits and costs of under SPP transmission projects under the Highway/Byway cost allocation methodology. With this methodology, SPP staff was directed to conduct two evaluations to report and assess the impacts of the Highway/Byway cost allocation methodology. The two evaluations would include an assessment of:

[24] At the time the RARTF was developing the methods under which the RCAR was to be conducted; SPP used a concept known as ATPs. Since the approval of the RARTF report, the term ATP is no longer used. Although the term ATP is no longer used, SPP staff still followed Principle 8 by including projects with an in-service date of ten years or less per the RARTF report.

(1) NTCs: All SPP projects that have been issued an NTC since June 2010;[25] and

(2) NTCs and Projects within 10 years: All SPP projects that have been issued an NTC[26] since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report.

3.3 RARTF Recognition of Weighting Given to Projects without NTCs.

When conducting the RCAR described in Section 3.2(2) above, the RARTF recommended that projects with an in-service of 10 years or less, but without NTCs, be considered in the review. However, in considering these projects, the RARTF recommended a reduced weighting of the valuation of the costs and benefits at seventy-five percent (75%) of the total value. The RARTF made this 0.75 weighting recommendation due to the less certain nature of these projects as well as their costs and benefits.

3.4 RARTF Recommended Baseline for the Regional Cost Allocation Review

Because the RCAR is for projects that will be built under SPP's Highway/Byway cost allocation methodology, the RARTF recommended that the baseline used to measure the benefits should include all projects which were in-service or received an NTC prior to June 2010. The RARTF recommended that the baseline used in the first RCAR should be the same baseline used in all future reviews.

3.5 RARTF Recommended Calculation of Benefits to Cost Ratios

The RARTF recommended using a methodology in which each assessment uses the aggregate value of dollars for all projects studied under the SPP Highway/Byway cost allocation methodology in dollars current to the year the review is conducted. Using the aggregate value of dollars instead of the average B/C ratios provides a more comprehensive view of the total benefits to individual zones over the course of multiple studies.

3.6 RARTF Recommends Use of a 40-Year Project Evaluation

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[25] Attachment J, Section III.D.2 of SPP's OATT, requires that the Regional Allocation Review "shall determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010." The RARTF viewed that the report in Section 3.2(1) will comply with the Tariff. However, the RARTF believed that additional analyses needed to be considered by SPP stakeholders in light of the fact the Highway/Byway applies to future projects that have yet to receive an NTC. Hence the RARTF recommended additional studies as stated in 3.2(2) so that the focus is not exclusively on the first projects that fall under SPP's Highway/Byway. As FERC noted in the October 20, 2011 Order on Rehearing, "the Priority Projects are just one set of projects to be constructed over the years of transmission development in SPP." *Southwest Power Pool, Inc*., 137 FERC ¶ 61,075 at P 32 (2011).

[26] The RARTF recommended that Conditional Notices to Construct or CNTCs are considered NTCs and therefore should be included and evaluated as a NTC in the RCAR Report.

To remain consistent with SPP's OATT, the RARTF recommended using a 40-year assessment to evaluate all transmission projects in the RCAR. Pursuant to SPP's OATT, the RARTF recommended that the last 20 years of benefits should have a terminal value.

3.7 RARTF Recommendation on the Calculation of Costs

When conducting the RCAR the RARTF recommended using the most up to date ATRR for each zone.

3.8 RARTF Recommendation on Benefits to be Calculated

The RARTF recommended that the set of benefit categories listed below in this section be used in the RCAR process. The RARTF further recommended that before the RCAR is conducted, the development of specific metrics that quantify the benefits in dollars using the procedures defined by the MOPC through the work of the Economic Studies Working Group (ESWG) be completed. For metrics without dollar amounts but in other terms (MW, MWh, Tons, etc.), the RARTF recommended that the ESWG should consider recommending a range of values that can be used to monetize those metrics without hard dollar values.

As part of the benefit evaluation, the RARTF recommended the most conservative or lowest number in any range provided by the ESWG will be used in the RCAR. For those metrics that the ESWG does not endorse monetizing, the ESWG would not provide a monetized value for use in the RCAR process. In defining these benefits, the ESWG and the MOPC should also develop a method to distribute these benefits by SPP zones. For those benefits that cannot be distributed to all zones but shared by fewer than all zones, if the benefited zones agree to an alternative method for allocating the benefits, then the agreed upon method will be used.

When conducting the RCAR, the RARTF recommended using the list of benefits provided in the RARTF Report to assess the B/C ratio. Additionally, the RARTF recommended that the Regional Cost Allocation Review should consider the use of any additional benefits that may be defined and quantified in dollar values or can be converted into dollar values by the EWSG and approved by the MOPC.

The list of benefits the RARTF recommended be used in the RCAR were:

- **Adjusted Production Cost** (APC) **Benefits** – APC captures the monetary cost associated with fuel prices, run times, grid congestion, ramp rates, energy purchases, energy sales, and other factors that are directly related to energy production by generating resources in SPP. APC is calculated by adding a zones production cost to the zones purchases and subtracting out their sales.

- **Positive Impact on Capacity Required for Losses**– This captures a value for the generation capacity that may no longer be required due to a reduction in losses.

- **Improvements in Reliability** – There are five parts to improvements in reliability:

- Benefits of avoided projects which are no longer needed due to additional transmission development.

- From major generation centers within SPP to key delivery points on the boundary of SPP. This category relates to export capability improvements.

- From key external receipt points at the boundary of SPP to load centers within SPP. This category relates to import capability improvements.

- From key external receipt points at the boundary of SPP to key delivery points on the boundary of SPP. This category relates to improvements in the ability of SPP to accommodate wheel-through transactions.

- Reliability projects provide more value than just reliability; reliability projects can provide measurable economic benefit. The ESWG will continue to develop this portion of the reliability metric in early 2012.

- **Remedy Benefits** – The value of previously approved remedies will be captured as a benefit during all following Regional Allocation Reviews.[27]

- **Reduction of Emission Rates and Values** – This metric addresses the analytical deficiency and quantifies the changes in mercury emissions. This metric also quantifies the changes in SO_2, NO_X, and CO_2 emissions so they may be represented as stand-alone values, separate from APC.

- **Reduced Operating Reserves Benefits** – As additional transmission is put in service it may reduce the amount of operating reserves needed in the SPP footprint. This metric captures the value of reduction in reserves.

- **Improvements to Import/Export Limits** – This metric quantifies the change in ATC that corresponds to an alternative topology.

- **Public Policy Benefits** – This metric captures the value of meeting the requirements of public policy.[28]

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[27] This benefit would only be applicable in subsequent reviews for any mitigation that was implemented as a result of a previous Regional Cost Allocation Review.

[28] The RARTF notes that although it is SPP's current practice is to plan for public policy objectives, under FERC Order No. 1000 SPP is required to plan for public policy objectives. Consequently, the evaluation and measurement of these benefits are consistent with the requirement to plan for them.

3.9 RARTF Recommendation on Assumptions to be Used

The RARTF recommended that the assumptions used in the RCAR should be vetted through SPP's open and transparent stakeholder process.

SECTION 4: REPORT THRESHOLDS

4.1 RARTF Recommended a Remedy Threshold

Pursuant to the RARTF Charter, the RARTF recommended that a threshold be established to determine when it is warranted for SPP staff to study possible remedies to address an imbalance based upon the results of a RCAR. The threshold set by the RARTF defined when SPP staff should study a zonal mitigation. If a zone is determined to be below this threshold, mitigation may be necessary to create equity.

The RARTF recommended that a threshold be set at a 0.8 B/C ratio for projects that are a part of the assessment report stated in Section 3.2(2) above.[29] Section 3.2(2) calls for a report on "all SPP projects that have been issued an NTC since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report."

The RARTF found that during the first Regional Cost Allocation Review, few, if any, projects will actually be in service;[30] and that consideration should be given to all Board of Directors approved projects contained in plans that have an in-service date of ten years or less from the year of the report. The importance of considering future plans is highlighted by FERC's Order on Rehearing in Docket No. ER10-1069-001 in which FERC noted that the Highway/Byway cost allocation methodology will be applied to projects other than the Priority Projects.[31]

4.2 RARTF Recommendation for Zones Above Threshold but Below 1.0 B/C

Pursuant to the RARTF Charter, the RARTF recommended that a threshold be established to determine when it is warranted that SPP staff study possible remedies as stated in Section 4.1.

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[29] The RARTF notes that the 0.8 B/C ratio recommended in this report based upon the ESWG and SPP Stakeholder approving a method to measure the benefits listed in Section 3.8. Additionally, the RARTF notes that the 0.8 B/C may not be appropriate or practical if a Review produces a B/C ratio for all projects lower than anticipated by the RARTF.

[30] The RARTF Report noted that the Tulsa Reactor from SPP's Priority Projects was at the time the only project expected to be in service by June 2012. As of the drafting of the RCAR report only 48 of the 298 Highway/Byway funded upgrades that are subject to the RCAR review are in service. These upgrades account for only 3.2% of the cost of Highway/Byway funded transmission upgrades and only 1.8% of the new miles of transmission facilities that are included in the RCAR study.

[31] As FERC noted in the October 20, 2011 Order on Rehearing, "the Priority Projects are just one set of projects to be constructed over the years of transmission development in SPP." *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at P 32 (2011).

Additionally, the RARTF recommended that any Regional Cost Allocation Review, which shows that a zone is above the 0.8 threshold in Section 4.1, but below a 1.0 B/C ratio, should be used and considered as a part of SPP's transmission planning process in the future.

SECTION 5: POTENTIAL REMEDIES TO BE STUDIED

5.1 RARTF Recommended Zonal Remedies

If the results for a zone following a RCAR are below the threshold in Section 4.1, the RARTF recommended that the SPP staff evaluate and recommend possible mitigation remedies for the zone. In Figure 5 of the RARTF Report, the RARTF provided a list of mitigation remedies that SPP staff should consider for study and to be made part of the report. The purpose of the evaluations is to determine potential remedies that bring the zone above the threshold.

The potential list of remedies recommended by the RARTF, which were listed in order of preference, that SPP staff could evaluate include, but are not limited to:

Figure 5.1
Potential Remedies

Remedy	Entity with Authority/Duty to Implement
(1) Acceleration of planned upgrades;	**SPP BOD**
(2) Issuance of NTCs for selected new upgrades;	**SPP BOD**
(3) Apply Highway funding to one or more Byway Projects;	**RSC, SPP BOD & FERC**
(4) Apply Highway funding to one or more Seams Projects;	**RSC, SPP BOD & FERC**
(5) Zonal Transfers (similar to Balanced Portfolio Transfers) to offset costs or a lack of benefits to a zone;	**RSC, SPP BOD & FERC**
(6) Exemptions from cost associated with the next set of projects;	**RSC, SPP BOD & FERC**
(7) Change Cost Allocation Percentages.	**RSC, SPP BOD & FERC**

SECTION 6: STAKEHOLDER DEVELOPMENT OF MONITIZED BENEFITS

6.1 Formation of the Metrics Task Force

After the RARTF Report was approved by the MOPC, RSC, Members Committee and Board of Directors, the ESWG established the MTF to address the monetization of benefit metrics for the RCAR. The MTF was commissioned to meet as needed to develop tangible dollar oriented measures and metrics for use in economic evaluations as identified by the RARTF. The MTF was given direction to address these categories of benefits and any others that could be monetized:

- **Reduced Capacity Reserve Requirements** - as measured by reduced capacity margin (reserve) requirements. Capital cost impacts have been previously identified therefore the group would focus on a methodology for calculating how transmission improvements would reduce reserves.

- **Improvements in Reliability** - improvements other than cost reductions from the elimination or delay of reliability upgrades which have previously been identified.
- **Improvement in Import/Export Limits** - develop metrics that monetize increasing the import and export limits at the SPP borders.
- **Public Policy Benefits** - develop methods and/or metrics for monetizing the benefits associated with those projects that are identified as Public Policy Projects.
- **Reduced Operating Reserve Requirements** - develop metrics or methods that monetize the benefits associated a reduced operating reserve requirement in SPP.
- **Other benefits that can be monetized at the recommendation of the Task Force**

The MTF was composed of the following members[32]:

MTF Members	
Kip Fox	American Electric Power
Roy Boyer	Xcel Energy Services, Inc.
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
Mitchell Williams	Western Farmers Electric Cooperative

The MTF scope of work and key deliverables[33] included the following:

- A recommendation on which of the benefits identified above can be quantified in dollars.
- Methodologies for the benefits identified above, including the allocation of the benefit to each SPP Zone (Reference the Southwest Power Pool Open Access Transmission Tariff, Attachment H, Section I, Table 1). An estimate of the effort to calculate the benefits identified above.
- A list of any issues identified from their efforts or any additional direction needed from other working groups.

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[32] Hannes Pfeifenberger and Kamen Madjarov from the Brattle Group were engaged to support the MTF: (1) to document the status of the current effort, including the extent to which different metrics have been specified and the quantification/monetization efforts that have been developed; (2) to identify possible overlaps between the specified metrics to avoid double counting of benefits; (3) to identify gaps to the extent which already-selected metrics do or do not completely capture the specified types of transmission benefits; (4) to identify any remaining gaps in the range of potential transmission benefits; and (5) to develop metrics to address the identified gaps.

[33] The MTF Charter is posted on SPP's website at: http://www.spp.org/publications/20120227%20Metrics%20Task%20Force%20Charter.pdf

- A plan for gaining consensus on the metric assumptions and methodologies.
- Progress updates at ESWG meetings.
- A written report containing such recommendations, was to be completed by MTF no later than the July, 2012 ESWG meeting.

6.2 Metrics Task Force Development of Benefit Metrics

At the conclusion of their work, the MTF submitted a final report (MTF Report) to the ESWG on September 13, 2012. The MTF provided the ESWG with a Report that contained a full analysis of the "wide-range of benefit metrics" that had been discussed and vetted through "multiple open and transparent stakeholder meetings."[34]

The MTF Report contained the following summary of the Task Force's efforts:

> 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.

[34] The MTF Report is posted on SPP's website at:
http://www.spp.org/publications/20120913%20MTF%20Report_approved.pdf

> 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.

In their Report, the MTF recommended that a total of thirteen (13) monetized benefit metrics be utilized in the RCAR process. Of those 13 metrics; 5 were benefit metrics previously used in the Integrated Transmission Planning (ITP) process; and 8 were benefit metrics newly developed by the MTF.

6.3 Stakeholder Approval of Metrics Task Force's Development of Benefit Metrics

At the September 13, 2012 meeting of the ESWG, the MTF presented the MTF Report. After the presentation of the MTF Report, the Report was amended and approved by the ESWG and sent on to the MOPC for approval.[35] At the October 16-17, 2012 MOPC meeting the MTF Report was presented for approval. After a presentation of the Report, the MOPC approved the Report.[36] Later in the month, the MTF Report was presented to the SPP Board of Directors and Members Committee on October 30, 2012. After a presentation of the Report, the Members

[35] *See* report posted on SPP's website at:
http://www.spp.org/publications/20120913%20MTF%20Report_approved.pdf

[36] *See* Agenda Item 12 in the MOPC October 16-17, 2012 minutes posted on SPP's website at:
http://www.spp.org/publications/MOPC%20Minutes%20&%20Attachments%20October%2016-17,%202012.pdf

Committee approved the metrics unanimously followed by the Board of Directors' approval of the Report.[37]

After the MTF benefit metrics were approved by SPP's stakeholder process, most of these benefits were included in the RCAR analyses. Section 7.5 below discusses which metrics developed by the MTF that were used in the RCAR.

SECTION 7: RESULTS OF THE RCAR

7.1 Summary of Benefits and Costs

Figures 7.1 and 7.2 summarize the 40-year present values of the estimated benefit metrics and costs (in 2013 dollars) and the resulting B/C ratios by SPP zone.[38] Per the direction of the RARTF, the RCAR review valued the suspended NTCs by weighting their benefits and cost at 75% (see Section 7.3 below). Figure 7.1 summarizes the 40-year present values of the benefits and costs of NTC projects (including suspended NTCs). Figure 7.2 shows the 40-year present value of the benefits and costs of the NTC projects (including suspended NTCs) plus all projects that have received an Authorization to Plan (ATP) and have an in-service date within 10 years.

Zones with a B/C ratio below the 0.8 threshold are marked with a red dot. For these zones, the additional amount of benefits needed to bridge this "gap" and achieve a B/C ratio of 0.8 are shown in the last two columns (also in 2013 dollars).

[37] *See* Summary of Action Items no. 9 in the Board of Directors October 30, 2012 Minutes posted at: http://www.spp.org/publications/BOD103012.pdf

[38] A list of RCAR study assumptions is contained in Appendix 3 to this report

Figure 7.1
Estimated 40-year Present Value of Benefit Metrics and Costs

(NTC Projects + Suspended NTCs at a 75% Weight)

	Present Value of 40-yr Benefits for 2013-2052												Present Value of 40-yr ATRRs			Est. Benefit-to-Cost Ratio	Gap to Reach B/C Ratio of 0.8	
	Adjusted Productio n Cost Savings (2013 $million)	Cost Savings from Reduced On-peak Trans-mission Losses (2013 $million)	Avoided or Delayed Reliability Projects (2013 $million)	Mitigation of Trans-mission Outage Costs (2013 $million)	Assumed Benefit of Mandated Reliability Projects (2013 $million)	Benefit from Meeting Public Policy Goals (2013 $million)	Increased Wheeling Through and Out Revenue s (2013 $million)	Reduced Cost of Extreme Events (2013 $million)	Capital Savings from Reduced Minimum Required Margin (2013 $million)	Reduced Loss of Load Probabilit y (2013 $million)	Marginal Energy Losses Benefits (2013 $million)	**Total Benefits** (2013 $million)	Before PtP Revenue Offset (2013 $million)	PtP Revenue Offset (2013 $million)	**After PtP Revenue Offset** (2013 $million)		TOTAL (2013 $million)	Levelize d Real (2013 $m/yr)
AEPW	$240	$31	$17	$76	$539	$32						$934	$1,102	$95	$1,007	**0.93**	$0	$0.0
CUS	$7	$0	$0	$5	$19	$0						$31	$58	$5	$53	**0.59**	**$11**	**$0.7**
EDE	$7	-$1	$1	$9	$30	$6						$51	$93	$8	$85	**0.60**	**$17**	**$1.1**
GMO	$23	$1	$1	$14	$50	$28						$117	$155	$14	$141	**0.83**	$0	$0.0
GRDA	$10	$1	$1	$7	$33	$0						$51	$83	$7	$76	**0.67**	**$10**	**$0.6**
KCPL	$24	$6	$2	$27	$93	$52						$203	$290	$25	$264	**0.77**	**$9**	**$0.5**
LES	$5	$1	$1	$7	$28	$0						$42	$79	$7	$72	**0.58**	**$16**	**$1.0**
MIDW	$60	$3	$14	$3	$35	$0						$115	$57	$5	$52	**2.23**	$0	$0.0
MKEC	$42	$8	$0	$5	$56	$1			**Not Monetized**			$112	$98	$8	$90	**1.25**	$0	$0.0
NPPD	$226	$13	$2	$23	$120	$25						$408	$288	$25	$263	**1.55**	$0	$0.0
OKGE	$175	$4	$12	$49	$236	$62						$539	$598	$52	$546	**0.99**	$0	$0.0
OPPD	$34	$2	$2	$17	$67	$26						$148	$195	$17	$178	**0.83**	$0	$0.0
SUNC	-$10	$2	$0	$4	$29	$0						$25	$56	$5	$51	**0.48**	**$16**	**$1.0**
SWPS	$1,939	$72	$8	$44	$563	$0						$2,626	$914	$77	$837	**3.14**	$0	$0.0
WEFA	$24	$2	$1	$11	$148	$14						$201	$230	$20	$210	**0.96**	$0	$0.0
WRI	$215	$11	$34	$39	$430	$51						$779	$718	$61	$656	**1.19**	$0	$0.0
TOTAL	**$3,020**	**$155**	**$97**	**$340**	**$2,475**	**$296**						**$6,383**	**$5,014**	**$433**	**$4,581**	**1.39**	**$79**	**$5**

Figure 7.2
Estimated 40-year Present Value of Benefit Metrics and Costs

(NTC Projects + Suspended NTCs at a 75% Weight
+ ATP Projects within 10 Years at a 75% Weight)

	Present Value of 40-yr Benefits for 2013-2052												Present Value of 40-yr ATRRs			Est. Benefit-to-Cost Ratio	Gap to Reach B/C Ratio of 0.8	
	Adjusted Productio n Cost Savings (2013 $million)	Cost Savings from Reduced On-peak Trans-mission Losses (2013 $million)	Avoided or Delayed Reliability Projects (2013 $million)	Mitigation of Trans-mission Outage Costs (2013 $million)	Assumed Benefit of Mandated Reliability Projects (2013 $million)	Benefit from Meeting Public Policy Goals (2013 $million)	Increased Wheeling Through and Out Revenue s (2013 $million)	Reduced Cost of Extreme Events (2013 $million)	Capital Savings from Reduced Minimum Required Margin (2013 $million)	Reduced Loss of Load Probabilit y (2013 $million)	Marginal Energy Losses Benefits (2013 $million)	**Total Benefits (2013 $million)**	Before PtP Revenue Offset (2013 $million)	PtP Revenue Offset (2013 $million)	**After PtP Revenue Offset (2013 $million)**		TOTAL (2013 $million)	Levelize d Real (2013 $m/yr)
AEPW	$265	$40	$17	$80	$567	$32						$1,001	$1,131	$98	$1,033	**0.97**	$0	$0.0
CUS	$8	$0	$0	$6	$20	$0						$34	$60	$5	$55	**0.63**	**$9**	**$0.6**
EDE	$8	-$1	$1	$9	$32	$6						$55	$96	$8	$87	**0.63**	**$15**	**$0.9**
GMO	$20	$1	$1	$15	$58	$28						$122	$163	$14	$148	**0.82**	$0	$0.0
GRDA	$11	$1	$1	$7	$35	$0						$54	$85	$7	$78	**0.70**	**$8**	**$0.5**
KCPL	$43	$6	$2	$28	$100	$52						$231	$298	$26	$272	**0.85**	$0	$0.0
LES	$6	$1	$1	$7	$30	$0						$45	$81	$7	$74	**0.61**	**$14**	**$0.9**
MIDW	$63	$3	$14	$3	$36	$0						$119	$58	$5	$52	**2.27**	$0	$0.0
MKEC	$47	$7	$0	$5	$64	$1			**Not Monetized**			$125	$105	$9	$97	**1.29**	$0	$0.0
NPPD	$216	$13	$2	$24	$127	$25						$406	$294	$25	$269	**1.51**	$0	$0.0
OKGE	$172	$5	$6	$52	$261	$62						$557	$623	$54	$569	**0.98**	$0	$0.0
OPPD	$33	$2	$1	$18	$72	$26						$153	$200	$17	$183	**0.84**	$0	$0.0
SUNC	$0	$2	$0	$4	$30	$0						$36	$57	$5	$52	**0.69**	**$6**	**$0.4**
SWPS	$2,077	$72	$13	$47	$584	$0						$2,794	$935	$79	$856	**3.26**	$0	$0.0
WEFA	$33	$3	$1	$12	$160	$14						$222	$242	$21	$221	**1.01**	$0	$0.0
WRI	$187	$11	$34	$41	$478	$51						$802	$766	$65	$700	**1.14**	$0	$0.0
TOTAL	**$3,188**	**$166**	**$96**	**$359**	**$2,654**	**$296**						**$6,759**	**$5,193**	**$447**	**$4,746**	**1.42**	**$52**	**$3**

7.2 Transmission Projects Evaluated in this RCAR Report

This Regional Cost Allocation Review was conducted by evaluating three sets of transmission projects. These three sets are:

- NTC: All SPP projects that have been issued a NTC since June 2010 and have not been suspended;
- Suspended NTC: All NTC projects that are suspended pending further review; and
- ATP: All projects that have received an Authorization to Plan (ATP) and have an in-service year of 2023 or earlier (ten years or less from issuance of RCAR report).

These projects were evaluated by looking at their projected cost and the estimated benefits. The projected costs of the projects were conducted by SPP Staff. The analyses to estimate the projected benefits were conducted by the Brattle Group by monetizing a subset of benefits developed by the MTF and approved by the SPP stakeholder (See Section 6 above).

7.3 RARTF Guidance Provided to SPP Staff While Conducting the Review

While conducting the RCAR analysis, SPP Staff was faced with a couple of unanticipated issues that were not contemplated in the RARTF Report approved by SPP Stakeholders in January 2012. As a result during the RARTF's May 31, 2013 conference call, SPP Staff sought the guidance from the RARTF on the following issues:

(1) How to handle the new NTC projects issued in 2013 that were not a part of the 2012 models developed for this RCAR effort.

(2) How to handle the existing NTC projects that were suspended by the SPP Board of Directors for further study.

During the conference call, the RARTF unanimously supported the inclusion of the 2013 NTC projects in the RCAR Report. Additionally, the RARTF also unanimously supported the inclusion of the suspended NTCs in the RCAR but at a reduced value of 75%. Upon receiving this direction from the RARTF, SPP staff updated the models to include 2013 NTC projects[39] and adjusted the study to reduce the value of the suspended NTCs by weighting their benefits and costs at 75%.

[39] RCAR power flow models were submitted to the Model Development Working Group and other known modeling contacts from member companies for comment and review. Economic models were submitted to the ESWG for comment and review. A list of comments and subsequent updates can be found in Appendix 1 to this Report.

7.4 Cost Calculations Contained in the RCAR Report

Per the RARTF Report, SPP Staff conducted two sets of cost projections:

(1) the 40-year present value of all NTC projects (including the suspended NTCs at a reduced weight of 75%), and

(2) the 40-year present value of NTC projects (including suspended NTCs at a 75% weight) plus approved projects with an in-service date within 10 years (also at a 75% weight).

In accord with Principle 3 from the RARTF Report and the direction of the RARTF at its September 12, 2013 meeting, SPP staff used the most recent cost estimates that were provided to SPP in August 2013 for project cost tracking. By using this information, the RCAR Report is using "the most up to date and best available information for the review" per Principle 3.

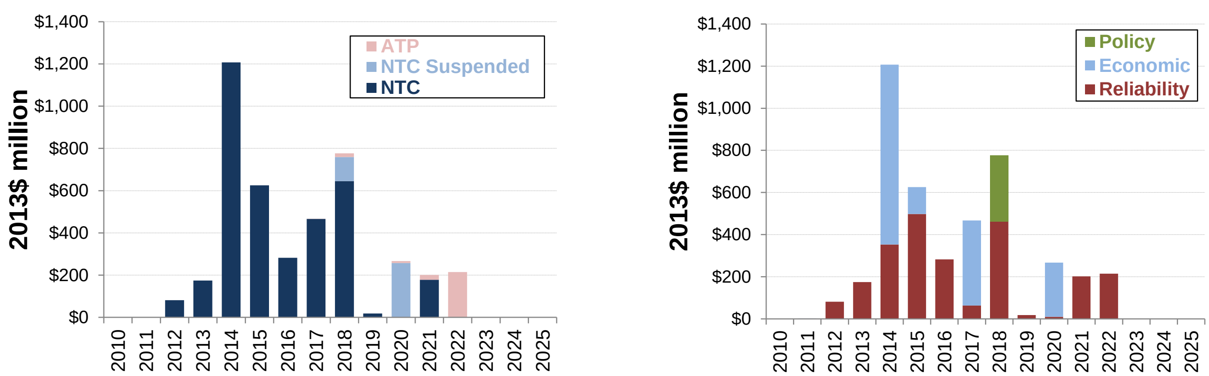
7.4.1 Classification of Projects

To conduct the RCAR analysis, the projects were classified by project type (NTCs, suspended NTCs, and ATPs within 10 years) and also by the primary driver (Reliability, Economic, and Public Policy).

Figure 7.3 below summarizes the capital costs by in-service year, classified by project type and by primary driver.

Figure 7.3
Summary of Capital Cost by In-Service Year

(a) By Project Type (b) By Primary Driver



7.4.2 Calculation of Annual Transmission Revenue Requirements (ATRRs)

Per SPP's tariff, SPP calculated the ATRRs for each zone at the project level, as summarized below:

- Cost allocated to zones based on SPP's **Highway/Byway methodology**:

– 100% regional if 300 kV or above,

– 33% regional, 67% zonal if between 100 kV and 299 kV, and

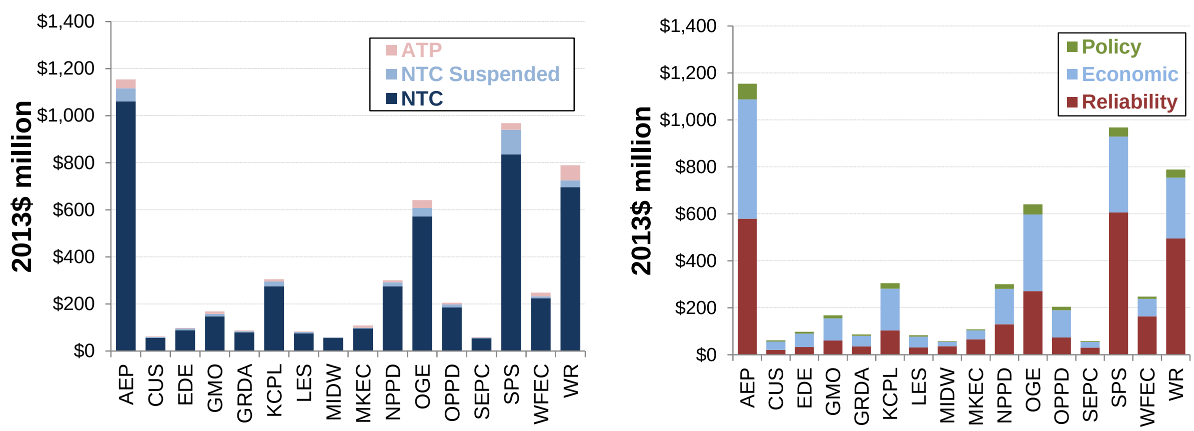
– 100% zonal if below 100 kV.

- **Load ratio share (LRS)** used for the portion of costs allocated on a regional basis
  - Used actual 12-coincident peak loads for 2012, as provided by SPP
- **Net plant carrying charge (NPCC)** applied at the zonal level to calculate first year ATRRs in 2013 dollars
- **2.5%/yr inflation** applied to estimate first year ATRRs in nominal dollars
- **2.5%/yr straight-line depreciation** applied in calculating declining ATRR profile over time in nominal dollars
- Present values calculated for 40-year depreciated ATRRs for 2013-2052 at a nominal **discount rate of 8.0%**

Figure 7.4 below summarizes the 40-year present value of ATRRs by SPP pricing zone. At the regional level, the present value of ATRRs are estimated to be **$4.8 billion** for the NTC projects, **$323 million** for the suspended NTC projects and **$239 million** for the ATP projects (in 2013 dollars).

Figure 7.4
40-Year Present Value of ATRRs by Zone

(a) By Project Type (b) By Primary Driver



7.4.3 Calculation of Point-to-Point (PTP) Revenue

Although the RCAR report did not calculate the increased wheeling revenue metric identified by the MTF (See Section 7.5 below), SPP Staff projected a PTP revenue credit to each Pricing Zone (Zone) over the 40 years of the study. This PTP revenue credit offsets the costs (ATRR) allocated to the individual Zones from Base Plan Zonal cost allocation and to all the Zones through a reduction in the Base Plan Regional rate. The PTP revenue reduces the ATRR that must be recovered in subsequent years by the Network Integrated Transmission Service (NITS) charges to all of the Transmission Customers of the SPP Zones.

Step 1: Estimate PTP Volumes

The PTP revenue is estimated by first determining the average PTP activity in the SPP footprint by PTP type (Annual, Monthly, Weekly, Daily Peak and Off-Peak, and Hourly Peak and Off-Peak) from the previous three years, 2010, 2011, and 2012. Once the average PTP volume was established by type it was fixed over the 40 years of the study. The following table shows the sales volumes used in the PTP offset calculation in the form of billable daily MW.

Figure 7.5

SPP PTP Service Types and Volumes, Averages of Years 2010, 2011 and 2012

PTP Service Types Considered (Ave. 2010-2012)	Yearly	Monthly	Weekly	Daily On-Peak	Daily Off-Peak	Hourly On-Peak	Hourly Off-Peak
Through (MW)	154	986	17	3,619	1,448	573,314	286,657
Out (MW)	2,445	2,376	3,678	24,753	9,901	1,320,647	660,324
Into (MW)	67	15	not incl.	not incl.	not incl.	not incl.	not incl.
Within (MW)	145	202	not incl.	not incl.	not incl.	not incl.	not incl.

Since SPP's future Integrated Marketplace provides congestion rights for service of one month or longer, shorter duration service for "Into" and "Within" service types was assumed to go away. Shorter duration service types serving external loads are still expected after SPP's Integrated Marketplace goes live and were therefore included.

PTP volumes associated with "Into" and "Within" PTP directions were further reviewed. Any PTP transactions that were purchased by a Network Customer that sank in their own Zone were removed from consideration. Only the BPR components of the remaining "Into" and "Within" PTP directions were considered in the PTP sales volumes.

Step 2: Determine PTP Zonal and Regional Rate from RCAR Upgrades

Next, a PTP rate was forecasted for each PTP type for the 40 years of the study. The PTP rate forecast was based upon the ATRR each year of the new Highway/Byway facilities divided by the SPP 12 CP in MW. The ITP20's 1.3% annual load growth projection was applied to years after 2013. A PTP rate was calculated for each PTP type (Monthly, Weekly, etc.). Also the NTC upgrades' ATRRs were considered at 100%, Suspended NTCs at 75%, and 10 year upgrades at 75%. All assumptions associated with the 40 year RCAR costs (ATRR generated by

RCAR upgrades) were also included in the ATRR portion of the rate calculation (2.5% straight line depreciation, 8% discount rate to 2013, etc.)

PTP revenue from the previous year was shown as a reduction in current year ATRR for every year of the study for the purposes of determining PTP rates.

Step 3: Estimate Annual RCAR PTP $

The PTP $ per year were estimated when the PTP volumes (MW) by type were multiplied by the PTP rate ($/MW) by type. This generated a total annual $ of RCAR PTP revenue for every year of the 40 year RCAR horizon. These resulting 40 years of RCAR PTP revenue projections were converted to 2013$.

Step 4: Allocate Total PTP $ to Each Pricing Zone

The Base Plan Zonal (BPZ) PTP revenue was allocated back to the Pricing Zone in-which the upgrades were built.

The Base Plan Regional (BPR) PTP revenue was allocated to all of the Pricing Zones in the SPP footprint based upon each Zone's Load Ratio Share (LRS %) of the total BPR PTP revenues. Since the total SPP Regional component of the costs that is applied to each Zone through cost allocation will be reduced by the BPR PTP revenue from the previous year this effectively reduced the "cost" component in the B/C ratios of each Zone based upon the Zone's LRS%.

Step 5: Apply PTP Revenue Credit to Each Zone's B/C Ratio

The total 40 years of BPZ and BPR PTP revenue credit in 2013$ was applied to each Zone's cost component of the RCAR B/C ratio in Tables 7.1 and 7.2.

7.5 Benefit Metrics

The benefit metrics considered for this RCAR effort includes the standard ITP metrics and three of the new metrics recommended in the September 2012 MTF report. Figure 7.6 below provides a list of these benefit metrics.

Figure 7.6
Benefit Metrics Considered in RCAR

Benefit Metric Name	Standard ITP Metric	MTF Recommended New Metric	Considered in this RCAR effort?
Adjusted Production Cost (APC) Savings	✓		Yes
Reduction of Emission Rates and Values	✓		Yes
Savings due to Lower Ancillary Service Needs and Production Costs	✓		Yes
Avoided or Delayed Reliability Projects	✓		Yes
Capacity Cost Savings due to Reduced On-Peak Transmission Losses	✓		Yes
Mitigation of Transmission Outage Costs		✓	Yes
Assumed Benefit of Mandated Reliability Projects		✓	Yes
Benefits from Meeting Public Policy Goals		✓	Yes
Increased Wheeling Through and Out Revenues		✓	No
Capital Savings due to Reduction of Members' Minimum Required Margin		✓	No
Reducing the Cost of Extreme Events		✓	No
Reduced Loss of Load Probability		✓	No
Marginal Energy Losses Benefits		✓	No

7.5.1 Adjusted Production Cost (APC) Savings

APC savings are estimated based on PROMOD simulations of the SPP system plus most of the Eastern Interconnect, for three study years: 2018, 2023, and 2033.

Five PROMOD simulation cases were developed with different transmission topology for each of the study years, holding all other inputs and assumptions constant:

Figure 7.7
Case Definitions in PROMOD

		NTC	Susp. NTC	ATP
Base Case		No	No	No
Change Case 1	CC_1	**Yes**	No	No
Change Case 1A	CC_{1A}	**Yes**	**Yes**	No
Change Case 2	CC_2	**Yes**	**Yes**	**Yes**
Change Case 2A	CC_{2A}	**Yes**	No	**Yes**

SPP provided the Brattle Group a powerflow and PROMOD system database (developed for the recent ITP20 study) to be used as a starting point for the analysis. The following changes were made to create more realistic cases for the purpose of RCAR study:

- Constraints from the ITP10 event file were added
- The top 40 temporary flowgates from 2012 were added to the event file
- The top 10 constraints from the 2011 SPP State of the Market Report were added the event file
- The PAT tool was used to develop additional transmission constraints for the SPP system
- Ratings of individual branches were taken from the powerflows used in the year/case combination
- 1% of peak load was added to the reserve requirement to represent regulation reserves

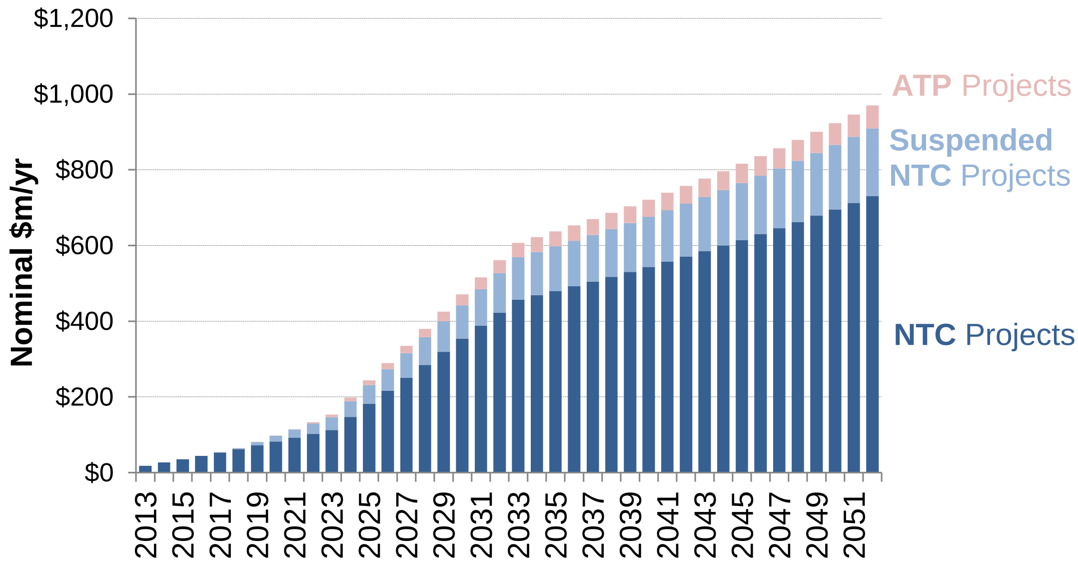
As shown in Figure 7.8, the estimated APC savings increase over time. These increases are driven by load growth and increases in fuel prices. Figure 7.9 shows the estimated APC savings for the 40-year study period, applying a 75% of weight for both suspended NTCs and ATP projects. The annual estimates between study years 2018, 2023 and 2033 are interpolated; after 2033 they are conservatively assumed to grow only at inflation.

Figure 7.8
Summary of APC Savings by Zone

Zone	NTC Projects				Suspended NTC Projects				ATP Projects (Suspended NTCs Not Built)				ATP Projects (Suspended NTCs Built)			
	2018 ($m)	2023 ($m)	2033 ($m)	40-yr NPV ($m)	2018 ($m)	2023 ($m)	2033 ($m)	40-yr NPV ($m)	2018 ($m)	2023 ($m)	2033 ($m)	40-yr NPV ($m)	2018 ($m)	2023 ($m)	2033 ($m)	40-yr NPV ($m)
AEPW	$1.6	$3.6	$56.3	$245.1	-$0.1	$0.4	-$2.1	**-$7.5**	-$0.3	-$1.5	$8.6	**$30.6**	-$0.2	-$1.2	$9.1	**$33.5**
CUS	$0.4	$0.8	$0.9	$7.9	$0.0	-$0.2	-$0.3	**-$1.7**	$0.0	$0.3	$0.5	**$2.6**	$0.0	$0.2	$0.3	**$1.8**
EDE	-$0.1	$0.4	$1.5	$6.7	$0.0	$0.1	$0.1	**$0.6**	$0.0	$0.4	$0.6	**$3.3**	-$0.1	$0.2	$0.3	**$1.4**
GMO	-$0.4	$1.4	$5.0	$23.1	$0.0	$0.0	$0.0	**-$0.1**	$0.0	-$0.5	-$1.2	**-$5.7**	$0.0	-$0.1	-$1.1	**-$4.5**
GRDA	$0.5	$1.1	$1.8	$12.9	$0.0	-$0.7	-$0.4	**-$3.8**	-$0.1	-$0.2	-$0.5	**-$2.8**	-$0.2	$0.0	$0.5	**$1.7**
KCPL	$4.0	$3.1	-$2.0	$18.6	$0.0	$0.7	$1.1	**$6.6**	$0.4	$3.6	$4.9	**$29.3**	$0.4	$2.5	$4.6	**$25.3**
LES	$0.3	$1.8	-$0.4	$5.6	$0.0	$0.0	-$0.1	**-$0.6**	$0.0	-$0.1	$0.2	**$0.8**	$0.0	$0.0	$0.2	**$1.0**
MIDW	-$0.1	$0.9	$14.7	$62.0	$0.0	-$0.4	-$0.5	**-$3.0**	$0.0	$0.3	$0.8	**$3.8**	$0.0	$0.3	$0.9	**$4.1**
MKEC	$0.1	$2.3	$9.1	$44.4	$0.0	-$0.4	-$0.5	**-$3.3**	$0.0	$0.4	$1.7	**$7.9**	$0.0	$0.5	$1.5	**$7.2**
NPPD	$6.8	$22.4	$30.8	$223.3	-$0.1	$0.4	$0.5	**$3.1**	$0.4	-$2.1	-$3.0	**-$16.0**	$0.5	-$1.7	-$2.6	**-$13.0**
OKGE	$2.9	$15.6	$28.8	$177.3	$0.1	-$0.9	-$0.1	**-$3.1**	-$0.3	$0.2	$0.4	**$1.3**	-$0.6	-$0.1	-$0.6	**-$4.3**
OPPD	$0.9	$2.3	$5.6	$33.3	$0.1	$0.0	$0.3	**$1.4**	$0.1	$0.4	-$0.4	**-$0.7**	$0.0	$0.2	-$0.4	**-$1.2**
SUNC	-$2.5	-$1.5	$2.4	-$5.9	$0.0	-$0.5	-$0.9	**-$5.5**	$0.0	$1.2	$3.4	**$16.6**	$0.0	$0.8	$2.8	**$13.1**
SWPS	$40.3	$45.0	$258.6	$1,354.1	$3.2	$49.0	$153.9	**$780.2**	$1.2	$2.4	$34.4	**$147.2**	$0.5	$7.8	$41.0	**$184.2**
WEFA	$0.8	$1.8	$6.3	$34.5	$0.1	-$1.5	-$2.2	**-$13.3**	$0.2	$1.2	$3.2	**$16.1**	$0.1	$1.0	$2.1	**$11.2**
WRI	$6.7	$11.3	$37.8	$215.7	$0.0	-$0.6	$0.2	**-$1.2**	$0.1	-$1.5	-$8.5	**-$37.5**	$0.0	-$1.5	-$8.3	**-$36.9**
Total	**$62.2**	**$112.5**	**$457.1**	**$2,458.5**	**$3.1**	**$45.3**	**$149.0**	**$748.8**	**$1.7**	**$4.6**	**$45.1**	**$196.9**	**$0.3**	**$8.8**	**$50.5**	**$224.5**

Figure 7.9
Estimated APC Savings for the 2013-2052 Period

(Applies 75% Weight for Suspended NTCs and ATP Projects)



7.5.2 Avoided or Delayed Reliability Projects

Avoided or delayed reliability projects were identified through powerflow models that represent transmission utilization based on selected snapshots of generation dispatch and system loads. Figure 7.10 summarizes the powerflow cases used in the study.

Figure 7.10
List of Powerflow Cases Analyzed

Cases	Description	Model Years
Base Case (BC)	no NTCs, no ATPs	2018, 2023
Change Case 1 (CC_1)	NTCs (excl. suspended NTCs), no ATPs	2018, 2023
Change Case 2 (CC_2)	NTCs (incl. suspended NTCs), and ATPs	2018, 2023
Change Case 1A (CC_{1A})	NTCs (incl. suspended NTCs), no ATPs	2018, 2023
Change Cases 2A (CC_{2A})	NTCs (excl. suspended NTCs), and ATPs	2018, 2023
Modified Change Cases (MCC_1, MCC_2, MCC_{1A}, MCC_{2A})	Same as Change Case but excludes selected NTCs	2018, 2023
Avoided Reliability Cases (AR_1, AR_2, AR_{1A}, AR_{2A})	Same as Modified Change Case but with avoided reliability projects	2018, 2023

Figure 7.11 lists the selected NTC projects excluded in the modified base cases to identify (a) the reliability violations and (b) the reliability projects (avoided by the selected NTC projects) that would be needed to narrowly address the identified reliability violations. The selected NTC projects include all projects designated as either economic or public policy projects.

Figure 7.11
List of Selected NTC Projects

PID	FACILITIES DESCRIPTION
936	Northwest Texarkana – Valliant 345 kV Ckt 1
937	Tulsa Power Station 138 kV
938	Sibley 345 kV – Maryville 345 kV; Nebraska City 345 kV – Maryville 345 kV (GMO)
939	Nebraska City 345 kV – Maryville 345 kV (OPPD)
940	Hitchland Interchange 345/230kV Transformer Ckt 2; Hitchland Interchange – Woodward District EHV 345 kV Ckts 1 & 2 (SPS)
941	Hitchland Interchange – Woodward District EHV 345 kV Ckts 1 & 2 (OGE)
942	Thistle – Woodward EHV 345 kV Ckts 1 & 2 (OGE)
943	Thistle – Woodward EHV 345 kV Ckts 1 & 2 (PW)
945	Spearville 345 kV – Clark Co 345 kV Ckt 1; Clark Co 345 kV – Thistle 345 kV Ckts 1 & 2; Thistle 345/138 kV Transformer; Flat Ridge – Thistle 138 kV
946	Wichita 345 kV
30375	Cherry Co – Gentleman 345 kV Ckt 1; Gentleman 345 kV Terminal Upgrades Cherry Co – Holt Co 345 kV Ckt 1; Cherry Co 345 kV Holt Co 345 kV
30376	Amoco-Tuco-Hobbs 345 kV Circuit 1 and associated 345/230 kV transformers

Figure 7.12 shows the avoided reliability projects that would be needed to address the identified reliability violations. Cost data provided by SPP was used to estimate the total costs of the avoided reliability projects. The benefits are assumed to be equal to the NPV of associated ATRRs for 2013-2052, applying the same approach used for estimating the ATRRs of NTC and ATP projects. They are allocated to zones based on the ratios that would have been applied for the costs of the reliability projects under Highway/Byway methodology.

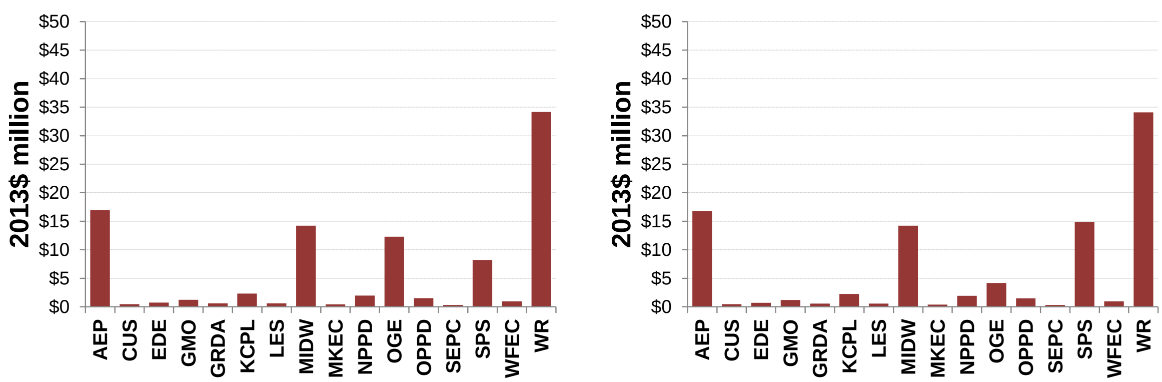
Figure 7.12
List of Avoided Reliability Projects

Project Name	Area	Cost ($m)	2018 CC1	2018 CC1A	2018 CC2	2018 CC2A	2023 CC1	2023 CC1A	2023 CC2	2023 CC2A
Huntsville-Hutchinson Energy Center 115 kV Line	MIDW/WERE	$22.2	✓	✓	✓	✓	✓	✓	✓	✓
Woodward-Windfarm 138 kV Line	OKGE	$12.0					✓	✓		
Gordon Evans-Lakeridge 138 kV Line	WERE	$9.6					✓	✓	✓	✓
Mound-Yost 69 kV Line	WERE	$5.1					✓	✓	✓	✓
Cowskin-45th St 138 kV Line	WERE	$7.6					✓	✓	✓	✓
Carnegie-Southwestern 138 kV Line	AEPW	$14.7					✓	✓	✓	✓
Sdierks2-Dierksr2 69 kV Line	AEPW	$2.6					✓	✓	✓	✓
Lawhill-Lec 230 kV Line	WERE	$0.3					✓	✓	✓	✓
Hillsboro-Spring Creek 115 kV Line	WERE	$10.9					✓	✓	✓	✓
Monument-Hobbs West 115 kV Line	SPS	$8.2					✓	✓	✓	
Texas County-Hitchland 115 kV Line	SPS	$12.6							✓	✓

Figure 7.13 below summarizes the benefits of avoided reliability projects by zone. At the regional level, the 40-year present value of benefits for avoided reliability projects adds up to **$97 million** (in 2013 dollars), with no estimated benefits from suspended NTC projects. The system-wide benefits do not change when ATP projects are included, but the allocation of the benefits across zones shift slightly.

Figure 7.13
Benefits of Avoided or Delayed Reliability Projects

(a) NTC (b) NTC + 75% of ATP



7.5.3 Capacity Savings due to Reduced On-Peak Transmission Losses

Reduced capacity expansion costs due to lower transmission losses on peak captures the value of system-wide generation capacity that will no longer be required (each MW of reduced on-peak losses saves 1.12 MW of new capacity).

On-peak transmission losses are quantified for two study years (2018, 2023) and five cases (Base, CC_1, CC_{1A}, CC_2, and CC_{2A}). As shown in Figure 7.14, SPP-wide on-peak transmission losses are estimated to decrease by about 72 MW in 2018 and 122 MW in 2023 as a result of NTC projects. Including the suspended NTC projects reduce the on-peak losses by an incremental 1 MW in 2018 and 2023. If the suspended NTC projects are not built, ATP projects further reduce the on-peak losses by 0.5 MW in 2018 and 14 MW in 2023, while if they are built, losses would increase by 0.5 MW in 2018 and decrease by 17 MW in 2023.

Figure 7.14
Change in On-Peak Transmission Losses by Zone

Zone	2018				2023			
	NTCs (MW)	Suspended NTCs (MW)	ATPs (Suspended NTCs Not Built) (MW)	ATPs (Suspended NTCs Built) (MW)	NTCs (MW)	Suspended NTCs (MW)	ATPs (Suspended NTCs Not Built) (MW)	ATPs (Suspended NTCs Built) (MW)
AEPW	(14.9)	(0.1)	0.0	0.0	(24.1)	(0.1)	(14.1)	(14.2)
CUS	(0.1)	0.0	0.0	0.0	(0.1)	0.0	0.0	0.0
EDE	0.4	0.0	0.0	0.0	0.7	0.0	0.0	0.0
GMO	(0.6)	0.0	(0.1)	(0.1)	(0.7)	0.0	(0.2)	(0.2)
GRDA	(0.4)	0.0	0.0	0.0	(0.6)	0.0	0.0	0.0
KCPL	(3.7)	0.0	(0.1)	(0.1)	(4.0)	0.0	(0.3)	(0.3)
LES	(0.7)	0.0	0.0	0.0	(0.8)	0.0	0.0	0.0
MIDW	(1.5)	0.0	0.0	0.0	(2.1)	0.0	0.0	0.0
MKEC	(4.0)	(0.1)	0.0	1.3	(6.8)	1.2	1.2	0.0
NPPD	(1.8)	0.0	0.0	0.0	(12.3)	0.0	0.2	0.2
OKGE	(1.1)	(0.1)	(0.1)	0.0	(4.0)	0.1	(0.4)	(0.3)
OPPD	(1.3)	0.0	0.0	0.0	(1.4)	0.0	0.0	0.0
SUNC	(1.0)	0.1	0.1	(1.2)	(0.2)	(1.3)	(1.2)	0.0
SWPS	(35.2)	(0.7)	(0.4)	(0.5)	(55.3)	(1.0)	2.3	(0.9)
WEFA	0.6	0.0	0.0	0.0	(2.6)	(0.1)	(0.4)	(0.4)
WRI	(6.4)	0.0	0.1	0.0	(7.7)	0.0	(0.8)	(0.8)
Total	**(71.7)**	**(0.9)**	**(0.5)**	**(0.6)**	**(122.0)**	**(1.2)**	**(13.7)**	**(16.9)**

The loss reductions are calculated on a zonal basis, then interpolated between 2018 and 2023, and assumed to increase at inflation afterwards. The results are then multiplied by **1.12** (1+reserve margin) to calculate the reduction in installed capacity requirements. The value of capacity savings is monetized on a zonal basis by applying a net cost of new entry (net CONE) of **$84/kW-yr** in 2013 dollars.

The net CONE value was calculated as the difference between an estimated gross CONE value and the expected operating margins (energy market revenues net of variable operating costs, also referred to as "net market revenues") for a combustion turbine. A gross CONE value of $95/kW-yr was obtained by levelizing the capital and fixed operating costs of a new advanced combustion turbine as reported in EIA's Annual Energy Outlook 2012. Net market revenues of $11/kW-yr were estimated based on the historical data for the margins of gas-fired combustion turbines, as provided in SPP's 2011 State of Market Report.

Figure 7.15 summarizes the capacity savings by SPP pricing zones. The NPV of capacity savings related to NTC projects is about **$154 million** in total and that related to suspended NTCs is about **$1.4 million**. The NPV of capacity savings related to ATP projects is about **$12.2 million** if suspended NTCs are not built and about **$15.3 million** if they are built.

Figure 7.15
Capacity Savings due to Reduced On-Peak Transmission Losses

SPP Zone	Savings Related to NTCs			Savings Related to Suspended NTC			Savings Related to ATPs (Suspended NTCs Not			Savings Related to ATPs (Suspended NTCs Built)		
	2018 (nominal $m/yr)	2023 (nominal $m/yr)	40-yr NPV (2013 $million)	2018 (nominal $m/yr)	2023 (nominal $m/yr)	40-yr NPV (2013 $million)	2018 (nominal $m/yr)	2023 (nominal $m/yr)	40-yr NPV (2013 $million)	2018 (nominal $m/yr)	2023 (nominal $m/yr)	40-yr NPV (2013 $million)
AEPW	$1.6	$2.9	$30.7	$0.0	$0.0	$0.1	$0.0	$1.7	$12.4	$0.0	$1.7	$12.7
CUS	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
EDE	$0.0	-$0.1	-$0.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
GMO	$0.1	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	$0.0	$0.0	$0.2
GRDA	$0.0	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
KCPL	$0.4	$0.5	$5.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.3	$0.0	$0.0	$0.3
LES	$0.1	$0.1	$1.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MIDW	$0.2	$0.3	$2.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
MKEC	$0.4	$0.8	$8.6	$0.0	-$0.1	-$1.2	$0.0	-$0.1	-$1.1	-$0.1	$0.0	-$0.3
NPPD	$0.2	$1.5	$13.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$0.2	$0.0	$0.0	-$0.2
OKGE	$0.1	$0.5	$4.5	$0.0	$0.0	-$0.1	$0.0	$0.0	$0.4	$0.0	$0.0	$0.3
OPPD	$0.1	$0.2	$2.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
SUNC	$0.1	$0.0	$0.6	$0.0	$0.2	$1.3	$0.0	$0.1	$1.0	$0.1	$0.0	$0.3
SWPS	$3.7	$6.6	$70.8	$0.1	$0.1	$1.1	$0.0	-$0.3	-$1.9	$0.1	$0.1	$0.9
WEFA	-$0.1	$0.3	$2.3	$0.0	$0.0	$0.1	$0.0	$0.0	$0.4	$0.0	$0.0	$0.4
WRI	$0.7	$0.9	$10.5	$0.0	$0.0	$0.0	$0.0	$0.1	$0.7	$0.0	$0.1	$0.7
TOTAL	**$7.6**	**$14.7**	**$153.6**	**$0.1**	**$0.1**	**$1.4**	**$0.1**	**$1.6**	**$12.2**	**$0.1**	**$2.0**	**$15.3**

7.5.4 Mitigation of Transmission Outage Costs

The PROMOD runs used to estimate APC savings do not account for transmission outages, and thereby ignore the added congestion-relief and production cost benefits of new transmission facilities during the planned and unplanned outages of existing transmission facilities.

To estimate the incremental savings associated with the mitigation of transmission outage costs, "outage" cases were analyzed in PROMOD for the 2023 study year. The cases were developed based on 12 months of historical transmission data provided by SPP for December 2011 to November 2012.

Because of the volume of historical transmission outage data (approximately 6,400 outage events) and based on the expectation that many outages would not necessarily lead to significant increases in congestion, only a subset of all outage events was modeled. The outage events selected were those expected to create significant congestion. The outages selected to be modeled in PROMOD meet at least one of the following conditions:

- Involved facilities with a nominal voltage over 230 kV and lasted 5 days or longer

- Involved facilities with a nominal voltage over 100 kV, lasted 4 hours or longer, and had a significant impact on a defined contingency[40]
- Involved facilities with a nominal voltage over 100 kV, lasted 4 hours or longer, and had a significant impact on a binding constraint in the Base Case PROMOD runs[41]

In total, 732 outage events were modeled, capturing 11.4% of the 6,405 historical outage events in the 12-month period, and 21.5% of the historical outage hours.

Figure 7.16 shows the impact of the outages on the APC savings estimated in PROMOD for the 2023 study year.[42] Comparing the outage results for Base Case and CC_2 translates to an annual savings that were 11.3% higher than the APC savings estimated with simulations that do did not consider transmission outages. We used this difference to monetize the SPP-wide benefits of mitigating transmission outage costs and get a 40-year NPV of benefits of **$277 million** for NTC projects, **$84 million** for Suspended NTC projects and up to **$25 million** for ATP projects. As recommended in the September 2012 MTF report, the SPP-wide benefits are allocated to SPP pricing zones based on a load ratio share.

Figure 7.16
Impact of Transmission Outages in Estimated APC Savings
(Simulation results prior to updating NTC, Suspended NTC and ATP project lists and classification)[43]

	Base (nominal $m/yr)	CC2 (nominal $m/yr)	Savings (nominal $m/yr)
2023	$8,398	$8,261	$137
2023 outage	$8,475	$8,322	$153
		Difference =	11.3%

40 An outage has a significant impact on a defined contingency if one of the elements in the contingency has a LODF over 50% with respect to the outage of the facility, and the voltage of the facility is higher than or equal to the voltage of contingency element.

41 An outage has a significant impact on a binding constraint if a monitored element in the constraint has a LODF over 35% and below 100% with respect to the outage of the facility, and the voltage of the facility is higher than or equal to the voltage of the monitored element. The 100% limit for LODF effectively removes the outage of monitored facilities, or facilities in series with monitored facilities, that do not increase flow on other binding monitored facilities.

42 These transmission outage cases are based on 2012 NTC and ATP simulations. They do not reflect the 2013 updated NTC, Suspended NTC and ATP project classification. Updating project classifications was not expected to change the 11.3% benefit factor of considering transmission outages. This 11.3% additional benefit factor from the 2012 NTC and ATP simulations was applied to the production cost savings of the simulation results reflecting 2013 updated NTC, Suspended NTC and ATP projects.

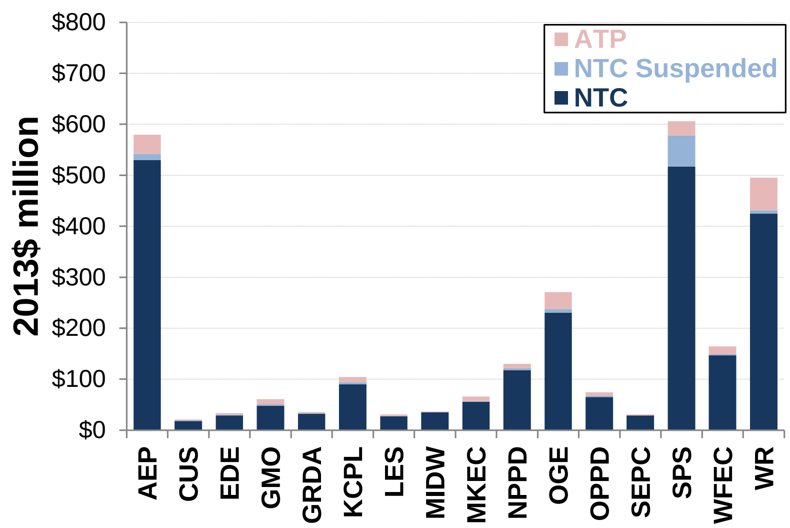
43 See previous footnote.

7.5.5 Benefits of Mandated Reliability Projects

The September 2012 MTF report recommended that this metric be calculated conservatively only for "regional" reliability projects and the benefits be set equal to the projects' costs, allocated to zones in the same way as the projects' costs are allocated.

For the purpose of this RCAR effort, all of the projects marked as reliability projects were considered to be mandated and regional. Benefits are estimated as the 40-year NPV of ATRRs for these reliability projects, allocated to zones in the same way as their costs are allocated. Figure 7.17 summarizes the estimated benefits of mandated reliability projects by zone. The SPP-wide benefits add up to **$2.4 billion** for NTC projects, **$107 million** for suspended NTC projects, and **$239 million** for ATP projects.

Figure 7.17
UPDATED Benefits of Mandated Reliability Projects by Zone



7.5.6 Benefits of Meeting Public Policy Goals

The September 2012 MTF report recommended that the benefits of meeting public policy goals be set equal to the cost of the *cost-effective* projects needed to meet the public policy goals. For the purpose of this RCAR effort, this metric is limited to the benefits of meeting public policy goals related to renewable energy.

The NTC projects marked as "public policy" projects were used as a very conservative designation of the *cost-effective* projects needed to meet the public policy goals. Therefore, the SPP-wide benefits are estimated to be **$296 million**, which is equal to the 40-year present value of the ATRRs of these public policy projects. None of the Suspended NTC or ATP projects are identified as "public policy" projects; therefore, their public policy benefits are conservatively assumed to be zero.

These very conservatively-estimated public policy benefits are allocated to the SPP pricing zones in proportion to each zone's share of unmet renewable energy goals. The unmet goals are based on the latest available SPP data for existing wind generation and renewable energy goals.

- Only the wind plants that were in-service as of June 19, 2010 are considered "existing" resources for the purpose of this calculation. Plant-specific capacity factors are used to calculate the annual generation from each resource, which is then aggregated to zonal level based on the ownership data provided by SPP.

- Total renewable energy goals are calculated as the sum of the Renewable Mandates and Targets as reported in SPP survey data.[44]

- The amount of "over-compliance" in some of the SPP zones (e.g., SWPS) is not counted towards the compliance of others.

Figure 7.18 summarizes the existing wind generation, unmet renewable goals, and each zone's share of total public policy goals. These shares are then applied to the 40-year present value of ATRRs of the NTC projects marked as "public policy" projects, which yields to $296 million in total.[45]

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44 The RCAR Report uses SPP survey data from the 2012 Public Policy Survey instead of the SPP 2013 Public Policy Survey. Differences exist between the 2012 and 2013 Public Policy Surveys. Although the 2013 survey contains "the most up-to-date information", the use of the 2013 survey would create inconsistencies between the models used in the RCAR and the allocation of Public Policy benefits. As a result, the RARTF at its September 12, 2013 meeting provided guidance to SPP staff to use data from the 2012 SPP Public Policy Survey in the RCAR Report consistent with Principle 4 of the RARTF Report.

45 It is important to note the public policy benefits shown in Figure 7.18 are very conservative. The September 2012 MTF Report defines the cost-effective projects to meet public policy goals as having "two categories: 1) projects displaced by the portfolio of projects receiving NTCs; and 2) projects included in the portfolio of projects receiving NTCs." The results shown in this section are based on the second category, and do not consider transmission costs that would likely be incurred to integrate the needed wind generation in the absence of the portfolio of NTC and ATP projects. The unmet renewable energy goal of 17.6 million MWh translates to approximately 5,000 MW of wind capacity. If valued at $450/kW-wind based on lowest "local" transmission cost reported in MISO's Regional Generation Outlet Study (RGOS) study, this would translate to more than $2.2 billion of public policy benefits, instead of the much lower $296 million shown in Figure 7.17 and as reflected in the benefit-cost analysis. Assuming $2.2 billion of public policy benefits would increase the region-wide benefits by almost $2 billion, and result additional zones to achieve a B/C ratio of 0.8 or higher (EDE, KCPL, and SUNC).

Figure 7.18
Public Policy Benefits to Meet Renewable Goals

SPP Zone	Existing Wind as of Jun'10 (MWh)	Renewable Goals 2033 Mandate (MWh)	Target (MWh)	Total (MWh)	Unmet Goal (MWh)	(%)	40-yr NPV of Public Policy Projects ($m)	Allocated Benefits of Public Policy Projects ($m)
AEPW	3,083,978	1,241,236	3,629,868	**4,871,104**	1,787,126	10.8%	$66.4	**$31.9**
CUS	196,318	0	0	**0**	0	0.0%	$4.7	**$0.0**
EDE	995,678	1,314,000	0	**1,314,000**	318,322	1.9%	$7.5	**$5.7**
GMO	187,133	1,737,706	0	**1,737,706**	1,550,573	9.3%	$12.4	**$27.7**
GRDA	0	0	0	**0**	0	0.0%	$6.0	**$0.0**
KCPL	606,426	3,512,963	0	**3,512,963**	2,906,537	17.5%	$23.3	**$51.9**
LES	27,135	0	0	**0**	0	0.0%	$6.0	**$0.0**
MIDW	193,177	0	0	**0**	0	0.0%	$2.5	**$0.0**
MKEC	250,688	322,355	0	**322,355**	71,667	0.4%	$4.2	**$1.3**
NPPD	393,018	0	1,767,552	**1,767,552**	1,374,534	8.3%	$19.8	**$24.5**
OKGE	1,514,043	0	5,000,000	**5,000,000**	3,485,957	21.0%	$42.8	**$62.2**
OPPD	132,626	0	1,602,696	**1,602,696**	1,470,070	8.9%	$15.1	**$26.2**
SUNC	322,355	322,355	0	**322,355**	0	0.0%	$3.2	**$0.0**
SWPS	2,378,980	1,558,029	0	**1,558,029**	0	0.0%	$38.7	**$0.0**
WEFA	775,606	0	1,580,000	**1,580,000**	804,394	4.8%	$9.7	**$14.4**
WRI	1,016,460	3,854,400	0	**3,854,400**	2,837,940	17.1%	$34.0	**$50.6**
Total	**12,073,621**	**13,863,043**	**13,580,116**	**27,443,160**	**16,607,120**	**100.0%**	**$296.4**	**$296.4**

7.6 High Gas Price Sensitivity

As a part of the RCAR analyses, SPP staff requested that the Brattle Group to perform a "High Gas Price" sensitivity as a part of the analysis for calculating the adjusted project cost savings. The results of this sensitivity analysis are provided in Addendum 1 to this RCAR Report.[46] As shown in Addendum 1, assuming higher gas prices increase the overall B/C ratio from 1.42 to 1.55 in the NTC only case, and from 1.45 to 1.59 in the NTC plus 10 year projects case.[47] Additionally, the High Gas Price sensitivity shows that the number of zones below a 0.8 B/C ratio falls from 6 to 3 in the NTC only case, and from 5 to 4 in the NTC plus 10 year projects case.

[46] The market simulations for the High Gas Price sensitivity assumed gas prices to be 27.5% higher for all three study years, compared those used in the main study. The average Henry Hub prices used for the sensitivity analysis are $6.2/MMBtu in 2018, $8.0/MMBtu in 2023, and $12.1/MMBtu in 2033 (in nominal dollars).

[47] The High Gas Price sensitivity analysis was performed in the same manner as the main study that was undertaken to estimate the results shown in Figures 7.1 and 7.2 except for the higher gas prices used in the APC savings calculations.

SECTION 8: RECOMMENDATION ON REMEDIES

8.1 Overview of RARTF Report on Remedies

The RARTF report recommended that if the RCAR of "[a]ll SPP projects that have been issued an NTC since June 2010 and all projects that have received an Authorization to Plan (ATP) that have an in-service date of ten years or less from the year of the report" shows that a zone is below the 0.8 B/C ratio Section 4.1 of the RARTF Report then "SPP staff should evaluate, and recommend possible mitigation remedies for the zone."

Figure 7.2 of the RCAR Report show that there are 5 zones are below the 0.8 for projects with NTCs and all projects that have an in-service date of ten years or less. These zones are:

- City Utilities of Springfield
- The Empire District Electric Company
- Grand River Dam Authority
- Lincoln Electric System
- Sunflower Electric Power Corporation

Figure 5 of the RARTF Report, provided a list of mitigation remedies that SPP staff should consider for study and to be made part of the report.

8.2 RCAR Report on Remedies

SPP Staff and the RARTF recommend that this RCAR Report be finalized in October 2013 in order to incorporate and include the finding in SPP's current ITP10 assessment that commenced in July 2013. This recommendation is in-line with the direction of the RARTF Report approved in January 2012 as described below.

As shown above in Figure 8 above, which is also found in Section 5.1 of the RARTF Report, the first two remedies for SPP staff to consider for City Utilities of Springfield, Empire District Electric Company, Grand River Dam Authority, Lincoln Electric System, and Sunflower Electric Power Corporation as a part of the RCAR Report is the "[a]cceleration of planned upgrades" and "[i]ssuance of NTCs for selected new upgrades."

Furthermore, Section 4.2 of the RARTF Report states, "[a]dditionally, the RARTF recommends that any Regional Cost Allocation Review, which shows that a zone is above the 0.8 threshold in Section 4.1, but below a 1.0 B/C ratio, should be used and considered as a part of SPP's transmission planning process in the future."

Because SPP's 18-month ITP10 assessment has recently commenced and remedies contemplated in the RARTF Report include the evaluation of transmission upgrade remedies, SPP Staff recommends that the RCAR Report be finalized and considered in SPP's current ITP10 assessment in collaboration with deficient zones and SPP Stakeholders.

In addition to this recommendation, SPP staff and the RARTF recommend that a second RCAR process [RCAR II] be commenced and work in parallel with the ITP10 assessment which is expected to be completed in January 2015. This will allow SPP staff to follow the directions contained in Sections 4.2 and Section 5.1 of the RARTF Report through ITP10 while utilizing RCAR II as a means to understand whether proposed remedies approved in the ITP10 provide equity for certain zones.[48] If RCAR II does not show that adequate remedies exist, SPP staff, deficient zones, and SPP Stakeholders can begin the process of analyzing additional potential remedies for any zone below the threshold. The report will be completed either (i) shortly after the ITP10 is completed, if cost estimates are to be used in the RCAR II analysis; or (ii) shortly after the completion of the competitive solicitation process, if the RFP results are to be used in the RCAR II analysis.

SECTION 9: GUIDANCE FOR FUTURE RCAR ASSESSMENTS

9.1 Overview of RCAR Lessons Learned

In Section 7.1 of their Report, the RARTF made four recommendations in addition to their recommendations of how to conduct the RCAR. Recommendation four stated:

> [T]he RARTF found the process of developing the recommended methodology under which the Regional Cost Allocation Review will be performed to be a very informative and collaborative process. As a result, the RARTF recommends that the task force be reconvened before subsequent Regional Cost Allocation Reviews are performed. This will enable the SPP stakeholders to review lessons learned from prior Regional Cost Allocation Reviews and to suggest improvements to the methodology recommended in this report.

In accord with the fourth additional recommendation contained in Section 7.1 of the RARTF Report, it is recommended that the RARTF "be reconvened before subsequent Regional Cost Allocation Reviews are performed." This aligns with the recommendations contained in Section 8.2 of this Report, that the RCAR "be finalized in October 2013 in order to incorporate and include the finding in SPP's current ITP10 assessment" and to allow "that a second RCAR process [RCAR II] be commenced and work in parallel with the ITP10 assessment."

As a result, the final recommendation is for the RARTF to begin a "lessons learned" and to finalize any "suggested improvements" to the RCAR process by the January 2014 stakeholder meeting cycle. This will allow these improvements to be incorporated into the RCAR II process.

[48] Because many of the zones below the 0.80 threshold in the RCAR Report are at or near the seam, SPP staff and the RARTF recommend that an analysis of seams projects be a part of ITP10's consideration of remedies for the RCAR. A review of potential seams projects is in alignment with SPP's interregional compliance filing for Order No. 1000 in FERC Docket No. ER13-1939.

ADDENDUM 1

High Gas Price Sensitivity

Estimated Present Value of Benefit Metrics and Costs by Zone

(a) NTC Projects + 75% of Suspended NTCs

	Present Value of 40-yr Benefits for 2013-2052: Adjusted Production Cost Savings (2013 $million)	Cost Savings from Reduced On-peak Trans-mission Losses (2013 $million)	Avoided or Delayed Reliability Projects (2013 $million)	Mitigation of Trans-mission Outage Costs (2013 $million)	Assumed Benefit of Mandated Reliability Projects (2013 $million)	Benefit from Meeting Public Policy Goals (2013 $million)	Increased Wheeling Through and Out Revenues (2013 $million)	Reduced Cost of Extreme Events (2013 $million)	Capital Savings from Reduced Minimum Required Margin (2013 $million)	Reduced Loss of Load Probability (2013 $million)	Marginal Energy Losses Benefits (2013 $million)	**Total Benefits** (2013 $million)	Present Value of 40-yr ATRRs: Before PtP Revenue Offset (2013 $million)	PtP Revenue Offset (2013 $million)	**After PtP Revenue Offset** (2013 $million)	**Est. Benefit-to-Cost Ratio**	Gap to Reach B/C Ratio of 0.8: TOTAL (2013 $million)	Levelized Real (2013 $m/yr)
AEPW	$263	$31	$17	$90	$539	$32						$971	$1,102	$95	$1,007	**0.96**	$0	$0.0
CUS	$21	$0	$0	$6	$19	$0						$46	$58	$5	$53	**0.87**	$0	$0.0
EDE	$7	-$1	$1	$10	$30	$6						$53	$93	$8	$85	**0.62**	**$15**	**$1.0**
GMO	$38	$1	$1	$17	$50	$28						$134	$155	$14	$141	**0.95**	$0	$0.0
GRDA	$20	$1	$1	$8	$33	$0						$62	$83	$7	$76	**0.82**	$0	$0.0
KCPL	$39	$6	$2	$32	$93	$52						$224	$290	$25	$264	**0.85**	$0	$0.0
LES	$2	$1	$1	$8	$28	$0						$40	$79	$7	$72	**0.55**	**$18**	**$1.1**
MIDW	$57	$3	$14	$3	$35	$0						$113	$57	$5	$52	**2.19**	$0	$0.0
MKEC	$43	$8	$0	$6	$56	$1			**Not Monetized**			$114	$98	$8	$90	**1.27**	$0	$0.0
NPPD	$319	$13	$2	$27	$120	$25						$506	$288	$25	$263	**1.92**	$0	$0.0
OKGE	$223	$4	$12	$58	$236	$62						$596	$598	$52	$546	**1.09**	$0	$0.0
OPPD	$33	$2	$2	$21	$67	$26						$150	$195	$17	$178	**0.84**	$0	$0.0
SUNC	-$20	$2	$0	$4	$29	$0						$15	$56	$5	$51	**0.30**	**$26**	**$1.6**
SWPS	$2,262	$72	$8	$53	$563	$0						$2,957	$914	$77	$837	**3.53**	$0	$0.0
WEFA	$29	$2	$1	$13	$148	$14						$208	$230	$20	$210	**0.99**	$0	$0.0
WRI	$246	$11	$34	$46	$430	$51						$817	$718	$61	$656	**1.24**	$0	$0.0
TOTAL	**$3,582**	**$155**	**$97**	**$403**	**$2,475**	**$296**						**$7,007**	**$5,014**	**$433**	**$4,581**	**1.53**	**$59**	**$4**

(b) NTC Projects + 75% of Suspended NTCs + 75% of ATP Projects

	Present Value of 40-yr Benefits for 2013-2052: Adjusted Production Cost Savings (2013 $million)	Cost Savings from Reduced On-peak Trans-mission Losses (2013 $million)	Avoided or Delayed Reliability Projects (2013 $million)	Mitigation of Trans-mission Outage Costs (2013 $million)	Assumed Benefit of Mandated Reliability Projects (2013 $million)	Benefit from Meeting Public Policy Goals (2013 $million)	Increased Wheeling Through and Out Revenues (2013 $million)	Reduced Cost of Extreme Events (2013 $million)	Capital Savings from Reduced Minimum Required Margin (2013 $million)	Reduced Loss of Load Probability (2013 $million)	Marginal Energy Losses Benefits (2013 $million)	**Total Benefits** **(2013 $million)**	Present Value of 40-yr ATRRs: Before PtP Revenue Offset (2013 $million)	PtP Revenue Offset (2013 $million)	**After PtP Revenue Offset** **(2013 $million)**	**Est. Benefit-to-Cost Ratio**	Gap to Reach B/C Ratio of 0.8: TOTAL (2013 $million)	Levelized Real (2013 $m/yr)
AEPW	$283	$40	$17	$95	$567	$32						$1,034	$1,131	$98	$1,033	**1.00**	$0	$0.0
CUS	$25	$0	$0	$7	$20	$0						$52	$60	$5	$55	**0.96**	$0	$0.0
EDE	$10	-$1	$1	$11	$32	$6						$58	$96	$8	$87	**0.67**	**$11**	**$0.7**
GMO	$33	$1	$1	$18	$58	$28						$139	$163	$14	$148	**0.93**	$0	$0.0
GRDA	$15	$1	$1	$9	$35	$0						$59	$85	$7	$78	**0.76**	**$3**	**$0.2**
KCPL	$66	$6	$2	$33	$100	$52						$260	$298	$26	$272	**0.96**	$0	$0.0
LES	$2	$1	$1	$9	$30	$0						$43	$81	$7	$74	**0.58**	**$16**	**$1.0**
MIDW	$61	$3	$14	$4	$36	$0						$118	$58	$5	$52	**2.25**	$0	$0.0
MKEC	$48	$7	$0	$6	$64	$1			**Not Monetized**			$127	$105	$9	$97	**1.31**	$0	$0.0
NPPD	$306	$13	$2	$28	$127	$25						$501	$294	$25	$269	**1.86**	$0	$0.0
OKGE	$225	$5	$6	$61	$261	$62						$620	$623	$54	$569	**1.09**	$0	$0.0
OPPD	$37	$2	$1	$22	$72	$26						$160	$200	$17	$183	**0.88**	$0	$0.0
SUNC	-$9	$2	$0	$5	$30	$0						$28	$57	$5	$52	**0.53**	**$14**	**$0.9**
SWPS	$2,414	$72	$13	$55	$584	$0						$3,139	$935	$79	$856	**3.67**	$0	$0.0
WEFA	$41	$3	$1	$14	$160	$14						$232	$242	$21	$221	**1.05**	$0	$0.0
WRI	$208	$11	$34	$49	$478	$51						$830	$766	$65	$700	**1.19**	$0	$0.0
TOTAL	**$3,766**	**$166**	**$96**	**$424**	**$2,654**	**$296**						**$7,401**	**$5,193**	**$447**	**$4,746**	**1.56**	**$45**	**$3**

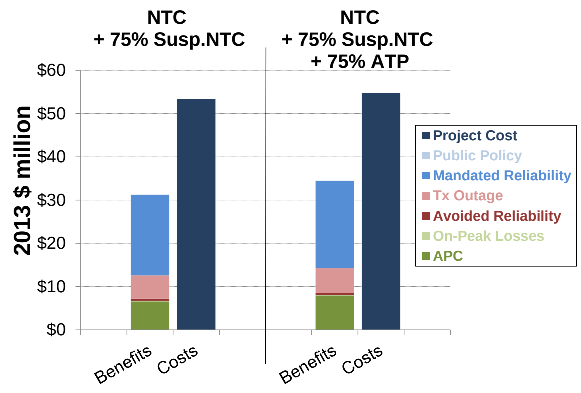
Appendix 1 – Stakeholder Comment and Resolutions for RCAR Models and Draft Report

All stakeholder comments have been posted at
http://www.spp.org/section.asp?group=2172&pageID=27

Appendix 2 –Analysis of Zones Below the 0.8 B/C Ratio Threshold

City Utilities of Springfield (CUS)

	NTC +75% Susp. NTC (2013 $million)	NTC +75% Susp. NTC +75% ATP (2013 $million)
Present Value of 40-yr ATRRs		
Reliability Projects	$19	$20
Economic Projects	$35	$35
Public Policy Projects	$5	$5
Offset from PtP Revenues	-$5	-$5
Total Costs	**$53**	**$55**
Present Value of 40-yr Benefits		
Adjusted Production Cost Savings	$7	$8
Capacity Cost Savings from Reduced On-Peak Losses	$0	$0
Avoided or Delayed Reliability Projects	$0	$0
Mitigation of Transmission Outage Costs	$5	$6
Assumed Benefit of Mandated Reliability Projects	$19	$20
Benefit from Meeting Public Policy Goals	$0	$0
Total Benefits	**$31**	**$34**
Benefit-to-Cost Ratio	**0.59**	**0.63**
Gap to Reach a B/C Ratio of 0.8	**$11**	**$9**



- The estimated B/C ratio in CUS is 0.59 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It slightly increases to 0.63 when ATP projects are also included (at a reduced value of 75 percent).

- Overall, the low B/C ratio in CUS is primarily driven by the limited APC savings.
  - The cost of economic projects is $35 million in CUS, accounting for approximately 60% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $7-8 million due to relatively lower congestion-relief provided in the CUS zone.

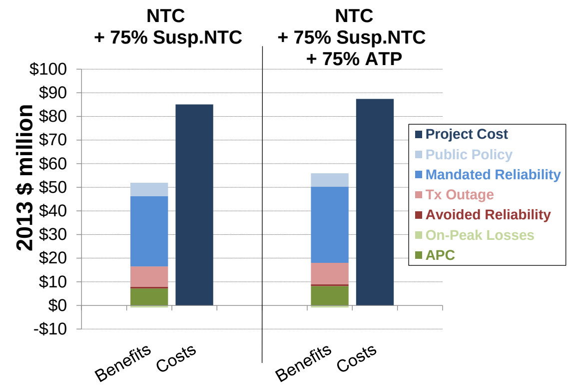
  - The benefit related to mitigation of transmission outage costs is estimated to be $5-6 million, reducing CUS' gap to reach a B/C ratio of 0.8 (but it is not large enough to fully eliminate the gap).

- Another factor that contributes to a lower B/C ratio in CUS is that it does not receive any public policy benefits.
  - CUS does not have a renewable goal, but it is responsible for about $5 million of the costs for public policy projects (allocated regionally on a LRS basis).

- Note that these results <u>do not</u> include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).
  - These additional benefits could either reduce or eliminate CUS' gap to reach a B/C ratio of 0.8.

Empire District Electric (EDE)

	NTC +75% Susp. NTC (2013 $million)	NTC +75% Susp. NTC +75% ATP (2013 $million)
Present Value of 40-yr ATRRs		
Reliability Projects	$30	$32
Economic Projects	$56	$56
Public Policy Projects	$7	$7
Offset from PtP Revenues	-$8	-$8
Total Costs	**$85**	**$87**
Present Value of 40-yr Benefits		
Adjusted Production Cost Savings	$7	$8
Capacity Cost Savings from Reduced On-Peak Losses	-$1	-$1
Avoided or Delayed Reliability Projects	$1	$1
Mitigation of Transmission Outage Costs	$9	$9
Assumed Benefit of Mandated Reliability Projects	$30	$32
Benefit from Meeting Public Policy Goals	$6	$6
Total Benefits	**$51**	**$55**
Benefit-to-Cost Ratio	**0.60**	**0.63**
Gap to Reach a B/C Ratio of 0.8	**$17**	**$15**



- The estimated B/C ratio in EDE is 0.60 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It slightly increases to 0.63 when ATP projects are also included (at a reduced value of 75 percent).

- Overall, the low B/C ratio in EDE is primarily driven by the limited APC savings.
  - The cost of economic projects is $56 million in EDE, accounting for approximately 60% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $7-8 million due to relatively lower congestion-relief provided in the EDE zone.

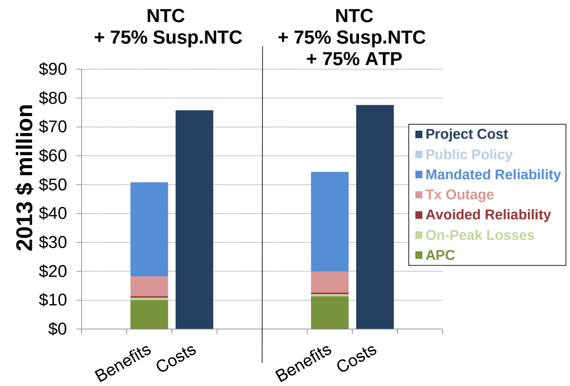
  - The benefit related to mitigation of transmission outage costs is estimated to be $9 million, reducing EDE's gap to reach a B/C ratio of 0.8 (but it is not large enough to fully eliminate the gap).

- Costs from meeting public policy goals exceed the benefits of public policy projects by approximately $1 million, which decreases the B/C ratio in EDE (but not sufficient to close the gap).

- Note that these results <u>do not</u> include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).
  - These additional benefits could either reduce or eliminate EDE's gap to reach a B/C ratio of 0.8.

Grand River Dam Authority (GRDA)

	NTC +75% Susp. NTC (2013 $million)	NTC +75% Susp. NTC +75% ATP (2013 $million)
Present Value of 40-yr ATRRs		
Reliability Projects	$33	$35
Economic Projects	$44	$44
Public Policy Projects	$6	$6
Offset from PtP Revenues	-$7	-$7
Total Costs	**$76**	**$78**
Present Value of 40-yr Benefits		
Adjusted Production Cost Savings	$10	$11
Capacity Cost Savings from Reduced On-Peak Losses	$1	$1
Avoided or Delayed Reliability Projects	$1	$1
Mitigation of Transmission Outage Costs	$7	$7
Assumed Benefit of Mandated Reliability Projects	$33	$35
Benefit from Meeting Public Policy Goals	$0	$0
Total Benefits	**$51**	**$54**
Benefit-to-Cost Ratio	**0.67**	**0.70**
Gap to Reach a B/C Ratio of 0.8	**$10**	**$8**



- The estimated B/C ratio in GRDA is 0.67 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It slightly increases to 0.70 when ATP projects are also included (at a reduced value of 75 percent).

- Overall, the low B/C ratio in GRDA is primarily driven by the limited APC savings.
  - The cost of economic projects is $44 million in GRDA, accounting for approximately 55% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $10-11 million due to relatively lower congestion-relief provided in the GRDA zone.

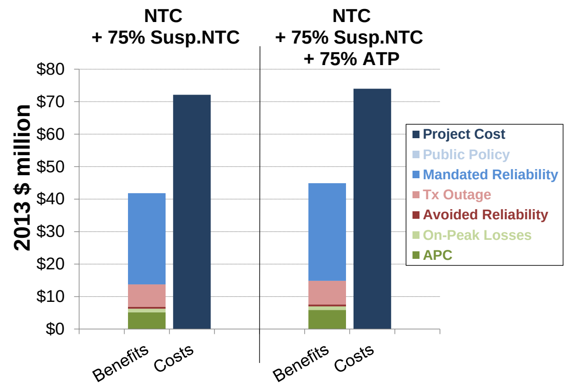
  - The benefit related to mitigation of transmission outage costs is estimated to be $7 million, reducing GRDA's gap to reach a B/C ratio of 0.8.

- Another factor that contributes to a lower B/C ratio in GRDA is that it does not receive any public policy benefits.
  - GRDA does not have a renewable goal, but it is responsible for about $6 million of the costs for public policy projects (allocated regionally on a LRS basis).

- Note that these results do not include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).
  - These additional benefits could either reduce or eliminate GRDA's gap to reach a B/C ratio of 0.8.

Lincoln Electric System (LES)

	NTC +75% Susp. NTC (2013 $million)	NTC +75% Susp. NTC +75% ATP (2013 $million)
Present Value of 40-yr ATRRs		
Reliability Projects	$28	$30
Economic Projects	$45	$45
Public Policy Projects	$6	$6
Offset from PtP Revenues	-$7	-$7
Total Costs	**$72**	**$74**
Present Value of 40-yr Benefits		
Adjusted Production Cost Savings	$5	$6
Capacity Cost Savings from Reduced On-Peak Losses	$1	$1
Avoided or Delayed Reliability Projects	$1	$1
Mitigation of Transmission Outage Costs	$7	$7
Assumed Benefit of Mandated Reliability Projects	$28	$30
Benefit from Meeting Public Policy Goals	$0	$0
Total Benefits	**$42**	**$45**
Benefit-to-Cost Ratio	**0.58**	**0.61**
Gap to Reach a B/C Ratio of 0.8	**$16**	**$14**



- The estimated B/C ratio in LES is 0.58 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It slightly increases to 0.61 when ATP projects are also included (at a reduced value of 75 percent).

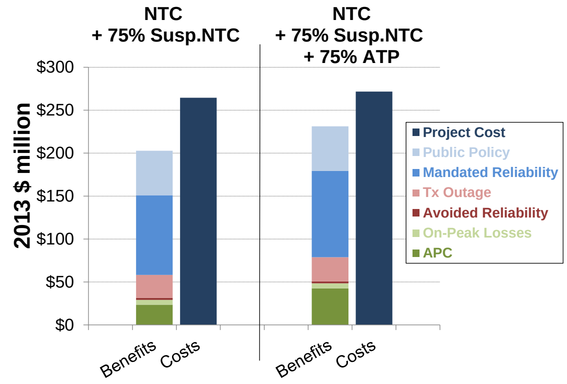
- Overall, the low B/C ratio in LES is primarily driven by the limited APC savings.
  - The cost of economic projects is $45 million in LES, accounting for approximately 60% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $5-6 million due to relatively limited congestion-relief provided in the later years.
  - The benefit related to mitigation of transmission outage costs is estimated to be $7 million, reducing LES' gap to reach a B/C ratio of 0.8.

- Another factor that contributes to a lower B/C ratio in LES is that it does not receive any public policy benefits.
  - LES does not have a renewable goal, but it is responsible for about $6 million of the costs for public policy projects (allocated regionally on a LRS basis).

- Note that these results <u>do not</u> include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).
  - These additional benefits could either reduce or eliminate LES' gap to reach a B/C ratio of 0.8.

Kansas City Power & Light (KCPL)

	NTC +75% Susp. NTC (2013 $million)	NTC +75% Susp. NTC +75% ATP (2013 $million)
Present Value of 40-yr ATRRs		
Reliability Projects	$93	$100
Economic Projects	$174	$174
Public Policy Projects	$23	$23
Offset from PtP Revenues	-$25	-$26
Total Costs	**$264**	**$272**
Present Value of 40-yr Benefits		
Adjusted Production Cost Savings	$24	$43
Capacity Cost Savings from Reduced On-Peak Losses	$6	$6
Avoided or Delayed Reliability Projects	$2	$2
Mitigation of Transmission Outage Costs	$27	$28
Assumed Benefit of Mandated Reliability Projects	$93	$100
Benefit from Meeting Public Policy Goals	$52	$52
Total Benefits	**$203**	**$231**
Benefit-to-Cost Ratio	**0.77**	**0.85**
Gap to Reach a B/C Ratio of 0.8	**$9**	**$0**



- The estimated B/C ratio in KCPL is 0.77 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It increases to 0.85 when ATP projects are also included (at a reduced value of 75 percent) and thus exceed the 0.8 threshold.

- Overall, the low B/C ratio in KCPL is primarily driven by the limited APC savings.
  - The cost of economic projects is $174 million in KCPL, accounting for approximately 60% of total costs. The present value of 40-year APC savings for 2013-2052 is only $24 million if ATP projects are not built and $43 million if they are built. ATP projects allow KCPL to slightly increase its sales quantity and associated sales revenues, which result in an additional $19 million of APC savings in present value terms.

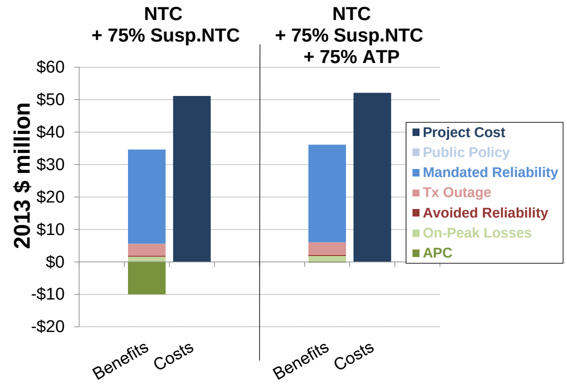
  - The benefit related to mitigation of transmission outage costs is estimated to be $27-28 million, reducing KCPL's gap to reach a B/C ratio of 0.8.

- Benefits from meeting public policy goals exceed the costs of public policy projects by approximately $29 million, which increases the B/C ratio in KCPL.

- Note that these results do not include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).
  - These additional benefits could either reduce or eliminate KCPL's gap to reach a B/C ratio of 0.8.

Sunflower Electric Power Corporation (SUNC)

	NTC +75% Susp. NTC (2013 $million)	NTC +75% Susp. NTC +75% ATP (2013 $million)
Present Value of 40-yr ATRRs		
Reliability Projects	$29	$30
Economic Projects	$24	$24
Public Policy Projects	$3	$3
Offset from PtP Revenues	-$5	-$5
Total Costs	**$51**	**$52**
Present Value of 40-yr Benefits		
Adjusted Production Cost Savings	-$10	$0
Capacity Cost Savings from Reduced On-Peak Losses	$2	$2
Avoided or Delayed Reliability Projects	$0	$0
Mitigation of Transmission Outage Costs	$4	$4
Assumed Benefit of Mandated Reliability Projects	$29	$30
Benefit from Meeting Public Policy Goals	$0	$0
Total Benefits	**$25**	**$36**
Benefit-to-Cost Ratio	**0.48**	**0.69**
Gap to Reach a B/C Ratio of 0.8	**$16**	**$6**



- The estimated B/C ratio in SUNC is 0.48 for NTC projects including the suspended NTCs at a reduced value of 75 percent. It increases to 0.69 when ATP projects are also included (at a reduced value of 75 percent).

- Overall, the low B/C ratio in SUNC is primarily driven by the higher APCs.
  - The cost of economic projects is $24 million in SUNC. At the same time, the present value of 40-year APCs for 2013-2052 increases by $10 million.
  - ATP projects reduce congestion in SUNC and increase sales revenues, which result in an estimated increase of $10 million in APC savings in present value terms.
  - The benefit related to mitigation of transmission outage costs is estimated to be $4 million, reducing SUNC's gap to reach a B/C ratio of 0.8.

- Another factor that contributes to a lower B/C ratio in SUNC is that it receives no public policy benefits, but it is responsible for about $3 million of the costs for public policy projects (allocated regionally on a LRS basis).

- Note that these results do not include some of the new benefit metrics identified in September 2012 MTF report (increased wheeling through and out revenues, capital savings from reduced minimum required margin, reduced cost of extreme events, reduced loss of load probability, and marginal energy losses benefits).
  - These additional benefits could either reduce or eliminate SUNC's gap to reach a B/C ratio of 0.8.

Appendix 3 – RCAR PROMOD Assumptions

PROMOD Assumptions

This appendix summarizes the key modeling assumptions in PROMOD market simulations that are used to estimate adjusted production cost (APC) savings.

1. Transmission

SPP has provided a powerflow and PROMOD system database (developed for the 2013 ITP20 study) to be used as a starting point. The data represents the Business as Usual (BAU) future, set up to model years prior to 2033.

The following changes were made to create more realistic cases for the purpose of the RCAR study:

- Constraints from the ITP10 event file were added
- The top 40 temporary flowgates from 2012 were added to the event file
- The top 10 constraints from the 2011 SPP State of the Market Report were added the event file
- The PAT tool was used to develop additional transmission constraints for the SPP system
- Ratings of individual branches were taken from the powerflows used in the year/case combination

2. External Regions

The external regions were modeled consistently across all of the cases analyzed to ensure that the benefits pertain only to changes in SPP's transmission expansion. The system footprint is based on what is used in the SPP ITP20 process, including the following regions:

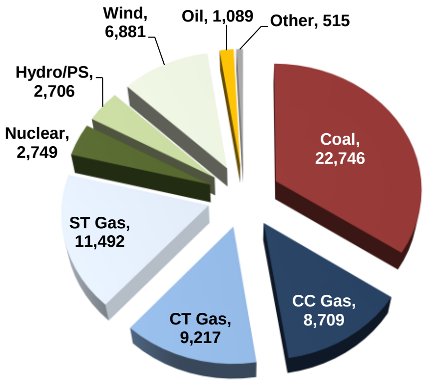
- SPP
- MISO (including Entergy and CLECO)
- MAPP Non-MISO
- PJM
- SERC – Central Sub-region, Southeast Sub-region, AECI

3. Generation

The generation was modeled consistent with the assumptions used in the 2013 ITP20 study. As shown below, the capacity additions through 2018 are mainly driven by the renewable goals. Significant amount gas capacity is added after 2018 to maintain reserve margins at or above target levels. Only limited amount of existing capacity is assumed to retire, mostly after 2023.

Figure 1
Generation Assumptions in SPP Footprint

(a) Existing Capacity



(b) Additions and Retirements

	Additions and Retirements between 2014-2018	**Online Capacity in 2018**	Additions and Retirements between 2019-2023	**Online Capacity in 2023**	Additions and Retirements between 2024-2033	**Online Capacity in 2033**
Coal	0	**21,339**	0	**21,339**	-442	**20,898**
CC Gas	470	**6,403**	3,788	**10,191**	3,682	**13,873**
CT Gas	284	**8,651**	3,479	**12,130**	3,923	**16,053**
ST Gas	0	**10,938**	-261	**10,677**	-876	**9,800**
Nuclear	0	**2,749**	0	**2,749**	0	**2,749**
Hydro/PS	0	**726**	0	**726**	0	**726**
Wind	2,116	**8,419**	0	**8,419**	0	**8,419**
Oil	0	**892**	0	**892**	0	**892**
Other	23	**460**	-9	**451**	-102	**349**
TOTAL	**2,893**	**60,578**	**6,997**	**67,575**	**6,185**	**73,760**

* Numbers reflect total nameplate capacity in MW for SPP's 16 pricing zones

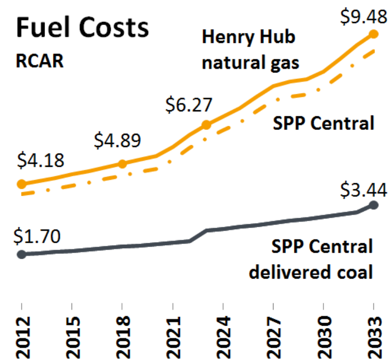
4. Fuel Costs

Fuel price projections were modeled consistent with the assumptions used in the 2013 ITP20 study. The data is derived from the Ventyx Spring 2012 Reference Case and NYMEX futures.

- The gas price assumptions are developed based on the NYMEX futures for Henry Hub as of April 23, 2012. They increase from current levels to $4.9 per MMBtu in 2018, $6.3 in 2023, and $9.5 in 2033 (in nominal dollars). The prices in the SPP footprint are slightly lower than Henry Hub prices, as a result of negative basis differentials.

- The coal prices also increase, although not as fast as gas prices. The average delivered price in SPP is assumed to be $2.0 per MMBtu in 2018, $2.5 in 2023, and $3.4 in 2033 (in nominal dollars). The plant-specific prices vary due to differences in transportation costs.

Figure 2
Fuel Price Projections for SPP Footprint

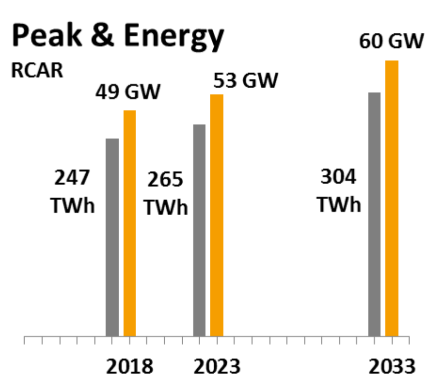


5. Load Forecast

Load projections were modeled consistent with the assumptions used in the 2013 ITP20 study. The load forecast was obtained through a survey of membership.

- Data based on the 2023 Summer Peak MDWG powerflow with adjustments for load growth up until 2033
- MDWG submitted summer peak values used to determine the load in the years 2018 and 2023
- Both peak and energy in SPP increases by approximately 1.3% per year through the study horizon

Figure 3
Load Projections for SPP Footprint



6. Emission Prices

Emission price projections were modeled consistent with the assumptions used in the 2013 ITP20 study.

- $500/ton for annual NOX, $1,000/ton for seasonal NOX, $250-500/ton for SO2, and zero for CO2 and Hg, increasing at inflation

Figure 4
Emission Price Projections

	2018	2023	2033
CSAPR Annual .NOx	$580	$656	$840
CSAPR Seasonal .NOx	$1,160	$1,312	$1,680
CSAPR 1.SO2	$580	$656	$840
CSAPR 2.SO2	$290	$328	$420
National .CO2	$0	$0	$0
RGGI .CO2	$0	$0	$0
Mercury (Hg)	$0	$0	$0

Appendix 4 - RCAR Project List

The projects included in the RCAR analysis are posted at:
http://www.spp.org/section.asp?group=2172&pageID=27