Regional Cost Allocation Review (RCAR II)

July 11, 2016
SPP Regional Cost Allocation Review Report for RCAR II

Table of Contents

EXECUTIVE SUMMARY

This report contains the results of the second Regional Cost Allocation Review (RCAR II) 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 II Report (the RCAR Report) were conducted based on the recommendations of the Regional Allocation Review Task Force (RARTF) approved by SPP stakeholders in January 2012 (the RARTF Report) and the RCAR I Lessons Learned Report approved in April 2014. These analyses included the calculation of ten 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 (Board) in 2012 and in July 2014.

When conducting the RCAR II, SPP staff applied nine of the ten principles contained in the RARTF Report[1]:

- Simplicity
- Acknowledgment of the "roughly commensurate" legal standard
- Equity over time
- Use of the best quantifiable information available
- Consistency
- Transparency
- Stakeholder input
- Use of real dollars values
- Inclusion in the review of SPP Board approved transmission projects.[2]

Applying these principles the RCAR Report demonstrates a 2.46:1 overall benefit to cost (B/C) ratio to the region for projects approved for construction since June 2010 under the Highway/Byway cost allocation methodology. This shows a strong increase from the RCAR I analysis, which showed a 1.39:1 B/C for projects issued an NTC since June 2010.

The assessment shows, for projects approved for construction since June 2010:

- One zone was below the .80 threshold established by the RARTF
- Two additional zones were greater than the .80 threshold but below 1.0

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[1] In the RCAR I Lessons Learned the RARTF agreed to not include Principle 8 in the RCAR II analysis. This is further explained in Section 3 of this report. The RARTF agreed to use all projects approved for construction as of October 1, 2015 for the RCAR II analysis. See July 8, 2015 RARTF Meeting minutes; https://www.spp.org/documents/29110/rartf%20minutes%2020150708%20draft.pdf

[2] Attachment J, Section III.D.3 of SPP's OATT.

- The remaining fourteen zones were above a 1.0 B/C ratio.

Additionally, the RARTF Report recommends two next steps:

- In order to provide a potential remedy, SPP Staff will assist City Utilities of Springfield (CUS) efforts to participate in the upcoming SPP planning processes. The upcoming studies are the 2017 ITP10, Seams Planning Study with AECI and a proposed Seams Planning Study with the Midcontinent Independent System Operator (MISO). Should these planning processes not provide benefits to the CUS zone; Staff will work with the RARTF and the stakeholder process to request the SPP Board to initiate a High Priority study to evaluate the system needs and solutions for the Springfield zone.

- That the RARTF begin a process to evaluate "lessons learned" from SPP's RCAR II Report and finalize "suggested improvements" to the RCAR process. This recommendation will allow any improvements to be incorporated into the next RCAR process and will be in accordance with Section 7.1 of the RARTF Report.

BACKGROUND

In approving SPP's Highway/Byway cost allocation methodology, the Federal Energy Regulatory Commission (FERC) also approved a requirement that SPP review the "reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every three years."[3] This review is required to "determine the cost allocation impacts of the Base Plan Upgrades approved for construction issued after June 19, 2010 to each pricing Zone within the SPP Region."[4] Thus, the purpose of this analysis is to measure by zone the cost allocation impacts of SPP's Highway/Byway methodology.

The review is hereinafter referred to as the "Regional Cost Allocation Review" or "RCAR". RCAR I was completed in 2013.

SPP's Open Access Transmission Tariff (tariff or OATT) requires that "the MOPC and Regional State Committee (RSC) will define the analytical methods to be used" in conducting the RCAR.[5] 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 original RARTF membership included three representatives from the RSC, three SPP Members, and one member from the independent Board. RARTF members were jointly appointed by then RSC President Jeff Davis and then MOPC Chairman Bill Dowling who were serving in these capacities at the time. The members of the original RARTF were:

Original 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 group prepared a report that recommended how to define the analytical methods to be used in the RCAR. In January 2012, the RARTF Report was approved unanimously by the RARTF, RSC, MOPC, Members Committee, and Board.

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

After the initial RCAR was completed, the MOPC and RSC agreed to expand the RARTF's membership to include an additional representative from both the MOPC and RSC. This change allowed for more continuity of the group as members of the RSC change from time to time. In July 2013, then RSC President Olan Reeves and then MOPC Chairman Rob Janssen appointed new members to the RARTF. The group's roster was then as follows:

RARTF Members as of July 2013	
Chairman Olan Reeves	Arkansas Public Service Commission
Vice-Chairman Richard Ross	American Electric Power
Commissioner Shari Albrecht	Kansas Corporation Commission
Commissioner Steve Lichter	Nebraska Power Review Board
Commissioner Steve Stoll	Missouri Public Service Commission
Bary Warren	The Empire District Electric Company
Philip Crissup	Oklahoma Gas and Electric Company
Bill Grant	Xcel Energy/SPS
Harry Skilton	SPP Board of Directors

In January 2014, Commissioner Olan Reeves left the Arkansas Public Service Commission (APSC) and was replaced on the RARTF by Commissioner Lamar Davis of the APSC. At this time Commissioner Steve Stoll assumed the role of Chairman of the RARTF.

RARTF Members as of February 2014	
Chairman Steve Stoll	Missouri Public Service Commission
Vice-Chairman Richard Ross	American Electric Power
Commissioner Shari Albrecht	Kansas Corporation Commission
Commissioner Steve Lichter	Nebraska Power Review Board
Commissioner Lamar Davis	Arkansas Public Service Commission
Bary Warren	The Empire District Electric Company
Philip Crissup	Oklahoma Gas and Electric Company
Bill Grant	Xcel Energy/SPS
Harry Skilton	SPP Board of Directors

The membership and roles of the RARTF remained unchanged through the completion of the RCAR II.

RCAR I

In October 2013, SPP Staff completed RCAR I, and stakeholder groups — including the Regional Tariff Working Group (RTWG), RSC[6] and MOPC[7] — reviewed and voted on its results.

The RCAR I consisted of two separate analyses:

- Projects that had received NTCs since June 2010
- Projects that had received NTCs since June 2010 plus authorization to plan (ATP) projects needed within 10 years.

It is noteworthy that not all of the approved benefit metrics were monetized in RCAR I. The B/C results from RCAR I can be found at spp.org.[8]

RCAR I Lessons Learned

At the conclusion of RCAR I, SPP Staff led stakeholders in a formal lessons-learned process to develop a list of improvements to be implemented in the next RCAR analysis. The concept of the RCAR I Lessons Learned Report (Lessons Learned Report) was first raised in the 2012 RARTF Report and further detailed in the RCAR I endorsed by SPP stakeholders in 2013.

The purpose of the Lessons Learned Report is to evaluate lessons learned from RCAR I and make suggested improvements to the RCAR process. A final Lessons Learned Report was adopted by the RARTF on March 31, 2014 after receiving and reviewing stakeholder comments and suggestions over a six-month period. These recommendations have been incorporated into the RCAR II process.

To initiate the lessons-learned process, SPP staff sought stakeholder comments and suggestions. Responses were received from the following SPP stakeholder groups:

SPP Stakeholder Group	Date of Submission
Southwestern Public Service Company (SPS)	November 18, 2013
Omaha Public Power District (OPPD)	November 18, 2013
Lincoln Electric System (LES)	November 18, 2013
Missouri Public Service Commission (MoPSC)	November 20, 2013
City Utilities of Springfield (CUS)	November 21, 2013
Kansas City Power & Light (KCPL)	December 6, 2013

[6] *See* "RSC Minutes 10/28/13" at page 4; http://www.spp.org/documents/21575/rsc102813.pdf.
[7] *See* "MOPC Meeting Minutes & Attachments October 15-16, 2013" at page 5; http://www.spp.org/documents/21032/mopc%20meeting%20minutes%20&%20attachments%20october%2015-16,%202013.pdf
[8] *See* RCAR I Final Report at; http://www.spp.org/documents/37781/rcar%20report%20final%20clean.pdf.

The chart below summarizes stakeholders' comments and suggestions.

Stakeholder Entity	Area of Comment or Suggestion						
	Metrics/ Allocation	Modeling	Remedy	NTC/ATP	PTP Offset	Sched/ Process	Total
CUS	2		4		1	1	**8**
LES	2		1				**3**
OPPD	2		1		4	2	**9**
SPS	1	4					**5**
KCPL	2	2	1	1	1	1	**8**
MoPSC			1	1			**2**
Totals	**9**	**6**	**8**	**2**	**6**	**4**	**35**

On February 3, 2014, the RARTF reviewed stakeholders' suggestions for improving the RCAR process[9], then met on March 3 in Dallas, Texas to begin finalizing the RARTF Lessons Learned Report after the completion of RCAR I.[10]

On March 24 the RARTF held a conference call to finalize stakeholder recommendations and approve the RARTF Lessons Learned Report. Once approved by the RARTF, this report was posted publicly and shared with the appropriate SPP working groups.

After reviewing and considering the comments and suggestions from SPP stakeholders, the RARTF has adopted ten "lessons learned" to be incorporated into the RCAR II process. These recommendations are:

LESSONS LEARNED RECOMMENDATION NO. 1:

> That the principles and the detailed guidance provided to SPP staff in conducting RCAR I were a major success of the SPP stakeholder process with meaningful stakeholder input. Notwithstanding this success, improvements to the RCAR process can be made as SPP staff begins to analyze the Highway/Byway for RCAR II. As a result, the RARTF recommends that the January 2012 RARTF Report continue to be the basis upon which SPP staff conducts the RCAR II analysis with the exception of, or additions to, the recommendations contained in this Lessons Learned Report. The recommendations contained in this Lessons Learned Report should be incorporated and used by SPP staff when conducting the RCAR II assessment of the SPP Highway/Byway.

[9] More than thirty-five SPP stakeholders participated in the RARTF's February 3, 2014 call.
[10] More than thirty-five SPP stakeholders participated in the RARTF's March 3, 2014 in-person meeting.

LESSONS LEARNED RECOMMENDATION NO. 2:

> That the Economic Studies Working Group (ESWG) continues to review the benefits contained in the Metrics Task Force (MTF) Report that were approved through the SPP stakeholder process in 2012. This review should be established to provide SPP stakeholders the opportunity to offer wide-ranging improvements to the benefits contained in the MTF Report. Any changes or improvements to the benefits shall be presented to the ESWG, RARTF, MOPC, and RSC for recommendation to the BOD for approval by the July 2014 meeting cycle.[11]

LESSONS LEARNED RECOMMENDATION NO. 3:

> That the ESWG continue to review the benefits contained in the MTF Report that were approved through the SPP stakeholder process in 2012. This review should provide SPP stakeholders the opportunity to suggest which benefits should be included in future RCAR reports. Any changes or improvements to the benefits shall be presented to the ESWG, RARTF, MOPC, and RSC for recommendation to the BOD for approval by the July 2014 meeting cycle.[12]

LESSONS LEARNED RECOMMENDATION NO. 4:

> That SPP staff continue to work with the SPP Transmission Working Group (TWG) and ESWG to improve models used for RCAR II. This effort should provide SPP stakeholders the opportunity to offer or suggest improvements to models used in future RCAR reports. Any changes or improvements to the models should be vetted by the TWG and ESWG as appropriate. These changes or improvements should also be in alignment with the ten guiding principles contained in the RARTF Report.

LESSONS LEARNED RECOMMENDATION NO. 5:

> That SPP staff utilize, to the maximum extent possible, models used in the Integrated Transmission Plan 10-year planning horizon assessment (ITP10) for RCAR II. Conducting the ITP10 and RCAR II processes in parallel should allow leveraging of models and promote consistency and efficiency in the model vetting process. This measure could reduce cost and help to eliminate redundancy of efforts between SPP staff and stakeholders.

LESSONS LEARNED RECOMMENDATION NO. 6:

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[11] Per Lessons Learned Recommendation No. 3, SPP Board of Directors approved changes to Benefit Metrics on July 29, 2014. See, http://www.spp.org/documents/22963/bocmc%20minutes%20072914.pdf.

[12] Per Lessons Learned Recommendation No. 3, SPP Board of Directors approved changes to Benefit Metrics on July 29, 2014. See, http://www.spp.org/documents/22963/bocmc%20minutes%20072914.pdf.

That SPP staff evaluate remedies for zones below the threshold in the Notification to Construct (NTC)-only review for RCAR II.[13]

LESSONS LEARNED RECOMMENDATION NO. 7:

That SPP staff continue to work with SPP stakeholders to find ways to improve upon calculating Point to Point (PTP) revenue credits for RCAR II. This effort should provide SPP stakeholders the opportunity to suggest improvements to PTP revenue credits calculations for use in future RCAR reports that most closely align with SPP's OATT. Additionally, by updating how PTP revenue credits are projected with up-to-date information, SPP staff will be using "the most up [-] to [-] date and best available information," consistent with Principle 3 contained in the RARTF Report. Any changes or improvements to the PTP projection methodology should be vetted by the RARTF and RTWG as it was handled during the RCAR I Report in an open and transparent manner that will enable the participation of SPP stakeholders.[14]

LESSONS LEARNED RECOMMENDATION NO. 8:

That the RARTF and SPP stakeholder-approved 0.8 benefit to cost ratio threshold continue to be the basis to determine when it is warranted for members to request and for SPP staff to subsequently study possible remedies as stated in Section 4.1 of the RARTF Report. Additionally, the RARTF recommends that if RCAR II shows that a zone is above the 0.8 threshold, but below a 1.0 benefit to cost ratio, that this analysis should be used and considered as a part of SPP's transmission planning process in the future.

LESSONS LEARNED RECOMMENDATION NO. 9:

That SPP staff continue to update and brief the RARTF throughout the RCAR II analysis and seek guidance from the RARTF when input from SPP stakeholders is necessary for SPP staff to complete RCAR II.[15]

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[13] Following the completion of the first draft of the RCAR II Report, SPP Staff has begun communications with City of Springfield, the only deficient zone in the RCAR II analysis.

[14] Per Lessons Learned Recommendation No. 7, SPP Staff facilitated a stakeholder process to develop revisions of the SPP Tariff for the purposes of clarifying and ensuring consistency in the treatment of PTP revenue credits for calculating rates. This set of revisions allows PTP revenue credits to be projected in a more reliable manner in the RCAR analysis. The Tariff revisions were ultimately approved by SPP's Board of Directors and the FERC. See, FERC Docket No. ER16-165.

[15] SPP Staff implemented Lessons Learned No. 9 by facilitating 12 meetings with the RARTF since August 13, 2014. Agendas and minutes for RARTF meetings can be found at: http://www.spp.org/organizational-groups/board-of-directorsmembers-committee/markets-and-operations-policy-committee/regional-allocation-review-task-force/

LESSONS LEARNED RECOMMENDATION NO. 10:

That SPP make a filing with the Federal Energy Regulatory Commission (FERC) to amend Attachment J, Section III.D.2 to read as follows:

> 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 ***approved for construction*** ~~with Notifications to Construct issued~~ after June 19, 2010 to each pricing Zone within the SPP Region.[16]

The Lessons Learned were adopted by the RARTF on March 31, 2014 and also reviewed and approved by the RSC and MOPC[17] to be implemented in RCAR II.

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[16] SPP Staff facilitated Lessons Learned No. 10 through SPP's stakeholder process which was ultimately approved by the SPP Board of Directors and FERC. See, FERC Docket: ER15-307. This filing was approved by FERC on December 22, 2014.

[17] See RARTF approval of RCAR I Lessons Learned items at page 1 of March 31, 2014 minutes; http://www.spp.org/documents/22238/rartf%20meeting%20minutes%2031%20march%202014%20draftgf.pdf

SECTION 1: OVERVIEW OF THE RARTF AND RCAR REVIEW

The next sections of the RCAR II Report highlight the implementation the RARTF Final Report as modified by RCAR I Lessons Learned Report.

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 RCAR analysis. 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 under Section III.D and suggest adjustments to the RSC and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint.[18]

Step 2: For each RCAR conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades approved for construction[19] 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 Attachment J to the SPP OATT.[20]

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.[21]

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.[22]

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[18] *Id.*
[19] Based on Lessons Learned #9 and approved by FERC in Docket: ER15-307
[20] Attachment J, Section III.D.2 of SPP's OATT.
[21] Attachment J, Section III.D.3 of SPP's OATT.
[22] Attachment J, Section III.D.4 of SPP's OATT.

1.2 Overview of RARTF Charter

In addition to SPP's tariff requirements, the RARTF's charter defined further additional work and deliverables for the group. 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 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.

The charter also defined key deliverables for the RARTF:

> The RARTF scope of work and key deliverables include the following:
>
> 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 group 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 roughly commensurate standard as articulated by the United States Court of Appeals for the Seventh Circuit ("Seventh Circuit") and the FERC. The roughly commensurate standard is the Seventh Circuit's and FERC's interpretation of the just and reasonable standard as applied to regional cost allocation for transmission facilities.

The term "roughly commensurate" was used for the first time in association with electric transmission facilities by the Seventh Circuit in *Illinois Commerce Commission v. FERC* ("*ICC I*")[23] and was subsequently used and elaborated on in two other Seventh Circuit cases also named *Illinois Commerce Commission v. FERC*.[24]

Specifically, the Seventh Circuit stated that FERC may approve a cost allocation mechanism that does not perfectly match costs and benefits, even if FERC cannot precisely quantify the benefits, provided that FERC has "an articulable and plausible reason to believe that the benefits are at least roughly commensurate with" the costs a customer would pay under the cost allocation methodology.[25]

Following the *ICC I* opinion, FERC cited the Seventh Circuit's roughly commensurate standard in approving SPP's Highway/Byway cost allocation methodology,[26] MISO's MVP cost allocation,[27] and California Independent System Operator Corporation's convergence bidding proposal.[28] Additionally, in Order No. 1000,[29] FERC established several cost allocation principles for regional and interregional transmission facilities, including a principle that:

> The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is

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[23] 576 F.3d 470 (7th Cir. 2009). In this case, the Seventh Circuit remanded FERC orders approving 100% region-wide cost allocation for extra high voltage transmission facilities in PJM Interconnection, L.L.C. ("PJM"), on the basis that FERC did not demonstrate that the cost allocation proposal allocated costs to utilities in the western portion of PJM on a basis "roughly commensurate" with the benefits that those utilities would realize from extra high voltage transmission facilities built in the eastern portion of PJM.

[24] 721 F.3d 764 (7th Cir. 2013) (affirming FERC orders approving the Midcontinent Independent System Operator, Inc.'s ("MISO") "multi-value project" ("MVP") regional cost allocation) ("*ICC II*"); 756 F.3d 556 (7th Cir. 2014) (remanding for a second time FERC's orders approving PJM's region-wide cost allocation for extra high voltage transmission facilities) ("*ICC III*").

[25] *ICC I*, 476 F.3d at 477; *see also ICC II*, 721 F.3d at 775.

[26] *Southwest Power Pool, Inc*., 131 FERC ¶ 61,252, at PP 78, 98 (2010), *order denying reh'g*, 137 FERC ¶ 61,075 (2011).

[27] *Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,221, at P 200 (2010), *order on reh'g*, 137 FERC ¶ 61,074 (2011).

[28] *Cal. Indep. Sys. Operator, Corp.*, 133 FERC ¶ 61,039, at P 64 (2010), *order denying reh'g*, 134 FERC ¶ 61,070 (2011).

[29] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,323 (2011), *order on reh'g & clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014), *reh'g denied en banc*, 2014 U.S. App. LEXIS 19968 (D.C. Cir. Oct. 17, 2014).

> *at least roughly commensurate* with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting Public Policy Requirements.[30]

Since issuing Order No. 1000, FERC repeatedly has cited the roughly commensurate standard in acting on various utility cost allocation proposals. Additionally, SPP staff notes that various FERC and court precedents, both before and after the *ICC* line of cases, articulate certain principles that a cost allocation method must satisfy. These include (but are not limited to):

- 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.
- A cost allocation method need not be perfect, but in fact can be crude; if crude is all that is possible, it will have to suffice.
- While not requiring exacting precision, the roughly commensurate standard requires "some effort" to quantify or otherwise show benefits.

From these principles, the RARTF determined that "roughly commensurate" does not necessarily mean net cost-beneficial to each customer. Thus, something less than a 1.0 B/C ratio may comply with the standard.

FERC has said, "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."[31]

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[30] *Id.* at P 622. The United States Court of Appeals for the District of Columbia Circuit upheld Order No. 1000 in its entirety, including this cost allocation principle, in 2014. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (2014), *reh'g denied en banc*, 2014 U.S. App. LEXIS 19968 (D.C. Cir. Oct. 17, 2014).

[31] *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 at P 26 (emphasis added). Indeed, in *ICC II*, the Seventh Circuit rejected arguments by certain customers that the allocation of MVP costs to them was not just and reasonable *(footnote continued)*

The conclusions drawn in both the RARTF and RCAR I reports consider the *ICC* and related cases as well as subsequent FERC orders citing the Seventh Circuit's roughly commensurate standard.

1.4 Cost Allocation Challenges for Transmission Upgrades

The allocation of costs for public projects with significant and widespread public benefits is a complex matter. This is particularly true for electric transmission projects, as stated by 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.[32]

The RARTF noted the difficulties of implementing cost allocation methods for transmission projects. The RCAR I and RCAR II Reports reflect the RARTF's reasoned, sound, and well-established methods endorsed by SPP stakeholders in January 2012 with the adoption of the RARTF Report as well as RCAR I Lessons Learned Report in 2014.

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because MISO and FERC had failed to show that the projects will confer benefits greater than their costs and because FERC failed to compare costs and benefits of the MVPs on a subregion-by-subregion or utility-by-utility basis. *See ICC II*, 721 F.3d at 774 ("It's impossible to allocate these cost savings with any precision across MISO members."). In addition, the Seventh Circuit very recently upheld FERC's decision to approve a MISO cost allocation method for reliability projects that allocates 100% of the costs to the pricing zone(s) in which a facility is located, even though some other zones may receive some benefit from the facilities. *See MISO Transmission Owners v. FERC*, 2016 U.S. App. LEXIS 6279, at *15-16 (7th Cir. Apr. 6, 2016) ("But FERC's calculations suggest that the spillover of benefits to other zones is modest enough to make the local allocation of costs "roughly commensurate" with the allocation of benefits.") (citing *ICC I*, 576 F.3d at 477).

[32] *Transmission Planning Processes Under Order No.* 890, Notice of Request for Comments at 5, Docket No. AD09-8-000 (Oct. 8, 2009).

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

2.1 Highway/Byway Summarized

The RSC established the Highway/Byway cost allocation methodology that was subsequently approved by FERC.[33]

The Highway/Byway methodology assigns 100% of all 300+ 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 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

Upgrade Voltage	Region Pays	Local Zone Pays
>300 kV	100%	0%
100 - 300 kV	33%	67%
<100 kV	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 defined in Attachment J of the OATT. The recovery of the ATRR is through OATT Schedule 11 and booked by each zone in OATT Attachment H. Additionally, these costs are offset by point-to-point (PTP) revenues collected by SPP for transmission service sold on the SPP system.

Once PTP revenues are collected, they offset the amount zones pay under Highway/Byway as provided for in OATT Attachment L.

As described in the RCAR I Lessons Learned Section above, per Lessons Learned No. 7, PTP revenues have been offset for the RCAR II analysis as approved by FERC in Docket Number ER16-165.

[33] *Southwest Power Pool, Inc.*, 137 FERC ¶ 61,075 (2011).

Via a settlement agreement in FERC Docket EL14-21, MISO and NRG, Inc. pay SPP transmission owners for the use of SPP transmission facilities. The revenue has been allocated per the methodology conditionally approved by FERC in ER16-791-111.[34]

[34] FERC has approved this revenue distribution methodology, subject to refund, and set it for hearing and settlement judge procedures and is currently in settlement discussions.

SECTION 3: RECOMMENDED REVIEW METHODOLOGY

3.1 Principles that Guided How SPP Staff Conducted the RCAR II Review

Following research, stakeholder input and extensive discussion, the RARTF Report defined ten key principles to guide SPP staff in conducting RCAR analyses:

(1) Simplicity - The RCAR should be as simple as possible, so that the report is understandable.

(2) Roughly Commensurate – The RCAR 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 RCAR should use the most up-to-date and best available information for the review.

(4) Consistency – The RCAR should be consistent.

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

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

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

(8) Consideration Given to Certain Plans – The RCAR should give considerations to certain plans that have been approved by the Board. This includes projects that have been approved for construction since June 2010.[35]

(9) More Weight should be Given to Nearer Term Projects than Future Projects – Although the RCAR should give consideration to certain plans approved by the Board, less weight should be given to plans which have been given an ATP as opposed to an NTC.[36]

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

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[35] At the time the RARTF was developing the methods under which the RCAR I was to be conducted; SPP used a concept known as ATPs. After the approval of the RARTF Report, the term ATP was 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 when conducting RCAR I. Beginning with RCAR II, pursuant to Lessons Learned # 6, only projects "approved by the SPP Board" will be evaluated. See, FERC Docket: ER15-307

[36] Per Lessons Learn No. 6, the RCAR II analysis only considers projects that have been approved for construction by the SPP Board of Directors. As a result, RARTF principal 9 was not used during RCAR II.

3.2 Regional Cost Allocation Review Methodologies

Because the RCAR evaluates projects built under SPP's Highway/Byway cost allocation methodology, the RARTF recommended that certain projects and plans which are approved by the Board be evaluated. However, due to the uncertainty of some projects, the RARTF recommendation for RCAR I was that emphasis of the review be placed on Board-approved plans that have in-service dates ten or fewer years in the future. Only projects approved for construction by the BOD Board are analyzed in the RCAR II process per Lesson Learned 6.

Since approach to analyzing benefits of transmission projects that are either too conservative or too broad can be problematic, the RARTF originally proposed a single methodology for assessing the benefits and costs of SPP transmission projects under the Highway/Byway cost allocation methodology for RCAR I. With this methodology, staff was directed to conduct two evaluations to report and assess the impacts of the Highway/Byway cost allocation methodology.[37] Because this philosophy was changed for RCAR II per Lessons Learned 6, only one evaluation is conducted for RCAR II.

3.3 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. As a result, RCAR II uses the same baseline as RCAR I.

3.4 RARTF Recommended Calculation of Benefits to Cost Ratios

The RARTF recommended 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. As a result, RCAR II used 2016 dollars.

[37] During RCAR I the two evaluations included an assessment of: (1) NTCs: All SPP projects that have been issued an NTC since June 2010; and (2) NTCs and Projects within 10 years: 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.

3.5 RARTF Recommends Use of a 40-Year Project Evaluation

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

3.6 RARTF Recommendation on the Calculation of Costs

When conducting the RCAR, the RARTF recommended using the most up-to-date ATRR for each zone. As a result, RCAR II uses cost from the May 2016 Project Tracking cost update.

3.7 RARTF Recommendation on Benefits to be calculated

The RARTF recommended that the set of benefit categories listed below be used in the RCAR process. The RARTF further recommended that, before RCAR I was conducted, specific metrics be developed to quantify the benefits in dollars using procedures defined by the MOPC through the work of the ESWG.

For metrics without dollar amounts but in other terms (MW, MWh, Tons, etc.), the RARTF recommended that the ESWG 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 that the RCAR use the most conservative or lowest value in any range provided by the ESWG. For 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 benefits that are shared by some zones but cannot be distributed to 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 their report to assess the B/C ratio. Additionally, the group recommended that the RCAR 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. As a result, RCAR II uses benefits developed by the ESWG and approved by the SPP Board of Directors.

Prior to the start of 2015 ITP10 and RCAR II, the ESWG[38] reviewed the calculation and allocation processes of all approved benefit metrics; including those approved for RCAR I but not monetized in that analysis. The metrics changed from RCAR I were as follows:

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[38] The ESWG and TWG were assigned MOPC Action Item #222 to finalize the benefits metrics & allocation methods for the 2015 ITP10 Portfolio Analysis in the October 15-16, 2013 MOPC Meeting; see Page 5 of the MOPC Minutes at
(footnote continued)

- Mitigation of Transmission Outages – The calculation of the benefit remained unchanged; however the allocation of the benefit was changed to load-ratio share. This allocation methodology was proposed by the ESWG and supported by SPP staff. The allocation change was not approved by the MOPC[39] but was adopted by the Board[40].

- Assumed Benefit of Mandated Reliability Projects – The benefit's calculation remained unchanged, but its allocation was changed to a hybrid allocation as follows:

Upgrade Voltage	Allocation
>300 kV	33% System Reconfiguration 66% Load-ratio share
100 - 300 kV	66% System Reconfiguration 33% Load-ratio share
<100 kV	100% System Reconfiguration

  This allocation methodology was proposed by the ESWG and supported by SPP staff. The allocation change was not approved by the MOPC but was adopted by the Board.

- Benefits from Meeting Public Policy Goals - The benefit's calculation remained unchanged, but its allocation was changed to be allocated to zones based on share of unmet renewable mandates/goals in state(s) driving policy projects. Both the MOPC and Board approved this ESWG recommendation.

- Marginal Energy Losses Benefit – This benefit has been monetized for the first time in RCAR II. The benefit value is captured from the Marginal Loss Component of the Locational Marginal Price (LMP) and allocated by the physical location of loss savings. This benefit calculation and allocation was recommended by the ESWG and approved by the MOPC and Board.

- Increased Wheeling Through and Out - This benefit is monetized for the first time in RCAR II. The benefit is captured based on a firm service methodology and allocated based on tariff specified revenue distribution rules. This benefit calculation and allocation was recommended by the ESWG and approved by the MOPC and Board.

The list of benefits the RARTF recommended to be monetized in the RCAR II were:

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http://www.spp.org/documents/21032/mopc%20meeting%20minutes%20&%20attachments%20october%2015-16,%202013.pdf

[39] See July 15-16, 2014 MOPC Minutes Page 4 at http://www.spp.org/documents/22945/mopc%20minutes%20&%20attachments%20july%2015-16,%202014.pdf

[40] See July 29, 2014 BOD Minutes Page 9 at http://www.spp.org/documents/22963/bocmc%20minutes%20072914.pdf

- **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 directly related to energy production by generating resources in SPP. APC is calculated by adding a zone's production cost to the zone's purchases and subtracting out their sales. Other approved benefit metrics that are captured as part of the APC calculation are:
  - **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.
  - **Savings due to Lower Ancillary Service Needs -** Ancillary Services are essential to the reliable operation of the electrical system. A number of operating reserves and products fall into this category—spinning reserves, ramping (up/down), regulation, 10-minute quick start.

- **Assumed Benefit of Mandated Reliability Projects -** Treating benefits for mandated reliability projects equal to their costs avoids potential undervaluing of the portfolio value of reliability projects which are mandated and thus not justified solely by other economic benefits.

- **Increased Wheeling Through and Out –** Increasing the Available Transfer Capacity (ATC) with a neighboring region improves import and export opportunities outside the SPP footprint. Increased inter-regional transmission capacity that causes increased through and out transactions will also increase SPP wheeling revenues. These increased wheeling revenues are a benefit as they will offset part of the transmission projects' revenue requirement.

- **Mitigation of Transmission Outage Costs –** Standard production cost simulations assume that lines and facilities are available during all hours of the year and that no planned or unexpected transmission outages of transmission facilities will occur. In practice, planned and unexpected transmission outages impose non-trivial additional congestion on the system.

- **Marginal Energy Losses Benefits –** Standard production cost simulations used to estimate APC do not reflect that transmission expansions may reduce the MWh quantity of transmission losses. In simulations, loads are "grossed up" for average transmission losses and assume that losses are fixed and do not change with transmission additions.

- **Benefits from Meeting Public Policy Goals -** This metric captures the value of meeting the requirements of public policy.

- **Cost Savings from Reduced On-peak Transmission Losses –** Quantifies the reduction in generating capacity needed due to a reduction on system losses during the peak hour.

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

The following approved benefit metrics were not monetized for RCAR II.

- **Reduced Cost of Extreme Events**
- **Capital Savings from Reduced Minimum Required Margin**
- **Reduced Loss of Load Probability**

3.8 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. As with RCAR I, RCAR II uses assumptions vetted by SPP stakeholders.

SECTION 4: REPORT THRESHOLDS

4.1 RARTF Recommended a Remedy Threshold

Pursuant to the RARTF's charter, the group 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 an RCAR analysis. 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 were a part of the RCAR I assessment report.[41] This was reaffirmed for use in RCAR II as stated in Lesson Learned 8.

The RARTF found during the RCAR I few projects, if any, were actually in service.[42] 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.[43]

Significantly more projects subject to the RCAR analysis were in service in RCAR II than in RCAR I. In particular, as of the drafting of RCAR II, 274 of the 503 Highway/Byway-funded upgrades subject to the RCAR II review are in service, as compared to 48 of 298 projects in RCAR I. These upgrades account for 41.5% of the cost of Highway/Byway funded transmission upgrades and approximately 50% of the new miles of transmission facilities included in the RCAR study.

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

Pursuant to the RARTF's charter, the group recommended that a threshold be established to determine when SPP staff should study possible remedies as stated in Section 4.1.

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[41] In RCAR I, the RARTF noted that the 0.8 B/C ratio recommended in the RARTF Report was based upon the ESWG and SPP Stakeholder approving a method to measure the benefits listed in Section 3.8. Additionally, the RARTF noted 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.

[42] 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 I 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. Comparisons between RCAR I and RCAR II are contained in Appendix 5.

[43] 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 RCAR which shows a zone is above the 0.8 threshold in Section 4.1 but below a 1.0 B/C ratio should be considered a part of SPP's transmission planning process in the future.

At the conclusion of RCAR I the RARTF and SPP stakeholders debated the use of the 0.8 threshold. The RARTF concluded that the 0.8 threshold was still appropriate and should be maintained for RCAR II. This decision was memorialized in Lesson Learned 8. As a result, RCAR II uses the same policy as RCAR I.

SECTION 5: POTENTIAL REMEDIES TO BE STUDIED

5.1 RARTF Recommended Zonal Remedies

If the results for a zone following an 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 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. This policy was reaffirmed in Lesson Learned 8.

The potential list of remedies recommended by the RARTF that SPP staff could evaluate, listed in order of preference, 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 MOPC, RSC, Members Committee and Board approved the RARTF Report, 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 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's roster included[44]:

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's scope of work and key deliverables[45] included the following:

[44] 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.

- 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 (defined in the SPP's tariff's Attachment H, Section I, Table 1). An estimate of the effort to calculate the benefits identified above.
- A list of any issues identified from the MTF efforts or any additional direction needed from other working groups.
- 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, on September 13, 2012 the MTF submitted a final report to the ESWG 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."[46]

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.

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[45] The MTF Charter is posted on SPP's website at:
http://www.spp.org/documents/16613/20120227%20metrics%20task%20force%20charter.pdf

[46] The MTF Report is posted on SPP's website at:
http://www.spp.org/documents/18175/20120913%20mtf%20report_approved.pdf

> At the conclusion of the effort the MTF identified five (5) metrics that are currently used by SPP in the ITP process, eight (8) new metrics that the MTF recommends be calculated as part of the Regional Cost Allocation Review, and nine (9) other metrics that received significant consideration but have not yet gained enough consensus amongst the MTF or cannot currently be monetized for inclusion in the Regional Cost Allocation Review.
>
> The most important aspect of the metrics to be developed is that the metrics should be able to provide "hard dollar" impacts of transmission to rate payers. In terms of this report, "hard dollar" means that each recommended metric must be able to provide incontrovertible evidence that a benefit will result in lowering of the overall cost to a rate payer. As part of this test, the MTF reviewed the metrics through the open SPP stakeholder meetings, transmission summits, and public postings, provided progress updates to the Cost Allocation Working Group (CAWG) to gather their feedback on the acceptability of the metrics being proposed, and sought feedback from the Chair and Vice-Chair of the original RARTF to reasonably assure that the MTF was addressing the metrics the RARTF recommended in the RARTF Report.
>
> Due to the short amount of time before the Regional Cost Allocation Review will commence, the MTF concentrated on those metrics that could be reasonably implemented for the first Regional Cost Allocation Review. Section 9 of this report identifies additional metrics the Regional Cost Allocation Review team may want to consider especially after the Integrated Marketplace goes live in March of 2014 or in the second Regional Cost Allocation Review.

In their report, the MTF recommended that a total of thirteen monetized benefit metrics be utilized in the RCAR process. Of those 13 metrics, five were previously used in the Integrated Transmission Planning (ITP) process and eight were 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 their report, which was amended and approved by the ESWG and sent to the MOPC for approval.[47] At the October 16-17, 2012 MOPC meeting the MTF report was presented for approval, and the MOPC approved

[47] *See* report posted on SPP's website at:
http://www.spp.org/documents/18175/20120913%20mtf%20report_approved.pdf

it.[48] The report was presented to the board and Members Committee on October 30, 2012, where the Members Committee approved the metrics unanimously and the Board approved the report.[49]

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 were used in the RCAR.

6.4 Stakeholder Approval of the MTF's RCAR II Benefit Metrics

At the conclusion of RCAR I, the MOPC approved Action Item 222[50] that instructed the ESWG and TWG to finalize the benefits and metrics to be used for the 2015 ITP10. These same benefits and metrics would be used for the RCAR II analysis.

After debating the benefit metrics, ESWG presented their recommendations to the MOPC in July 2014[51]. MOPC agreed to three of the five metrics recommendations made by the ESWG. Thought a majority agreed on remaining metrics, a supermajority consensus was note reached, so the Assumed Benefit of Mandated Reliability Projects and Mitigation of Transmission Outage Costs metrics were not approved.

In the July Board meeting, the Board approved all five metrics as recommended by the ESWG.

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[48] *See* Agenda Item 12 in the MOPC October 16-17, 2012 minutes posted on SPP's website at: http:// http://www.spp.org/documents/18378/mopc%20minutes%20&%20attachments%20october%2016-17,%202012.pdf

[49] *See* Summary of Action Items no. 9 in the Board of Directors October 30, 2012 Minutes posted at: http://www.spp.org/documents/18398/bod103012.pdf

[50] MOPC October 15-16, 2013 Info http://www.spp.org/documents/18378/mopc%20minutes%20&%20attachments%20october%2016-17,%202012.pdf at Page 5

[51] MOPC July 15-16, 2014 Info http://www.spp.org/documents/22945/mopc%20minutes%20&%20attachments%20july%2015-16,%202014.pdf

SECTION 7: RESULTS OF RCAR II

7.1 Summary of Benefits and Costs

Figure 7.1 summarizes the 40-year present values of the estimated benefit metrics and costs and the resulting B/C ratios by SPP zone.[52]

Zones with a B/C ratio below the 0.8 threshold are marked with a red dot. For these zones, the additional dollar amount of benefits needed to bridge this “gap” and achieve a B/C ratio of 0.8 are shown in the two columns on the right .

[52] SPP staff was supported by Johannes Pfeifenberger, Onur Aydin, Akarsh Sheilendranath, and David Kwok of The Brattle Group in the preparation of the analyses and results presented in this report. Supporting analyses were also conducted by Keith Smith and Nader Moharari of ABB and Ric Austria of Pterra Consulting. A list of RCAR study assumptions is contained in Appendix 3 to this report and a zonal comparison between RCAR I and RCAR II is included in Appendix 5 to this report.

Figure 7.1
Estimated 40-year Present Value of Benefit Metrics and Costs (2016 $million)

	Present Value of 40-yr Benefits for the 2015-2054 Period (2016 $million)												PV of 40-yr ATRRs (2016 $million)				Gap to Reach B/C Ratio of 0.8 (2016 $million)	
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-Peak Losses	Mitigation of Trans-mission Outage Costs	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Increased Wheeling Through and Out Revenues	Marginal Energy Losses Benefits	Reduced Cost of Extreme Events	Reduced Loss of Load Probability	Capital Savings from Reduced Minimum Required Margin	Total Benefits	Before PtP and MISO Revenue Offset	PtP and MISO Revenue Offset	After PtP and MISO Revenue Offset	Benefit/ Cost Ratio	TOTAL	Levelized Real
AEP	$1,216	$20	$87	$207	$965	$0	$133	$59				$2,686	$1,654	$121	$1,533	**1.75**	$0	$0.0
CUS	-$33	$0	$0	$14	$53	$0	$5	$2				$42	$76	$5	$71	**0.59**	$15	$0.9
EDE	-$25	$0	$0	$24	$83	$0	$12	$0				$95	$126	$9	$117	**0.81**	$0	$0.0
GMO	$174	$1	$3	$38	$180	$0	$19	-$2				$412	$207	$15	$192	**2.15**	$0	$0.0
GRDA	$82	$0	$1	$19	$70	$0	$13	-$6				$179	$114	$8	$106	**1.68**	$0	$0.0
KCPL	$642	$1	$6	$76	$308	$0	$37	$51				$1,122	$407	$29	$378	**2.97**	$0	$0.0
LES	$115	$0	$1	$19	$64	$0	$8	$15				$223	$106	$8	$98	**2.27**	$0	$0.0
MIDW	$76	$0	$11	$8	$93	$0	$5	-$3				$190	$71	$5	$66	**2.89**	$0	$0.0
MKEC	$60	$0	$17	$13	$171	$0	$14	$30		**Not Monetized**		$306	$259	$20	$239	**1.28**	$0	$0.0
NPPD	$158	$1	$53	$58	$275	$0	$38	-$9				$574	$404	$29	$375	**1.53**	$0	$0.0
OGE	$1,428	$2	$65	$131	$635	$0	$66	-$64				$2,262	$838	$60	$777	**2.91**	$0	$0.0
OPPD	$24	$1	$3	$48	$150	$0	$23	$9				$257	$320	$23	$297	**0.87**	$0	$0.0
SEPC	$83	$0	$12	$9	$159	$0	$8	$11				$283	$82	$6	$76	**3.73**	$0	$0.0
SPS	$3,537	$12	$357	$115	$1,024	$0	$90	-$13				$5,122	$1,402	$102	$1,301	**3.94**	$0	$0.0
UMZ	$281	$1	$47	$96	$595	$0	$55	$191				$1,266	$397	$45	$352	**3.60**	$0	$0.0
WFEC	$159	$0	$77	$34	$222	$0	$20	$56				$568	$295	$21	$274	**2.08**	$0	$0.0
WR	$996	$1	$5	$105	$710	$0	$94	$100				$2,011	$1,002	$73	$930	**2.16**	$0	$0.0
TOTAL	**$8,974**	**$41**	**$743**	**$1,014**	**$5,759**	**$0**	**$641**	**$427**				**$17,599**	**$7,760**	**$579**	**$7,180**	**2.45**		

7.2 Transmission Projects Evaluated in this RCAR Report

The RCAR II was conducted by evaluating all SPP projects approved for construction since June 2010.[53]

These projects were evaluated by looking at their projected costs and estimated benefits. Projects' projected costs were determined by staff using the most recent cost data submitted by project sponsors (as of May 2016). Projected benefits estimations were conducted by the Brattle Group by monetizing a subset of benefits developed by the MTF and approved by stakeholders (see Section 6 above).

7.3 RARTF Guidance Provided to SPP Staff While Conducting RCAR II

Since the completion of RCAR I in October 2013, SPP staff and the RARTF have anticipated the RCAR II's scheduled completion in July 2016. The RARTF provided SPP staff with guidance for RCAR II as listed below:

- RCAR I Lessons Learned – approved March 31, 2014
- RCAR II to be an NTC-only study in that no analysis of the 10+ year projects should be completed – August 13, 2014
- The delay of the initial RCAR II scheduled to be completed in July 2015 to have additional time to resolve modeling issues – March 13, 2015
- To cut off transmission updates to the RCAR II models on October 1, 2015 – July 8, 2015
- For the ESWG and Staff to determine solutions for trapped generation and load pocket modeling issue by November 18, 2015 – July 8, 2015
- To include the Integrated System pre-October 2015 projects in base-case models for RCAR II – November 2, 2015
- RCAR II analysis window of 2015-2054 for both costs and benefits – November 2, 2015
- Accepted the proposal and analysis of the ESWG for the trapped generation and load pocket modeling issue resolutions – November 2, 2015

7.4 Cost Calculations Contained in the RCAR Report

Pursuant to the RARTF Report and Lessons Learned Report, SPP staff conducted cost projections using the 40-year present value of all Base Plan Upgrades approved for construction after June 19, 2010.[54]

[53] On July 8, 2015 the RARTF voted unanimously to "cut-off" any transmission updates to the models being used for RCAR II on October 1, 2015; see July 8, 2015 RARTF meeting minutes at agenda item #6: http://www.spp.org/documents/29110/rartf%20minutes%2020150708%20draft.pdf

[54] *Id.*

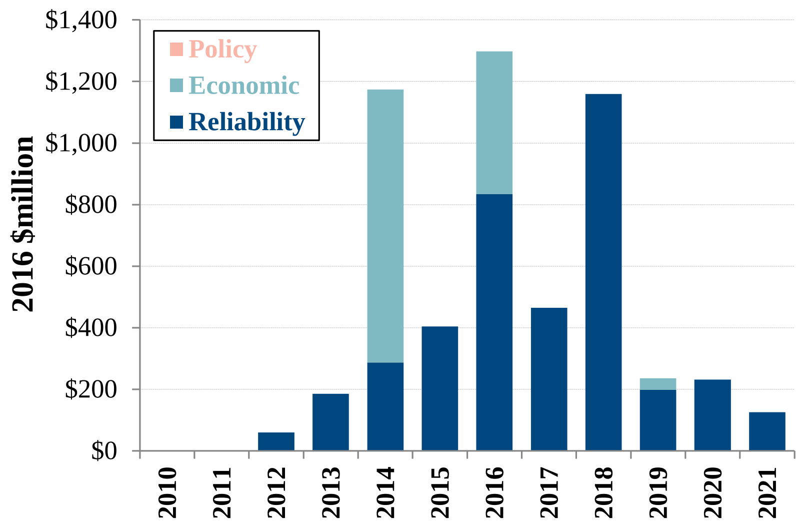
In accordance with Principle 3 from the RARTF Report, SPP staff used the most recent cost estimates provided to SPP in May 2016 for project cost tracking. Thus, the RCAR analysis uses the most up to date and best available information for the review, per Principle 3.

7.4.1 Classification of Projects

To conduct the RCAR analysis, the Base Plan Upgrades approved for construction were classified by the primary driver (Reliability, Economic, and Public Policy).

Figure 7.3 below summarizes the capital costs by in-service year, categorized by the primary driver.

Figure 7.3
Summary of Capital Cost by In-Service Year



7.4.2 Calculation of Annual Transmission Revenue Requirements (ATRRs)

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

- Costs 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)** based on 2015 12-coincident peak loads used for the portion of costs allocated on a regional basis
- **Net plant carrying charge (NPCC)**, including depreciation expenses, applied at the zonal level to calculate first year ATRRs

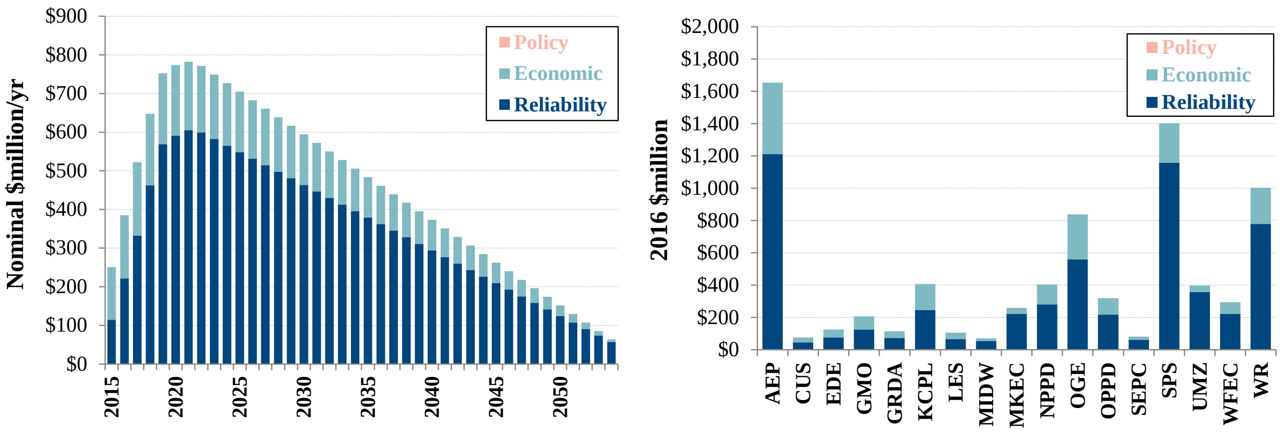
- **2.5%/yr inflation** applied to estimate first year ATRRs in nominal dollars
- **2.5%/yr straight-line depreciation** applied in calculating declining ATRR profile over time in nominal dollars
- Present values calculated for 40-year depreciated ATRRs for 2015-2054 at a nominal **discount rate of 8.0%**

Figure 7.4 below shows the estimated ATRRs over the 40-year study horizon (2015–2054) and summarizes the present values for each SPP zone. At the regional level, the present value of ATRRs is approximately **$7.8 billion** (in 2016$) for all Base Plan Upgrades approved for construction.

Figure 7.4
Summary of Estimated ATRRs by Project Type

(a) ATRR by Year

(b) 40-yr PV by Zone



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

SPP staff projected a PTP revenue credit to each zone over the 40 years of the study period. This PTP revenue credit offsets the costs (ATRR) allocated to individual zones from Base Plan Zonal cost allocation and to all zones through a reduction in the Base Plan Regional rate. The PTP revenue credit reduces the ATRR that must be recovered in subsequent years by the Network Integrated Transmission Service (NITS) charges to all Transmission Customers of the SPP zones.

Step 1: Estimate PTP Volumes

PTP revenue is estimated by first determining the average PTP activity during the previous two years (since the inception of the Integrated Marketplace, or March 2014-February 2016) in the SPP footprint by PTP type (Annual, Monthly, Weekly, Daily Peak and Off-Peak, and Hourly Peak and Off-Peak). 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 March 2014-February 2016

PTP Service Types Considered (Avg. Mar'14 – Feb'16)	Yearly	Monthly	Weekly	Daily On-Peak	Daily Off-Peak	Hourly On-Peak	Hourly Off-Peak
Through (MW)	-	55	5	35	14	128,152	64,076
Out (MW)	3,061	780	784	7,364	2,946	717,231	286,892

Since SPP's Integrated Marketplace provides congestion rights for service of one month or longer, amounts for "Into" and "Within" service types were not included in this analysis.

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

Next, a PTP rate was forecast for each PTP type for the 40 years of the study. The PTP rate forecast was based on the annual ATRR of new Highway/Byway facilities, divided by the SPP 12 CP in MW. The ITP10's 1.1% annual load growth projection was applied to years after 2016. A PTP rate was calculated for each PTP type (Monthly, Weekly, etc.).

Also, ATRRs were considered at 100% for all Base Plan Upgrades approved for construction. 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 2016, etc.)

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

Step 3: Estimate Annual RCAR PTP Dollars

Per-year PTP revenues were estimated by multiplying PTP volumes (MW) by the PTP rate ($/MW), both by type. This generated total annual revenues of RCAR PTP revenue for every year of the 40-year RCAR horizon. The resulting 40 years of RCAR PTP revenue projections were converted to 2016 dollars.

Step 4: Allocate Total PTP Revenues to Each Pricing Zone

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

Base Plan Regional (BPR) PTP revenue was allocated to all pricing zones in the SPP footprint based on each zone's Load Ratio Share (LRS percentage) of total BPR PTP revenues.

The total SPP regional component of costs 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 percentage. PTP revenue amounts, by zone, are presented below in Figure 7.6.

Step 5: Calculate an Estimation of MISO Seams Revenue by Zone to Further Offset PTP Revenues for Each Pricing Zone

The first step was to develop a ratio of Highway/Byway costs as a percent of total Base Plan Funded costs by zone. This ratio was applied to Schedule 11 MISO seams dollars[55] allocated to each zone for the period February 2014 - January 2016. The resulting dollar amount of the Highway/Byway portion of Schedule 11 MISO revenues was then annualized to obtain a dollar amount by zone for use in 2015, the historical period.

To derive MISO seams dollars, which will be allocated by zone going forward through 2021 (the initial term of the settlement agreement), the most current megawatt miles allocation percent by zone of SPP's total MISO seams revenue was applied to an estimate of $27 million for Phase II compensation for the period of February 2016 - January 2017. That amount was then reduced by half, per the approved tariff language.

Next, the percent of Schedule 11 MISO seams revenue compared to all MISO seams revenue was determined by zone and applied to the February 2016 - January 2017 amount of total MISO seams revenue reduced by fifty percent. That was used to derive a Schedule 11 MISO seams revenue amount by zone going forward.

[55] These amounts are currently approved by FERC, subject to refund.

This amount was reduced using the Highway/Byway dollars ratio by zone to calculate an annual Schedule 11 Highway/Byway MISO seams revenue amount for 2016 through 2019.

The Highway/Byway Schedule 11 portion was further allocated between zonal and regional portions, and the regional portion was reallocated based on LRS to distribute revenues to zones having no upgrades in this RCAR portfolio.

Finally, beginning in 2020 and going forward, a two-percent annual inflation rate was applied, as directed by the tariff.

Once the seven-year stream of MISO seams dollars was calculated by zone, those totals were discounted back to a present value using an eight-percent discount rate.

This present value amount by zone was then added to the PTP offset calculated in Steps 1-4 above to obtain the total revenue offset amount. MISO seams revenue amounts, by zone, are presented below in Figure 7.6:

Figure 7.6
PTP Revenue and MISO seams Revenue, 40-yr PV 2015-2054 (in 2016$)

Zone	PTP Revenue Offset	MISO SEAMS Revenue	TOTAL
AEP	$116,025,190	$4,704,596	**$120,729,786**
CUS	$5,308,833	$153,522	**$5,462,355**
EDE	$8,753,773	$253,144	**$9,006,918**
GMO	$14,338,655	$440,502	**$14,779,157**
GRDA	$7,940,107	$224,819	**$8,164,926**
KCPL	$28,251,381	$830,045	**$29,081,425**
LES	$7,357,663	$313,642	**$7,671,305**
MIDW	$4,957,667	$83,488	**$5,041,155**
MKEC	$18,468,382	$1,441,960	**$19,910,341**
NPPD	$28,351,614	$861,462	**$29,213,076**
OGE	$58,477,019	$1,992,400	**$60,469,419**
OPPD	$22,337,721	$712,648	**$23,050,369**
SEPC	$5,770,667	$270,870	**$6,041,537**
SPS	$99,951,038	$1,762,204	**$101,713,242**
UMZ	$44,770,883	$567,002	**$45,337,885**
WFEC	$20,498,423	$363,653	**$20,862,076**
WR	$70,570,020	$2,223,857	**$72,793,877**
Total	**$562,129,035**	**$17,199,814**	**$579,328,849**

Step 6: Apply PTP Revenue Credit (including MISO revenue) to Each Zone's B/C Ratio

The total 40 years of BPZ and BPR PTP revenue credit in 2016 dollars and the MISO seams revenue offset were applied to each zone's cost component of the RCAR B/C ratio as illustrated in Figure 7.1 above.

7.5 Model Development for the Calculation of Benefit Metrics

To estimate benefits, the RCAR II analysis used powerflow and economic (PROMOD) models from the 2017 ITP10 Future 3[56] set. Powerflow models were developed for five and ten years out (2020 and 2025, respectively), and economic models were also built for 20 years out (2035).

7.5.1 Powerflow Model Development

The 2017 ITP10 Future 3 powerflow models were used as RCAR II change case models. Base case models were developed by removing all Highway/Byway upgrades from the change case. Powerflow models were developed for 2020 and 2025 to provide topology input for economic models and for use in powerflow metric calculations.

While economic models were built for 2035, no powerflow models were built for this year because there are no Highway/Byway upgrades with in-service dates between 2025 and 2035. The 2025 powerflow models were used in building the 2025 economic models and the 2035 economic models since there is no change in transmission topology during that time due to Highway/Byway upgrades.

7.5.2 Economic Model Development

Economic models were built for 2020, 2025, and 2035. All modeling assumptions were as consistent as possible with 2017 ITP10 Future 3 assumptions including fuel prices, generation parameters, generation retirements, topology, load, etc.

Three cases are developed for each study year, consistent with the new hybrid approach approved by the ESWG:

[56] Future 3 of the 2017 ITP10 is the "Business as Usual" future, in which there is no Clean Power Plan.

1. **Change Case** with the Highway/Byway upgrades,
2. **Primary Base Case** without the Highway/Byway upgrades, and
3. **Alternate Base Case** without the NTC projects and without the renewable resources identified to be contingent upon Highway/Byway upgrades.

   In both Base Cases, generic CTs were added to areas with load serving challenges.

Under the hybrid approach, SPP-wide savings are first estimated as the difference in APC between the change case and primary base case. Then, savings are allocated to zones based on shares, calculated by comparing the change case against the alternate base case. This approach was developed by SPP staff and stakeholders to achieve more reasonable results than by the standard APC benefit approach. The latter has often produced unrealistic results in areas with significant amounts of trapped renewable generation (i.e., from resources that wouldn't have been added without the Highway/Byway upgrades) due to distorted market prices affecting zones' purchase costs and sales revenues.

In the alternate base case, renewable resources are removed if they met either of the following criteria:

1. The Generator Interconnection Agreement (GIA) for the unit specified that the interconnection was contingent upon specific Highway/Byway upgrades being in service, OR
2. The unit was added after the Highway/Byway upgrades went into service, and is located at the same point of interconnection (POI) as another unit that included GIA specification of Highway/Byway upgrades required to interconnect.

Renewable resources removed from the alternate base case models totaled:

- 5.2 GW in 2020
- 5.4 GW in 2025
- 5.9 GW in 2035

Both primary and alternative base cases included generic gas CT resources in the south SPS load pocket. These resources were added to curb excessive emergency generation observed in the original models, leading to less reasonable APC results. On a cumulative basis, about 1.3 GW of gas CTs are added by 2020, 1.9 GW by 2025, and 3.2 GW by 2035.

7.5.3 Constraints

Constraints used in the economic model were developed through a constraint assessment. For 2020 and 2025 change case models, constraints were set identical to those developed for the 2017 ITP10 Future 3. For the base case and 2035 models, a constraint assessment was performed identical to the process performed in the 2017 ITP10. Constraints include existing flowgates and new future constraints developed using the PAT software tool.

7.5.4 Summary

Figures 7.7 and 7.8 below summarize the RCAR II models and approvals by the appropriate SPP working groups.

Figure 7.7 Summary of RCAR II Models

	Includes HWBW Upgrades	Includes Renewables Contingent on HWBW Upgrades	Powerflow Models		PROMOD Models		
			2020	2025	2020	2025	2035
Change Case	✓	✓	✓	✓	✓	✓	✓
Primary Base Case		✓	✓	✓	✓	✓	✓
Alternative Base Case					✓	✓	✓

Figure 7.8 Approval of RCAR II Models

	TWG	ESWG	RARTF
Economic Modeling Approaches Trapped Generation & Load Pockets	-	Feb-15, Oct-15	Nov-15
Powerflow Models	Jan-16	-	-
Economic Models	-	Mar-16	-
Constraints	Mar-16	-	-

7.6 Benefits Metrics

The benefit metrics analyzed for RCAR II include all metrics developed, monetized, and approved by SPP stakeholders, provided in Figure 7.9 below, which also shows which metrics were monetized for use in the RCAR I and RCAR II studies.

Figure 7.9
Benefit Metrics Analyzed in RCAR

Benefit Metric Name	Monetized in RCAR I?	Monetized in RCAR II?
Adjusted Production Cost (APC) Savings	✓	✓
Reduction of Emission Rates and Values	✓	✓
Savings due to Lower Ancillary Service Needs and Production Costs	✓	✓
Avoided or Delayed Reliability Projects	✓	✓
Capacity Cost Savings due to Reduced On-Peak Transmission Losses	✓	✓
Mitigation of Transmission Outage Costs	✓	✓
Assumed Benefit of Mandated Reliability Projects	✓	✓
Benefits from Meeting Public Policy Goals	✓	✓
Increased Wheeling Through and Out Revenues		✓
Marginal Energy Loss Benefits		✓
Reducing the Cost of Extreme Events		
Reduced Loss of Load Probability		
Capital Savings due to Reduction of Members' Minimum Required Margin		

Figure 7.10 shows the benefit metric approval dates by working group. The methodology and calculation for several benefit metrics were reevaluated and modified in 2014 by appropriate SPP working groups.

Figure 7.10 Benefit Metric Approvals

	Initial Approvals				Updated Approvals		
	MTF	ESWG	MOPC	BOD	ESWG	MOPC	BOD
Adjusted Production Cost Savings	Sep-12	Sep-12	Oct-12	Oct-12			
Capacity Cost Savings from Reduced On-Peak Losses	Sep-12	Sep-12	Oct-12	Oct-12			
Avoided or Delayed Reliability Projects	Sep-12	Sep-12	Oct-12	Oct-12			
Assumed Benefit of Mandated Reliability Projects	Sep-12	Sep-12	Oct-12	Oct-12	Jun-14		Jul-14
Increased Wheeling Through and Out Revenues					Jun-14	Jul-14	Jul-14
Public Policy Benefits	Sep-12	Sep-12	Oct-12	Oct-12	Jun-14	Jul-14	Jul-14
Mitigation of Transmission Outage Costs	Sep-12	Sep-12	Oct-12	Oct-12	Jun-14	Jul-14	Jul-14
Marginal Energy Losses Benefits					Jun-14	Jul-14	Jul-14

7.6.1 Adjusted Production Cost (APC) Savings

APC savings are calculated based on economic model simulations of the SPP system plus much of the Eastern Interconnect for three study years: 2020, 2025, and 2035. The primary base case, alternate base case, and change case were simulated for each study year.

APC savings were calculated for each study year as:

$$\text{APC Benefit}_{\text{regional}} = \text{Primary Base Case APC}_{\text{regional}} - \text{Change Case APC}_{\text{regional}}$$

Zonal benefits were then determined by running the alternate base case compared to the change case:

$$\text{APC benefit}_{\text{zone X}} = \text{APC benefit}_{\text{regional}} \times (\text{Alternate Base Case APC}_{\text{zone X}} - \text{Change Case APC}_{\text{zone X}}) \div (\text{Alternate Base Case APC}_{\text{regional}} - \text{Change Case APC}_{\text{regional}})$$

The results from three study years (2020, 2025, and 2035) were used to estimate 40-year present value of APC savings for the 2015–2054 timeframe. Benefits for the intervening years between studies were interpolated, and after 2035 they were assumed to grow at 2.5% inflation rate (constant in real dollars). An 8% discount rate was used.

As shown in Figure 7.11, APC savings increase over time, driven by continued load growth, increases in renewable generation, and higher fuel prices.

Figure 7.11
APC Savings Results

Zone	Annual Savings 2020 ($m)	Annual Savings 2025 ($m)	Annual Savings 2035 ($m)	40-yr PV 2015-54 (2016 $m)
AEP	$48	$79	$162	**$1,216**
CUS	($1)	($1)	($6)	**($33)**
EDE	($1)	($2)	($3)	**($25)**
GMO	$6	$10	$26	**$174**
GRDA	$3	$6	$11	**$82**
KCPL	$22	$43	$89	**$642**
LES	$4	$7	$16	**$115**
MIDW	$1	$4	$13	**$76**
MKEC	($1)	($2)	$17	**$60**
NPPD	$9	$17	$13	**$158**
OGE	$45	$100	$198	**$1,428**
OPPD	$2	$3	$1	**$24**
SEPC	$4	$5	$11	**$83**
SPS	$125	$287	$445	**$3,537**
UMZ	$7	$20	$41	**$281**
WFEC	($4)	$17	$28	**$159**
WR	$41	$65	$131	**$996**
Total	**$308**	**$658**	**$1,193**	**$8,974**

As shown, the 40-year present value of APC savings for this RCAR II was estimated to be $8.97 billion. This represents a large increase compared to results from the RCAR I study. The observed increase (~2.5x) in savings in RCAR II is driven by a combination of factors as described below:

- ***Larger Highway/Byway Portfolio*** – Both RCAR studies included transmission projects approved to be built under SPP's Highway/Byway cost allocation methodology using a baseline of June 2010. However, RCAR II includes a larger portfolio of transmission projects, as additional projects have been approved since the RCAR I study was completed. The larger portfolio of transmission projects provide higher congestion relief and increased access to lower-cost resources in the SPP footprint.

- ***Larger SPP Footprint*** – RCAR II considers a larger SPP footprint following the addition of Integrated Systems' Upper Missouri Zone (UMZ). The addition of UMZ increases total load obligations within SPP by 9–15% and allows unobstructed transfers between the UMZ and the rest of SPP system. The expanded SPP footprint allows for the Highway/Byway projects to provide larger APC savings, with UMZ accounting for $281 million of the $8.97 billion SPP-wide total benefits estimated over the 40-year study horizon.

- ***Significantly Higher Renewable Resources*** – RCAR II includes 19–24 GW of installed renewable capacity (wind and solar) in the market simulations, which is substantially higher compared to the 8 GW assumed in the RCAR I study. Further, a significant portion (more than 25%) of the modeled renewable resources is contingent on the RCAR II portfolio to be deliverable to SPP load centers. With more renewables, Highway/Byway projects provide larger APC savings, as they relieve constraints on renewable resources and allow more renewable energy to be delivered to the SPP system with lower curtailments. Highway/Byway projects also provide additional savings (partially captured in APC savings) by facilitating more efficient dispatch of flexible units in response to variable output from renewable resources.

- ***Higher load*** – Load projections in RCAR II are higher than in RCAR I, partly due to the two-year shift in forecast horizon and partly due to increased expectations of future demand. Excluding the UMZ, load inputs for the SPP region were about 2–8% higher in RCAR II than in RCAR I. Higher loads in the system typically exacerbate congestion, especially in the constrained base cases, and contribute to higher APC savings provided by the Highway/Byway projects.

- ***Higher Fuel Prices*** – Due to the change in forecasting approach, RCAR II includes approx. 15–30% higher natural gas and coal prices assumptions compared to RCAR I assumptions.. With higher fuel prices, production costs and congestion in the system tend to increase, so transmission projects typically provide larger economic benefits. (This is consistent with the High Gas Price sensitivity performed in RCAR I, which showed that increasing gas prices by 27.5% would result in 18% higher APC savings.)

Appendix 3 provides additional detail on fundamental input assumptions in RCAR II.

7.6.2 Avoided or Delayed Reliability Projects

Potential reliability needs were reviewed to determine if economic and policy upgrades defer or replace any reliability upgrades. Accordingly, avoided or delayed reliability project benefit represents the costs associated with these additional reliability upgrades that would otherwise have to be pursued.

2020 and 2025 powerflow models are utilized with and without economic upgrades to estimate the avoided or delayed reliability projects benefit. Figure 7.12 lists the economic upgrades excluded to identify: (a) thermal reliability violations arising and (b) the reliability projects that would be needed to address the identified reliability violations.

Figure 7.12
List of Economic Upgrades in the RCAR 2 Highway/Byway Portfolio

PID	Facilities Description
936	Northwest Texarkana - Valliant 345KV Ckt 1
937	Tulsa Power Station 138 kV
938	Sibley - Mullin Creek 345 kV
938	Nebraska City - Mullin Creek 345 kV (GMO)
939	Nebraska City - Mullin Creek 345 kV (OPPD)
940	Hitchland Interchange - Woodward District EHV 345 kV CKT 1&2 (SPS)
941	Hitchland Interchange - WOODWARD DISTRICT EHV 345KV CKT 1&2 (OGE)
942	Thistle - Woodward EHV 345 kV Ckt 1&2 (OGE)
943	Thistle - Woodward EHV 345 kV Ckt 1&2 (PW)
945	Ironwood - Clark Co. 345 kV Ckt 1&2; Clark Co 345 kV - Thistle 345 kV ckt 1&2; Thistle 345/138 kV Transformer; Flat Ridge - Thistle 138 kV; Ironwood 345 kV Substation; Ironwood - Spearville 345 kV Ckt 1&2
946	Thistle - Wichita 345 kV ckt 1&2 (PW); Wichita 345 kV Terminal Upgrades
30850	Iatan 345 kV Voltage Conversion; Iatan - Stranger Creek 345 kV Ckt 1 Voltage Conversion (GMO) (WR)

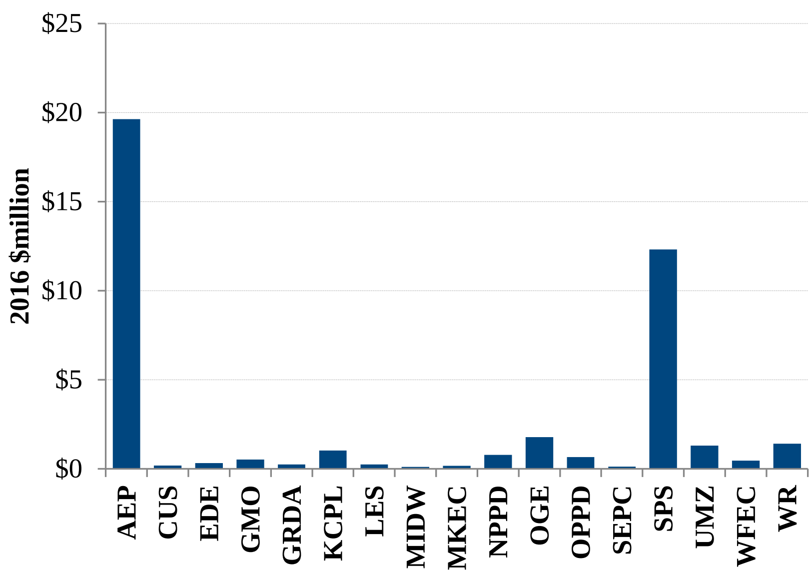
Figure 7.13 below shows the initial list of avoided or delayed reliability projects that would be needed to address the identified reliability violations. A standardized ITP cost template was used to estimate the total costs of the avoided or delayed projects. The benefits are assumed to be equal to the 40-year present value of associated ATRRs of avoided or delayed reliability projects for 2015–2054. They are allocated to zones based on ratios that would have been applied for reliability project costs under the Highway/Byway methodology.

Figure 7.13
Avoided or Delayed Reliability Projects

Project Name	Zone	40-yr PV ATRRs (2016 $m)	Project In (% Load)	Project Out (% Load)	% Delta
Carnegie - Hobart Junction 138 kV Line	AEP	$25	93.9%	101.0%	7.2%
Potter - Harrington 230 kV Line	SPS	$10	83.5%	105.6%	22.0%
Wheeler - Howard 115 kV Line	SPS	$6	89.8%	119.1%	29.3%
~~Etter - Moore 115 kV Line~~	~~SPS~~	~~$8~~	~~98.6%~~	~~104.7%~~	~~6.1%~~
~~Waterford - Coyote Charm 115 kV Line~~	~~UMZ~~	~~$6~~	~~99.9%~~	~~101.0%~~	~~1.0%~~
~~Erskine - Indiana 115 kV Line~~	~~SPS~~	~~$3~~	~~98.6%~~	~~100.7%~~	~~2.1%~~
~~North St. - Salina 115 kV Line~~	~~WR~~	~~$2~~	~~99.8%~~	~~100.5%~~	~~0.8%~~

A 98% maximum loading threshold was applied to determine which projects are included in the final benefit calculations. Accordingly, if a project mitigated a potential overload but the loading remained above 98% of the facility rating, the relief was determined to be insignificant to conclude that a reliability project would be avoided. Based on these criteria, only three projects (highlighted at the top of Figure 7.13) were included in benefit calculations. At the regional level, the 40-year present value of benefits for avoided reliability projects totals $42.1 million in 2016 dollars. Figure 7.14 below shows the zonal allocations of these benefits.

Figure 7.14
Benefits of Avoided or Delayed Reliability Projects



7.6.3 Capacity Savings due to Reduced On-Peak Transmission Losses

Transmission projects often reduce losses during peak load conditions, which lower costs associated with additional generation capacity needed to meet capacity requirements. Reduced capacity expansion costs, due to lower transmission losses on peak, captures the value of unnecessary system-wide generation capacity.

Capacity cost savings are calculated based on on-peak losses estimated in the 2020 and 2025 powerflow models. Loss reductions are then multiplied by 112%, based on the reserve margin requirement, to estimate the reduction in installed capacity requirements.

The value of capacity savings is calculated by applying a net cost of new entry (CONE) of $68.0/kW-year in 2016 dollars. The net CONE value is 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" and non-spinning reserve revenue) for an advanced technology combustion turbine (per EIA's Annual Energy Outlook data).

The average of the net CONE estimates for 2011-2015 was used for this study. A gross CONE value of $86.3/kW-yr (2016$) was obtained by levelizing the capital and fixed operating costs of a new advanced combustion turbine as reported in EIA's Annual Energy Outlook 2013.

Average net market revenues of $18.3/kW-yr were estimated based on the historical data for energy margins and non-spinning reserve revenues.

As shown in Figure 7.15, SPP-wide, on-peak transmission losses are estimated to decrease by about 362 MW in 2020 and 547 MW in 2025 as a result of the Highway/Byway projects. This figure also summarizes the capacity savings by SPP pricing zones. The 40-year present value of capacity savings is $743 million.

Figure 7.15
Capacity Savings due to Reduced On-Peak Losses (in 2016$)

Zone	2020 Base	2020 Change	2020 Diff.	Loss Reduction	Capacity Savings	2025 Base	2025 Change	2025 Diff.	Loss Reduction	Capacity Savings	40-yr PV 2015-54
	(MW)	(MW)	(MW)	(MW)	($m)	(MW)	(MW)	(MW)	(MW)	($m)	(2016 $m)
AEP	280	260	(21)	21	$2	363	303	(60)	60	$6	**$87**
CUS	10	10	0	(0)	($0)	13	13	0	(0)	($0)	**($0)**
EDE	30	30	0	(0)	($0)	32	32	0	0	$0	**$0**
GMO	27	25	(2)	2	$0	29	27	(2)	2	$0	**$3**
GRDA	24	23	(0)	0	$0	26	26	(0)	0	$0	**$1**
KCPL	57	53	(4)	4	$0	52	48	(5)	5	$0	**$6**
LES	10	10	(1)	1	$0	12	11	(1)	1	$0	**$1**
MIDW	11	9	(2)	2	$0	19	12	(7)	7	$1	**$11**
MKEC	21	15	(6)	6	$0	29	17	(12)	12	$1	**$17**
NPPD	152	117	(35)	35	$3	164	123	(41)	41	$4	**$53**
OGE	185	153	(32)	32	$3	265	218	(48)	48	$5	**$65**
OPPD	36	34	(2)	2	$0	38	36	(2)	2	$0	**$3**
SEPC	16	14	(3)	3	$0	24	16	(8)	8	$1	**$12**
SPS	394	216	(178)	178	$15	642	378	(264)	264	$25	**$357**
UMZ	275	230	(45)	45	$4	276	236	(39)	39	$4	**$47**
WFEC	86	62	(25)	25	$2	125	71	(54)	54	$5	**$77**
WR	142	134	(9)	9	$1	152	147	(5)	5	$0	**$5**
Total	**1,754**	**1,392**	**(362)**	**362**	**$30**	**2,260**	**1,714**	**(547)**	**547**	**$52**	**$743**

7.6.4 Mitigation of Transmission Outage Costs

The standard production cost simulations 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 planned and unplanned outages of existing facilities.

To estimate incremental savings associated with mitigation of transmission outage costs, outage cases were analyzed in PROMOD for the 2025 study year. Cases were developed based on 12 months of historical SPP transmission data.

Because of the high volume of historical transmission outage data (approximately 7,000 outage events) and based on the expectation that many outages would not lead to significant increases in congestion, only a subset of outage events was modeled. The events selected were those expected to create significant congestion and which met 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[57]
- 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[58]

After developing and implementing the outage set in the economic model, new constraints based on these outages are needed to properly capture the additional APC savings due to transmission outages. Additional constraints are identified through a constraint assessment.

PROMOD simulations are then performed to calculate APC savings for the primary base case with outages and the change case with outages. The incremental increase in APC savings benefit with outages above the APC savings benefit with no outages is the benefit from the Mitigation of Transmission Outage Costs. SPP-wide benefits are then allocated to SPP pricing zones based on load ratio share.

In RCAR I, 1,076 outage events were modeled, capturing 15.5% of the 6,951 historical outage events in the 12-month period and 48.4% of the historical outage hours. Comparing outage results for the base and change cases produced annual savings 11.3% higher than APC savings estimated with simulations that did not consider transmission outages.

In RCAR II, 11.3% of APC benefit was utilized, consistent with the RCAR I and 2015 ITP10 studies.[59] Based on the APC savings benefit estimated in RCAR II, this translated to a 40-year present value benefit of $1.0 billion, allocated to zones as shown in Figure 7.16.

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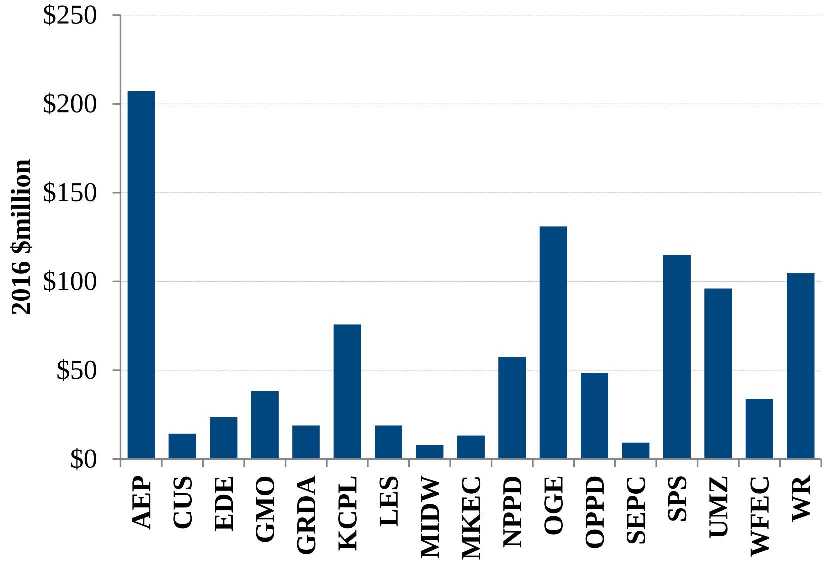
[57] An outage has a significant impact on a defined contingency if one of the elements in the contingency has a LODF over 50% with respect to the outage of the facility, and the voltage of the facility is higher than or equal to the voltage of contingency element.

[58] 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.

[59] See RARTF Report at page 16 for the Principle of Consistency; http://www.spp.org/documents/16210/final%20rartf%20report%20011012.pdf

Figure 7.16
Benefits of Mitigation of Transmission Outage Costs



7.6.5 Assumed Benefits of Mandated Reliability Projects

This metric monetizes reliability benefits of mandated reliability projects. As recommended in the September 2012 MTF report and reaffirmed by the ESWG in 2014, the 40-year PV of regional benefits are assumed to be equal to 40-year PV of ATRRs for the reliability projects. The 40-year PV of ATRRs for reliability projects totaled approx. $5.8 billion in 2016 dollars.

The ESWG[60] and Board[61] approved the allocation of region-wide benefits based on a hybrid approach to reflect different characteristics of higher and lower voltage reliability upgrades:

- **300 kV or above**: 1/3 based on System Reconfiguration and 2/3 based on Load Ratio Share,
- **Between 100 kV and 300 kV**: 2/3 based on System Reconfiguration and 1/3 based on Load Ratio Share, and
- **Below 100 kV**: 100% based on System Reconfiguration

The system reconfiguration approach utilizes powerflow models to measure incremental flows shifted onto the existing system during outage of the proposed reliability upgrade. This is used as a proxy for how each upgrade's reduction of flows on the zones' existing transmission facilities. Results from production cost simulations are used to determine hourly flow direction on the upgrades and then applied as weighting factors for powerflow results.

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60 http://www.spp.org/spp-documents-filings/?id=20236
61 http://www.spp.org/spp-documents-filings/?id=18449

Figure 7.17 summarizes zonal allocations of the Assumed Benefit of Mandated Reliability Projects and illustrates the breakdown by voltage level, System Reconfiguration component, and Load Ratio Share component.

Figure 7.17
Assumed Benefit of Mandated Reliability Projects

	< 100 kV	100–300 kV			> 300 kV			All NTC Projects	
SPP-wide Benefit	$651	$2,929			$2,178			$5,759	
Zone	100% SR	66.7% SR	33.3% LRS	Wtd. Avg.	33.3% SR	66.7% LRS	Wtd. Avg.	Overall Allocation	Benefit (2016 $m)
AEP	37.9%	10.5%	20.4%	13.8%	2.4%	20.4%	14.4%	16.8%	$965
CUS	1.3%	0.3%	1.4%	0.7%	0.5%	1.4%	1.1%	0.9%	$53
EDE	1.5%	0.4%	2.3%	1.0%	1.2%	2.3%	2.0%	1.4%	$83
GMO	4.3%	1.4%	3.8%	2.2%	4.6%	3.8%	4.0%	3.1%	$180
GRDA	2.1%	0.4%	1.9%	0.9%	0.4%	1.9%	1.4%	1.2%	$70
KCPL	4.0%	2.8%	7.5%	4.4%	6.4%	7.5%	7.1%	5.4%	$308
LES	0.0%	0.6%	1.9%	1.0%	1.1%	1.9%	1.6%	1.1%	$64
MIDW	0.0%	3.0%	0.8%	2.3%	2.1%	0.8%	1.2%	1.6%	$93
MKEC	0.1%	4.8%	1.3%	3.6%	6.3%	1.3%	3.0%	3.0%	$171
NPPD	1.7%	4.5%	5.7%	4.9%	5.3%	5.7%	5.6%	4.8%	$275
OGE	10.3%	10.7%	12.9%	11.5%	6.2%	12.9%	10.7%	11.0%	$635
OPPD	1.4%	1.0%	4.8%	2.3%	0.5%	4.8%	3.4%	2.6%	$150
SEPC	1.1%	4.0%	0.9%	3.0%	7.1%	0.9%	3.0%	2.8%	$159
SPS	11.0%	27.1%	11.3%	21.8%	20.4%	11.3%	14.4%	17.8%	$1,024
UMZ	0.1%	7.3%	9.5%	8.0%	30.6%	9.5%	16.5%	10.3%	$595
WFEC	6.6%	4.2%	3.3%	3.9%	2.3%	3.3%	3.0%	3.9%	$222
WR	16.8%	17.0%	10.3%	14.8%	2.6%	10.3%	7.7%	12.3%	$710
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**$5,759**

7.6.6 Benefits of Meeting Public Policy Goals

This metric represents the economic benefits provided by the transmission upgrades for facilitating public policy goals. For the purpose of this RCAR, it is limited to benefits of meeting public policy goals related to renewable energy. System-wide benefits are assumed to be equal to the cost of policy projects.

Since no policy projects were identified in RCAR II, associated benefits are estimated to be **zero**.

7.6.7 Increased Wheeling Through and Out Revenues

Increasing available transfer capacity (ATC) with neighboring regions improves import and export opportunities for the SPP footprint. Increased inter-regional transmission capacity that increases through- and out-transactions will also increase SPP wheeling revenues.

While the benefit of increased exports is captured in APC savings (which values exports at the weighted average generation LMP of the exporting zone), APC savings do not capture increases in wheeling out or wheeling through revenues associated with increased transfer capability.

Collected wheeling revenues are not counted in either the exporting or importing region's APC. Increased wheeling revenues are a benefit as they offset part of transmission projects' revenue requirements. Currently, SPP collects wheeling revenues through Schedules 7 and 11 for firm through and out transactions.

To evaluate increased wheeling revenues based on long-term firm TSRs, a First Contingency Incremental Transfer Capacity (FCITC) analysis is conducted to determine the change in ATC for exports. Increases in ATC due to the transmission upgrades are used to project future long-term transmission service revenues.

Transmission service revenues due to transmission expansion were estimated to be $19 million in 2020 and $51 million in 2025. The 40-year PV of benefits totaled $641 million for this benefit metric. The zonal allocation of this regional benefits is shown in Figure 7.18, and are based on tariff language governing Schedules 7 and 11 revenue allocation.

Figure 7.18
Benefits of Increased Wheeling Through and Out Revenues

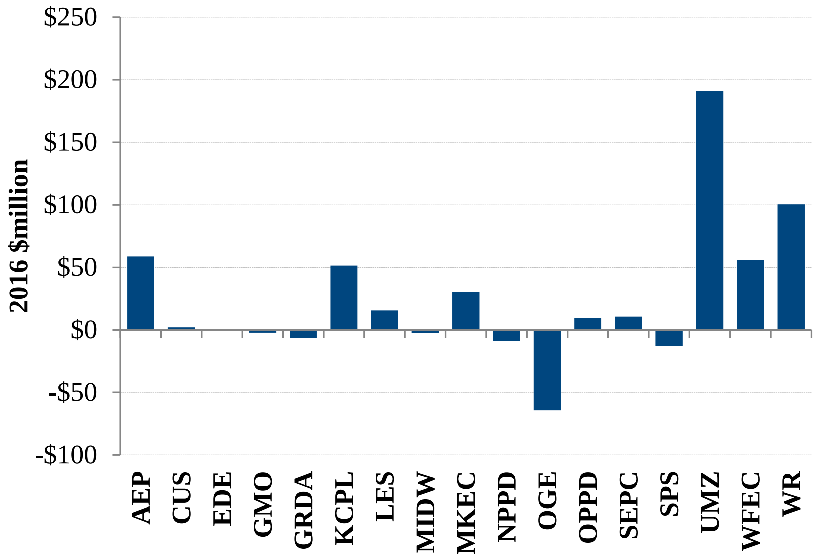
Zone	2020 ($m)	2025 ($m)	40-yr PV 2015-54 (2016 $m)
AEP	$4	$11	**$133**
CUS	$0	$0	**$5**
EDE	$0	$1	**$12**
GMO	$1	$1	**$19**
GRDA	$0	$1	**$13**
KCPL	$1	$3	**$37**
LES	$0	$1	**$8**
MIDW	$0	$0	**$5**
MKEC	$0	$1	**$14**
NPPD	$1	$3	**$38**
OGE	$2	$5	**$66**
OPPD	$1	$2	**$23**
SEPC	$0	$1	**$8**
SPS	$3	$7	**$90**
UMZ	$2	$4	**$55**
WFEC	$1	$2	**$20**
WR	$3	$7	**$94**
Total	**$19**	**$51**	**$641**

7.6.8 Marginal Energy Losses Benefits

Standard production cost simulations used to estimate APC do not reflect that transmission expansions may reduce the MWh quantity of transmission losses. In production cost simulations used to estimate APC savings, load inputs are grossed up for average transmission losses to make run-time more manageable. Accordingly, the MWh quantity of losses is fixed and does not change with transmission additions. Therefore, simulations do not capture potential savings from reduced MWh quantity of losses that may be realized with the Highway/Byway upgrades.

APC savings due to such energy loss reductions can be estimated by post-processing the Marginal Loss Component (MLC) of the LMPs in PROMOD simulation results. Applying the methodology approved by ESWG and Board, which accounts for losses on generation and market imports, the 40-year PV of SPP-wide benefits were estimated to be $427 million, as shown in Figure 7.19 below.

Figure 7.19
Marginal Energy Losses Benefits



SECTION 8: RECOMMENDATION ON REMEDIES

8.1 Overview of RARTF Report on Remedies

The RARTF Report recommended that if the RCAR analysis shows that a zone is below the 0.8 B/C threshold described in Section 4.1 of the RARTF Report then "SPP staff should evaluate, and recommend possible mitigation remedies for the zone." The RCAR I Lessons Learned Report re-affirmed this, recommending, "SPP staff should evaluate remedies for zones below the threshold in the NTC –only review for RCAR II."

Figure 7.1 of the RCAR II Report shows that only City Utilities of Springfield (CUS) is below the 0.8 threshold for projects that have been approved for construction since June 19, 2010.

Figure 5 of the RARTF Report provided a list of potential remedies that SPP should consider for zones that are below the 0.8 B/C threshold.

8.2 RCAR Report on Remedies

RCAR I Lessons Learned Report stated that "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."

SPP staff has discussed potential remedies with CUS. The first potential remedy RARTF suggested was to accelerate an already approved project. Since CUS has not had any Highway/Byway projects approved, this remedy was not feasible. Given that, CUS agreed to pursue the second suggested remedy, focused on the issuance of NTCs for selected new upgrades.

SPP staff and the RARTF recommend the RCAR II Report be finalized in July 2016 and that CUS pursue projects in upcoming planning processes that will provide benefits to the Springfield zone. SPP staff will support and assist CUS' participation in the upcoming planning processes.

CUS has agreed to introduce project proposals in the upcoming 2017 ITP10[62] scheduled to conclude in January 2017, a seams study with AECI[63] scheduled to complete in late 2016 and a seams study with MISO scheduled to begin in 2016. If these studies do not result in projects that provide benefits for the Springfield zone, then SPP will work with the RARTF and recommend through the stakeholder process that the SPP Board initiate a High Priority Study to look for system needs and solutions in the Springfield zone.

[62] The ITP10 Needs Assessment published on June 2, 2016 showed needs in the CUS zone.

[63] The AECI-SPP seams study current scope includes projects can be seen in the Seams Steering Committee Meeting Minutes from June 6, 2016 at; https://www.spp.org/spp-documents-filings/?id=20425

In the event that no remedy is found for CUS in the planning processes described above, SPP will evaluate the other potential remedies described in the RARTF Report and make a recommendation to the RARTF.

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 accordance 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."

The final recommendation is for the RARTF to begin a lessons-learned process, similar to that used after RCAR I, and to finalize suggested improvements to the RCAR process by the January 2017 stakeholder meeting cycle. This will allow improvements to be incorporated into the next RCAR process.

APPENDIX

Appendix 1 – Stakeholder Comment and Resolutions for RCAR II Draft Results and Report

Stakeholder comments and suggestions have been posted at https://www.spp.org/spp-documents-filings/?id=20184

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

This appendix briefly describes the highlights of RCAR II results for City Utilities of Springfield (CUS). A short discussion of transmission benefits, costs, and a comparison to results from RCAR-I follows.

Share of Transmission Costs

In RCAR-II, CUS's share of the 40-year transmission revenue requirement was estimated to be $76 million. About 60% of these costs were driven by reliability projects and the rest by economic projects. Additionally, CUS was estimated to benefit from point-to-point revenue offsets as a result of the RCAR-II portfolio of projects. These revenues, which offset CUS's share of transmission costs, were estimated to be equal to approximately $5 million over a 40-year period. The net total cost for CUS was thus estimated to be $71 million as shown in Figure A2.1.

Figure A2.1:
City Utilities of Springfield's PV of 40-yr Benefits and Costs (2015-54)

	(2016 $m)
Present Value of 40-yr ATRRs	
Reliability Projects	$46
Economic Projects	$31
Offset from PtP and MISO Revenues	-$5
Total Costs	$71
Present Value of 40-yr Benefits	
Adjusted Production Cost Savings	-$33
Capacity Savings from Reduced On-Peak Losses	$0
Avoided or Delayed Reliability Projects	$0
Assumed Benefit of Mandated Reliability Projects	$53
Increased Wheeling Through and Out Revenues	$5
Mitigation of Transmission Outage Costs	$14
Marginal Energy Losses Benefits	$2
Benefit from Meeting Public Policy Goals	$0
Total Benefits	$42
Benefit-to-Cost Ratio	0.59
Gap to Reach a B/C Ratio of 0.8	$15

Estimated Benefits

The RCAR-II evaluation of NTC projects resulted in an estimated B/C ratio for CUS of 0.59. As shown in Figure A2.1 this low B/C ratio is primarily driven by the 40-year APC dis-benefits of $33 million.

It should be noted that in RCAR II, the APC savings metric has been modified to reflect a hybrid approach. This new approach was approved by the ESWG in 2015 and is designed to mitigate potentially unreasonable APC savings that may result from trapped renewable generation in several SPP zones.

RCAR II assessments indicate that CUS is not significantly impacted by trapped generation. However, its APC benefits are slightly affected by the new hybrid methodology, resulting in slightly higher APC dis-benefits.

The RCAR II assessment indicates that CUS would experience positive benefits from RCAR-II projects based on other benefit metrics analyzed in the study. Benefit such as those from mandated reliability projects, transmission outage costs savings, increased wheeling revenues, and savings from reduced marginal energy losses all indicate positive benefits to CUS from RCAR-II projects.

Figure A2.1 illustrates the 40-year benefits to CUS from each of these benefit metrics. The 40-year present value of total benefits to CUS (inclusive of the aforementioned APC dis-benefit) was estimated to be equal to $42 million. See details in Figure A2.1

Appendix 3 – RCAR II PROMOD Assumptions

This appendix summarizes key modeling assumptions in PROMOD market simulations that are used to estimate adjusted production cost (APC) savings, mitigation of transmission outage costs, and marginal energy losses benefit.

Simulations of the SPP system and most of the Eastern Interconnect were undertaken for 2020, 2025, and 2035. As described in the report, three cases were developed for each of the study years consistent with the approved methodology:

1. Change Case with the Highway/Byway portfolio
2. Primary Base Case without the Highway/Byway portfolio
3. Alternate Base Case without the Highway/Byway projects and without the renewable energy resources identified to be contingent upon Highway/Byway upgrades.

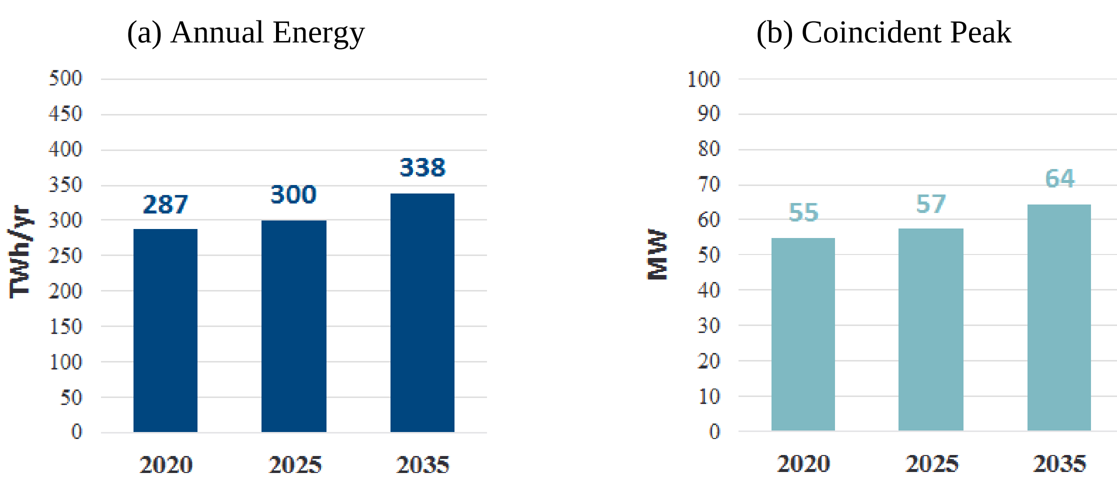
All inputs are the same across the three cases except for: Highway/Byway projects, renewables identified to be contingent on Highway/Byway portfolio, and the generic CTs added to the base cases to address load serving challenges.

1. Load Forecast

Load projections were modeled consistent with assumptions developed for the 2017 ITP10 study, obtained through a survey of the members. Accordingly, the SPP's annual load is assumed to be 287 TWh in 2020, 300 TWh in 2025, and 338 TWh in 2035. The system-wide coincident peak load is assumed to be 55 GW in 2020, 57 GW in 2025, and 64 GW in 2035.

Both peak and energy levels increase at an annual average growth rate of 0.9%–1.2% through the study horizon.

Figure A3.1
Load Projections for SPP Footprint



2. Generation

Generation resources included under the change case models are based on assumptions developed for the 2017 ITP10 study. As shown below, significant capacity is added from gas-fired combined cycle and combustion turbine units as well as renewable resources (wind and solar). The generation portfolio also reflects anticipated retirements of older coal, gas, oil, and nuclear plants.

Figure A3.2
Generation Assumptions in SPP Footprint (Change Case)

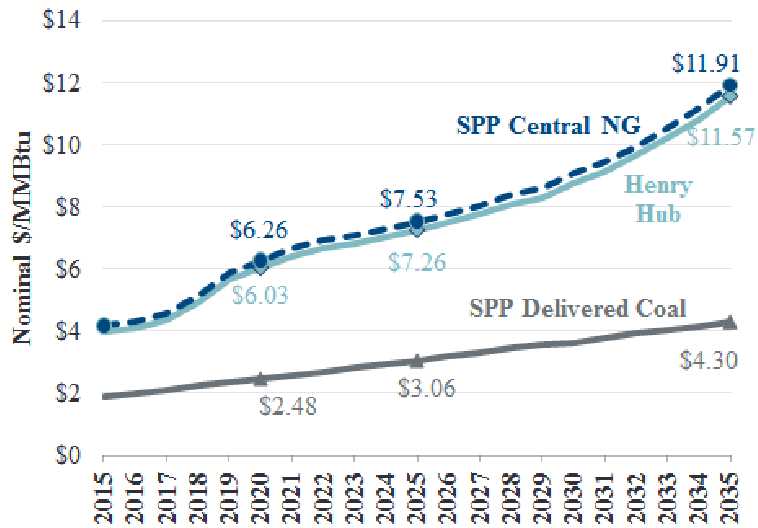
	Existing Capacity as of 2016	Additions and Retirements between 2016-2020	Online Capacity in 2020	Additions and Retirements between 2021-2025	Online Capacity in 2025	Additions and Retirements between 2026-2035	Online Capacity in 2035
ST Coal	23,469	(821)	22,648	(692)	21,956	(1,143)	20,813
ST Gas	10,738	86	10,824	(774)	10,049	(3,434)	6,615
CC Gas	9,379	5,167	14,546	2,200	16,746	9,137	25,883
CT Gas	9,772	1,059	10,831	1,975	12,806	4,498	17,304
IC Gas	252	240	493	0	493	(32)	460
Nuclear	2,432	5	2,437	0	2,437	(479)	1,959
Hydro/PS	3,277	0	3,277	0	3,277	0	3,277
Wind	12,909	3,696	16,605	420	17,025	712	17,738
Solar	50	1,023	1,073	1,605	2,678	2,345	5,023
Oil	1,654	0	1,654	(25)	1,629	(276)	1,353
Other	109	9	118	3	120	(15)	106
Total	**74,041**	**10,466**	**84,507**	**4,711**	**89,218**	**11,313**	**100,531**

Fuel Prices

The Henry Hub gas prices assumed in PROMOD start at $6.03/MMBtu in 2020 and increase to $7.26/MMBtu in 2025 and $11.57/MMBtu in 2035 (in nominal $). The gas prices at the SPP Central NG Hub are assumed to be about 23–35 cents higher compared to Henry Hub due to basis differential.

Coal prices are also assumed to grow over time, starting at $2.48/MMBtu in 2020, growing to $3.06/MMBtu in 2025 and $4.30/MMBtu in 2035 (in nominal $).

Figure A3.3
Fuel Price Projections for SPP Footprint



Emissions Prices

Allowance prices for NOx emissions were assumed to be $57/ton in 2020, increasing to $64/ton in 2025, and $82/ton in 2035 (in nominal $). These prices correspond to the EPA's Cross-State Air Pollution Rule (CSAPR), which replaces the EPA's 2005 Clean Air Interstate Rule (CAIR). No other emission prices are assumed in the model.

Figure A3.4
PROMOD Emission Price Assumptions ($/ton)

	2020	2025	2035
CAIR Annual and Seasonal NOx	$57	$64	$82
CSAPR Annual NOx	$57	$64	$82
CSAPR Seasonal NOx	$0	$0	$0
CSAPR 1 SO2	$0	$0	$0
CSAPR 2 SO2	$0	$0	$0
National CO2	$0	$0	$0
RGGI CO2	$0	$0	$0
Mercury (Hg)	$0	$0	$0

Appendix 4 - RCAR Project List

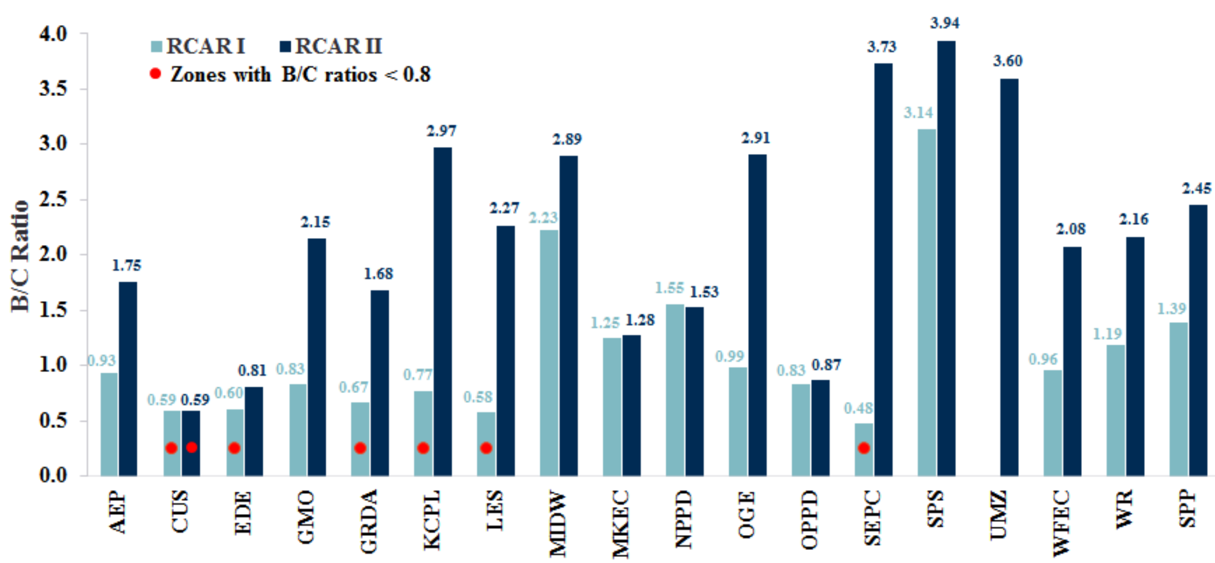
The RCAR II project list has been published at https://www.spp.org/documents/39026/appendix%204%20-%2020160531_rcar2_project%20list_summary.pdf

Appendix 5 – Comparison between RCAR I and RCAR II

This appendix provides a comparison of zonal Benefit/Cost (B/C) ratios and estimated benefits for RCAR I and RCAR II. As noted previously in this report, RCAR II analyses were based on simulations of the Eastern Interconnect and the expanded SPP system for 2020, 2025, and 2035.The expanded SPP system included the Integrated Systems (UMZ), which was integrated into SPP's footprint in October 2015. In comparison, RCAR I analyses simulated system performance of the Eastern Interconnect and the SPP system without the Integrated Systems for years 2018, 2023, and 2033.

It is important to note that fairly significant changes were implemented in the RCAR II models to reflect developments that have occurred over the two years since RCAR I analyses were undertaken. As a result, a direct comparison of results between RCAR I and RCAR II is not a true apple to apples comparison unless controlled for several of these substantial differences in modeling assumptions. Section 7.6.1 of this report highlights the most important of these differing assumptions implemented in RCAR II. As a recap, these differing assumptions implemented in RCAR II include: (1) the assessment of a larger highway/byway portfolio, (2) the implementation of the expanded SPP footprint to include the UMZ, (3) the assumption of higher renewable resource penetrations, and (4) the expectation of higher future load and higher fuel prices. Notwithstanding these significant differences, a high-level comparison of B/C ratios of RCAR I and RCAR II illustrate a few key takeaways, which are described below.

Figure A5.1
Comparison of Benefit/Cost Ratios



Note:
The UMZ was not part of SPP in RCAR I; therefore, no B/C ratio is shown for this zone for RCAR I in Figure above.

Figure A5.1 above illustrates zonal and SPP-wide B/C ratios for RCAR I and RCAR II. As shown, the SPP-wide B/C ratio increased in RCAR II compared with RCAR I. At the zonal level, B/C ratios were higher in RCAR II for all zones except for two: CUS and NPPD. This indicates that the larger project portfolio and expanded footprint of SPP, along with other differences and refinements in modeling assumptions in RCAR II are estimated to provide significantly greater benefits relative to their cost shares for most zones (also note that the increase in B/C ratios are quite significant for most zones, and for SPP system-wide).

Further, increased zonal B/C ratios in RCAR II compared with RCAR I indicate that five of the six zones with previously lower than 0.8 threshold B/C ratios, are now above that cut-off (zones with lower than 0.8 B/C ratios are indicated with red dots in Figure A5.1). As shown, except for CUS, all zones were estimated to have a greater than 0.8 B/C ratio in RCAR II. More importantly, only three zones were estimated to have lower than 1.0 B/C ratio in RCAR II. See Figure A5.2 below for the three zones estimated to have lower than 1.0 B/C ratio and their estimated dollar gap to reach a 1.0 B/C. In comparison, majority of the zones, i.e., 11 of 16 zones analyzed in RCAR I had lower than 1.0 B/C ratios, and six of these 11 zones had lower than 0.8 B/C ratios.

Figure A5.2
Zones with Lower than 1.0 B/C Ratio for RCAR II with Estimated Dollar Gap to 1.0 B/C

	Gap to Reach B/C Ratio of 1.0 (2016 $million)	
	Total	Levelized Real
CUS	$29	$1.8
EDE	$23	$1.4
OPPD	$39	$2.5

Figure A5.2 below shows the estimated SPP-wide benefits by metric for RCAR I and RCAR II portfolios. As noted previously, the differences in estimated benefits are largely driven by the difference in scale and size of the analyzed highway/byway portfolios, expanded system footprint, monetization of two additional metrics, and other changes in fundamental modeling assumptions implemented in RCAR II. These differences are discussed in section 7.6.1 of the report. As shown, APC savings and Assumed Benefits of Mandated Reliability Projects made up over 80% of the total estimated benefits in both RCAR I and RCAR II. The two newly monetized benefit metrics in RCAR II together constituted about 6% of the total estimated benefits. Details on each of these metrics and their benefit contributions in RCAR II analysis are discussed in section 7.0 of this report.

Figure A5.2
Comparison of SPP-Wide Benefits by Metric for RCAR I and II

Metric	RCAR I (2013$m)	RCAR II (2016$m)
APC Savings	$3,020	$8,974
Assumed Benefit of Mandated Reliability Projects	$2,475	$5,759
Mitigation of Transmission Outage Costs	$340	$1,014
Capacity Savings from Reduced On-Peak Losses	$155	$743
Increased Wheeling Through and Out Revenues	Not Monetized	$641
Marginal Energy Losses Benefits	Not Monetized	$427
Avoided or Delayed Reliability Projects	$97	$41
Benefit from Meeting Public Policy Goals	$296	$0
Reduced Cost of Extreme Events	Not Monetized	Not Monetized
Reduced Loss of Load Probability	Not Monetized	Not Monetized
Capital Savings from Reduced Minimum Required Margin	Not Monetized	Not Monetized
Total Benefits (PV of 40-yr Benefits for 2015-2054)	**$6,383**	**$17,599**
Total Portfolio Cost (PV of 40-yr ATRR)	**$4,581**	**$7,180**

Note:
RCAR I benefits are shown in 2013$ to be consistent with the RCAR I's RARTF Final Report.