BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Authority to Extend the Transfer of Functional Control of Certain Transmission Assets to the Southwest Power Pool, Inc.	))))	File No. EO-2012-0135
In the Matter of the Application of KCP&L Greater Missouri Operations Company for Authority to Extend the Transfer of Functional Control of Certain Transmission Assets to the Southwest Power Pool, Inc.	))))	File No. EO-2012-0136

KANSAS CITY POWER & LIGHT COMPANY AND
KCP&L GREATER MISSOURI OPERATIONS COMPANY'S
RESPONSE TO COMMISSION ORDER DIRECTING FILING

COME NOW Kansas City Power & Light Company ("KCP&L"), and KCP&L Greater Missouri Operations Company ("GMO")(collectively, the "Company") and hereby file their response to the Missouri Public Service Commission's ("Commission") *Order Directing Filing* issued in the above-captioned dockets on September 19, 2019 ("Order").

1. Copies of analysis referenced in ordered paragraph 1 of the Commission's Order are attached and/or linked, as follows:

Exhibit A: *The Value of Transmission*, A Report by Southwest Power Pool ("SPP"), January 26, 2016;

Exhibit B: *SPP Regional Cost Allocation Review Report for RCAR I*, October 8, 2013;

Exhibit C: *SPP Regional Cost Allocation Review Report for RCAR II*, July 11, 2016

SPP 2018 Market Monitoring Unit's Annual State of the Market Report, May 15, 2019;[1]

Exhibit D: SPP Member Value Study, *14 to 1 The Value of Trust*, May 24, 2019; and

[1] Due to the voluminous nature of the SPP's 2018 *Market Monitoring Unit's Annual State of the Market Report*, the Company is providing a link to the document as opposed to attaching it to this pleading. (https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf)

2. Additionally, a summary of the work to be performed and a breakdown of the cost estimates for the proposed study requested in ordered paragraph 2 of the Commission's Order are contained in attached **Exhibit E**. The study cost estimate was provided by a consultant based on the entire study scope. There was no cost breakdown for individual components.

WHEREFORE, the Company respectfully requests that the Commission consider this response to its Order.

Respectfully submitted,

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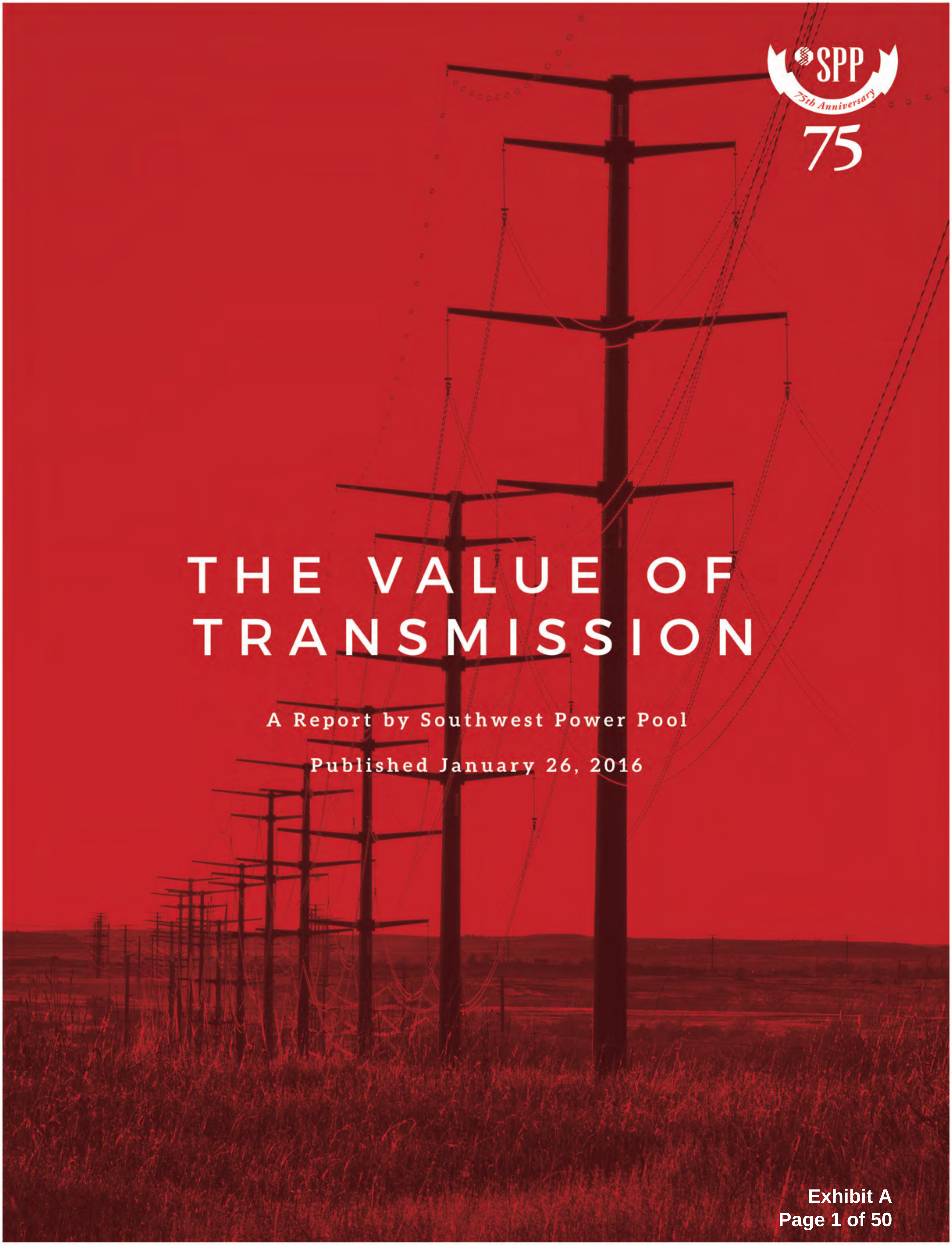
CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Application was served on all counsel of record either by electronic mail or by first class mail, postage prepaid, on this 25th day of September 2019.

|s| Roger W. Steiner

Roger W. Steiner



THE VALUE OF TRANSMISSION

A Report by Southwest Power Pool

Published January 26, 2016

Exhibit A
Page 1 of 50

ACKNOWLEDGEMENTS

This study was led by staff in SPP's Research, Development, and Special Studies Department and published by the Communications Department at the request of the SPP's Strategic Planning Committee. Its contents also reflect significant contributions from staff in SPP's Economic Studies, Market Support and Analysis, and Market Monitoring Departments. Their support was critical to the success of this effort and much appreciated.

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Images provided by ITC Holdings Corp.


NATIONAL CRANE

EXECUTIVE SUMMARY

Southwest Power Pool (SPP) has approved the construction of significant transmission expansion since becoming a Regional Transmission Organization (RTO) in 2004. In this report, SPP attempts to quantify the value of transmission expansion projects placed in service from 2012 through 2014. A portion of the value quantified in this report is captured from an analysis of the first year of operation of the Integrated Marketplace (IM) which began March 1, 2014. While many large projects installed in 2012-2014 were not in service at the launch of the IM, their value in the mid-to-late portion of 2014 are partially captured in this assessment and will continue into the future.

Traditional planning studies have previously projected economic benefits of future transmission expansion projects, but a study to quantify the *actual* benefits of major projects in SPP is needed to validate the conclusions and recommendations of prior planning studies.

From 2012 to 2014, SPP installed almost $3.4 billion of transmission expansion projects. These include major Extra High Voltage (EHV) backbone projects approved with SPP's Balanced Portfolio and Priority Projects studies. While these costs are significant, their "bang for the buck" in creating an effective, efficent network in the SPP footprint is also noteworthy. SPP's actual costs to install EHV backbone facilities are roughly one-third the total cost of projects being built and installed by other transmission system operators during the same time period, according to EEI data.

This study determines production cost benefits realized during actual operations resulting from transmission expansion placed into service between 2012 and 2014. These production cost benefits were derived from operational models reflecting a subset of actual system conditions from March 2014 through February 2015. The estimated benefits of production cost savings are significant and higher than planning model projections. Based on actual experience during the Integrated Marketplace's first year, and excluding the full benefits of economically efficient interchange with neighbors, Adjusted Production Cost (APC) savings are calculated at more than $660,000 per day or $240M per year. The net present value (NPV) of these APC benefits is expected to exceed $10 billion over the next 40 years, which compares favorably to an NPV of the projects' costs of less than $5 billion over the same period.

In addition to APC savings, this study also quantified benefits associated with reliability and resource adequacy, generation capacity cost savings, reduced transmission losses, increased wheeling revenues, and public policy benefits associated with optimal wind development. Some sources of additional value, which were either partially captured or excluded altogether, have not been quantified. These include environmental benefits, employment and economic development benefits, and other metrics like storm hardening and reduction in the costs of future transmission needs. The value of these benefits may be large – some even larger than those included in the study. All of these are shown in Appendix B.

BENEFITS OF THESE PROJECTS ... ARE EXPECTED TO EXCEED $16.6B, A BENEFIT-COST RATIO OF 3.5

Overall, the NPV of all quantified benefits for the evaluated projects, including production cost savings, are expected to exceed $16.6 billion over the 40-year period, which results in a Benefit-to-Cost ratio of 3.5.

Following an independent assessment of the Value of Transmission study, the Brattle Group called it "a path-breaking effort" that "provides a more accurate estimate of the total benefits that a more robust and flexible transmission network delivers," concluded that the estimated present value of production cost savings are likely understated and recommended future study refinements. A letter from the Brattle Group with their comments regarding the study is presented on page 25 of this document.

BACKGROUND

SPP staff, its members and stakeholders, and the bulk power industry as a whole have done much work to quantify the benefits of transmission. SPP has been a leader in doing so to justify economic expansion in its footprint. Typical metrics to determine the benefits of transmission expansion include: adjusted production cost savings, reliability and resource adequacy benefits and generation capacity cost savings, market benefits, environmental and public policy benefits, employment and economic stimulus benefits, and other project-specific benefits. However, transmission expansion provides other values in addition to those SPP is able to quantify.

Transmission enables and defines markets. Quantifying the benefits of bulk electric power transmission facilities is as much an art as a science. Planning studies have attempted to quantify the benefits of transmission, but actual system performance demonstrates that real world value provided by additional enabling infrastructure such as transmission is higher than what was originally projected.

While SPP members have approved billions of dollars of investment in transmission expansion to date, it's important that grid enhancements in SPP provide "bang for the buck" in a timely manner. The installed cost per mile of EHV transmission lines and substations in SPP are low compared to transmission facilities of similar design in other regions. More importantly, lead times for long linear projects like major EHV transmission lines crossing multiple jurisdictions can be problematic. SPP and its Transmission Owners have successfully gotten such projects placed in service, with a few exceptions, in noteworthy timeframes. The timely execution of approved plans is the best way to manage risks and uncertainties.

As an RTO, SPP has made significant transmission capacity additions using standard designs for EHV backbone facilities placed in service, both quickly and inexpensively compared to peers. In its most recent *Transmission Projects: At A Glance*[1] report from March 2015 , the Edison Electric Institute (EEI) documents major transmission projects which have been recently completed or are in the process of being implemented.

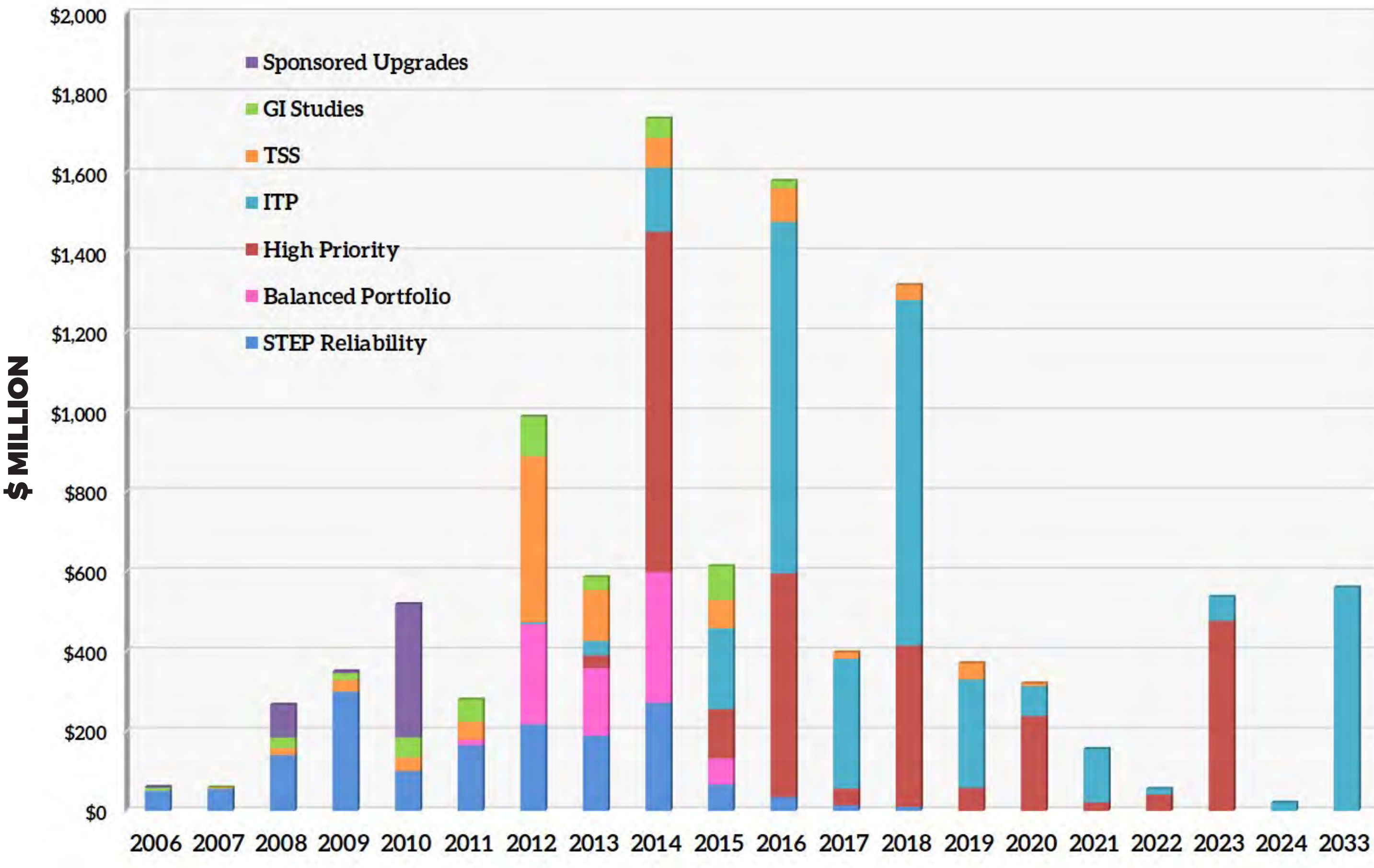
Looking at overhead 345 kV projects, EEI members expect to spend over $10.4 billion for 23 projects representing 3,444 circuit miles of new transmission lines. Non-SPP 345 kV transmission projects among EEI members cost in excess of $3M per circuit mile. In comparison, SPP's 345 kV Balanced Portfolio and Priority Projects installed in 2012-2014 represent an investment of $1.64 billion, provided 1,536 circuit miles of new transmission, and cost just slightly more than $1 million per circuit mile to construct.

Not only are SPP's actual 345 kV construction costs one-third of the cost of peer projects in the EEI report on a circuit mile basis, but SPP builds its EHV network with 3,000-Amp design standards. SPP builds for the future to create an efficient and effective EHV backbone network in the long-term.

Firm data regarding lead time for transmission expansion in SPP compared to other regions are not readily available, but some RTOs experience lead times of 10 years to plan, approve, design, route, permit and install their EHV projects. In contrast, the majority of the SPP Balanced Portfolio and Priority Projects have been placed in service in substantially less time: one factor that drives SPP's cost-per-mile of EHV transmission lower than its peers'.

1 Edison Electric Institute (March 2015), Transmission Projects: At a Glance http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf

FIGURE 1: TOTAL INVESTMENT PER IN-SERVICE YEAR



Transmission expansion in SPP is shown in Figure 1 and Table 1.

The 345 kV projects considered in this assessment – those installed from 2012 through 2014 – represent more than 1,800 circuit miles of high-capacity backbone facilities that have been integrated into an effective bulk power network. They represent a more-than-25 percent increase in new 345 kV infrastructure, resulting in an improvement in network capability by at least 40 percent based on SPP's approved design standards. Grid expansion in SPP positions us to address uncertainties and capture opportunities in the future and facilitates optimal network performance in the long-term as aging facilities get rebuilt. The SPP EHV overlay and subsequent Integrated Transmission Plan 20-Year Assessments (ITP20) create a visionary, evolutionary plan that moves us away from a "patchwork" grid and toward a more efficient, robust system able to support many potential futures.

It is difficult to monetize the value of enabling infrastructure, especially long-life assets in an industry which typically adjusts slowly to opportunities due to lead times of changes in portfolios, transactions, etc. New transmission is a lumpy investment and a long-life asset that works best as part of an efficient and effective grid that takes decades to plan, design, approve and install.

TABLE 1: TRANSMISSION INVESTMENTS (MILES AND COST) BY VOLTAGE

NEW LINES IN SPP: 2006-2014

Miles

VOLTAGE	2006	2007	2008	2009	2010	2011	2012	2013	2014	TOTAL
69		14.0	25.3	4.5					14.0	129.3
115				8.7	47.4	130.0	23.0	3.7	135.5	486.9
138	30.0	30.0	27.0	13.5	29.0	16.5	50.7	44.9	37.2	339.5
161		12.0		8.0		0.8		14.9	9.0	44.7
230				54.4			63.0	55.0	62.6	276.4
345			14.0	67.0	163.8		527.7	118.0	1170.9	2092.3
Total	30.0	56.0	66.3	156.1	240.2	147.3	664.4	236.5	1429.2	3369.0

Cost

VOLTAGE	2006	2007	2008	2009	2010	2011	2012	2013	2014	TOTAL
69		$9,320,377	$7,590,000						$12,775,975	$113,833,739
115				$2,632,405	$21,858,002	$82,167,931	$39,111,891	$13,379,401	$91,382,532	$352,782,211
138	$24,883,016	$24,560,016	$16,760,000	$17,440,000	$20,202,750	$11,988,400	$36,676,068	$42,152,931	$51,927,755	$291,182,457
161		$9,842,225						$27,154,374	$16,372,087	$53,368,686
230				$21,688,257			$39,757,157	$40,215,864	$97,192,386	$257,361,437
345			$14,405,000		$202,794,938		$598,241,806	$165,000,000	$1,186,747,952	$2,173,865,627
Total	$24,883,016	$43,722,618	$38,755,000	$41,760,662	$244,855,690	$94,156,331	$713,786,922	$287,902,570	$1,456,398,687	$3,242,394,157

REBUILDS IN SPP: 2006-2014

Miles

VOLTAGE	2006	2007	2008	2009	2010	2011	2012	2013	2014	TOTAL
69	5.2	5.9	34.0	35.9	18.6	42.1	60.0	33.4	57.3	367.0
115		1.5	29.2	55.3	26.4	31.2	44.0	80.1	50.1	317.7
138	13.7	0.2	4.8	16.5	20.3	68.9	1.8	86.5	33.2	258.8
161	2.0	20.7	14.7	45.4	12.0	33.9		13.0	6.3	148.0
230										0.0
345										0.0
Total	20.9	28.3	82.7	153.1	77.2	176.0	105.8	213.0	146.7	1091.3

Cost

VOLTAGE	2006	2007	2008	2009	2010	2011	2012	2013	2014	TOTAL
69		$8,322,741	$10,498,991	$14,848,800	$11,905,127	$23,247,319	$41,012,999	$23,460,579	$48,222,740	$237,450,481
115		$3,094,877	$7,326,381	$13,773,487	$22,001,721	$18,652,609	$30,270,320	$32,412,034	$30,875,130	$158,406,558
138	$5,960,000	$85,105	$4,440,000	$13,192,530	$25,392,766	$66,096,701	$4,857,641	$47,572,321	$27,346,650	$208,310,029
161	$640,000	$7,625,399	$6,019,002	$35,810,637	$7,467,000	$13,756,472		$6,782,380	$5,142,363	$83,243,253
230										$0
345										$0
Total	$6,600,000	$19,128,122	$28,284,374	$77,625,454	$66,766,614	$121,753,101	$76,140,961	$110,227,314	$111,586,883	$687,410,320

ALL OTHER PROJECTS IN SPP: 2006-2014

Cost

VOLTAGE	2006	2007	2008	2009	2010	2011	2012	2013	2014	TOTAL
69	$466,765	$969,408	$1,960,847	$2,693,587	$4,504,817	$2,595,970	$4,302,974	$2,508,753	$8,928,440	$36,466,282
115	$6,000,000	$5,613,830	$3,262,050	$126,175,946	$35,360,755	$19,234,043	$27,684,105	$35,855,634	$37,111,929	$362,235,177
138	$3,127,787	$6,008,142	$19,934,672	$10,223,518	$5,830,986	$9,106,223	$35,709,240	$66,788,412	$41,980,747	$239,818,819
161		$2,894,854	$21,806,875	$31,394,877	$18,321,158	$13,397,980	$2,115,237	$10,185,312	$19,163,572	$119,279,866
230		$10,073,312		$26,906,550	$6,858,047	$9,329,355	$35,130,882	$32,222,848	$44,528,599	$206,685,667
345		$8,852,316	$945,625	$15,173,000	$21,851,834	$21,300,052	$63,085,781	$42,330,439	$76,693,251	$366,735,044
Total	$9,594,553	$34,411,861	$47,910,069	$212,567,478	$92,727,597	$74,963,623	$168,028,219	$189,891,398	$228,406,539	$1,331,220,855

TOTAL PROJECTS IN SPP: 2006-2014

Cost

VOLTAGE	2006	2007	2008	2009	2010	2011	2012	2013	2014	TOTAL
69	$466,765	$18,612,526	$20,049,838	$17,542,387	$16,409,944	$25,843,289	$45,315,974	$25,969,332	$69,927,155	$387,750,503
115	$6,000,000	$8,708,707	$10,588,431	$142,581,838	$79,220,478	$120,054,583	$97,066,317	$81,647,069	$159,369,591	$873,423,946
138	$33,970,803	$30,653,263	$41,134,672	$40,856,048	$51,426,502	$87,191,324	$77,242,949	$156,513,664	$121,255,152	$739,311,305
161	$640,000	$20,362,478	$27,825,877	$67,205,514	$25,788,158	$27,154,452	$2,115,237	$44,122,066	$40,678,022	$255,891,804
230		$10,073,312		$48,594,807	$6,858,047	$9,329,355	$74,888,039	$72,438,712	$141,720,985	$464,047,104
345		$8,852,316	$15,350,625	$15,173,000	$224,646,772	$21,300,052	$661,327,587	$207,330,439	$1,263,441,203	$2,540,600,671
Total	$41,077,569	$97,262,601	$114,949,443	$331,953,593	$404,349,901	$290,873,055	$957,956,102	$588,021,282	$1,796,392,109	$5,261,025,333

This engineering analysis is limited in its horizon and cases analyzed, only looking at the actual benefits for the Integrated Marketplace's (IM) first year of operation – March 2014 through February 2015 – for the 348 projects representing $3.394 billion in investment, which were eligible for base plan funding and placed in service between 2012 and 2014. The 2012-2014 Portfolio of Projects evaluated in these 2014 simulations are shown in Appendix B to this study.

The Annual Transmission Revenue Requirement (ATRR) for these projects is approximately $501 million per year at the beginning of 2015 and assumed to depreciate at 2.5% per year over the typical 40-year life of projects. Since many of these projects, especially several of the 345 kV Priority Projects, were installed in the second half of 2014, the actual ATRR going into 2014 is only $316 million, comparable to the benefits quantified in the analyses. For example, the Woodward District EHV – Thistle and Thistle – Clark Co – Ironwood 345 kV projects were not installed until early-November and mid-December 2014, respectively, and only contributed benefits to SPP in terms of quantified production cost savings to a few of the actual 34 operational simulations used in this study.

The Thistle - Clark Co – Ironwood double-circuit 345 kV lines were the final segments of the Priority Projects in the central and south plains of KS, OK and TX which facilitated effective integration of renewables and developed a robust network integrating western SPP into the existing EHV systems at Wichita and Oklahoma City. The benefits of the other 345 kV double-circuit Priority Projects in the central and south plains were not fully realized until mid-December 2014.

The benefits quantified in this study reflect average-study-year APC savings, compared to 2014 year-end costs.

While planning studies reflect perfect foresight and no uncertainty, actual system operations will see events due to human or mechanical issues and natural phenomena like weather fronts that create opportunities to improve the efficiency and overall effectiveness of grid operations that can only be captured with a robust transmission network. Such assumptions in modeling and analyses need to be considered in any valuation study. For example, SPP's projections of the Integrated Marketplace benefits were half of those actually realized during the market's first year. Similar adjustments would not be unreasonable in engineering analyses attempting to quantify the value of transmission using models.

ANALYSIS APPROACH

ADJUSTED PRODUCTION COST SAVINGS

REDUCED PRODUCTION COSTS DUE TO LOWER UNIT COMMITMENT, ECONOMIC DISPATCH, AND ECONOMICALLY EFFICIENT TRANSACTIONS WITH NEIGHBORING SYSTEMS

Actual operational models for the Integrated Marketplace's first year were used to quantify production cost impacts due to lower unit commitment and dispatch costs for SPP resources to serve SPP obligations in five highest production cost days and five lowest production cost days in each season.

The modeling results for those simulations that show production cost savings are shown in Table 2.

To determine annual production cost savings based on these daily actual operational models, SPP validated the model results prior to any extrapolation efforts. Of the 40 days simulated, the models were not able to solve in two days (results shown as N/A) and showed negative benefits in four days.

Operations staff found that a refined simulation would result in significant positive benefits in these six days if a local modeling issue was resolved. Hence, results with N/A and negative values were considered as outliers, thus not included in average daily savings calculations.

As a final note, these analyses focused on new projects and did not capture the incremental capacity associated with transmission rebuilds and transformer upgrades which did not affect system topology. These rebuilds and upgrades to existing facilities are important and provide value but are not incorporated into this analysis and savings calculation.

TABLE 2: PRODUCTION COST SAVINGS

DATE	SEASON	HIGH/LOW PROD. COST DAY	TRANSMISSION VALUE
3/10/2014	Winter	Low	255,945
3/11/2014	Winter	Low	(79,548)
3/13/2014	Winter	Low	357,094
3/20/2014	Winter	Low	798,336
3/21/2014	Winter	Low	603,442
3/22/2014	Spring	Low	N/A
3/30/2014	Spring	Low	579,521
4/12/2014	Spring	Low	783,220
4/19/2014	Spring	Low	783,096
4/29/2014	Spring	Low	372,534
5/29/2014	Spring	High	(122,468)
5/30/2014	Spring	High	340,300
6/4/2014	Spring	High	609,492
6/5/2014	Spring	High	1,485,418
6/19/2014	Spring	High	917,044
6/27/2014	Summer	Low	575,763
7/4/2014	Summer	Low	968,855
7/22/2014	Summer	High	2,011,082
7/23/2014	Summer	High	(409,467)
8/18/2014	Summer	High	781,603
8/25/2014	Summer	High	1,107,308
8/26/2014	Summer	High	906,053
9/12/2014	Summer	Low	521,871
9/13/2014	Summer	Low	44,407
9/14/2014	Summer	Low	704,028
10/12/2014	Fall	Low	515,607
11/2/2014	Fall	Low	N/A
11/9/2014	Fall	Low	337,043
11/13/2014	Fall	High	988,642
11/19/2014	Fall	High	2,150,285
12/1/2014	Fall	High	475,844
12/3/2014	Fall	High	161,933
12/13/2014	Fall	Low	386,676
12/14/2014	Fall	Low	428,725
12/18/2014	Fall	High	175,688
1/1/2015	Winter	High	174,185
1/9/2015	Winter	High	383,485
1/13/2015	Winter	High	190,194
1/14/2015	Winter	High	(254,537)
2/27/2015	Winter	High	640,288

Table 3 displays the count of data points used to achieve simple average seasonal daily savings figures after removing outliers (i.e., those with N/A and negative results).

TABLE 3: NUMBER OF DATA POINTS

# OF DATA POINTS	HIGH	LOW	TOTAL
Fall	5	4	9
Spring	4	4	8
Summer	4	5	9
Winter	4	4	8
TOTAL	**17**	**17**	**34**

In this process, simple averages were calculated from the data in Table 2, as shown in Table 4.

TABLE 4: SIMPLE AVERAGES

SEASON	HIGH	LOW
Fall	$790,478	$417,013
Spring	$838,064	$629,593
Summer	$1,201,512	$562,985
Winter	$347,038	$503,704
High/Low Simple Averages	$794,273	$528,324
ANNUAL AVERAGE DAILY SAVINGS (SIMPLE AVERAGE)	**$661,298**	

A simple average of the production cost savings across each seasonal high and low production cost day indicates $661,298 of daily benefits to SPP for the first year of the IM beginning in March 2014. In future studies, it may be desirable to simulate more than 40 days (including different types of days, such as high/average/low congestion days) to represent a full 12-month period and use a study period during which all of the evaluated transmission project would have been in service.

Extrapolating the average daily savings of $661,298 per day to the first year of the Integrated Marketplace (March 2014 through February 2015) results in an Annual Production Cost Savings of $241.3 million associated with the 2012-2014 transmission expansion projects in SPP.

Production cost savings can be expected to increase over time, particularly since the majority of the large EHV upgrades associated with the Balanced Portfolio and Priority Projects were added in the latter half of the production cost simulations. The 2012-2014 EHV projects installed in SPP were arguably unprecedented in terms of long-term impacts to improve grid performance and capabilities. In the 2015 ITP10 study, the annual APC savings increased by 16.5 percent per year on average, based on the different study year models. In the most recent ITP20 study, the annual APC savings increased by 29.1 percent per year on average. For this analysis, we assume that production cost savings will escalate at a rate of 10 percent per year.

The growth of APC savings over time is driven by increasing load, additional generation, and higher fuel costs in future years, which combine to cause more congestion. Transmission system topology remains essentially unchanged, but load, generation, and fuel costs change significantly over the study horizons.

With load growth, inefficient gas resources are dispatched more frequently and system marginal costs grow, which increases APC at rates higher than forecasted natural gas prices. Natural gas prices are projected to increase at 3-7 percent per year in our models, which includes growth and inflation. While natural gas prices are projected to grow at rates higher than escalation, that factor by itself is not a significant driver of APC benefit growth compared to how load and generation changes, which can be expected over the study horizon.

Economic planning studies typically identify APC savings that include the impacts of power purchases and sales between the study region and its neighboring regions. In the SPP analyses performed by the Operations staff, power transactions were assumed to be constant between the two cases simulated (with and without projects). This approach understates the value of grid expansion with respect to opportunities to reduce capacity and energy costs for purchases from adjacent regions, as well as increased revenues associated with sales to adjacent regions. More specifically, typical APC values would include the impacts associated with the ability to purchase from more suppliers at a cheaper cost or sell to more buyers at a higher price. While not reflected in these modeling results, these impacts to transactions with adjacent systems can be attributed to more enabling infrastructure to market participants, which creates efficiencies and real benefits to wholesale and retail consumers.

Actual production cost savings are typically larger than those projected in planning simulations, which is consistent with analyses conducted by Brattle and others. Transmission capabilities are most valued in extreme market conditions and events which were not captured in planning analyses, but occur in actual system operations.

Weather events such as the Polar Vortex of 2014, which occurred prior to the IM and was not captured in this study horizon, resulted in unprecedented peak system demands while fuel supplies were disrupted and generating resources failed to operate due to extreme cold weather. The value provided by the interconnected transmission system during those extreme events is often much larger compared to normal conditions. The insurance value of additional transmission capability is difficult to quantify and has not been reflected in these analyses since the market simulations typically assume perfect foresight and the study period does not include any major extreme events.

Consumers also benefit from lower production costs resulting from transmission expansion projects. Southwestern Public Service/Xcel Energy announced in a news release on September 10, 2015:

> *Lower fuel and purchased power costs are leading Xcel Energy to refund $18.6 million to Texas retail customers, a move driven by continued low natural gas costs and cheaper power imports into the Panhandle and South Plains made possible by new transmission line connections.*
>
> *Beginning in November, Texas residential customers using 1,000 kilowatt-hours per month will see a one-time credit, prorated over two billing cycles for most customers, amounting to $34.42.*
>
> *David Hudson, president of Southwestern Public Service Company, an Xcel Energy company, said hundreds of millions of dollars have been invested in the transmission system, and new lines connecting Xcel Energy with the Southwest Power Pool have expanded the purchase of competitively priced power. In addition, natural gas prices remained very low through the first part of this year.*
>
> *The company lowered its fuel and purchased power cost factors in March, which resulted in ongoing residential customer savings of $7.*

ADDITIONAL PRODUCTION COST SAVINGS

The Adjusted Production Cost estimates obtained from traditional planning studies fail to capture the full range of the production cost savings provided by transmission investments due to the simplified nature of the market simulations used in planning studies. For example, planning studies typically do not consider the effect of multiple, concurrent transmission outages, the impact of new transmission facilities on the annual transmission-related energy losses, or the fact that real-time loads and intermittent generation output is uncertain on a day-ahead basis. To capture these additional production cost savings in planning studies typically requires additional analysis. In contrast, SPP's methodology to estimate production cost savings based on the re-run of its entire day-ahead and real-time market fully or partially captures many of these benefits as summarized below.

(A) IMPACT OF GENERATION OUTAGES AND A/S UNIT DESIGNATIONS

SPP's methodology relies on the re-run of its day-ahead and real-time energy and ancillary services markets, including actual generation outages and generation capability used to provide ancillary service. As a result, this benefit has been captured in the APC savings which were quantified in this Value of Transmission assessment.

(B) REDUCED TRANSMISSION ENERGY LOSSES

SPP's market software fully considers hourly energy losses and how they are affected by the outage or addition of transmission facilities. As a result, this benefit (i.e., the extent to which new transmission facilities can reduce energy losses) has been captured in the APC savings which were quantified in this Value of Transmission assessment.

(C) REDUCED CONGESTION DUE TO TRANSMISSION OUTAGES

The Mitigation of Transmission Outages Costs metric for the ITP planning studies is not applicable since actual outages from the Control Room Operations Window (CROW) system have been included in these operational models and simulations. Despite this, actual outages in operations can be significant and can only be expected to increase in frequency and duration with aging infrastructure and more volatile and extreme weather patterns. As a result, it is increasingly critical for SPP planning analyses to accurately forecast outages and capture the impacts of this metric in its plans.

The inability to accommodate necessary outages and costs of rebuilding aging transmission assets may warrant the installation of overlay facilities or accelerate the installation of major EHV projects to maintain an efficient and secure network as we create the future grid. With time and load growth, it is increasingly costly and difficult to accommodate necessary maintenance and rebuild outages of major transmission facilities.

(D) MITIGATION OF EXTREME EVENTS AND SYSTEM CONTINGENCIES

The SPP methodology selected five days with the highest production costs for each of the four seasons. To the extent that high production costs during selected days are the result of extreme events and unusually challenging system conditions, this benefit has been partially captured in the APC savings which were quantified in this Value of Transmission assessment. Note that none of the selected days included clearly-identified extreme weather or system conditions, such as those experienced during the 2014 Polar Vortex.

(E) MITIGATION OF WEATHER AND LOAD UNCERTAINTY

The SPP methodology selected 5 days with the highest production costs for each of the four seasons. To the extent that high production costs during selected days are the result of challenging weather conditions and load uncertainty (such as 90/10 peak load conditions), this benefit has been partially captured in the APC savings which were quantified in this Value of Transmission assessment. Note that the days analyzed were not specifically selected based on weather or load conditions. For example, additional benefits would likely be realized in situations such as during 90/10 peak load days or during a heat wave in the southeastern portion of SPP when the northwestern portions of SPP experience more moderate temperatures.

(F) REDUCED COST DUE TO IMPERFECT FORESIGHT OF REAL-TIME SYSTEM CONDITIONS

This metric has not been fully quantified in this assessment. Since the day-ahead market was simulated based on the day-ahead forecasts but the real-time market was simulated based on actuals, this benefit would have been captured in the 40 days simulated.

(G) REDUCED COST OF CYCLING POWER PLANTS

This metric has been partially quantified in this assessment. To the extent that variable O&M expenses are reduced due to less cycling of generators as a result of the 2012 through 2014 projects being included in the 40 operational simulations, this benefit is captured. Increased wear and tear on generating units which results in accelerated equipment replacements and other capital expenditures have not been included in these assessments.

(H) REDUCED AMOUNTS AND COSTS OF OPERATING RESERVES AND OTHER ANCILLARY SERVICES

This metric has been partially quantified in this assessment. Operating reserve requirements were not changed in these simulations to capture the impact of increased transmission capabilities on operating requirements.

(I) MITIGATION OF RELIABILITY-MUST-RUN (RMR) CONDITIONS

This metric has not been quantified in this assessment.

OTHER METRICS

In addition to APC savings, SPP has identified other benefit metrics to quantify the value of transmission projects. Some have been monetized in past and existing ITP10 efforts. The approaches to calculate these metrics have been refined over time as the industry acquires knowledge, data, and tools to more accurately quantify the value of transmission assets. The full set of benefit metrics quantified in the most recent ITP10 study consisted of:

- 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
- Assumed Benefit of Mandated Reliability Projects
- Benefit from Meeting Public Policy Goals (Public Policy Benefits)
- Mitigation of Transmission Outage Costs
- Increased Wheeling Through and Out Revenues
- Marginal Energy Losses Benefits

A few of those metrics are appropriate to monetize above APC savings in this Value of Transmission study. Some, like emission reductions and values to society, are difficult to monetize and therefore not quantified in this assessment. For this analysis, SPP is focusing on the following additional metrics.

RELIABILITY AND RESOURCE ADEQUACY BENEFITS

(A) BENEFITS OF MANDATED RELIABILITY PROJECTS

This metric reflects the reliability benefits of the transmission projects built to meet transmission reliability standards (i.e., classified as "Reliability Projects" by the ITP Manual). Consistent with the methodologies used in ITP10 and RCAR studies, such reliability benefits are assumed to be equal to the projects' costs. The ATRR associated with the Reliability Projects installed in SPP from 2012 through 2014 is estimated to be $231.4 million in 2015 and then assumed to decline with depreciation over 40 years, which results in an NPV of $2.166 billion.

Setting benefits equal to costs may underestimate the value of reliability benefits, since it implies that reliability standards are not cost effective. Stated another way, it effectively assumes that value of reliability-related costs incurred without reliability upgrades (not meeting reliability standards) is no higher than the cost of the facilities. In fact, the value of reliability can be significantly higher than costs of reliability upgrades. This was demonstrated by the August 2003 blackout, which has been estimated to cost society about $6–$10 billion[2] for that single event.

While the industry has struggled to develop a methodology to quantify benefits of grid reliability improvements through transmission expansion, it is important to note that Westar has reported a 40% reduction in transmission Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Duration Index (SAIDI) associated with transmission expansion[3], and the need to value enhanced grid security and resiliency.

While reliability metrics like CAIDI an SAIDI are critically important performance measures for distribution systems, and radial or normally-open loops for transmission and sub-transmission systems, these metrics are valuable in improving operational efficiencies with regards to optimal scheduling of maintenance outages for bulk power system networks. Shorter durations of outages for transmission facilities limit the risk and exposure of customers to outages and the reliability problems that result from them, as well as dispatch of emergency generators or curtailments of interruptible loads which can be costly.

Outages of aging infrastructure to inspect and replace components of transmission facilities will become increasingly necessary and more expensive with time. It's no coincidence that FERC is proposing transmission

2 "Transforming the Grid to Revolutionize Electric Power in North America," Bill Parks, U.S. Department of Energy, Edison Electric Institute's Fall 2003 Transmission, Distribution and Metering Conference, October 13, 2003 and ICF Consulting, "The Economic Cost of the Blackout: An Issue Paper on the Northeastern Blackout, August 14, 2003."

3 "SPP Board Update: Customer impact due to building a more integrated, efficient grid", Westar Energy, June 8, 2015

investment metrics to help the bulk power industry quantify the value of major transmission projects.

(B) AVOIDED/DEFERRED RELIABILITY PROJECTS

This metric captures the reliability benefits of economic transmission projects based on the avoided cost of delaying or avoiding reliability projects. Resources were not available to remove Economic Projects in this 2012-2014 portfolio and determine reliability needs based on traditional N 1 overloads and voltage deficiencies. However, for this benefit metric, the results from a recent SPP staff analysis were used to estimate first-year benefits of $14.9 million and 40-year NPV benefits of $105 million associated with reliability projects that were avoided or deferred as a result of the Priority Projects.

(C) REDUCED LOSS OF LOAD PROBABILITY OR REDUCED PLANNING RESERVE MARGIN (2 PERCENT ASSUMED)

The long-term benefits of an efficient bulk power integration and delivery network are difficult to quantify but significant. The ability to lower planning reserve margins in a region is driven largely by resource and load diversity as well as the network's ability to accommodate outages, integrate resources and maintain system reliability and security above minimum standards.

The projects installed in 2012-2014 represent a substantial portion of the new EHV backbone facilities that have been approved since SPP became an RTO. Lower planning reserve margins can be attributed to significant transmission expansion, as well as market enhancements and organic footprint growth, providing more diversity. This diversity will improve system performance and result in lower loss of load probabilities, as well as loss of load expectations, in SPP. Lower reserve margins within SPP will occur primarily due to 2012-2014 transmission projects evaluated in this study.

Using ITP10 assumptions and reasonable engineering judgment, it can be demonstrated that each percent decrease in planning reserve margins in SPP are worth approximately $50 million per year in reduced costs. Reducing reserve margins by one percent in SPP, approximately a 50 GW system, would lower capacity needs by 500 MW. Marginal capacity costs are estimated to be $81.9/kW-yr in ITP10 based on the Net Cost of New Entry (CONE) for a gas-fired combustion turbine (CT).

So as to not overstate the reserve margin impacts associated with the noted transmission expansion projects, the benefits of a two-percent reduction in SPP's planning reserve margin for this Value of Transmission study is based on the methodology used in the ITP10, which only considers the avoided capacity costs of new resources, and not other related costs to integrate or support the capacity resource additions. As a result, this Value of Transmission study only reflects $94.5 million in cost savings starting in 2017. Those benefits are included in the quantified reliability metrics, along with mandated reliability project benefits and avoided/deferred reliability projects.

The 40-year NPV of benefits associated with a two-percent reduction in planning reserve margins starting in 2017 is estimated to be $1.354 billion assuming that the annual savings would grow at an inflation of 2.5% per year.

GENERATION CAPACITY COST SAVINGS

(A) CAPACITY COST BENEFITS FROM REDUCED ON-PEAK TRANSMISSION LOSSES

While lower unit commitment and energy dispatch costs are captured in production cost simulations and APC savings, the addition of new transmission capacity could also improve the overall system efficiency by reducing system losses. Such reduction in losses during on-peak hours provide capacity cost savings due to lower generation capacity needed. These benefits are captured in this assessment based on the analysis of actual 2014 system peak hour, which occurred on July 22, 2014.

The Operational model simulations showed that the addition of the transmission projects built in 2012-2014 has reduced SPP's system losses by 43 MW during the 2014 system peak hour. Using ITP-approved calculations and assumptions, the capacity cost savings from reduced on-peak losses for the 2012-2014 portfolio of projects is estimated to be about $4 million per year, which is then escalated at 5% per year over time. The 40-year NPV of these capacity cost benefits is $92 million.

(B) DEFERRED GENERATION CAPACITY INVESTMENTS

This metric has not been quantified in this assessment. A more robust transmission grid may allow utilities to defer generation capacity investment by relying on market purchases of generation capacity in other zones (or even outside the SPP footprint) that are made deliverable by the transmission upgrades. SPP staff has not analyzed the extent to which this benefit is realized by the evaluated portfolio.

(C) ACCESS TO LOWER-COST GENERATION RESOURCES

This metric has only been partially captured in this assessment. To the extent that the transmission upgrades have allowed wind generation to be located in lower-cost/higher-capacity-factor locations, that benefit has been captured in the analysis of Public Policy Benefits below. Not included are the extent to which the more robust transmission grid allows conventional generating plants to be built in lower-cost locations (e.g., at locations with lower-cost sites or access to lower-cost fuel supply).

MARKET BENEFITS

A more robust transmission grid reduces transmission congestion and allows more suppliers and buyers to reach the available trading locations. The associated increase in competition and market liquidity offers a wide range of benefits, such as reduced bid-ask spreads of bilateral transactions, reduced price and deliverability risks associated with market transactions, and the availability and forward-horizon of financial hedging products (such as forwards and futures).

(A) INCREASED COMPETITION

This metric has not been quantified in this assessment.

(B) INCREASED MARKET LIQUIDITY

This metric has not been quantified in this assessment.

OTHER BENEFITS

(A) STORM HARDENING

This metric has not been quantified in this assessment. The focus on grid resiliency and need for effective system restoration plans are predicated on risk management of long lead time components of the bulk power system, like EHV autotransformers. This is becoming increasingly important with aging infrastructure and the difficulties in taking outages to rebuild/replace existing assets which are key elements of the bulk power network.

(B) FUEL DIVERSITY

This metric has not been fully quantified in this assessment. Some benefits of fuel diversity may have been partially captured to the extent that fuel diversity in the integrated footprint was enhanced as a result of the transmission expansion projects installed from 2012 through 2014.

(C) SYSTEM FLEXIBILITY

This metric has not been fully quantified in this assessment. Some benefits of increased system flexibility may have been partially captured to the extent that system flexibility in the integrated footprint was enhanced as a result of the transmission expansion projects installed from 2012 through 2014.

(D) REDUCING THE COSTS OF FUTURE TRANSMISSION NEEDS

This metric has not been quantified in this assessment. The extent to which the transmission upgrades evaluated avoided or reduced the costs of future transmission upgrades has not been captured.

(E) INCREASED WHEELING REVENUES

Additional long-term firm transmission reservations for exports from SPP have been enabled by the 2012-2014 portfolio of projects evaluated in this study. In the past several years, SPP has approved about 800 MW of long-term firm transmission exports which provided $100 million of additional annual wheeling revenues to offset wholesale transmission costs.

Leveraging prior analyses from SPP staff and applying those results to the specifics of this assessment, SPP estimated that the annual wheeling revenues associated with these projects during the first year of the IM would be $43.3 million with a 40-year NPV value of $1.133 billion. The $43.3 million annual benefit is based on MW of Firm PTP Transmission Service sold and revenues based on Schedules 7 and 11 of the SPP OATT. This credit is shown as the "wheeling" benefits in the Value of Transmission study.

Pricing of export services in SPP needs to reflect the true cost of those services, which should include appropriate contributions to offset a portion of major system enhancements. Many of these large, high-capacity projects in the 2012-2014 portfolio enable those transactions.

(F) HVDC OPERATIONAL BENEFITS

This metric is not applicable to SPP at this time, although substantial opportunities to upgrade, rightsize and potentially bypass existing HVDC ties between SPP and our neighboring systems in the Western Electricity Coordinating Council (WECC) and ERCOT, will be facilitated to a large extent by the substantial EHV network capabilities that have been installed in SPP from 2012 through 2014.

ENVIRONMENTAL BENEFITS

(A) REDUCED EMISSIONS OF AIR POLLUTANTS

This metric has not been quantified in this assessment. However, the 2012-2014 transmission portfolio has facilitated emissions reduction by (a) reducing or entirely eliminating curtailment of wind resources and (b) the development and integration of additional renewable resources.

(B) IMPROVED UTILIZATION OF TRANSMISSION CORRIDORS

This metric has not been quantified in this assessment. It is likely, however, that large, high-capacity transmission projects in the 2012-2014 portfolio utilize transmission corridors more effectively than smaller, incremental upgrades that would be required over time.

PUBLIC POLICY BENEFITS

(A) OPTIMAL WIND GENERATION DEVELOPMENT

The benefits of enabling renewable resource development have not been captured to a large extent in this study. Transmission is necessary and very effective in integrating renewable resources and creating value for these resources across the broad geographic footprint of SPP. The Integrated Marketplace, with its Consolidated Balancing Authority (CBA), helped with the integration of renewable resources, which was realized as a result of installed, enabling infrastructure.

In retrospect, 187 MW of new wind farms installed in 2014 would not have been interconnected to SPP absent the evaluated transmission projects. New wind farms are projected to cost $1400/kW per year based on Lazard estimates being used in the ITP10. The avoided or opportunity costs, as well as economic development and jobs associated with those projects, which represent almost a direct investment of $300 million in SPP, are large and do not count multiplier impacts for indirect benefits. None of these impacts have been quantified or included in the benefits portions of this analysis.

Operational analyses have been used to project the amount of wind curtailments avoided, based on an average of 255 MW of wind curtailments without the noted transmission expansion projects. Without considering energy value and the impact on lower market prices, 2.2 million MWh of wind curtailments annually equates to $30-60 million in lost revenue to developers/generators in terms of Production Tax Credits (PTCs), etc. The actual value of lost wind production to developers/generators are driven by federal, state and local programs and data to identify specific costs and are not available from the analyses performed. While this lost revenue does not provide a direct benefit to consumers like other metrics, it does improve the bottom line to resource providers and can be expected to translate into lower costs to consumers in the long run since all costs and revenues to producers will ultimately be seen over time by consumers in an efficient market.

A robust system also enables the effective integration and delivery of renewables across a broad geographic area. SPP is blessed with high quality wind and solar renewable resources. The diversity of those resources increases their aggregate capacity contribution, which is additional value that SPP's efficient and effective transmission network provides to our members and customers. Other ISO/RTOs have attempted to quantify the benefits of transmission expansion to allow members and customers access to higher quality renewable resources. Although the Balanced Portfolio and Priority Projects installed in 2012 through 2014 have enabled the integration of higher quality renewables to SPP customers, the associated incremental value has not been fully monetized in this assessment.

For the purposes of this study, the optimal wind development benefits are quantified as the avoided wind investment and local transmission costs. Estimating that the transmission expansion during 2012-2014 has enabled the development of approximately 5,000 MW of higher quality wind resources with an improvement in capacity factor, SPP staff estimated the avoided wind investment costs to be about $22 million per year, which equates to an NPV of $285 million over 40 years. Additionally, the 2012-2014 projects also help avoid the higher local transmission costs that would have been necessary to integrate wind resources located closer to the buyers' load centers. At an estimated cost of $180/kW-wind, the avoided local transmission cost benefit is estimated at $77 million per year, which equates to an NPV of $998 million over 40 years.

(B) OTHER BENEFITS OF MEETING PUBLIC POLICY GOALS

This metric has not been quantified in this assessment. For example, it is expected that a more robust transmission system created by the portfolio of transmission upgrades evaluated in this study will reduce the compliance cost related to the future implementation of new environmental regulations (such as EPA's Clean Power Plan).

EMPLOYMENT AND ECONOMIC DEVELOPMENT BENEFITS

(A) INCREASED EMPLOYMENT AND ECONOMIC ACTIVITY; INCREASED TAX REVENUES

This metric has not been quantified in this assessment. SPP and others have attempted to quantify these benefits in the past. These benefits can be large, particularly considering the high-quality, renewable generation developed in the central and south plains of the United States, enabled by SPP's Balanced Portfolio and Priority Projects. SPP has not monetized the value of increased employment and economic activity or increased tax revenues associated with investment in excess of $3.4 billion from 2012 through 2014 for transmission infrastructure in SPP.

Appendix B summarizes the metrics and quantified benefits in terms of NPV for the SPP transmission expansion projects placed in service over the period 2012 through 2014 based on the first full year of the Integrated Marketplace from March 2014 through February 2015.

SUMMARY

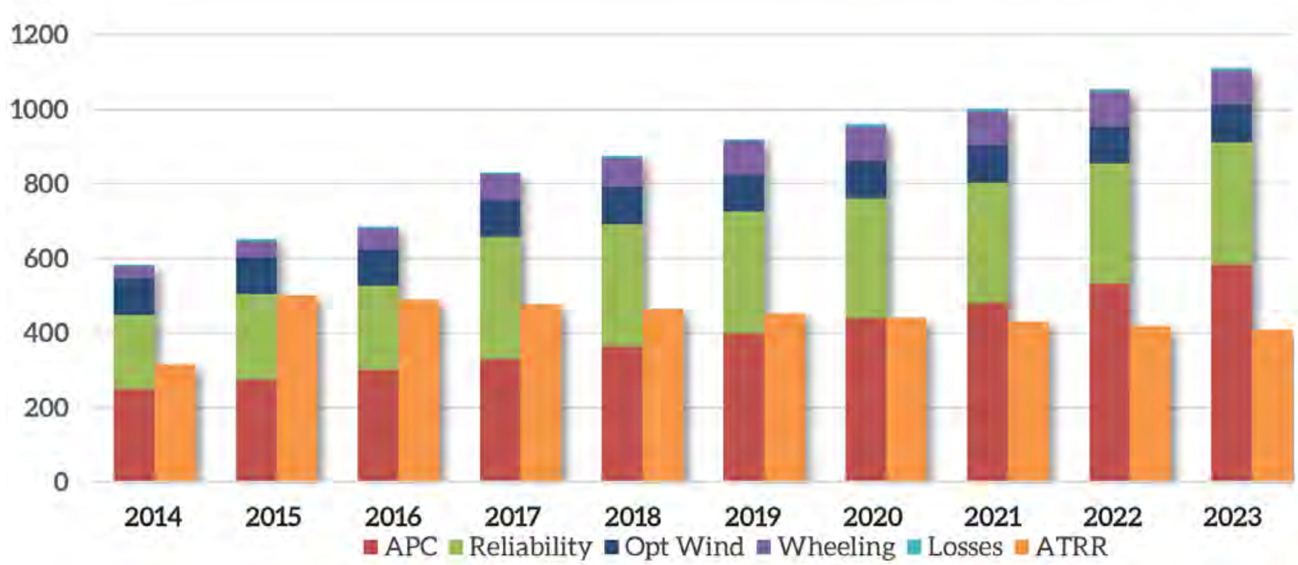
The quantified benefits as part of this Value of Transmission assessment for SPP transmission expansion projects installed from 2012 through 2014 based on the first year of the Integrated Marketplace are summarized in Table 5 and Figure 2 (in millions of nominal year dollars). Note that the benefits shown only capture metrics that have been quantified in this assessment.

Based on this analysis and quantified metrics, Net Present Value (NPV) benefits are substantial. This study contemplated a 40- year planning horizon with an eight-percent discount rate. Based on actual operations in the first year of SPP's Integrated Marketplace and using conservative approaches and assumptions, these projects are expected to provide a benefit-cost ratio of 3.5 to 1.

TABLE 5: VALUE OF TRANSMISSION BASED ON QUANTIFIED BENEFITS*

YEAR	APC	RELIABILITY	WHEELING	ON-PEAK LOSSES	OPTIMAL WIND	TOTAL VALUE	COSTS ATRR
2014	241.4	199.9	31.3	4.0	99.0	575.6	316.4
2015	265.5	231.4	43.3	4.1	99.0	643.3	501.3
2016	292.1	225.6	55.3	4.4	99.0	676.4	488.8
2017	321.3	328.3	67.3	4.6	99.0	820.4	476.6
2018	353.4	328.4	79.2	4.8	99.0	864.8	464.6
2019	388.7	325.6	91.2	5.0	99.0	909.6	453.0
2020	427.6	323.0	91.5	5.3	99.0	946.4	441.7
2021	470.4	320.6	91.7	5.6	99.0	987.3	430.7
2022	517.4	323.6	92.0	5.8	99.0	1,037.8	419.9
2023	569.1	326.8	92.3	6.1	99.0	1,093.3	409.4

FIGURE 2: QUANTIFIED BENEFITS* AND COSTS FOR 2014-2023



* Conservative benefits reflect average APC savings compared to year-end costs.

Exhibit A
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TABLE 6: NET PRESENT VALUE (NPV) OF STUDY METRICS

METRIC*	NPV ($M)
APC	10,470
Reliability – Mandated	2,166
Reliability – 2% RM	1,354
Reliability – Avoided/Def	105
Losses	92
Wheeling	1,133
Opt Wind	1,283

Quantified Benefits	16,603
Cost (ATRR)	4,751
B/C	3.5

** Conservative benefits using quantified metrics and average APC savings compared to year-end costs.*

Escalation and discount rates have a major impact on NPVs. A 2.5 percent escalation rate and an eight-percent discount rate have typically been used by SPP in performing calculations for long-term planning studies, and have been incorporated in this analysis.

Some would argue that EHV transmission is a long-term, enabling infrastructure that provides public good and should be assessed at a lower "societal" discount rate, which would be in the range of 3-5 percent per year. Applying a societal discount rate to the portfolio of transmission projects would significantly increase the B/C ratio shown above.

TRANSMISSION BENEFITS BEYOND THE QUANTIFIED METRICS ARE SIGNIFICANT

In the recent WIRES–sponsored Brattle Group report: Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid [4], the authors noted that one of the three deficiencies that expose markets to higher risks and overall costs is that "planners and policy makers do not consider the full range of benefits that transmission investments can provide and thus understate the expected value of such projects."

EHV grid expansion, which results from coordinated transmission planning in SPP, is partially responsible for footprint expansion. The KETA 345 kV line was the best solution for Kansas renewable development and became part of the Balanced Portfolio, which facilitated organic growth of the SPP footprint to include the Nebraska entities in 2009.

Transmission is a multi-faceted asset in that it not only improves grid security and system reliability but also facilitates more efficient operations and maintenance of the network and power supply assets. This effectively integrates and enhances the value of renewable resources and provides optionality for the future grid, which faces a myriad of uncertainties. The Tuco – Yoakum – Hobbs 345 kV project in High Priority Incremental Load Study (HPILS) not only improved the design and lowered the costs of a previously approved ITP solution, but also will facilitate the effective integration of the best solar resources in the entire Eastern Interconnection.

Transmission planning at SPP has been very effective to date. Although existing transmission planning processes are agile and transparent, continuous improvements are expected as a result of the efforts of the Transmission Planning Improvement Task Force (TPITF).

Aging infrastructure and the ability to accommodate transmission outages without adversely impacting grid operational efficiencies is a challenge with least-cost incremental planning based on pristine models. This value will increase significantly with time.

The benefits of grid expansion are cumulative and cannot be captured in incremental, snap-shot analyses. Standardization for backbone facilities and development of an efficient network will create significant benefits in reduced reserve margins over broad footprints with diverse resources and needs. The ability to effectively address supply adequacy needs is critically dependent upon network design and capabilities.

4 Pfeifenberger, J., Change, J., and Sheilendranath, A. (2015). The Brattle Group: Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid.

Planning a cost effective and reliable bulk power integration and delivery system in advance of implementing market mechanisms to capture efficiencies is a critical success factor. This is especially true for long-life infrastructure projects which provide optionality for resource planning decisions. Others have struggled to expand transmission capabilities after markets were placed in service.

The success of the South Central Electric Companies (SCEC) in the early 1960s is important to note because it demonstrated how utilities could go beyond joint planning to the installation of EHV backbone facilities based on common design standards which lowered costs and facilitated maintenance and outage restoration. The SCEC built a 500 and 345 kV EHV network to support 1,500MW of seasonal diversity exchanges between the winter peaking TVA system with SPP members in AR, LA, OK, KS, MO and TX that were summer peaking. The SCEC facilities became the backbone for many utilities, not just a way to share diverse capacity and energy among neighboring systems, but also to enable tremendous economies of scope and scale and timely integration of new resource additions in the 1970s and beyond. Those 500 and 345 kV facilities provide tremendous value to current and future customers and will continue to be invaluable for many decades to come.

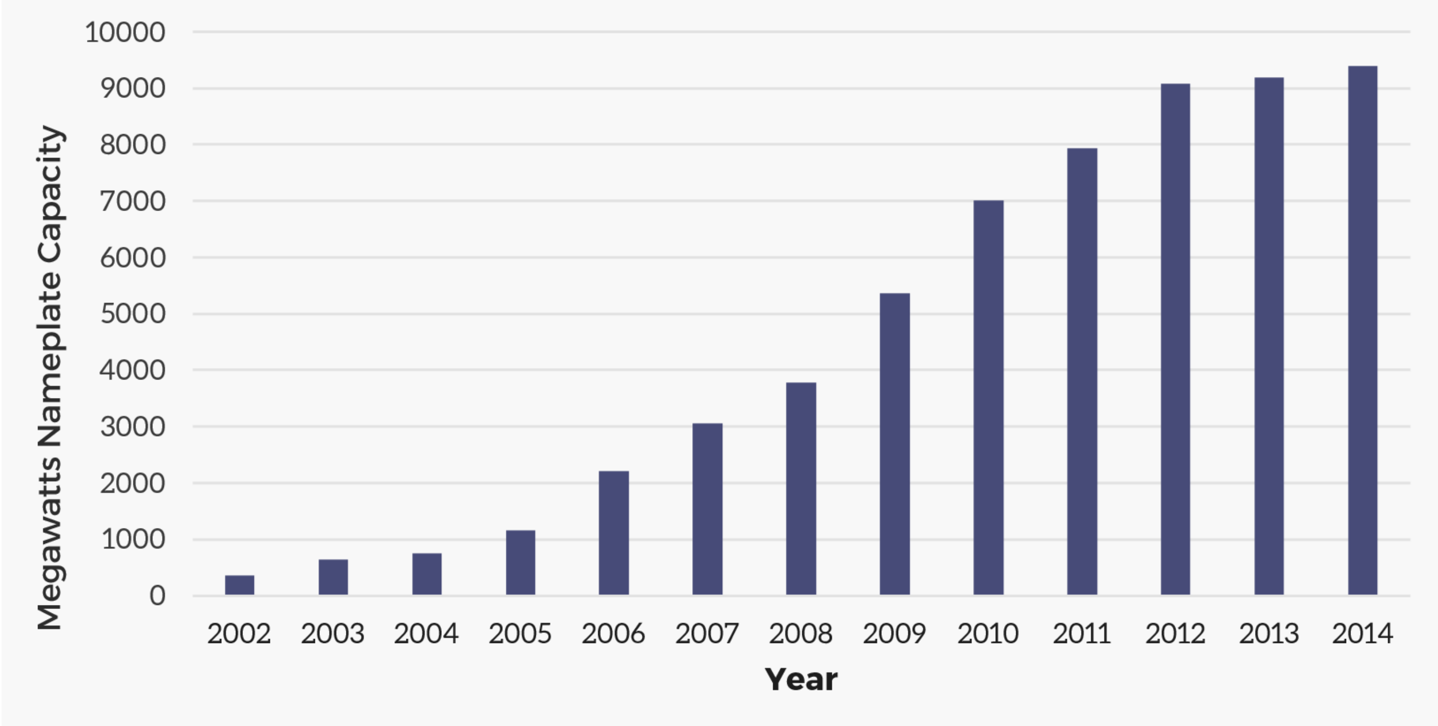
The magnitude of transmission facilities which will require rebuilds in the next twenty years is unknown. While significant rebuilds of 69-161 kV facilities have been accomplished since 2006 (as shown in Table 1), SPP has yet to experience the need to rebuild EHV facilities. Projects like the Wichita – Reno Co – Summit 345 kV expansion by Westar in central Kansas have been facilitated to a large extent by the need to rebuild aging 115 kV and 138 kV facilities and the ability to accommodate EHV expansion using double circuit towers in the existing rights-of-way.

The Integrated Marketplace in SPP has lowered operating costs and reserve requirements for its members as a result of enabling infrastructure and market rules, which are predicated on adequate transmission capability.

While lower losses and improved system efficiencies due to transmission expansion can be monetized in terms of unit commitment, system dispatch and off-system transactions, SPP has not quantified the environmental benefits of improved operations or the more effective integration of renewables in SPP for consumption, both within the SPP footprint and to support transfers to neighboring systems.

The environmental, public policy, and employment and economic stimulus benefits of transmission expansion projects can be large. The benefits of renewable developments and the resulting environmental benefits in SPP are hard to quantify for consumption within the footprint. Recently, renewable developments in SPP are being made to support exports to adjacent systems which are predicated on adequate transmission capacity to support deliveries. Pricing of transmission service needs to assign appropriate portions of backbone system facilities that are required to accommodate effective and efficient deliveries to adjacent systems.

FIGURE 3: WIND ADDITIONS IN SPP



Cumulative wind developments within SPP are shown in Figure 3.

Although 2015 data is not shown in Figure 3, significant wind resources are being installed in SPP in 2015 with minimal incremental transmission expansion beyond the projects completed in 2012 through 2014. SPP's experience shows that transmission expansion enables development of the best wind resources, and one would expect the same for solar resources in the future, as witnessed by recent Generation Interconnection (GI) queue developments.

Economies of scale are expected to persist for renewable resources. Larger scale wind and solar projects are cheaper, have greater potential and higher capacity factors, and account for the majority of installed renewable generating capacity in the US and globally. Transmission is effective at integrating variable resources to smooth out natural variability. Connecting diverse resources over large regions slashes variability, which reduces the need for more expensive resources like storage and fast-start generation.

Seams are critical and focus at SPP will need to evolve beyond managing interfaces and transmission expansion with AECI, MISO and other neighbors in the Eastern Interconnection. Opportunities with ERCOT, WestConnect and Canadian provincial utilities need to be addressed given aging infrastructure near the seams and future upgrades and system reconfigurations that may make sense in terms of improving system economics and reliability.

Joint planning studies like the proposed 2016-2017 DOE-funded and NREL-led effort to access and optimize the existing Back-to-Back HVDC stations between the Eastern Interconnection and the Western Electricity Coordinating Council are timely and critically important in effective joint planning of the bulk power system in the heartland of North America. The flexibility and optionality provided by transmission capabilities between the eastern and western grids, particularly considering the opportunity to leverage new technologies and controls, needs to be considered to effectively address challenges like the EPA's Clean Power Plan.

CONCLUSIONS

Transmission enables and defines markets. Transmission, unlike other assets in the bulk power system, provides system flexibility and optionality which improves operating efficiencies. Transmission expansion also provides other benefits to grid operations and planning, though metrics are difficult to quantify.

The actual benefits for transmission assets, similar to market benefits, exceed planning model projections due to assumptions used in those simulations. Uncertainties and volatility in real world operations increase system costs and the value of transmission. Extreme market conditions and weather events demonstrate the tremendous value that enabling infrastructure like transmission provides.

The benefits quantified for these 2012-2014 transmission expansion projects, based on the first year of the SPP Integrated Marketplace, are significant and expected to grow in the near-term as large, high-capacity 345 kV projects from the Balanced Portfolio and Priority Projects were placed in service in the latter half of these simulations. The net present value savings and benefit-to-cost ratio for these 2012-2014 projects in SPP, based on operational analyses for the period March 1, 2014 through February 2015, are large, despite the fact that the benefits of those large, backbone EHV network upgrades were not fully captured.

Major transmission expansion is versatile and facilitates efficient resource planning and economic transfers that are very difficult, if not impossible, to forecast in advance. Transmission expansion is key to maximizing value and maintaining system flexibility when one must plan and address uncertainties.

BRATTLE GROUP LETTER

"THE SPP VALUE OF TRANSMISSION STUDY IS A PATH-BREAKING EFFORT. IT PROVIDES A MORE ACCURATE ESTIMATE OF THE TOTAL BENEFITS THAT A MORE ROBUST AND FLEXIBLE TRANSMISSION INFRASTRUCTURE PROVIDES TO POWER MARKETS, MARKET PARTICIPANTS AND, ULTIMATELY, RETAIL ELECTRIC CUSTOMERS."

- JOHANNES PFEIFENBERGER, JUDY CHANG AND ONUR AYDIN

The Brattle Group performed an independent assessment of this SPP study and provided the letter enclosed on the following pages. Brattle noted that the SPP study provided a more accurate estimate of the total benefits that a more robust and flexible transmission network delivers. In addition to recommendations regarding future study refinements, Brattle concludes that estimate present value of the production cost savings are likely to be understated.

THE Brattle GROUP

December 30, 2015

Mr. Jay Caspary
Director, R&D and Special Studies
Southwest Power Pool
201 Worthen Drive
Little Rock AR 72223-4936

Re: SPP Value of Transmission Study

Dear Jay:

Thank you for giving us the opportunity to review the "Value of Transmission" report and the associated PowerPoint summary presentation prepared by SPP staff in December 2015. The SPP study attempts to quantify the overall value provided by SPP transmission projects placed in service during 2012-2014. Based on our review of the final drafts of your study and several prior rounds of discussions in response to earlier drafts, we are pleased to provide the following comments:

- The SPP Value of Transmission study is a path-breaking effort. It provides a more accurate estimate of the total benefits that a more robust and flexible transmission infrastructure provides to power markets, market participants and, ultimately, retail electric customers.
- Relying on a full "re-run" of SPP's day-ahead and real-time markets without the evaluated transmission projects for 40 representative days during the first year of operation of SPP's Integrated Marketplace and comparing the re-run results to actual market results (which include the evaluated transmission projects after they were placed in service) yields a more complete and more accurate estimate of the production cost savings provided by the evaluated projects than the savings estimated in traditional planning studies.
- The estimated present value of the production cost savings in the SPP study likely is understated because: (a) many of major transmission projects evaluated were not yet in service during most of the 40 days that were analyzed; (b) the selected representative days did not include a full spectrum challenging system conditions (such as extreme weather or generation/transmission outage events) that must be expected to occur over the long service life of the evaluated transmission projects; and (c) based on the experience from other SPP transmission benefit studies, the growth rate of the quantified production cost savings may exceed the assumed annual rate of 10% per year.
- The methodologies applied by SPP staff to quantify the range of other transmission-related benefits are consistent with the methodologies applied in the ITP and RCAR evaluation process. Where deviations from the ITP and RCAR processes exist (e.g., in the estimation of public policy benefits), the methodologies applied are reasonable and represent best available industry practice.

For future Value of Transmission studies, we also offer the following recommendations for further consideration:

- Reassess the selection of the typical days used to approximate each season of a study period. For example, in addition to highest and lowest production cost days, more reliable annual estimates might be obtained if (a subset of) the selected days also included a few average production cost days, or represented a combination of highest/lowest/average load days, highest/lowest/average market-price days, or highest/lowest/average congestion-cost days. Additional research would be necessary to establish which combination of typical days would most accurately capture the value of transmission for an entire study period.
- Select a study period which starts after all of the evaluated projects have been placed in service to ensure that the production cost analysis captures the benefit of the entire portfolio in each of the representative days simulated.
- Analyze the actual annual rates at which the production cost savings estimated for the study period are growing over time.
- Refine the methodologies used to estimate public policy benefits and wheeling revenue offsets to more accurately capture the benefits specifically attributable to the portfolio of transmission projects evaluated.
- Quantify the transmission-related benefits that are qualitatively discussed in the report as data and methodologies to estimate the value of those benefits become available. Some of the benefits discussed but not quantified are likely to provide significant additional value. Examples are "insurance" benefits that: (a) reduce the risks of high-cost outcomes during challenging system conditions (such as extreme weather or generation/transmission outage events), or (b) facilitate lower-cost options to address challenging future market conditions (such as those encountered under uncertain but plausible future environmental compliance scenarios).

We appreciate the opportunity to provide these comments on the Value of Transmission study, which we believe is a path-breaking effort that provides a more accurate estimate of the benefits that a more robust and flexible transmission infrastructure provides to power markets, its participants, and retail electric customers.

Sincerely,

Johannes Pfeifenberger	Judy Chang	Onur Aydin
Principal	Principal	Senior Associate

APPENDIX A: ACRONYMS

ACRONYM	DESCRIPTION
APC	Adjusted production cost
ATRR	Annual Transmission Revenue Requirement
CAIDI	Customer average interruption duration index. CAIDI is a measure of duration that provides the average amount of time a customer is without power per interruption.
CMTF	Capacity Margin Task Force
CONE	Cost of new entry
CPP	Clean Power Plan
CROW	Control Room Operations Window software
CT	Current transformer
EEI	Edison Electric Institute
EHV	Extra high voltage
FERC	Federal Energy Regulatory Commission
HPILS	High Priority Incremental Loads Study
ITP	Integrated Transmission Plan
ITP10	ITP 10-Year Assessment
ITP20	ITP 20-Year Assessment
MISO	Midcontinent Independent System Operator
MVP	Multi-value project
NYISO	New York Independent System Operator
PTC	Production Tax Credit
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SAIDI	System average interruption duration index. SAIDI is a measure of duration. It measures the number of minutes over the year that the average customer is without power.
SCEC	South Central Electric Companies
SONGS	SDG&E's Steam Generator Replacement Project
SDG&E	San Diego Gas & Electric
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority

APPENDIX B:

Projected NPV of SPP Transmission Projects Installed in 2012-14, Based on the First Year of SPP's Integrated Marketplace (Mar 2014 - Feb 2015)

BENEFIT CATEGORY	TRANSMISSION BENEFIT	NPV ($M)
Adjusted Production Cost Savings	Reduced production costs due to lower unit commitment, economic dispatch, and economically efficient transactions with neighboring systems	10,442*
1. Additional Production Cost Savings **	a. Impact of generation outages and A/S unit designations	INCLUDED
	b. Reduced transmission energy losses	INCLUDED
	c. Reduced congestion due to transmission outages	INCLUDED
	d. Mitigation of extreme events and system contingencies	PARTIAL
	e. Mitigation of weather and load uncertainty	PARTIAL
	f. Reduced cost due to imperfect foresight of real-time system conditions	INCLUDED
	g. Reduced cost of cycling power plants	PARTIAL
	h. Reduced amounts and costs of operating reserves and other ancillary services	PARTIAL
	i. Mitigation of reliability-must-run (RMR) conditions	N/Q
	j. More realistic "Day 1" market representation	N/Q
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects	105
	b. Reduced loss of load probability or c. reduced planning reserve margin (2% assumed)	1,354
	d. Mandated reliability projects	2,166
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses	171
	b. Deferred generation capacity investments	N/Q
	c. Access to lower-cost generation resources	PARTIAL
4. Market Benefits	a. increased competition	N/Q
	b. Increased market liquidity	N/Q
5. Other Benefits	a. storm hardening	N/Q
	b. fuel diversity	N/Q
	c. flexibility	N/Q
	d. reducing the costs of future transmission needs	N/Q
	e. wheeling revenues	1,133
	f. HVDC operational benefits	N/A
6. Environmental Benefits	a. Reduced emissions of air pollutants	N/Q
	b. Improved utilization of transmission corridors	N/Q
7. Public Policy Benefits	a. Optimal wind development	1,283
8. Employment and Economic Development Benefits	b. Other benefits of meeting public policy goals	N/Q
	Increased employment and economic activity; Increased tax revenues	N/Q
	TOTAL	**16,670 +**

** Benefits limited to SPP footprint since transactions with neighbors fixed*

***Partially captured since APC savings based on 40 days and did not include weather events like polar vortex, increased capital investments for rebuilds to address wear and tear impacts beyond in variable O&M, etc.*

APPENDIX C: INCLUDED TRANSMISSION PROJECTS

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
10927	Line - Sooner – Cleveland 345 kV (GRDA)	E	Balanced Portfolio	1/31/13	$3,718,139	$1,020,328	$1,020,328	$1,020,328	$1,020,328	$3,627,453	$9,012,312
10929	Line - Sooner - Cleveland 345 kV (OGE)	E	Balanced Portfolio	12/31/12	$46,000,000	$5,845,866	$5,845,866	$5,845,866	$5,845,866	$43,783,462	$49,768,061
10930	Line - Seminole - Muskogee 345 kV	E	Balanced Portfolio	12/31/13	$165,000,000	$21,493,088	$21,493,088	$21,493,088	$21,493,088	$160,975,610	$189,843,221
10932	Multi - Tuco - Woodward 345 kV (OGE)	E	Balanced Portfolio	5/19/14	$115,000,000	$15,354,532	$9,533,308	$12,022,092	$15,354,532	$115,000,000	$140,547,378
10933	Multi - Tuco - Woodward 345 kV (OGE)	E	Balanced Portfolio	5/19/14		$0	$0	$0	$0	$0	$0
10934	Tap - Swissvale - Stilwell	E	Balanced Portfolio	1/31/13	$2,866,604	$546,695	$546,695	$546,695	$546,695	$2,796,687	$4,828,821
10936	Multi - Tuco - Woodward 345 kV (SPS)	E	Balanced Portfolio	9/30/14	$192,875,814	$24,652,394	$6,230,825	$10,226,680	$24,652,394	$192,875,814	$225,655,156
10937	Multi - Tuco - Woodward 345 kV (OGE)	E	Balanced Portfolio	5/19/14		$0	$0	$0	$0	$0	$0
10938	Tap Anadarko - Washita 138 kV line into Gracemont 345 kV	E	Balanced Portfolio	10/12/12	$1,136,240	$197,264	$197,264	$197,264	$197,264	$1,081,489	$1,679,380
10940	Multi - Axtell - Post Rock - Spearville 345 kV	E	Balanced Portfolio	6/18/12	$79,171,915	$17,613,648	$17,613,648	$17,613,648	$17,613,648	$75,356,968	$149,951,630
10941	Multi - Axtell - Post Rock - Spearville 345 kV	E	Balanced Portfolio	6/18/12	$6,138,472	$1,365,647	$1,365,647	$1,365,647	$1,365,647	$5,842,686	$11,626,268
10942	Line - Axtell - Kansas Border 345 kV (NPPD)	E	Balanced Portfolio	12/10/12	$55,559,673	$6,171,746	$6,171,746	$6,171,746	$6,171,746	$52,882,497	$52,542,399
10943	Multi - Axtell - Post Rock - Spearville 345 kV	E	Balanced Portfolio	12/15/2012	$62,906,085	$13,994,933	$13,994,933	$13,994,933	$13,994,933	$59,874,917	$119,144,143
11085	Multi - Tuco - Woodward 345 kV (SPS)	E	Balanced Portfolio	6/2/2014	$12,550,762	$1,604,174	$934,299	$1,194,316	$1,604,174	$12,550,762	$14,683,770
10296	Line - Turk - SE Texarkana - 138 kV	X	Generation Interconnection	3/12/2012	$26,565,750	$3,363,691	$3,363,691	$3,363,691	$3,363,691	$25,285,663	$28,636,374
50459	SUB - PAWNEE 138 KV	X	Generation Interconnection	10/3/2014	$2,500,000	$703,199	$171,936	$285,916	$703,199	$2,500,000	$6,436,716

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
50460	LINE - FAIRFAX - PAWNEE 138 KV	X	Generation Intercon-nection	10/14/2014	$11,900,000	$3,347,227	$717,263	$1,259,808	$3,347,227	$11,900,000	$30,638,769
50461	SUB - SHIDLER 138KV OG&E Osage Sub work	X	Generation Intercon-nection	4/30/2014	$399,000	$53,078	$35,726	$44,329	$53,078	$399,000	$485,848
50462	Line - Washita - Grace-mont 138 kv ckt 2	X	Generation Intercon-nection	10/12/2012	$4,740,546	$823,011	$823,011	$823,011	$823,011	$4,512,120	$7,006,600
50463	SUB - SLICK HILLS 138KV	X	Generation Intercon-nection	2/1/2012	$1,500,000	$260,416	$260,416	$260,416	$260,416	$1,427,722	$2,217,023
50464	MULTI - RICE - CIRCLE 230KV CONVERSION	X	Generation Intercon-nection	11/7/2012	$10,225,261	$1,348,228	$1,348,228	$1,348,228	$1,348,228	$9,732,551	$11,477,971
50465	MULTI - RICE - CIRCLE 230KV CONVERSION	X	Generation Intercon-nection	11/29/2012	$5,373,496	$723,986	$723,986	$723,986	$723,986	$5,114,571	$6,163,568
50466	LINE - RICE COUNTY - LYONS 115KV	X	Generation Intercon-nection	4/1/2013	$3,245,758	$438,661	$438,661	$438,661	$438,661	$3,166,593	$3,874,584
50467	MULTI - RICE - CIRCLE 230KV CONVERSION	X	Generation Intercon-nection	10/1/2012	$2,473,404	$326,125	$326,125	$326,125	$326,125	$2,354,222	$2,776,424
50508	SUB - POI for GEN-2008-079 (Crooked Creek 115kV)	X	Generation Intercon-nection	10/2/2012	$665,522	$148,061	$148,061	$148,061	$148,061	$633,453	$1,260,499
50511	Sub - Wheatland 115 kV	X	Generation Intercon-nection	12/31/2012	$80,326	$10,591	$10,591	$10,591	$10,591	$76,455	$90,167
50562	Line(s) - Harrington - Nichols 230kV DBL CKT	X	Generation Intercon-nection	12/1/2012	$1,142,058	$138,938	$138,938	$138,938	$138,938	$1,087,027	$1,182,834
50614	Sub - POI for GEN-2012-001	X	Generation Intercon-nection	12/20/2012	$7,316,677	$890,118	$890,118	$890,118	$890,118	$6,964,119	$7,577,909
50617	Sub - Lopez 115kV	X	Generation Intercon-nection	2/8/2013	$151,581	$18,902	$18,902	$18,902	$18,902	$147,884	$166,955
50646	SUB - SHIDLER 138KV OG&E Osage Sub work	X	Generation Intercon-nection	7/1/2014	$399,300	$53,314	$26,803	$35,445	$53,314	$399,300	$488,005
50664	Sub - Spearville 345kV GEN-2005-012 Addi-tion	X	Generation Intercon-nection	6/1/2012	$2,903,000	$695,193	$695,193	$695,193	$695,193	$2,763,117	$5,918,443

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
50667	Sub - Sweetwater 230kV GEN-2006-035 Addition	X	Generation Intercon-nection	10/5/2012	$624,000	$79,009	$79,009	$79,009	$79,009	$593,932	$672,637
50670	Sub - Viola 345kV	X	Generation Intercon-nection	6/1/2012	$9,567,558	$1,289,064	$1,289,064	$1,289,064	$1,289,064	$9,106,539	$10,974,289
50671	Sub - Buckner 345kV	X	Generation Intercon-nection	4/10/2012	$5,395,772	$1,292,148	$1,292,148	$1,292,148	$1,292,148	$5,135,773	$11,000,540
50674	Sub - Hunter 345kV	X	Generation Intercon-nection	9/26/2012	$8,226,915	$1,045,510	$1,045,510	$1,045,510	$1,045,510	$7,830,496	$8,900,818
50676	Line(s) - Harrington - Nichols 230kV DBL CKT	X	Generation Intercon-nection	12/1/2012	$1,142,058	$138,938	$138,938	$138,938	$138,938	$1,087,027	$1,182,834
50677	Sub - Potter County 345kV GEN-2008-051 Addition	X	Generation Intercon-nection	5/1/2012	$3,005,283	$365,611	$365,611	$365,611	$365,611	$2,860,472	$3,112,582
50678	Sub - Deer Creek - Sin-clair 69kV Ckt 1	X	Generation Intercon-nection	10/1/2012	$2,079,212	$264,235	$264,235	$264,235	$264,235	$1,979,024	$2,249,529
50679	Sub - Viola 345kV GEN-2010-005 Addition	X	Generation Intercon-nection	10/1/2012	$26,000	$3,503	$3,503	$3,503	$3,503	$24,747	$29,823
50681	Sub - Buckner 345kV GEN-2010-009 Addi-tion	X	Generation Intercon-nection	9/15/2012	$570,131	$136,532	$136,532	$136,532	$136,532	$542,659	$1,162,345
50682	Sub - Cimarron 345kV GEN-2010-040 Addi-tion	X	Generation Intercon-nection	12/31/2012	$4,516,234	$573,941	$573,941	$573,941	$573,941	$4,298,617	$4,886,179
50683	Sub - Minco 345kV GEN-2011-010 Addition	X	Generation Intercon-nection	8/30/2012	$2,554,395	$324,623	$324,623	$324,623	$324,623	$2,431,310	$2,763,637
50684	Sub - Lopez 115kV	X	Generation Intercon-nection	2/15/2013	$3,371,204	$420,380	$420,380	$420,380	$420,380	$3,288,980	$3,713,118
50685	Sub - POI for GEN-2012-001	X	Generation Intercon-nection	12/20/2012	$7,086,677	$862,137	$862,137	$862,137	$862,137	$6,745,201	$7,339,697
50686	Sub - Petersburg North 115kV	X	Generation Intercon-nection	11/9/2012	$450,000	$49,987	$49,987	$49,987	$49,987	$428,316	$425,562
50687	Sub - Petersburg North 115kV	X	Generation Intercon-nection	11/9/2012	$450,000	$49,987	$49,987	$49,987	$49,987	$428,316	$425,562

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
50751	SUB - Finney 345kV GEN-2008-018 Addition	X	Generation Interconnection	11/2/2013	$2,252,249	$280,850	$280,850	$280,850	$280,850	$2,197,316	$2,480,677
51009	Sub - Steele City 115kV GEN-2011-018 Addition	X	Generation Interconnection	11/15/2013	$200,000	$22,772	$22,772	$22,772	$22,772	$195,122	$201,140
51010	Sub - Jones 230kV GEN-2011-045 Addition	X	Generation Interconnection	2/15/2013	$1,957,010	$244,034	$244,034	$244,034	$244,034	$1,909,278	$2,155,494
51011	Sub - Mustang 230kV GEN-2011-048 Addition	X	Generation Interconnection	11/26/2012	$878,667	$106,895	$106,895	$106,895	$106,895	$836,328	$910,039
51012	Sub - Rubart 115kV	X	Generation Interconnection	11/15/2013	$11,209,762	$2,751,559	$2,751,559	$2,751,559	$2,751,559	$10,936,353	$24,303,848
51023	Sub - Tatonga 345kV GEN-2007-021 Addition	X	Generation Interconnection	11/1/2014	$1,973,375	$263,480	$43,431	$86,138	$263,480	$1,973,375	$2,411,762
51024	Sub - Tatonga 345kV GEN-2007-044 Addition	X	Generation Interconnection	10/1/2014	$1,973,375	$263,480	$65,870	$108,577	$263,480	$1,973,375	$2,411,762
51038	Sub - Beaver County 345kV Substation	X	Generation Interconnection	9/29/2014	$15,744,936	$2,102,227	$537,107	$877,853	$2,102,227	$15,744,936	$19,242,691
51041	Sub - Madison County 230kV Substation	X	Generation Interconnection	12/23/2013	$1,450,000	$165,097	$165,097	$165,097	$165,097	$1,414,634	$1,458,265
51042	Sub - Madison County 230kV Substation	X	Generation Interconnection	12/23/2013	$1,450,000	$165,097	$165,097	$165,097	$165,097	$1,414,634	$1,458,265
51043	Sub - Madison County 230kV Substation	X	Generation Interconnection	12/23/2013	$5,900,000	$671,776	$671,776	$671,776	$671,776	$5,756,098	$5,933,630
11241	Multi - Hitchland - Woodward 345 kV (SPS)	E	High Priority	5/1/2014		$0	$0	$0	$0	$0	$0
11242	Multi - Hitchland - Woodward 345 kV (SPS)	E	High Priority	5/1/2014	$56,479,846	$7,218,963	$4,839,085	$6,009,192	$7,218,963	$56,479,846	$66,078,624
11243	Multi - Hitchland - Woodward 345 kV (SPS)	R	High Priority	5/1/2014	$4,723,219	$603,698	$404,676	$502,528	$603,698	$4,723,219	$5,525,932
11244	Line - Hitchland - Woodward 345 kV dbl Ckt (OGE)	E	High Priority	5/16/2014	$168,000,000	$22,430,969	$14,111,791	$17,747,580	$22,430,969	$168,000,000	$205,321,387

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
11245	Line - Hitchland - Woodward 345 kV dbl Ckt (OGE)	E	High Priority	5/16/2014		$0	$0	$0	$0	$0	$0
11246	Line - Thistle - Woodward 345 kV dbl Ckt (OGE)	E	High Priority	11/4/2014	$142,040,000	$18,964,850	$2,969,770	$6,043,743	$18,964,850	$142,040,000	$173,594,344
11247	Line - Thistle - Woodward 345 kV dbl Ckt (OGE)	E	High Priority	11/4/2014		$0	$0	$0	$0	$0	$0
11248	Line - Thistle - Woodward 345 kV dbl Ckt (PW)	E	High Priority	11/4/2014	$22,610,000	$5,284,774	$827,561	$1,684,159	$5,284,774	$22,610,000	$48,374,069
11249	Line - Thistle - Woodward 345 kV dbl Ckt (PW)	E	High Priority	11/4/2014	$22,610,000	$5,284,774	$827,561	$1,684,159	$5,284,774	$22,610,000	$48,374,069
11252	Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double Circuit	E	High Priority	12/17/2014	$50,565,144	$11,818,902	$454,573	$2,370,274	$11,818,902	$50,565,144	$108,184,067
11253	Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double Circuit	E	High Priority	12/17/2014	$50,565,144	$11,818,902	$454,573	$2,370,274	$11,818,902	$50,565,144	$108,184,067
11254	Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double Circuit	E	High Priority	12/17/2014	$91,618,023	$21,414,444	$823,632	$4,294,655	$21,414,444	$91,618,023	$196,016,654
11255	Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double Circuit	E	High Priority	12/17/2014	$91,618,023	$21,414,444	$823,632	$4,294,655	$21,414,444	$91,618,023	$196,016,654
11258	Line - Thistle - Wichita 345 kV dbl Ckt	E	High Priority	5/19/2014	$58,140,000	$13,589,420	$8,437,387	$10,640,068	$13,589,420	$58,140,000	$124,390,463
11259	Line - Thistle - Wichita 345 kV dbl Ckt	E	High Priority	5/19/2014	$58,140,000	$13,589,420	$8,437,387	$10,640,068	$13,589,420	$58,140,000	$124,390,463
11260	Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double Circuit	E	High Priority	12/17/2014	$6,284,694	$1,468,960	$56,498	$294,599	$1,468,960	$6,284,694	$13,446,096
11497	Line - Thistle - Wichita 345 kV dbl Ckt	E	High Priority	6/4/2014	$10,746,938	$1,521,269	$877,655	$1,124,234	$1,521,269	$10,746,938	$13,924,899
50384	Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double Circuit	E	High Priority	12/17/2014	$7,106,987	$1,661,160	$63,891	$333,145	$1,661,160	$7,106,987	$15,205,390

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
50705	Device - Spalding 115 kV Cap Bank	R	High Priority	1/1/2014	$538,071	$62,797	$62,797	$62,797	$62,797	$538,071	$574,807
50792	Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double Circuit	E	High Priority	12/17/2014	$1,850,000	$432,412	$16,631	$86,720	$432,412	$1,850,000	$3,958,073
50793	Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double Circuit	E	High Priority	12/17/2014	$9,191,986	$2,148,499	$82,635	$430,880	$2,148,499	$9,191,986	$19,666,243
50810	Line - Jenson - Jenson Tap 138 kV Ckt 1	R	High Priority	8/1/2014	$0	$0	$0	$0	$0	$0	$0
50824	Line - Garden City - Kansas Avenue 115 kV Ckt 1	R	High Priority	3/20/2014	$112,722	$26,347	$20,701	$24,972	$26,347	$112,722	$241,169
51013	Line - Darlington - Red Rock 138 kV Ckt 1	R	High Priority	10/4/2013	$15,277,233	$1,982,726	$1,982,726	$1,982,726	$1,982,726	$14,904,618	$17,512,934
51015	Line - Grady - Phillips Gas 138 kV Ckt 1 and 2	R	High Priority	12/31/2014	$8,318,584	$1,106,601	$0	$179,367	$1,106,601	$8,318,584	$10,129,252
51029	Multi - Spearville - Ironwood - Clark Co. - Thistle 345 kV Double Circuit	E	High Priority	12/17/2014	$200,000	$46,747	$1,798	$9,375	$46,747	$200,000	$427,900
51045	Line - Benteler - Port Robson 138 kV Ckt 1 and 2	R	High Priority	9/5/2014	$2,248,743	$299,145	$96,154	$144,641	$299,145	$2,248,743	$2,738,217
51046	Line - Benteler - Port Robson 138 kV Ckt 1 and 2	R	High Priority	12/11/2014	$2,548,575	$339,031	$18,628	$73,581	$339,031	$2,548,575	$3,103,312
51047	Sub - Ellis 138 kV	R	High Priority	6/1/2013	$4,100,000	$532,110	$532,110	$532,110	$532,110	$4,000,000	$4,700,002
51052	Sub - S1260 161 kV	R	High Priority	11/7/2014	$4,636,045	$489,595	$72,632	$151,990	$489,595	$4,636,045	$4,481,495
51053	Sub - S1398 161 kV	R	High Priority	6/28/2013	$2,824,664	$291,026	$291,026	$291,026	$291,026	$2,755,770	$2,570,563
51055	Sub - Tallgrass 138 kV	R	High Priority	3/1/2014	$4,100,000	$580,370	$486,299	$580,370	$580,370	$4,100,000	$5,312,405
10140	Multi - Wallace Lake - Port Robson - RedPoint 138 kV	R	Regional Reliability	4/16/2012	$9,480,000	$1,200,335	$1,200,335	$1,200,335	$1,200,335	$9,023,200	$10,218,903
10141	Multi - Wallace Lake - Port Robson - RedPoint 138 kV	R	Regional Reliability	3/1/2012	$19,482,000	$2,466,764	$2,466,764	$2,466,764	$2,466,764	$18,543,248	$21,000,493

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10173	Multi - Lindsay - Lindsay SW and Bradley-Rush Springs	R	Regional Reliability	12/5/2012	$2,769,825	$480,872	$480,872	$480,872	$480,872	$2,636,360	$4,093,845
10179	Line - ACME - W Norman 69 kV	R	Regional Reliability	12/1/2014	$912,000	$166,349	$13,710	$40,673	$166,349	$912,000	$1,522,670
10195	XFR - Tuco 115/69 kV Transformer Ckt 3	R	Regional Reliability	5/16/2014	$3,212,132	$410,558	$258,291	$324,837	$410,558	$3,212,132	$3,758,035
10215	Line - Holcomb - Plymell 115 kV	R	Regional Reliability	6/1/2012	$3,986,076	$954,562	$954,562	$954,562	$954,562	$3,794,005	$8,126,546
10221	Line - Tecumseh Energy Center - Midland 115 kV	R	Regional Reliability	7/19/2013	$5,498,564	$759,358	$759,358	$759,358	$759,358	$5,364,453	$6,707,224
10231	Line - Chase - White Junction 69 kV	R	Regional Reliability	5/29/2013	$4,520,009	$624,218	$624,218	$624,218	$624,218	$4,409,765	$5,513,569
10300	Line - Fort Smith - Colony 161 kV 2	R	Regional Reliability	6/15/2014	$2,120,000	$283,057	$154,748	$200,629	$283,057	$2,120,000	$2,590,960
10303	Line - Atoka - WFEC Tupelo - Lane 138 kV	R	Regional Reliability	6/1/2013	$6,784,050	$1,207,230	$1,207,230	$1,207,230	$1,207,230	$6,618,585	$10,663,168
10305	Line - WFEC Snyder - AEP Snyder	R	Regional Reliability	3/1/2012	$1,273,772	$221,141	$221,141	$221,141	$221,141	$1,212,395	$1,882,655
10309	Multi - OU SW - Goldsby - Canadian SW 138 kV	R	Regional Reliability	10/25/2013	$369,740	$65,796	$65,796	$65,796	$65,796	$360,722	$581,157
10310	Multi - OU SW - Goldsby - Canadian SW 138 kV	R	Regional Reliability	10/15/2013	$369,740	$65,796	$65,796	$65,796	$65,796	$360,722	$581,157
10311	Multi - OU SW - Goldsby - Canadian SW 138 kV	R	Regional Reliability	10/31/2013	$3,469,399	$617,384	$617,384	$617,384	$617,384	$3,384,780	$5,453,201
10326	Multi - Hitchland - Texas Co. 230 kV and 115 kV	R	Regional Reliability	6/8/2012	$36,991,437	$4,500,231	$4,500,231	$4,500,231	$4,500,231	$35,208,982	$38,312,164
10330	Multi - Hitchland - Texas Co. 230 kV and 115 kV	R	Regional Reliability	4/9/2013	$20,137,782	$2,511,129	$2,511,129	$2,511,129	$2,511,129	$19,646,617	$22,180,195
10331	Multi - Hitchland - Texas Co. 230 kV and 115 kV	R	Regional Reliability	4/9/2013	$8,121,300	$1,012,705	$1,012,705	$1,012,705	$1,012,705	$7,923,220	$8,944,978
10351	Line - Halstead - Mud Creek Jct. - 69 kV	R	Regional Reliability	2/24/2012	$703,186	$94,742	$94,742	$94,742	$94,742	$669,303	$806,576
10352	Line - Halstead - Mud Creek Jct. - 69 kV	R	Regional Reliability	5/23/2012	$4,313,368	$581,152	$581,152	$581,152	$581,152	$4,105,526	$4,947,568
10385	Multi - Kansas Tap - Siloam City 161KV	R	Regional Reliability	11/15/2013	$4,780,359	$1,311,822	$1,311,822	$1,311,822	$1,311,822	$4,663,765	$11,587,003

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10386	Multi - Kansas Tap - Siloam City 161KV	R	Regional Reliability	11/15/2013	$2,002,021	$549,393	$549,393	$549,393	$549,393	$1,953,191	$4,852,653
10388	XFR - Sallisaw 161/69 kV Auto #2	R	Regional Reliability	7/15/2012	$2,115,237	$566,304	$566,304	$566,304	$566,304	$2,013,313	$4,821,158
10415	Multi - Cowskin - Westlink - Tyler - Hoover 69 kV	R	Regional Reliability	5/9/2014	$4,737,867	$670,662	$434,825	$543,531	$670,662	$4,737,867	$6,138,895
10417	Line - Oaklawn - Oliver 69 kV	R	Regional Reliability	7/25/2012	$2,709,837	$365,104	$365,104	$365,104	$365,104	$2,579,262	$3,108,268
10480	Line - Plymell - Pioneer Tap 115 kV	R	Regional Reliability	6/1/2012	$5,534,364	$1,325,337	$1,325,337	$1,325,337	$1,325,337	$5,267,687	$11,283,092
10505	Line - Riverside - Okmulgee 138 kV	R	Regional Reliability	3/1/2012	$125,000	$15,827	$15,827	$15,827	$15,827	$118,977	$134,743
10509	Line - Lone Star South - Pittsburg 138kV Ckt 1	R	Regional Reliability	5/11/2012	$300,000	$37,985	$37,985	$37,985	$37,985	$285,544	$323,383
10510	Line - Howell - Kilgore 69 kV	R	Regional Reliability	5/7/2012	$3,986,000	$504,698	$504,698	$504,698	$504,698	$3,793,932	$4,296,682
10520	Line - Pharoah - Weleetka 138 kV	R	Regional Reliability	9/28/2012	$0	$0	$0	$0	$0	$0	$0
10521	Line - WFEC Russell - AEP Altus Jct Tap 138 kV	R	Regional Reliability	6/1/2012	$50,000	$8,681	$8,681	$8,681	$8,681	$47,591	$73,901
10575	Line - Osborne - Osborne Tap	R	Regional Reliability	11/12/2013	$2,000,000	$259,566	$259,566	$259,566	$259,566	$1,951,220	$2,292,684
10582	Multi - Flint Creek – Centerton 345 kV and Centerton- East Centerton 161 kV	R	Regional Reliability	4/28/2014	$11,962,000	$1,591,276	$1,079,795	$1,337,721	$1,591,276	$11,962,000	$14,565,713
10584	Multi - Flint Creek – Centerton 345 kV and Centerton- East Centerton 161 kV	R	Regional Reliability	4/28/2014	$13,104,000	$1,743,194	$1,182,882	$1,465,432	$1,743,194	$13,104,000	$15,956,287
10585	Multi - Flint Creek – Centerton 345 kV and Centerton- East Centerton 161 kV	R	Regional Reliability	4/28/2014	$34,085,000	$4,534,246	$3,076,810	$3,811,756	$4,534,246	$34,085,000	$41,504,125
10603	Line - Gill - Interstate 138 kV	R	Regional Reliability	12/4/2013	$67,008	$9,254	$9,254	$9,254	$9,254	$65,374	$81,737
10647	Line - Northwest Henderson - Poynter 69 kV	R	Regional Reliability	6/6/2014	$7,815,833	$1,039,722	$594,127	$762,653	$1,039,722	$7,815,833	$9,517,069
10648	Line - Diana - Perdue 138 kV	R	Regional Reliability	12/31/2014	$1,004,187	$133,585	$0	$21,652	$133,585	$1,004,187	$1,222,763
10668	Line - Rose Hill - Sooner 345 kV (OGE)	R	Regional Reliability	6/1/2012	$45,935,000	$5,837,605	$5,837,605	$5,837,605	$5,837,605	$43,721,594	$49,697,737

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10674	Line - Rose Hill - Sooner 345 kV Ckt 1 (WR)	R	Regional Reliability	4/27/2012	$84,379,298	$11,368,661	$11,368,661	$11,368,661	$11,368,661	$80,313,431	$96,785,701
10698	Line - Maid - Pryor Foundry South 69 kV	R	Regional Reliability	1/15/2014	$1,993,805	$560,817	$539,247	$560,817	$560,817	$1,993,805	$5,133,423
10699	Line - Maid - Redden 69 kV	R	Regional Reliability	5/1/2014	$2,104,778	$592,031	$396,856	$492,817	$592,031	$2,104,778	$5,419,144
10701	Multi - Johnson - Massard 161 kV	R	Regional Reliability	3/29/2013	$9,684,152	$1,261,469	$1,261,469	$1,261,469	$1,261,469	$9,447,953	$11,142,246
10705	Multi: Dallam - Channing - Tascosa -Potter	R	Regional Reliability	5/29/2012	$9,590,276	$1,166,715	$1,166,715	$1,166,715	$1,166,715	$9,128,163	$9,932,683
10713	Multi - Litchfield - Aquarius - Hudson Jct. 69 kV Uprate	R	Regional Reliability	6/1/2013	$181,444	$25,058	$25,058	$25,058	$25,058	$177,019	$221,328
10757	Line - Ocotillo sub conversion 115 kV	R	Regional Reliability	3/23/2012	$3,102,202	$377,402	$377,402	$377,402	$377,402	$2,952,721	$3,212,962
10792	Multi: Dover-Twin Lake-Crescent-Cottonwood conversion 138 kV	R	Regional Reliability	10/30/2014	$8,100,000	$1,081,493	$184,210	$359,507	$1,081,493	$8,100,000	$9,899,424
10794	Multi: WFEC-Dover-Twin Lake_Cresent-Cottonwood conversion 138 kV	R	Regional Reliability	12/11/2013	$5,765,600	$1,025,996	$1,025,996	$1,025,996	$1,025,996	$5,624,976	$9,062,369
10795	Multi: WFEC-Dover-Twin Lake_Cresent-Cottonwood conversion 138 kV	R	Regional Reliability	12/9/2013	$5,315,700	$945,935	$945,935	$945,935	$945,935	$5,186,049	$8,355,216
10796	Multi: WFEC-Dover-Twin Lake_Cresent-Cottonwood conversion 138 kV	R	Regional Reliability	10/31/2013	$3,164,000	$563,038	$563,038	$563,038	$563,038	$3,086,829	$4,973,175
10797	Multi: WFEC-Dover-Twin Lake_Cresent-Cottonwood conversion 138 kV	R	Regional Reliability	10/31/2013	$3,937,500	$700,683	$700,683	$700,683	$700,683	$3,841,463	$6,188,962
10799	Multi - Lindsay - Lindsay SW and Bradley-Rush Springs	R	Regional Reliability	11/20/2012	$1,248,750	$216,797	$216,797	$216,797	$216,797	$1,188,578	$1,845,672
10806	Multi - NW Manhattan	R	Regional Reliability	5/11/2012	$4,249,559	$572,555	$572,555	$572,555	$572,555	$4,044,791	$4,874,377
10808	Multi - NW Manhattan	R	Regional Reliability	3/19/2012	$18,624,222	$2,509,294	$2,509,294	$2,509,294	$2,509,294	$17,726,803	$21,362,567
10812	Line - Fort Junction - West Junction City 115 kV	R	Regional Reliability	5/21/2013	$5,569,785	$769,194	$769,194	$769,194	$769,194	$5,433,937	$6,794,101

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10829	Line - Chaves Co - Roswell Int 69/115 kV Voltage Conversion	R	Regional Reliability	1/31/2014	$8,610,000	$1,100,486	$1,009,787	$1,100,486	$1,100,486	$8,610,000	$10,073,274
10830	Multi - Loma Vista - Montrose 161 kV - Tap into K.C. South	R	Regional Reliability	1/14/2013	$6,238,437	$788,087	$788,087	$788,087	$788,087	$6,086,280	$6,960,977
10837	Multi - Johnson - Massard 161 kV	R	Regional Reliability	3/29/2013		$0	$0	$0	$0	$0	$0
10839	Line - Sub 170 Nichols - Sub 80 Sedalia 69 kV	R	Regional Reliability	5/1/2012	$5,352,187	$814,930	$814,930	$814,930	$814,930	$5,094,289	$6,937,808
10843	Line - Kilgore - VBI 69 kV	R	Regional Reliability	11/23/2013	$33,267	$4,333	$4,333	$4,333	$4,333	$32,456	$38,276
10847	XFR - Clinton 161/69 kV	R	Regional Reliability	4/2/2014	$1,972,428	$255,401	$191,551	$232,949	$255,401	$1,972,428	$2,337,811
10853	Line - Lone Star-Locust Grove 115 kV	R	Regional Reliability	2/13/2014	$2,150,000	$286,009	$252,223	$286,009	$286,009	$2,150,000	$2,617,981
10854	Multi - South Harper 161 kV cut-in to Stilwell-Archie Junction 161 kV line	R	Regional Reliability	1/25/2013	$4,672,809	$590,305	$590,305	$590,305	$590,305	$4,558,838	$5,214,017
10858	Line - Pratt - St. John 115 kV rebuild	R	Regional Reliability	6/15/2014	$15,079,303	$3,524,578	$1,926,899	$2,498,190	$3,524,578	$15,079,303	$32,262,151
10865	Line - Reeding - Twin Lakes Switchyard conversion to 138 kV	R	Regional Reliability	10/31/2013	$1,971,000	$350,742	$350,742	$350,742	$350,742	$1,922,927	$3,098,017
10870	Line - GEC West - Waco 138 kV	R	Regional Reliability	10/30/2012	$4,857,641	$654,484	$654,484	$654,484	$654,484	$4,623,573	$5,571,867
10875	Line - Pecan Creek - Five Tribes 161 kV Ckt 1	R	Regional Reliability	2/1/2014	$3,022,363	$403,539	$369,172	$403,539	$403,539	$3,022,363	$3,693,784
10878	Line - El Reno - El Reno SW 69 kV	R	Regional Reliability	6/1/2012	$1,950,000	$338,541	$338,541	$338,541	$338,541	$1,856,038	$2,882,130
10879	Line - Bradley - Lindsay 69 kV Ckt 1 reconductor	R	Regional Reliability	9/11/2012	$3,712,500	$644,531	$644,531	$644,531	$644,531	$3,533,611	$5,487,132
10898	Line - Broadmoor - Fern Street 69 kV	R	Regional Reliability	12/31/2014	$4,923,124	$654,911	$0	$106,153	$654,911	$4,923,124	$5,994,718
10952	Line - Glenare - Liberty 69 kV Ckt 1	R	Regional Reliability	3/31/2014	$1,950,000	$252,497	$190,760	$231,687	$252,497	$1,950,000	$2,311,228
10953	Line - Blue Spring South - Prairie Lee 161 kV Ckt 1	R	Regional Reliability	6/20/2013	$24,933	$3,150	$3,150	$3,150	$3,150	$24,325	$27,821
10986	Line - Maloney - North Platte 115 kV	R	Regional Reliability	6/1/2012	$1,451,500	$161,237	$161,237	$161,237	$161,237	$1,381,559	$1,372,674

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10993	Line - Harper - Milan Tap 138 kV	R	Regional Reliability	8/1/2013	$19,662	$4,484	$4,484	$4,484	$4,484	$19,182	$39,603
11011	Multi - Canadian River - McAlester City - Dustin 138 kV	R	Regional Reliability	6/28/2013	$24,965,000	$3,240,034	$3,240,034	$3,240,034	$3,240,034	$24,356,098	$28,618,428
11012	Multi - Canadian River - McAlester City - Dustin 138 kV	R	Regional Reliability	6/28/2013	$9,513,000	$1,234,626	$1,234,626	$1,234,626	$1,234,626	$9,280,976	$10,905,151
11015	Line - Ashdown - Craig Junction 138 kV Rebuild	R	Regional Reliability	2/8/2013	$2,500,000	$324,458	$324,458	$324,458	$324,458	$2,439,024	$2,865,855
11019	Multi - Cherry Sub add 230kV source and 115 kV Hastings Conver-sion	R	Regional Reliability	3/21/2014	$3,792,408	$484,726	$379,525	$458,093	$484,726	$3,792,408	$4,436,930
11020	Multi - Cherry Sub add 230kV source and 115 kV Hastings Conver-sion	R	Regional Reliability	3/21/2014	$9,736,187	$1,244,429	$974,347	$1,176,054	$1,244,429	$9,736,187	$11,390,857
11021	Multi - Cherry Sub add 230kV source and 115 kV Hastings Conver-sion	R	Regional Reliability	5/1/2014	$1,048,295	$133,988	$89,816	$111,534	$133,988	$1,048,295	$1,226,453
11029	Line - Maddox - Sanger SW 115 kV	R	Regional Reliability	5/4/2012	$1,912,542	$232,672	$232,672	$232,672	$232,672	$1,820,385	$1,980,827
11033	XFR - Install 2nd Randall 230/115 kV transformer	R	Regional Reliability	5/13/2013	$7,997,141	$997,223	$997,223	$997,223	$997,223	$7,802,089	$8,808,227
11036	Line - Maddox Station - Monument 115 kV Ckt 1	R	Regional Reliability	11/30/2012	$1,689,108	$205,490	$205,490	$205,490	$205,490	$1,607,717	$1,749,415
11038	Line - Brasher Tap - Roswell Interchange 115 kV	R	Regional Reliability	10/25/2013	$75,000	$9,352	$9,352	$9,352	$9,352	$73,171	$82,607
11040	Multi - New Hart Inter-change 230/115 kV	R	Regional Reliability	1/31/2014	$12,864,507	$1,644,275	$1,508,758	$1,644,275	$1,644,275	$12,864,507	$15,050,836
11041	Multi - New Hart Inter-change 230/115 kV	R	Regional Reliability	12/19/2014	$19,959,385	$2,551,106	$84,102	$497,606	$2,551,106	$19,959,385	$23,351,493
11042	Multi - New Hart Inter-change 230/115 kV	R	Regional Reliability	3/25/2014	$16,108,465	$2,058,901	$1,589,426	$1,923,149	$2,058,901	$16,108,465	$18,846,107
11043	Multi - New Hart Inter-change 230/115 kV	R	Regional Reliability	1/31/2014	$15,491,109	$1,979,994	$1,816,808	$1,979,994	$1,979,994	$15,491,109	$18,123,831
11044	Multi - New Hart Inter-change 230/115 kV	R	Regional Reliability	1/31/2014	$2,568,905	$328,344	$301,283	$328,344	$328,344	$2,568,905	$3,005,492
11045	Multi - New Hart Inter-change 230/115 kV	R	Regional Reliability	12/19/2014	$17,384,254	$2,221,966	$73,252	$433,405	$2,221,966	$17,384,254	$20,338,717

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11046	Line - Cunningham - Buckey Tap 115 kV reconductor	R	Regional Reliability	6/27/2013	$3,516,246	$438,467	$438,467	$438,467	$438,467	$3,430,484	$3,872,871
11052	Multi - Pleasant Hill-Potter 230 kV Ckt 1	R	Regional Reliability	12/31/2014	$15,713,303	$2,008,394	$0	$325,536	$2,008,394	$15,713,303	$18,383,787
11053	Multi - Pleasant Hill-Potter 230 kV Ckt 1	R	Regional Reliability	12/31/2014	$13,694,777	$1,750,396	$0	$283,718	$1,750,396	$13,694,777	$16,022,211
11054	Multi - Pleasant Hill-Potter 230 kV Ckt 1	R	Regional Reliability	12/31/2014	$15,180,231	$1,940,259	$0	$314,493	$1,940,259	$15,180,231	$17,760,119
11078	Line - Albion - Genoa 115 kV	R	Regional Reliability	6/1/2014	$773,349	$90,255	$52,814	$67,443	$90,255	$773,349	$826,148
11079	Line - Albion - Spalding 115 kV	R	Regional Reliability	6/1/2013	$1,214,028	$138,230	$138,230	$138,230	$138,230	$1,184,418	$1,220,948
11080	Line - Loup City - North Loup 115 kV	R	Regional Reliability	6/1/2012	$1,818,986	$202,059	$202,059	$202,059	$202,059	$1,731,337	$1,720,202
11096	XFR - Kingsmill 115/69 kV Ckt 2	R	Regional Reliability	6/28/2013	$4,400,000	$548,669	$548,669	$548,669	$548,669	$4,292,683	$4,846,257
11100	XFR - Northeast Hereford 115/69 kV Transformer Ckt 2	R	Regional Reliability	8/29/2013	$4,200,902	$523,842	$523,842	$523,842	$523,842	$4,098,441	$4,626,966
11102	Multi - Move Load from East Clovis 69 kV to East Clovis 115 kV	R	Regional Reliability	6/30/2013	$2,125,000	$264,982	$264,982	$264,982	$264,982	$2,073,171	$2,340,522
11107	Multi - Kress Inter-change - Kiser - Cox 115 kV	R	Regional Reliability	11/21/2014	$13,584,121	$1,736,252	$190,797	$472,223	$1,736,252	$13,584,121	$15,892,749
11109	Multi - Kress Inter-change - Kiser - Cox 115 kV	R	Regional Reliability	3/7/2014	$6,850,000	$875,532	$719,187	$861,100	$875,532	$6,850,000	$8,014,161
11117	Line - Wakita - Nash 69 kV Ckt 1	R	Regional Reliability	12/15/2013	$6,705,000	$1,193,163	$1,193,163	$1,193,163	$1,193,163	$6,541,463	$10,538,918
11121	Line - Harrington - Randall County 230 kV	R	Regional Reliability	5/13/2013	$159,060	$19,834	$19,834	$19,834	$19,834	$155,180	$175,192
11129	Multi - Cushing Area 138 kV	R	Regional Reliability	6/1/2014		$0	$0	$0	$0	$0	$0
11130	Multi - Cushing Area 138 kV	R	Regional Reliability	6/1/2014		$0	$0	$0	$0	$0	$0
11131	Multi - Cushing Area 138 kV	R	Regional Reliability	12/1/2013		$0	$0	$0	$0	$0	$0
11132	Multi - Cushing Area 138 kV	R	Regional Reliability	6/1/2014	$10,600,000	$1,415,287	$828,176	$1,057,577	$1,415,287	$10,600,000	$12,954,802
11133	Multi - Cushing Area 138 kV	R	Regional Reliability	6/1/2014		$0	$0	$0	$0	$0	$0

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11134	Multi - Cushing Area 138 kV	R	Regional Reliability	3/1/2013		$0	$0	$0	$0	$0	$0
11151	Line - Twin Church - S. Sioux City 115 kV	R	Regional Reliability	9/27/2012	$29,030,640	$3,224,816	$3,224,816	$3,224,816	$3,224,816	$27,631,781	$27,454,076
11152	Line - Twin Church - S. Sioux City 115 kV	R	Regional Reliability	12/19/2012		$0	$0	$0	$0	$0	$0
11171	Line - Carthage - Rock Hill 69 kV Ckt 1 rebuild	R	Regional Reliability	6/1/2014	$11,830,128	$1,573,734	$920,894	$1,175,977	$1,573,734	$11,830,128	$14,405,137
11173	XFR - Eddy County 230/115 kV Transform-er Ckt 2	R	Regional Reliability	6/6/2013	$4,863,725	$606,494	$606,494	$606,494	$606,494	$4,745,098	$5,357,014
11177	Line - Randall - Amaril-lo S 230 kV Ckt 1	R	Regional Reliability	5/13/2013	$20,078,082	$2,503,685	$2,503,685	$2,503,685	$2,503,685	$19,588,373	$22,114,440
11182	Sub - Canadian River Substation	R	Regional Reliability	6/30/2013	$9,643,276	$1,256,144	$1,256,144	$1,256,144	$1,256,144	$9,408,074	$11,095,216
11183	Multi - Canadian River - McAlester City - Dustin 138 kV	R	Regional Reliability	5/16/2012	$4,096,000	$518,626	$518,626	$518,626	$518,626	$3,898,632	$4,415,256
11184	Multi - Canadian River - McAlester City - Dustin 138 kV	R	Regional Reliability	2/8/2013	$4,096,000	$531,591	$531,591	$531,591	$531,591	$3,996,098	$4,695,417
11195	Line - Holcomb - Fletcher 115 kV Ckt 1	R	Regional Reliability	12/31/2013	$4,091,866	$1,004,393	$1,004,393	$1,004,393	$1,004,393	$3,992,064	$8,871,561
11311	XFR - Colby 69/34.5 kV TrXFR - Colby 115/34.5 kV Transformer Ckt 4	R	Regional Reliability	5/1/2013	$1,097,586	$148,338	$148,338	$148,338	$148,338	$1,070,816	$1,310,230
11312	Line - MIDW Heizer - Mullergren 115kV	R	Regional Reliability	12/31/2012	$637,135	$84,008	$84,008	$84,008	$84,008	$606,434	$715,191
11316	Line - OXY Permian Sub - Sanger SW Station 115 kV Ckt 1 Reconductor	R	Regional Reliability	6/1/2012	$242,156	$29,460	$29,460	$29,460	$29,460	$230,488	$250,802
11319	Line - Wolford-Yuma 115 kV Ckt 1 Wave Trap	R	Regional Reliability	5/9/2013	$116,520	$14,530	$14,530	$14,530	$14,530	$113,678	$128,338
11321	Multi: Dallam - Chan-ning - Tascosa -Potter	R	Regional Reliability	5/29/2012	$19,180,552	$2,333,430	$2,333,430	$2,333,430	$2,333,430	$18,256,326	$19,865,366
11322	Multi: Dallam - Chan-ning - Tascosa -Potter	R	Regional Reliability	5/23/2012	$3,412,108	$415,103	$415,103	$415,103	$415,103	$3,247,694	$3,533,932
11323	Line - Heizer - Muller-gren 115kV	R	Regional Reliability	11/15/2012	$850,000	$189,102	$189,102	$189,102	$189,102	$809,042	$1,609,900
11331	Line - Diana - Perdue 138 kV Reconductor	R	Regional Reliability	12/31/2014	$18,805,489	$2,501,649	$0	$405,487	$2,501,649	$18,805,489	$22,898,793
11339	Line - Classen - South-west 5 Tap 138 kV	R	Regional Reliability	2/15/2014	$109,481	$14,618	$12,811	$14,618	$14,618	$109,481	$133,802

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11344	Multi - Craig - 87th - Stranger 345 kV Ckt 1	R	Regional Reliability	11/15/2012	$9,866,277	$1,329,311	$1,329,311	$1,329,311	$1,329,311	$9,390,864	$11,316,929
11345	Multi - Craig - 87th - Stranger 345 kV Ckt 1	R	Regional Reliability	11/15/2012	$15,119,789	$2,037,132	$2,037,132	$2,037,132	$2,037,132	$14,391,233	$17,342,872
11346	Multi - Craig - 87th - Stranger 345 kV Ckt 1	R	Regional Reliability	11/15/2012	$12,277,385	$1,654,167	$1,654,167	$1,654,167	$1,654,167	$11,685,792	$14,082,546
11355	XFR - Crosby Co. 115/69 kV Transformers Ckt 1 and Ckt 2	R	Regional Reliability	2/6/2015	$2,378,798	$311,647	$0	$18,836	$280,825	$2,438,268	$2,952,992
11359	Line - Hereford - Northeast Hereford 115 kV Ckt 1	R	Regional Reliability	2/11/2014	$4,139,406	$529,078	$469,484	$529,078	$529,078	$4,139,406	$4,842,900
11378	Multi - Cherry Sub add 230kV source and 115 kV Hastings Conversion	R	Regional Reliability	5/1/2014	$5,540,583	$708,169	$474,707	$589,492	$708,169	$5,540,583	$6,482,208
11383	Line - North Plainview line tap 115 kV	R	Regional Reliability	1/15/2015	$330,000	$43,233	$0	$5,226	$41,571	$338,250	$409,655
11384	Line - Kress Rural line tap 115 kV	R	Regional Reliability	12/9/2014	$400,000	$51,126	$3,090	$11,377	$51,126	$400,000	$467,980
11389	Multi - Hitchland - Texas Co. 230 kV and 115 kV	R	Regional Reliability	3/19/2013	$1,491,086	$185,935	$185,935	$185,935	$185,935	$1,454,718	$1,642,315
11411	Multi - Mulberry - Franklin - Sheffield 161 kV	R	Regional Reliability	7/25/2014	$6,949,300	$983,699	$429,693	$589,138	$983,699	$6,949,300	$9,004,267
11412	Multi - Mulberry - Franklin - Sheffield 161 kV	R	Regional Reliability	7/25/2014	$1,320,792	$186,963	$81,668	$111,972	$186,963	$1,320,792	$1,711,361
11413	Multi - Mulberry - Franklin - Sheffield 161 kV	R	Regional Reliability	6/4/2014	$8,063,989	$1,141,487	$658,550	$843,572	$1,141,487	$8,063,989	$10,448,579
11421	Line - Hooks - Lone Star Ordinance 69 kV Ckt 1	R	Regional Reliability	9/1/2013	$2,100,000	$272,544	$272,544	$272,544	$272,544	$2,048,780	$2,407,318
11424	Line - Alva - Freedom 69 kV Ckt 1	R	Regional Reliability	3/28/2014	$6,243,750	$1,138,860	$869,789	$1,054,384	$1,138,860	$6,243,750	$10,424,530
11438	Line - Canaday - Lexington 115Kv Ckt 1	R	Regional Reliability	4/1/2013	$513,981	$58,522	$58,522	$58,522	$58,522	$501,445	$516,911
11439	Line - OGE Alva - WFEC Alva 69 kV Ckt 1	R	Regional Reliability	11/20/2012	$363,184	$46,155	$46,155	$46,155	$46,155	$345,684	$392,934
11440	PRATT - ST JOHN 115 KV CKT 1	R	Regional Reliability	6/15/2014	$100,000	$23,374	$12,778	$16,567	$23,374	$100,000	$213,950
11444	Multi - Mulberry - Franklin - Sheffield 161 kV	R	Regional Reliability	7/28/2014	$5,348,455	$757,093	$324,469	$447,184	$757,093	$5,348,455	$6,930,039

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11498	Line - Loma Vista East - Winchester Junction North 161kV Ckt 1	R	Regional Reliability	1/14/2013	$176,118	$33,588	$33,588	$33,588	$33,588	$171,822	$296,672
11505	XFR - Spearman 115/69/13.2 Ckt 1 Upgrade	R	Regional Reliability	6/23/2013	$908,719	$113,315	$113,315	$113,315	$113,315	$886,555	$1,000,883
11507	XFR - Lubbock South 230/115/13.2 kV Ckt 2	R	Regional Reliability	2/3/2015	$4,063,897	$532,412	$0	$36,567	$484,144	$4,165,494	$5,044,840
50047	Device - Comanche	R	Regional Reliability	6/1/2012	$350,000	$60,764	$60,764	$60,764	$60,764	$333,135	$517,305
50073	Device - Quapaw Cap 69 kV	R	Regional Reliability	12/1/2012	$622,437	$94,773	$94,773	$94,773	$94,773	$592,444	$806,838
50080	Device - Tahlequah West 69 Cap kV	R	Regional Reliability	7/1/2012	$779,000	$208,559	$208,559	$208,559	$208,559	$741,463	$1,775,537
50092	Device - Jay Cap 69 kV	R	Regional Reliability	6/25/2012	$1,013,318	$271,291	$271,291	$271,291	$271,291	$964,490	$2,309,607
50093	Device - Bushland Interchange 230 kV Capacitor	R	Regional Reliability	12/19/2013	$1,865,510	$232,624	$232,624	$232,624	$232,624	$1,820,010	$2,054,714
50098	Device - Kolache 69 kV Capacitor	R	Regional Reliability	12/31/2013	$737,743	$96,099	$96,099	$96,099	$96,099	$719,749	$848,821
50104	Device - Plainville Cap 115 kV	R	Regional Reliability	3/27/2013	$1,169,968	$266,794	$266,794	$266,794	$266,794	$1,141,432	$2,356,526
50156	Line - Bann - Lone Star Ordinance 69 kV Ckt 1	R	Regional Reliability	6/1/2013	$6,600,000	$856,568	$856,568	$856,568	$856,568	$6,439,024	$7,565,857
50184	Device - Kinsley Capac-itor 115 kV	R	Regional Reliability	6/27/2012	$926,685	$122,186	$122,186	$122,186	$122,186	$882,032	$1,040,214
50186	Device - Electra 69 kV Capacitor	R	Regional Reliability	8/31/2012	$240,000	$41,667	$41,667	$41,667	$41,667	$228,435	$354,724
50197	Device-Pawnee 115 kV	R	Regional Reliability	1/31/2013	$712,979	$96,358	$96,358	$96,358	$96,358	$695,589	$851,110
50213	Device - Gordon 115 kV	R	Regional Reliability	6/1/2012	$673,574	$74,823	$74,823	$74,823	$74,823	$641,117	$636,994
50214	Device - Cozad 115 kV	R	Regional Reliability	4/1/2014	$518,350	$60,495	$45,537	$55,343	$60,495	$518,350	$553,739
50246	Device - Johnson Cor-ner 115 kV Capacitor	R	Regional Reliability	5/23/2012	$740,000	$177,211	$177,211	$177,211	$177,211	$704,343	$1,508,663
50247	Device - Johnson Corner 115 kV 2nd Capacitor	R	Regional Reliability	5/23/2012	$370,000	$88,605	$88,605	$88,605	$88,605	$352,171	$754,331
50248	Device - Kearney 115 kV	R	Regional Reliability	6/1/2012	$748,743	$83,173	$83,173	$83,173	$83,173	$712,664	$708,081
50249	Device - Holdrege 115 kV	R	Regional Reliability	6/1/2013	$496,486	$56,530	$56,530	$56,530	$56,530	$484,377	$499,316

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50319	XFR - Ogallala 230/115kV Replacement	R	Regional Reliability	6/1/2014	$4,384,489	$511,700	$299,429	$382,369	$511,700	$4,384,489	$4,683,831
50346	XFR - Paoli 138/69 kV	R	Regional Reliability	3/22/2013	$1,537,212	$200,239	$200,239	$200,239	$200,239	$1,499,719	$1,768,662
50347	Device - Little River Lake 69 kV	R	Regional Reliability	10/1/2012	$530,068	$67,363	$67,363	$67,363	$67,363	$504,527	$573,489
50363	Line - Easton Rec - Knox Lee 138 kV ckt 1	R	Regional Reliability	10/16/2012	$150,000	$18,993	$18,993	$18,993	$18,993	$142,772	$161,692
50364	Line - Easton Rec - Pirkey 138 kV ckt 1	R	Regional Reliability	11/10/2012	$500,000	$63,309	$63,309	$63,309	$63,309	$475,907	$538,972
50365	Line - Pirkey - Whitney 115 kV ckt 1	R	Regional Reliability	2/10/2013	$900,000	$116,805	$116,805	$116,805	$116,805	$878,049	$1,031,708
50397	Line - Cowskin - Centennial 138 kV rebuild	R	Regional Reliability	5/19/2013	$2,038,528	$281,523	$281,523	$281,523	$281,523	$1,988,808	$2,486,625
50398	XFR - Auburn Road 230/115 kV Transformer Ckt 1	R	Regional Reliability	5/28/2014	$32,936,593	$4,662,296	$2,779,446	$3,535,147	$4,662,296	$32,936,593	$42,676,223
50402	Sub - Move lines from Lea Co 230/115 kV sub to Hobbs Interchange 230/115 kV	R	Regional Reliability	5/16/2014	$11,628,992	$1,486,358	$935,099	$1,176,019	$1,486,358	$11,628,992	$13,605,345
50403	Line - Folsom & Pleasant Hill - Sheldon 115 kV Ckt 2	R	Regional Reliability	8/12/2013	$5,197,561	$550,645	$550,645	$550,645	$550,645	$5,070,791	$4,863,710
50405	Device - Coweta 69 kV Capacitor	R	Regional Reliability	6/1/2014	$1,428,440	$190,022	$111,194	$141,994	$190,022	$1,428,440	$1,739,363
50408	Device - Lula 69 kV	R	Regional Reliability	9/23/2013	$737,743	$96,099	$96,099	$96,099	$96,099	$719,749	$848,821
50411	Multi - Ellsworth - Bushton - Rice 115 kV	R	Regional Reliability	9/28/2012	$575,964	$75,942	$75,942	$75,942	$75,942	$548,211	$646,526
50438	Sub - Cornville 138 kV	R	Regional Reliability	12/31/2014	$21,664,838	$2,882,022	$0	$467,141	$2,882,022	$21,664,838	$26,380,523
50448	Multi - Ellsworth - Bushton - Rice 115 kV	R	Regional Reliability	7/10/2012	$2,604,440	$343,402	$343,402	$343,402	$343,402	$2,478,943	$2,923,513
50450	Multi - Kress Interchange - Kiser - Cox 115 kV	R	Regional Reliability	11/21/2014	$6,780,000	$866,585	$95,229	$235,692	$866,585	$6,780,000	$7,932,264
50504	XFR - Howard 115/69 kV Transformers	R	Regional Reliability	12/31/2014	$1,516,548	$193,837	$0	$31,419	$193,837	$1,516,548	$1,774,286
50505	Device - Kingsmill 115 kV Capacitors	R	Regional Reliability	11/14/2014	$937,420	$119,816	$15,471	$34,892	$119,816	$937,420	$1,096,735

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50506	XFR - Grapevine 230/115 kV Transformer Ckt 1	R	Regional Reliability	3/21/2014	$2,505,545	$320,246	$250,742	$302,650	$320,246	$2,505,545	$2,931,364
50507	Device - Howard 115 kV Capacitors	R	Regional Reliability	5/29/2014	$1,256,000	$160,535	$95,263	$121,284	$160,535	$1,256,000	$1,469,458
50512	Device - St. Joe 161 kV	R	Regional Reliability	9/27/2013	$300,109	$37,912	$37,912	$37,912	$37,912	$292,789	$334,868
50519	Line - Pheasant Run - Seguin 115 kV Ckt 1	R	Regional Reliability	7/15/2014	$7,811,905	$1,082,165	$502,434	$677,840	$1,082,165	$7,811,905	$9,905,575
50521	Device - Red Bluff 115 kV Capacitor	R	Regional Reliability	6/20/2013	$1,999,300	$249,308	$249,308	$249,308	$249,308	$1,950,537	$2,202,073
50526	Line - El Paso - Farber 138 kV Ckt 1	R	Regional Reliability	4/8/2014	$3,917,751	$554,572	$406,788	$496,677	$554,572	$3,917,751	$5,076,263
50529	Line - Arcadia - Redbud 345 kV	R	Regional Reliability	11/17/2013	$983,369	$128,095	$128,095	$128,095	$128,095	$959,384	$1,131,430
50531	Line - New Gladewater - Perdue 138 kV	R	Regional Reliability	12/31/2014	$1,000,000	$133,028	$0	$21,562	$133,028	$1,000,000	$1,217,665
50547	Line - Oxy Permian - Sanger Switching Station 115 kV Ckt 1	R	Regional Reliability	5/4/2012	$299,150	$36,393	$36,393	$36,393	$36,393	$284,735	$309,831
50561	XFR - Potash Junction 115/69 kV Ckt 2	R	Regional Reliability	7/24/2014	$2,289,368	$292,615	$128,622	$176,051	$292,615	$2,289,368	$2,678,447
50575	Sub - Sub 1366 161 kV	R	Regional Reliability	5/20/2013	$11,179,602	$1,151,838	$1,151,838	$1,151,838	$1,151,838	$10,906,929	$10,173,908
50586	Multi - Renfrow 345/138 kV substation and Renfrow - Grant 138 kV line	R	Regional Reliability	3/15/2014	$3,079,700	$411,194	$328,730	$395,379	$411,194	$3,079,700	$3,763,859
50587	Multi - Renfrow 345/138 kV substation and Renfrow - Grant 138 kV line	R	Regional Reliability	3/15/2014	$11,659,600	$1,556,763	$1,244,555	$1,496,887	$1,556,763	$11,659,600	$14,249,793
50588	Multi - Renfrow 345/138 kV substation and Renfrow - Grant 138 kV line	R	Regional Reliability	9/15/2014	$4,998,388	$667,373	$196,178	$304,351	$667,373	$4,998,388	$6,108,785
50589	Multi - Renfrow 345/138 kV substation and Renfrow - Grant 138 kV line	R	Regional Reliability	5/1/2014	$1,173,170	$156,639	$105,000	$130,389	$156,639	$1,173,170	$1,433,791
50590	Multi - Renfrow 345/138 kV substation and Renfrow - Grant 138 kV line	R	Regional Reliability	10/1/2014	$4,540,425	$606,227	$151,557	$249,819	$606,227	$4,540,425	$5,549,086
50591	XFR - Howard 115/69 kV Transformers	R	Regional Reliability	9/13/2013	$3,300,000	$411,501	$411,501	$411,501	$411,501	$3,219,512	$3,634,692

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
50592	Multi - Renfrow 345/138 kV substation and Renfrow - Grant 138 kV line	R	Regional Reliability	9/1/2014	$587,690	$78,467	$26,084	$38,802	$78,467	$587,690	$718,246
50594	Multi - Cushing Area 138 kV	R	Regional Reliability	3/1/2013		$0	$0	$0	$0	$0	$0
50595	Multi - Renfrow - Wakita - Noel Switch 138 kV	R	Regional Reliability	1/28/2013	$17,928,848	$3,190,460	$3,190,460	$3,190,460	$3,190,460	$17,491,559	$28,180,560
50596	Multi - Renfrow - Wakita - Noel Switch 138 kV	R	Regional Reliability	6/30/2013	$7,220,000	$1,284,808	$1,284,808	$1,284,808	$1,284,808	$7,043,902	$11,348,395
50597	Multi - Renfrow - Wakita - Noel Switch 138 kV	R	Regional Reliability	6/24/2013	$3,573,553	$635,918	$635,918	$635,918	$635,918	$3,486,393	$5,616,910
50610	Line - Buffalo - Buffalo Bear - Ft. Supply 69 kV	R	Regional Reliability	12/19/2014	$1,500,000	$273,600	$9,020	$53,367	$273,600	$1,500,000	$2,504,392
50611	Line - Buffalo - Buffalo Bear - Ft. Supply 69 kV	R	Regional Reliability	12/19/2014	$6,000,000	$1,094,400	$36,079	$213,468	$1,094,400	$6,000,000	$10,017,567
50619	Multi - Renfrow - Wakita - Noel Switch 138 kV	R	Regional Reliability	4/30/2014	$2,000,000	$364,800	$245,538	$304,668	$364,800	$2,000,000	$3,339,189
50622	Multi - Renfrow - Medford Tap - Chikaskia 138 kV	R	Regional Reliability	1/1/2015	$2,056,746	$281,477	$0	$44,851	$281,477	$2,108,165	$2,667,121
50627	Multi - Renfrow - Medford Tap - Chikaskia 138 kV	R	Regional Reliability	1/1/2015	$5,256,327	$719,358	$0	$114,623	$719,358	$5,387,735	$6,816,234
50629	Multi - Renfrow - Medford Tap - Chikaskia 138 kV	R	Regional Reliability	1/1/2015	$3,041,661	$416,268	$0	$66,328	$416,268	$3,117,703	$3,944,327
50630	Multi - Renfrow - Medford Tap - Chikaskia 138 kV	R	Regional Reliability	5/1/2014	$185,400	$24,754	$16,593	$20,606	$24,754	$185,400	$226,587
50634	Line - Hays Plant - Vine Street 115 kV Ckt 1	R	Regional Reliability	10/1/2014	$15,720	$2,178	$544	$897	$2,178	$15,720	$19,933
50704	Line - Maxwell - North Platt 115 kV Ckt 1	R	Regional Reliability	1/1/2014	$25,767	$3,007	$3,007	$3,007	$3,007	$25,767	$27,526
50741	XFR - Harrisonville 161/69 kV Ckt 2	R	Regional Reliability	2/10/2014	$2,773,480	$359,126	$319,662	$359,126	$359,126	$2,773,480	$3,287,254
50762	XFR - Harrisonville 161/69 kV Ckt 2	R	Regional Reliability	4/14/2014	$1,005,220	$130,162	$93,330	$114,428	$130,162	$1,005,220	$1,191,432
10374	Line - Valliant Substation - Install 345 kV terminal equipment	R	Transmission Service	4/17/2012	$3,840,000	$486,212	$486,212	$486,212	$486,212	$3,654,967	$4,139,303

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
10405	Line - Valliant - Hugo 345 kV	R	Transmission Service	6/8/2012	$23,189,835	$5,159,122	$5,159,122	$5,159,122	$5,159,122	$22,072,419	$43,921,554
10406	XFR - Hugo 345/138 kV	R	Transmission Service	6/30/2012	$6,328,605	$1,407,946	$1,407,946	$1,407,946	$1,407,946	$6,023,657	$11,986,380
10410	Line - South Hays - Hays Plant - Vine St. 115 kV Ckt 1 #2	R	Transmission Service	6/1/2012	$35,000	$4,615	$4,615	$4,615	$4,615	$33,314	$39,288
10456	Multi - McNab REC - Turk 115 kV	R	Transmission Service	6/30/2012	$7,310,000	$925,575	$925,575	$925,575	$925,575	$6,957,763	$7,879,766
10467	XFR - Anadarko 138/69 kV	R	Transmission Service	12/4/2012	$2,000,000	$347,222	$347,222	$347,222	$347,222	$1,903,629	$2,956,031
10487	Line - Creswell - Oak 69 kV Ckt 1	R	Transmission Service	11/8/2013	$150,000	$20,715	$20,715	$20,715	$20,715	$146,341	$182,972
10488	XFR - Rose Hill 345/138 kV Ckt 3	R	Transmission Service	5/30/2013	$7,395,975	$1,021,393	$1,021,393	$1,021,393	$1,021,393	$7,215,585	$9,021,712
10876	XFR - 3rd Arcadia 345/138 kV	R	Transmission Service	6/1/2012	$10,550,000	$1,340,737	$1,340,737	$1,340,737	$1,340,737	$10,041,642	$11,414,197
10994	XFR - Medicine Lodge 138/115 kV	R	Transmission Service	2/1/2013	$10,619,760	$2,421,680	$2,421,680	$2,421,680	$2,421,680	$10,360,741	$21,390,109
11200	Line - Clifton - Greenleaf 115 kV	R	Transmission Service	1/31/2013	$5,114,563	$1,166,301	$1,166,301	$1,166,301	$1,166,301	$4,989,818	$10,301,651
11201	Line - Flatridge - Medicine Lodge 138 kV	R	Transmission Service	1/20/2014	$4,631,255	$1,082,492	$1,025,988	$1,082,492	$1,082,492	$4,631,255	$9,908,565
11202	Line - Flatridge - Harper 138 kV	R	Transmission Service	6/20/2013	$11,008,945	$2,510,428	$2,510,428	$2,510,428	$2,510,428	$10,740,434	$22,173,998
11203	Line - Medicine Lodge - Pratt 115 kV	R	Transmission Service	5/16/2014	$13,645,827	$3,189,523	$2,006,596	$2,523,579	$3,189,523	$13,645,827	$29,195,231
11204	Line - Macarthur - Oatville 69 kV Ckt 1	R	Transmission Service	3/12/2012	$0	$0	$0	$0	$0	$0	$0
11262	Line - Arcadia - OMPA Edmond Garber 138 kV Ckt 1	R	Transmission Service	6/18/2012	$30,000	$3,813	$3,813	$3,813	$3,813	$28,554	$32,457
11314	Line - Jones Station Bus#2 - Lubbock South Interchange 230 kV CKT 2 terminal upgrade	R	Transmission Service	1/13/2015	$190,000	$24,892	$0	$3,146	$24,071	$194,750	$235,862
11342	Line - Greenleaf - Knob Hill 115kV Ckt 1	R	Transmission Service	1/31/2013	$4,462,093	$1,017,515	$1,017,515	$1,017,515	$1,017,515	$4,353,261	$8,987,459
11347	Line - Southwest Shreveport - Springridge REC 138 kV	R	Transmission Service	6/1/2013	$7,200,000	$934,438	$934,438	$934,438	$934,438	$7,024,390	$8,253,662
11348	Line - Eastex - Whitney 138 kV Accelerated	R	Transmission Service	6/1/2013	$2,800,000	$363,393	$363,393	$363,393	$363,393	$2,731,707	$3,209,758

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
11350	ALTUS SW - NAVAJO 69KV CKT 1	R	Transmission Service	6/1/2013	$150,000	$26,693	$26,693	$26,693	$26,693	$146,341	$235,770
11351	G03-05T - PARADISE 138KV CKT 1	R	Transmission Service	12/4/2012	$150,000	$26,042	$26,042	$26,042	$26,042	$142,772	$221,702
50148	Line - Turk - NW Texarkana 345 kV	R	Transmission Service	8/28/2012	$44,200,000	$5,596,498	$5,596,498	$5,596,498	$5,596,498	$42,070,196	$47,645,097
50149	Line - Turk - NW Texarkana 345 kV	R	Transmission Service	8/28/2012		$0	$0	$0	$0	$0	$0
50150	Line - Turk - NW Texarkana 345 kV	R	Transmission Service	8/28/2012		$0	$0	$0	$0	$0	$0
50160	Line - Linwood - Powell Street 138 kV	R	Transmission Service	6/1/2012	$456,000	$57,738	$57,738	$57,738	$57,738	$434,027	$491,542
50164	Line - SE Texarkana - Texarkana Plant 69 kV	R	Transmission Service	3/1/2012	$128,000	$16,207	$16,207	$16,207	$16,207	$121,832	$137,977
50165	Line - South Texarkana REC - Texarkana Plant 69 kV	R	Transmission Service	5/30/2012	$8,193,000	$1,037,378	$1,037,378	$1,037,378	$1,037,378	$7,798,215	$8,831,590
50169	Multi - Hugo - Sunnyside 345 kV (OGE)	R	Transmission Service	4/1/2012	$156,900,000	$19,939,486	$19,939,486	$19,939,486	$19,939,486	$149,339,679	$169,752,366
50171	Multi - Hugo - Sunnyside 345 kV (OGE)	R	Transmission Service	4/1/2012		$0	$0	$0	$0	$0	$0
50172	Line - VBI - VBI North 69 kV	R	Transmission Service	6/1/2014	$100,000	$13,352	$7,813	$9,977	$13,352	$100,000	$122,215
50173	Line - Hugo - Sunnyside 345 kV	R	Transmission Service	6/8/2012	$6,775,042	$1,507,267	$1,507,267	$1,507,267	$1,507,267	$6,448,583	$12,831,932
50228	Multi - Green - Coffey County No. 3 - Burlington Junction - Wolf Creek 69 kV	R	Transmission Service	12/18/2012	$4,380,845	$590,244	$590,244	$590,244	$590,244	$4,169,751	$5,024,967
50229	Device - Allen 69 kV Capacitor	R	Transmission Service	5/31/2012	$1,405,967	$189,430	$189,430	$189,430	$189,430	$1,338,220	$1,612,688
50231	Device - Athens 69 kV Capacitor	R	Transmission Service	10/14/2013	$700,000	$96,671	$96,671	$96,671	$96,671	$682,927	$853,870
50233	Multi - Green - Coffey County No. 3 - Burlington Junction - Wolf Creek 69 kV	R	Transmission Service	6/23/2014	$3,027,106	$428,498	$224,844	$294,298	$428,498	$3,027,106	$3,922,247
50234	Multi - Green - Coffey County No. 3 - Burlington Junction - Wolf Creek 69 kV	R	Transmission Service	10/1/2013	$3,535,570	$488,266	$488,266	$488,266	$488,266	$3,449,337	$4,312,737
50236	Multi - Green - Coffey County No. 3 - Burlington Junction - Wolf Creek 69 kV	R	Transmission Service	7/16/2014	$6,726,750	$952,196	$439,475	$593,815	$952,196	$6,726,750	$8,715,907

UPGRADE ID	PROJECT NAME	REL/ ECO	TYPE	IN-SERVICE DATE	BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015	INFLATED COST	40-YEAR NPV
50240	Multi - Green - Coffey County No. 3 - Burlington Junction - Wolf Creek 69 kV	R	Transmission Service	3/29/2012	$1,693,501	$228,170	$228,170	$228,170	$228,170	$1,611,899	$1,942,499
50284	Device - Dearing 138 kV Capacitor	R	Transmission Service	6/30/2013	$581,038	$80,242	$80,242	$80,242	$80,242	$566,866	$708,758
50327	Line - East Manhattan - NW Manhattan 230 kV Ckt 1	R	Transmission Service	3/19/2012	$199,416	$26,868	$26,868	$26,868	$26,868	$189,807	$228,736
50329	Line - Stillwell - West Gardner 345 kV Ckt 1	R	Transmission Service	2/1/2013	$457,827	$87,313	$87,313	$87,313	$87,313	$446,661	$771,214
50375	XFR - Diana 345/138 kV ckt 3	R	Transmission Service	6/1/2013	$5,500,000	$713,807	$713,807	$713,807	$713,807	$5,365,854	$6,304,881
50498	Line - Greenleaf - Knob Hill 115 kV CKT 1 WR	R	Transmission Service	3/1/2013	$329,538	$45,510	$45,510	$45,510	$45,510	$321,500	$401,975
50368	Sub - Chapman Junction 115 kV	R	Zonal Reliability	12/7/2012	$5,425,273	$730,962	$730,962	$730,962	$730,962	$5,163,853	$6,222,958
50369	Sub - Clay Center Junction 115 kV	R	Zonal Reliability	12/7/2012	$2,849,367	$383,903	$383,903	$383,903	$383,903	$2,712,069	$3,268,313
50370	Device - Chapman Junction 115 kV Capacitor	R	Zonal Reliability	11/6/2012	$406,402	$54,756	$54,756	$54,756	$54,756	$386,819	$466,156
50371	Line - Clay Center Junction - Clay Center Switching Station 115 kV	R	Zonal Reliability	12/7/2012	$7,476,811	$1,007,372	$1,007,372	$1,007,372	$1,007,372	$7,116,536	$8,576,137
50373	Sub - Clay Center Switching Station 115 kV	R	Zonal Reliability	12/7/2012	$2,774,851	$373,864	$373,864	$373,864	$373,864	$2,641,143	$3,182,841
50383	Device - Northwest Manhattan 115 kV Capacitor	R	Zonal Reliability	10/10/2012	$957,660	$129,028	$129,028	$129,028	$129,028	$911,515	$1,098,466

REL/ ECO	TYPE		BEST COST	1-YEAR COST	PRORATED COST 2014	3/1/14 - 2/28/15	PRORATED COST 2015		40-YEAR NPV
	Total		**$3,411,660,964**						
E	Economic Total		$1,590,690,489		$129,053,708	$161,750,083	$269,969,225		$2,434,836,003
X	GI Total		$175,636,492	1-Year Cost	$22,087,743	$23,187,672	$27,275,612		$238,205,412
R	Reliability Total		$1,645,333,984	$231,421,630	$187,345,196	$199,875,039	$231,340,056		$2,041,188,617

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Regional Cost Allocation Review

October 8, 2013

SPP Regional Cost Allocation Review Report

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EXECUTIVE SUMMARY

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

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

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

Applying these principles the RCAR Report shows:

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

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

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

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

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

BACKGROUND

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

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

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

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

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

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

SECTION 1: OVERVIEW OF THE RARTF AND RCAR REVIEW

1.1 Overview of SPP Tariff Requirements to Perform the RCAR Review

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

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

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

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

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

1.2 Overview of RARTF Charter

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

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

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

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

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

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

1.3 Overview of Legal Standards

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

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

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

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

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

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

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

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

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

1.3.1 Legal Rulings Subsequent to the Overview of Legal Standards

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

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

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

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

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

1.4 Cost Allocation Challenges for Transmission Upgrades

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

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

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

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

2.1 Highway/Byway Summarized

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

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

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

Figure 2.1
Highway/Byway Cost Allocation Overview

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

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

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

SECTION 3: RECOMMENDED REVIEW METHODOLOGY

3.1 Principles that Guided How SPP Staff Conducted the RCAR Review

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

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

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

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

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

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

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

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

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

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

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

3.2 Regional Cost Allocation Review Methodologies

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

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

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

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

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

3.3 RARTF Recognition of Weighting Given to Projects without NTCs.

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

3.4 RARTF Recommended Baseline for the Regional Cost Allocation Review

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

3.5 RARTF Recommended Calculation of Benefits to Cost Ratios

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

3.6 RARTF Recommends Use of a 40-Year Project Evaluation

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

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

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

3.7 RARTF Recommendation on the Calculation of Costs

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

3.8 RARTF Recommendation on Benefits to be Calculated

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

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

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

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

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

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

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

- Benefits of avoided projects which are no longer needed due to additional transmission development.
- From major generation centers within SPP to key delivery points on the boundary of SPP. This category relates to export capability improvements.
- From key external receipt points at the boundary of SPP to load centers within SPP. This category relates to import capability improvements.
- From key external receipt points at the boundary of SPP to key delivery points on the boundary of SPP. This category relates to improvements in the ability of SPP to accommodate wheel-through transactions.
- Reliability projects provide more value than just reliability; reliability projects can provide measurable economic benefit. The ESWG will continue to develop this portion of the reliability metric in early 2012.

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

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

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

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

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

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

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

3.9 RARTF Recommendation on Assumptions to be Used

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

SECTION 4: REPORT THRESHOLDS

4.1 RARTF Recommended a Remedy Threshold

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

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

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

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

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

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

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

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

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

SECTION 5: POTENTIAL REMEDIES TO BE STUDIED

5.1 RARTF Recommended Zonal Remedies

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

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

Figure 5.1
Potential Remedies

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

SECTION 6: STAKEHOLDER DEVELOPMENT OF MONITIZED BENEFITS

6.1 Formation of the Metrics Task Force

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

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

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

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

MTF Members	
Kip Fox	American Electric Power
Roy Boyer	Xcel Energy Services, Inc.
Mike Collins	Oklahoma Gas and Electric Company
Paul Dietz	Westar Energy, Inc.
Tom Hestermann	Sunflower Electric Power Corporation
Greg Sweet	The Empire District Electric Company
Mitchell Williams	Western Farmers Electric Cooperative

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

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

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

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

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

6.2 Metrics Task Force Development of Benefit Metrics

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

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

> The MTF approached its task as a brainstorming effort followed by refining the most promising alternatives. Members contributed ideas based on existing metrics from MISO, PJM, NYISO, ERCOT, member companies, and industry experience, as well as new ideas provided by the Brattle Group consultants. During the month of March 2012, the MTF identified 28 different ideas for metrics to be evaluated. After review and debate by the MTF, the list was narrowed down to approximately 13 metrics that would be reviewed, analyzed and further developed in order to provide a meaningful update to the ESWG and MOPC in July of 2012. Metrics that did not make it past the brainstorming phase were eliminated for one or more of the following reasons: the idea was not sufficiently developed to proceed further; there were no tangible dollars associated with the metric; the metric would be difficult, if not impossible, to calculate with current tools; or the metric was essentially a duplicate of an existing metric.
>
> At the conclusion of the effort the MTF identified five (5) metrics that are currently used by SPP in the ITP process, eight (8) new metrics that the MTF recommends be calculated as part of the Regional Cost Allocation Review, and nine (9) other metrics that received significant consideration but have not yet gained enough consensus amongst the MTF or cannot currently be monetized for inclusion in the Regional Cost Allocation Review.

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

> The most important aspect of the metrics to be developed is that the metrics should be able to provide "hard dollar" impacts of transmission to rate payers. In terms of this report, "hard dollar" means that each recommended metric must be able to provide incontrovertible evidence that a benefit will result in lowering of the overall cost to a rate payer. As part of this test, the MTF reviewed the metrics through the open SPP stakeholder meetings, transmission summits, and public postings, provided progress updates to the Cost Allocation Working Group (CAWG) to gather their feedback on the acceptability of the metrics being proposed, and sought feedback from the Chair and Vice-Chair of the original RARTF to reasonably assure that the MTF was addressing the metrics the RARTF recommended in the RARTF Report.
>
> Due to the short amount of time before the Regional Cost Allocation Review will commence, the MTF concentrated on those metrics that could be reasonably implemented for the first Regional Cost Allocation Review. Section 9 of this report identifies additional metrics the Regional Cost Allocation Review team may want to consider especially after the Integrated Marketplace goes live in March of 2014 or in the second Regional Cost Allocation Review.

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

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

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

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

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

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

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

SECTION 7: RESULTS OF THE RCAR

7.1 Summary of Benefits and Costs

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

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

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

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

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

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

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

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

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

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

7.2 Transmission Projects Evaluated in this RCAR Report

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

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

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

7.3 RARTF Guidance Provided to SPP Staff While Conducting the Review

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

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

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

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

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

7.4 Cost Calculations Contained in the RCAR Report

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

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

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

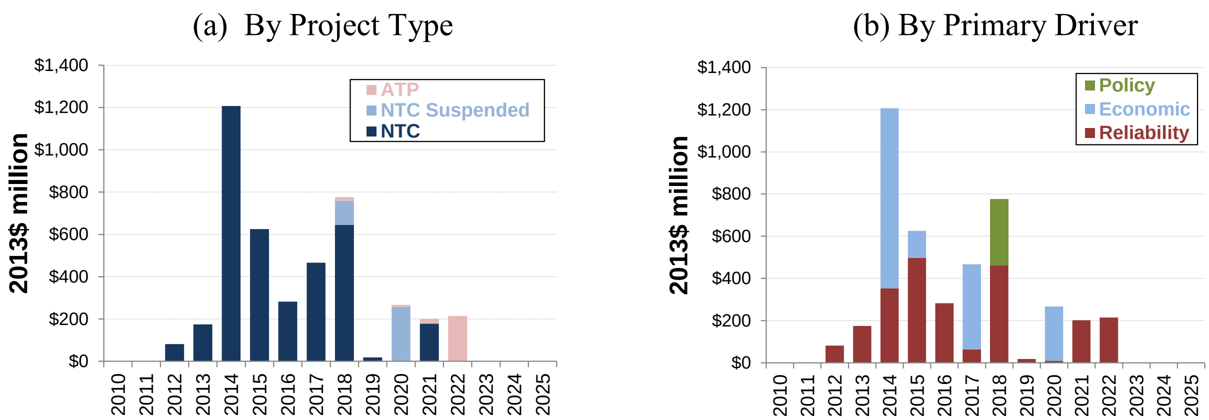
In accord with Principle 3 from the RARTF Report and the direction of the RARTF at its September 12, 2013 meeting, SPP staff used the most recent cost estimates that were provided to SPP in August 2013 for project cost tracking. By using this information, the RCAR Report is using "the most up to date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

7.4.1 Classification of Projects

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

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

Figure 7.3
Summary of Capital Cost by In-Service Year



7.4.2 Calculation of Annual Transmission Revenue Requirements (ATRRs)

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

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

– 100% regional if 300 kV or above,

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

– 100% zonal if below 100 kV.

- **Load ratio share (LRS)** used for the portion of costs allocated on a regional basis

  – Used actual 12-coincident peak loads for 2012, as provided by SPP

- **Net plant carrying charge (NPCC)** applied at the zonal level to calculate first year ATRRs in 2013 dollars

- **2.5%/yr inflation** applied to estimate first year ATRRs in nominal dollars

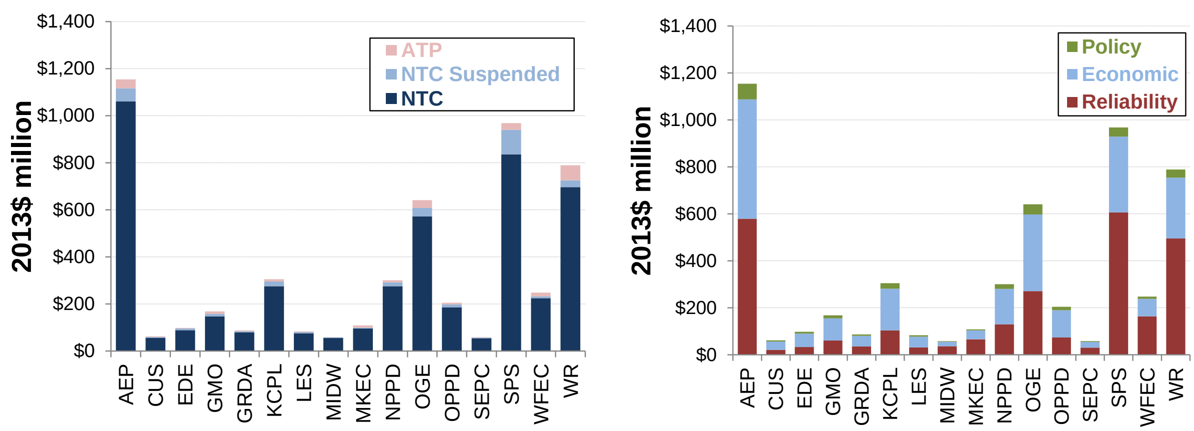
- **2.5%/yr straight-line depreciation** applied in calculating declining ATRR profile over time in nominal dollars

- Present values calculated for 40-year depreciated ATRRs for 2013-2052 at a nominal **discount rate of 8.0%**

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

Figure 7.4
40-Year Present Value of ATRRs by Zone

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



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

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

Step 1: Estimate PTP Volumes

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

Figure 7.5

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

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

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

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

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

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

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

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

Step 3: Estimate Annual RCAR PTP $

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

Step 4: Allocate Total PTP $ to Each Pricing Zone

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

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

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

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

7.5 Benefit Metrics

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

Figure 7.6
Benefit Metrics Considered in RCAR

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

7.5.1 Adjusted Production Cost (APC) Savings

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

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

Figure 7.7
Case Definitions in PROMOD

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

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

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

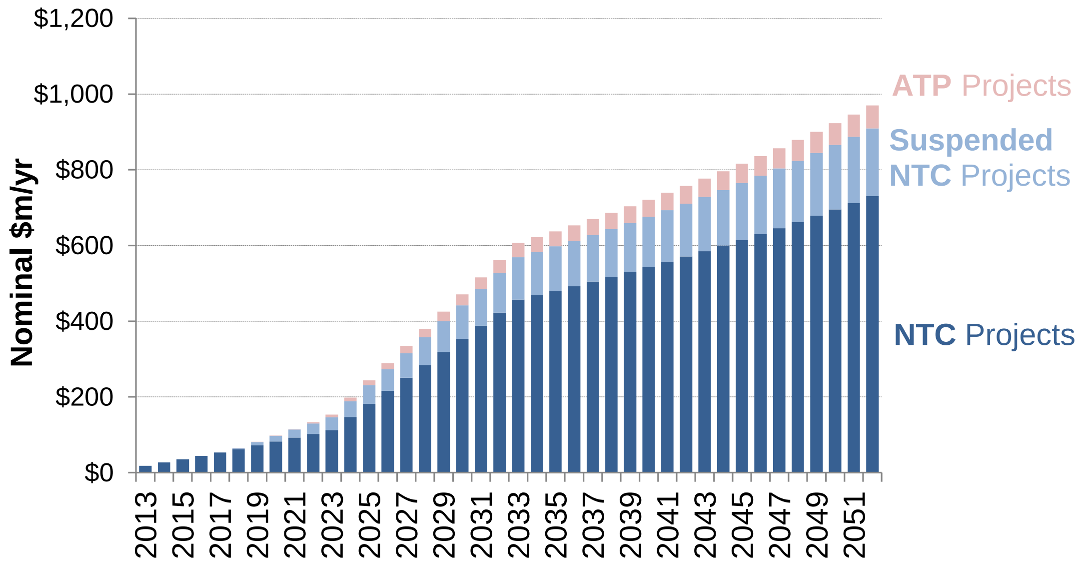
As shown in Figure 7.8, the estimated APC savings increase over time. These increases are driven by load growth and increases in fuel prices. Figure 7.9 shows the estimated APC savings for the 40-year study period, applying a 75% of weight for both suspended NTCs and ATP projects. The annual estimates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

Figure 7.8
Summary of APC Savings by Zone

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

Figure 7.9
Estimated APC Savings for the 2013-2052 Period

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



7.5.2 Avoided or Delayed Reliability Projects

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

Figure 7.10
List of Powerflow Cases Analyzed

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

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

Figure 7.11
List of Selected NTC Projects

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

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

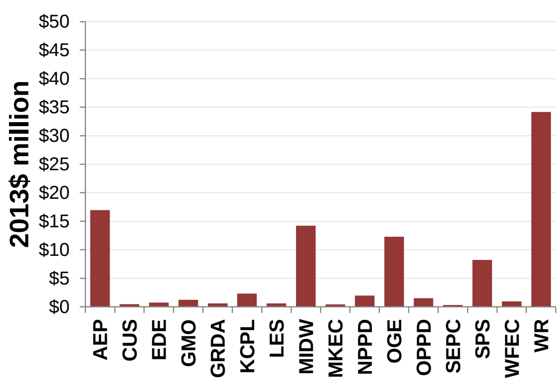
Figure 7.12
List of Avoided Reliability Projects

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

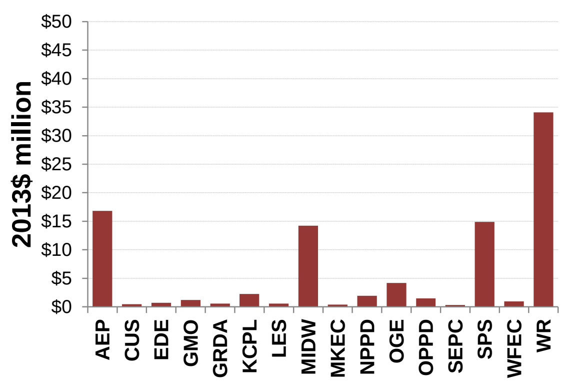
Figure 7.13 below summarizes the benefits of avoided reliability projects by zone. At the regional level, the 40-year present value of benefits for avoided reliability projects adds up to **$97 million** (in 2013 dollars), with no estimated benefits from suspended NTC projects. The system-wide benefits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

Figure 7.13
Benefits of Avoided or Delayed Reliability Projects

(a) NTC



(b) NTC + 75% of ATP



7.5.3 Capacity Savings due to Reduced On-Peak Transmission Losses

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

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

Figure 7.14
Change in On-Peak Transmission Losses by Zone

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

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

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

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

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

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

7.5.4 Mitigation of Transmission Outage Costs

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

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

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

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

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

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

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

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

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

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

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

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

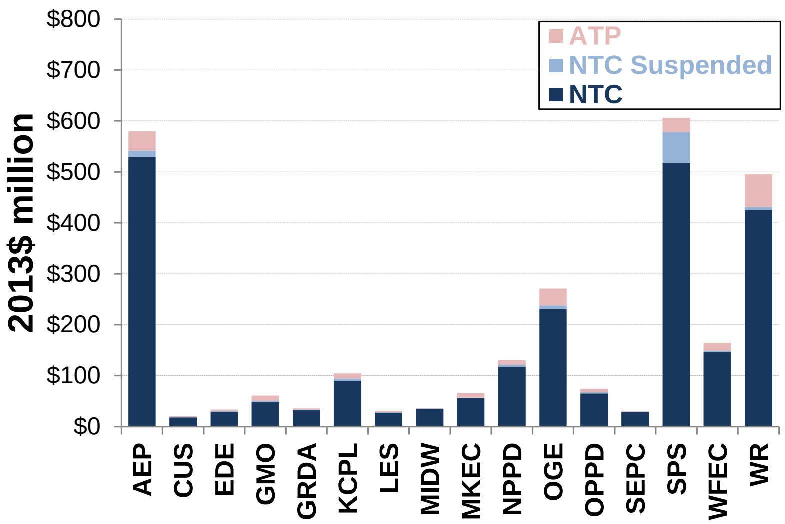
43 See previous footnote.

7.5.5 Benefits of Mandated Reliability Projects

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

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

Figure 7.17
UPDATED Benefits of Mandated Reliability Projects by Zone



7.5.6 Benefits of Meeting Public Policy Goals

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

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

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

- Only the wind plants that were in-service as of June 19, 2010 are considered "existing" resources for the purpose of this calculation. Plant-specific capacity factors are used to calculate the annual generation from each resource, which is then aggregated to zonal level based on the ownership data provided by SPP.
- Total renewable energy goals are calculated as the sum of the Renewable Mandates and Targets as reported in SPP survey data.[44]
- The amount of "over-compliance" in some of the SPP zones (e.g., SWPS) is not counted towards the compliance of others.

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

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

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

Figure 7.18
Public Policy Benefits to Meet Renewable Goals

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

7.6 High Gas Price Sensitivity

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

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

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

SECTION 8: RECOMMENDATION ON REMEDIES

8.1 Overview of RARTF Report on Remedies

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

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

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

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

8.2 RCAR Report on Remedies

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

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

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

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

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

SECTION 9: GUIDANCE FOR FUTURE RCAR ASSESSMENTS

9.1 Overview of RCAR Lessons Learned

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

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

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

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

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

ADDENDUM 1

High Gas Price Sensitivity

Estimated Present Value of Benefit Metrics and Costs by Zone

(a) NTC Projects + 75% of Suspended NTCs

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

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

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

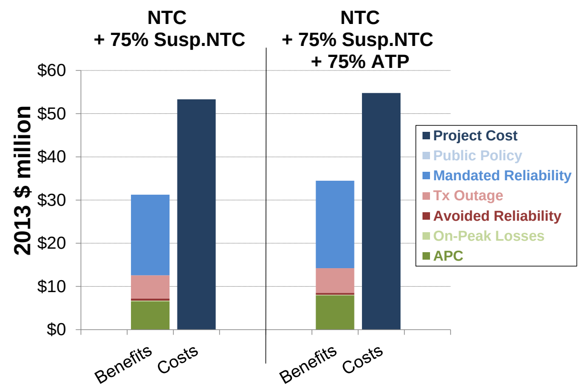
Appendix 1 – Stakeholder Comment and Resolutions for RCAR Models and Draft Report

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

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

City Utilities of Springfield (CUS)

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



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

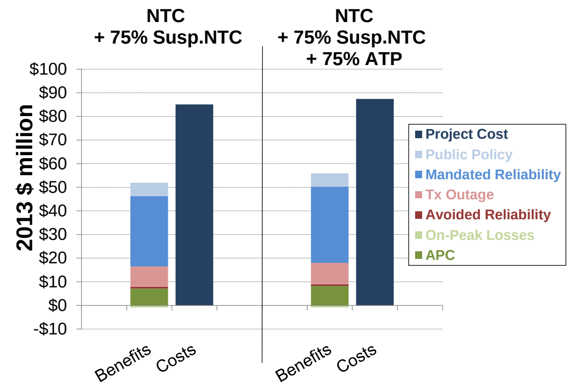
- Overall, the low B/C ratio in CUS is primarily driven by the limited APC savings.
  - The cost of economic projects is $35 million in CUS, accounting for approximately 60% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $7-8 million due to relatively lower congestion-relief provided in the CUS zone.
  - The benefit related to mitigation of transmission outage costs is estimated to be $5-6 million, reducing CUS' gap to reach a B/C ratio of 0.8 (but it is not large enough to fully eliminate the gap).

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

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

Empire District Electric (EDE)

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



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

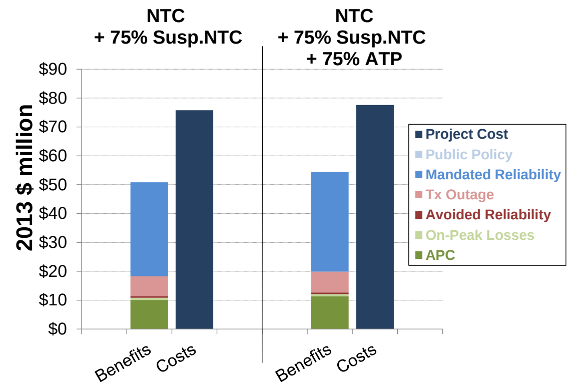
- Overall, the low B/C ratio in EDE is primarily driven by the limited APC savings.
  - The cost of economic projects is $56 million in EDE, accounting for approximately 60% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $7-8 million due to relatively lower congestion-relief provided in the EDE zone.
  - The benefit related to mitigation of transmission outage costs is estimated to be $9 million, reducing EDE's gap to reach a B/C ratio of 0.8 (but it is not large enough to fully eliminate the gap).

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

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

Grand River Dam Authority (GRDA)

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



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

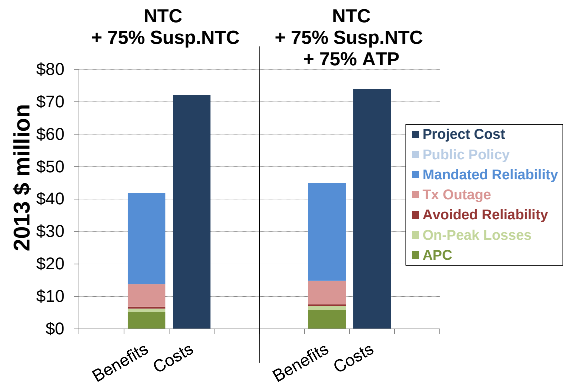
- Overall, the low B/C ratio in GRDA is primarily driven by the limited APC savings.
  - The cost of economic projects is $44 million in GRDA, accounting for approximately 55% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $10-11 million due to relatively lower congestion-relief provided in the GRDA zone.
  - The benefit related to mitigation of transmission outage costs is estimated to be $7 million, reducing GRDA's gap to reach a B/C ratio of 0.8.

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

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

Lincoln Electric System (LES)

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



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

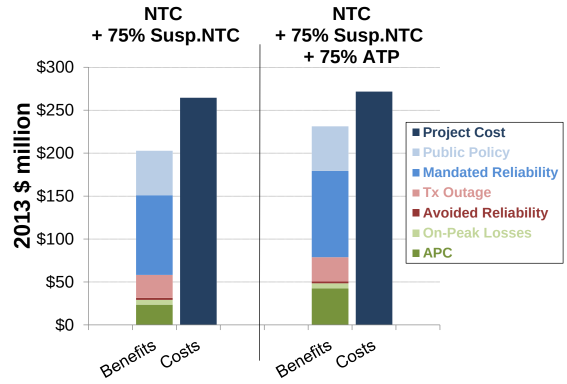
- Overall, the low B/C ratio in LES is primarily driven by the limited APC savings.
  - The cost of economic projects is $45 million in LES, accounting for approximately 60% of total costs. On the other hand, the present value of 40-year APC savings for 2013-2052 is only $5-6 million due to relatively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

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

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

Kansas City Power & Light (KCPL)

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



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

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

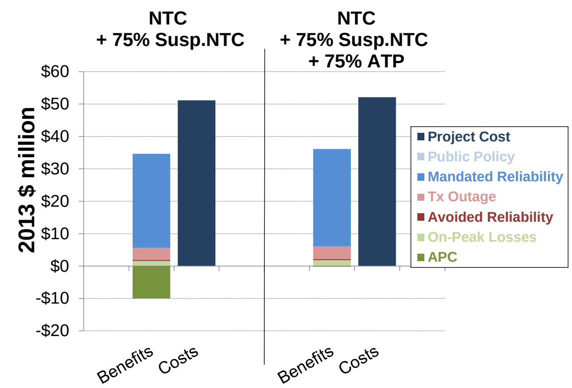
  - The benefit related to mitigation of transmission outage costs is estimated to be $27-28 million, reducing KCPL's gap to reach a B/C ratio of 0.8.

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

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

Sunflower Electric Power Corporation (SUNC)

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



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

- Overall, the low B/C ratio in SUNC is primarily driven by the higher APCs.
    - The cost of economic projects is $24 million in SUNC. At the same time, the present value of 40-year APCs for 2013-2052 increases by $10 million.
    - ATP projects reduce congestion in SUNC and increase sales revenues, which result in an estimated increase of $10 million in APC savings in present value terms.
    - The benefit related to mitigation of transmission outage costs is estimated to be $4 million, reducing SUNC's gap to reach a B/C ratio of 0.8.
- Another factor that contributes to a lower B/C ratio in SUNC is that it receives no public policy benefits, but it is responsible for about $3 million of the costs for public policy projects (allocated regionally on a LRS basis).

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

Appendix 3 – RCAR PROMOD Assumptions

PROMOD Assumptions

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

1. Transmission

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

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

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

2. External Regions

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

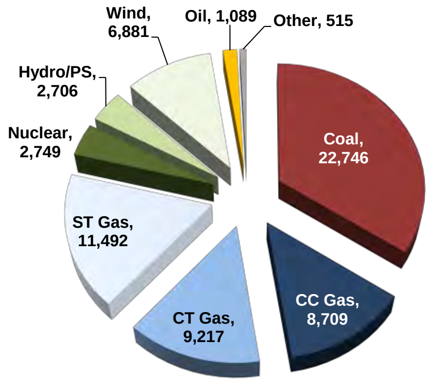
- SPP
- MISO (including Entergy and CLECO)
- MAPP Non-MISO
- PJM
- SERC – Central Sub-region, Southeast Sub-region, AECI

3. Generation

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

Figure 1
Generation Assumptions in SPP Footprint

(a) Existing Capacity



(b) Additions and Retirements

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

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

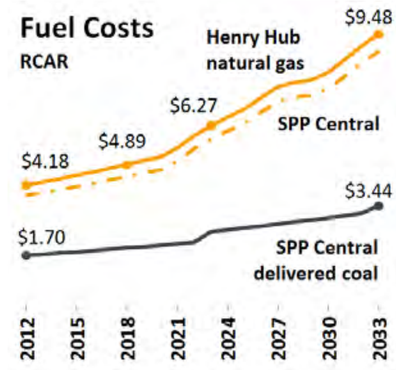
4. Fuel Costs

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

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

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

Figure 2
Fuel Price Projections for SPP Footprint

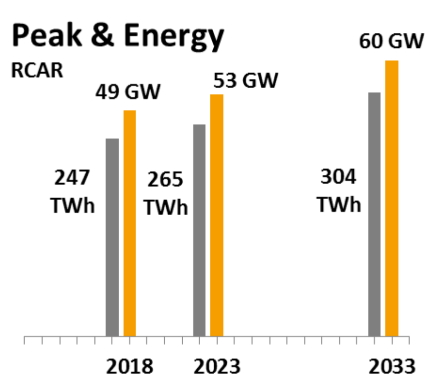


5. Load Forecast

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

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

Figure 3
Load Projections for SPP Footprint



6. Emission Prices

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

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

Figure 4
Emission Price Projections

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

Appendix 4 - RCAR Project List

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

Regional Cost Allocation Review (RCAR II)

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

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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

[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:

[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]

[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.

[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]

[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:

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

1.3 Overview of Legal Standards

Pursuant to the RARTF charter, the 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

[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]

[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

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.

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.

[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:

[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

- 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:

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.

[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.

[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.

[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.*

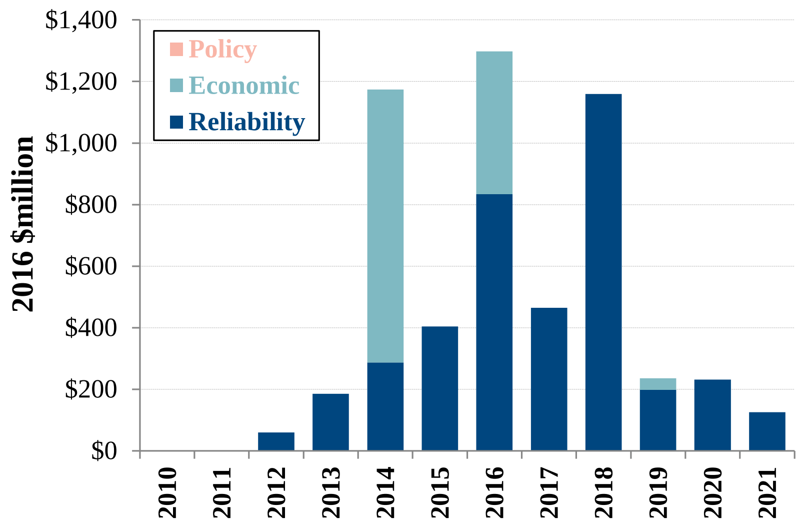
In accordance with Principle 3 from the RARTF Report, SPP staff used the most recent cost estimates provided to SPP in May 2016 for project cost tracking. Thus, the RCAR analysis uses the most up to date and best available information for the review, per Principle 3.

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)

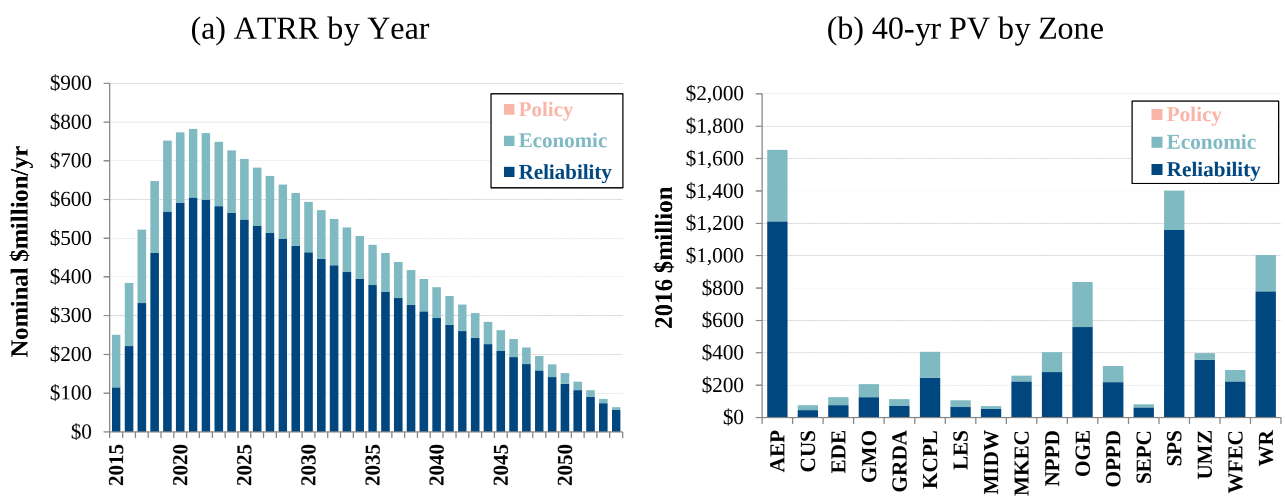
Per SPP's tariff, SPP staff calculated ATRRs for each zone at the upgrade level, as summarized below:

- 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



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 2020	Powerflow Models 2025	PROMOD Models 2020	PROMOD Models 2025	PROMOD Models 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** ($m)	**2025** ($m)	**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)

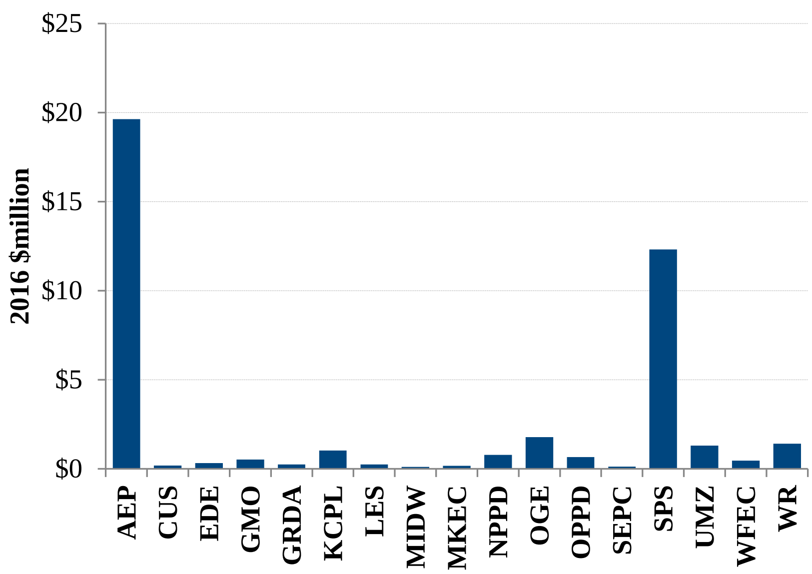
Figure 7.13 below shows the initial list of avoided or delayed reliability projects that would be needed to address the identified reliability violations. A standardized ITP cost template was used to estimate the total costs of the avoided or delayed projects. The benefits are assumed to be equal to 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 (MW)	2020 Change (MW)	2020 Diff. (MW)	2020 Loss Reduction (MW)	2020 Capacity Savings ($m)	2025 Base (MW)	2025 Change (MW)	2025 Diff. (MW)	2025 Loss Reduction (MW)	2025 Capacity Savings ($m)	40-yr PV 2015-54 (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.

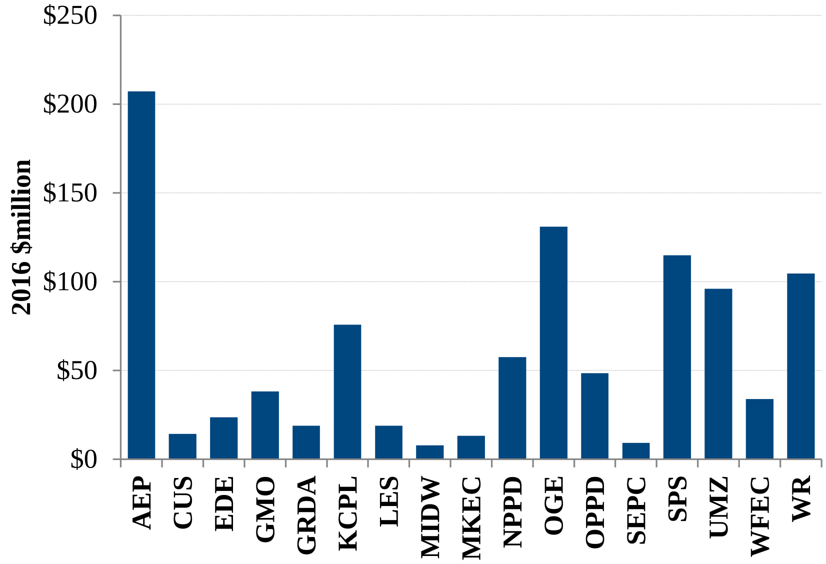
In RCAR II, 11.3% of APC benefit was utilized, consistent with the RCAR I and 2015 ITP10 studies.[59] Based on the APC savings benefit estimated in RCAR II, this translated to a 40-year present value benefit of $1.0 billion, allocated to zones as shown in Figure 7.16.

[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.

[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

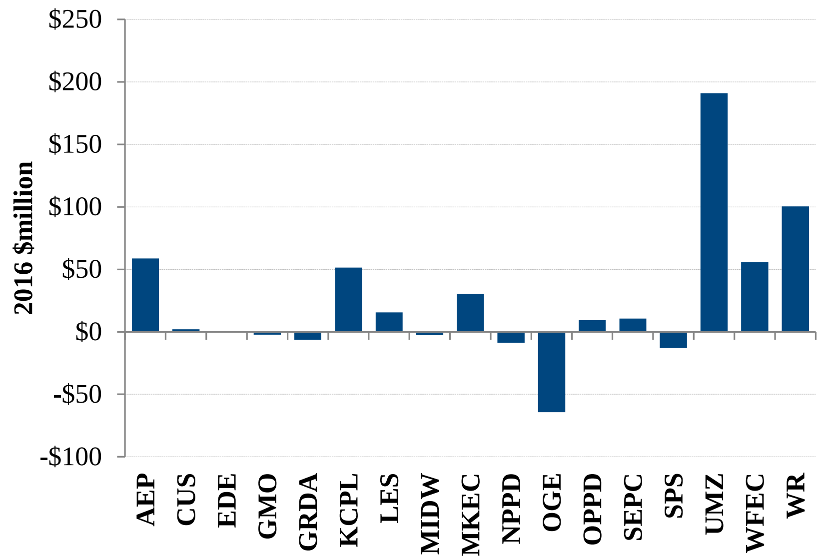
Zone	2020 ($m)	2025 ($m)	40-yr PV 2015-54 (2016 $m)
AEP	$4	$11	**$133**
CUS	$0	$0	**$5**
EDE	$0	$1	**$12**
GMO	$1	$1	**$19**
GRDA	$0	$1	**$13**
KCPL	$1	$3	**$37**
LES	$0	$1	**$8**
MIDW	$0	$0	**$5**
MKEC	$0	$1	**$14**
NPPD	$1	$3	**$38**
OGE	$2	$5	**$66**
OPPD	$1	$2	**$23**
SEPC	$0	$1	**$8**
SPS	$3	$7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

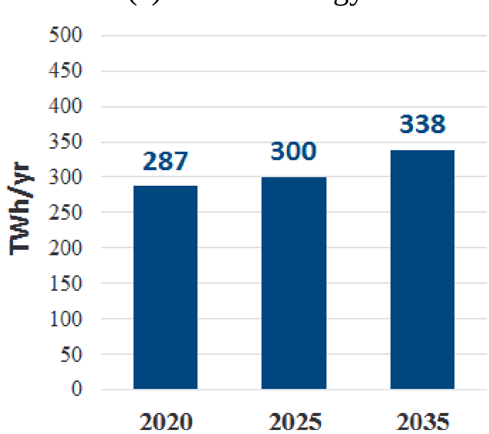
Load projections were modeled consistent with assumptions developed for the 2017 ITP10 study, obtained through a survey of the members. Accordingly, the SPP's annual load is assumed to be 287 TWh in 2020, 300 TWh in 2025, and 338 TWh in 2035. The system-wide coincident peak load is assumed to be 55 GW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

(a) Annual Energy

(b) Coincident Peak



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)

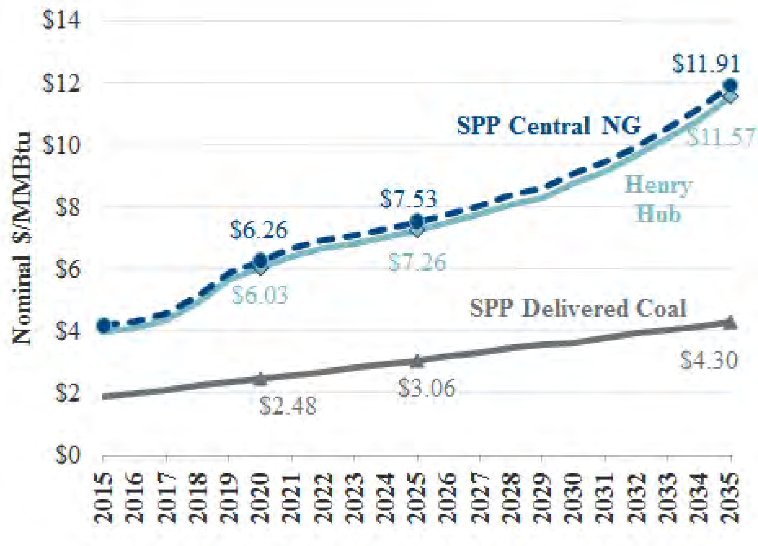
	Existing Capacity as of 2016	Additions and Retirements between 2016-2020	Online Capacity in 2020	Additions and Retirements between 2021-2025	Online Capacity in 2025	Additions and Retirements between 2026-2035	Online Capacity in 2035
ST Coal	23,469	(821)	22,648	(692)	21,956	(1,143)	20,813
ST Gas	10,738	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

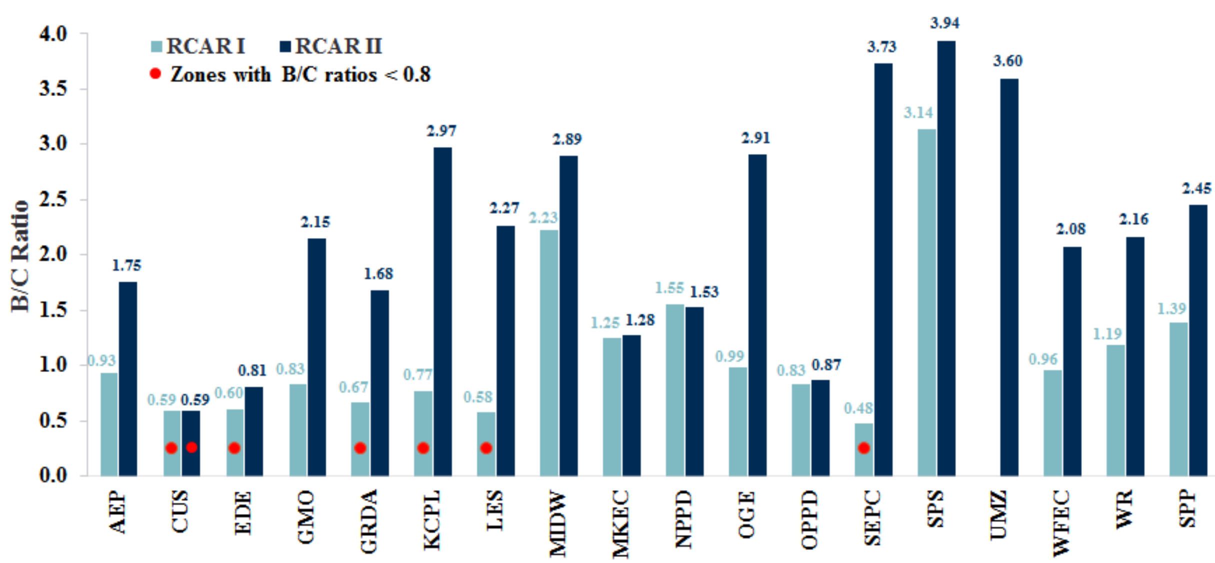
The RCAR II project list has been published at https://www.spp.org/documents/39026/appendix%204%20-%2020160531_rcar2_project%20list_summary.pdf

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

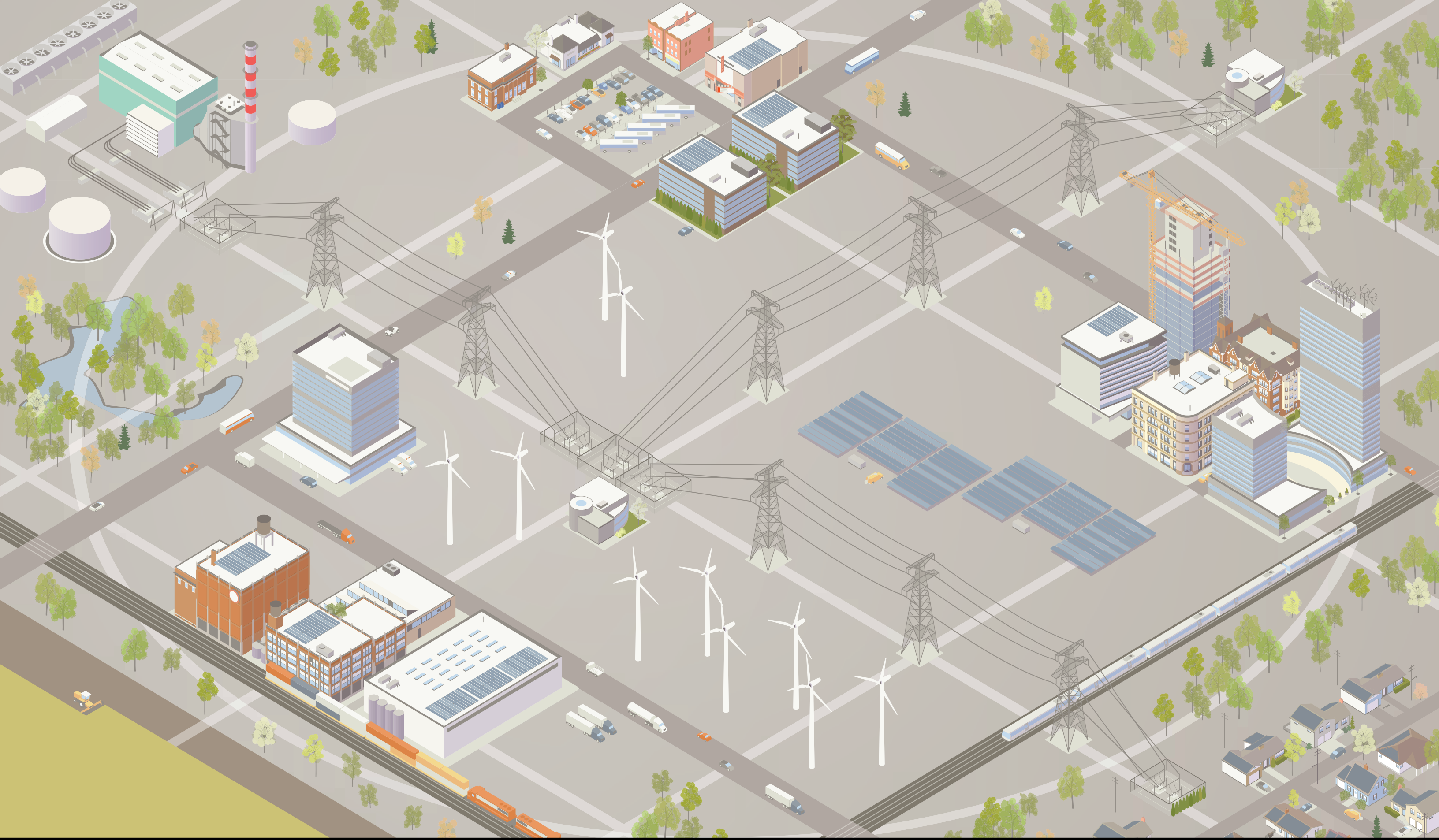
	Gap to Reach B/C Ratio of 1.0 (2016 $million) Total	Levelized Real
CUS	$29	$1.8
EDE	$23	$1.4
OPPD	$39	$2.5

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.



SPP Southwest Power Pool

14 to 1

THE VALUE OF TRUST

Southwest Power Pool is a smart investment. For utilities responsible for keeping customers' lights on, power marketers looking for the lowest-cost electricity in the nation, retailers with renewable-energy goals to meet and everyone in between, SPP provides something rare and invaluable in today's business climate: certainty.

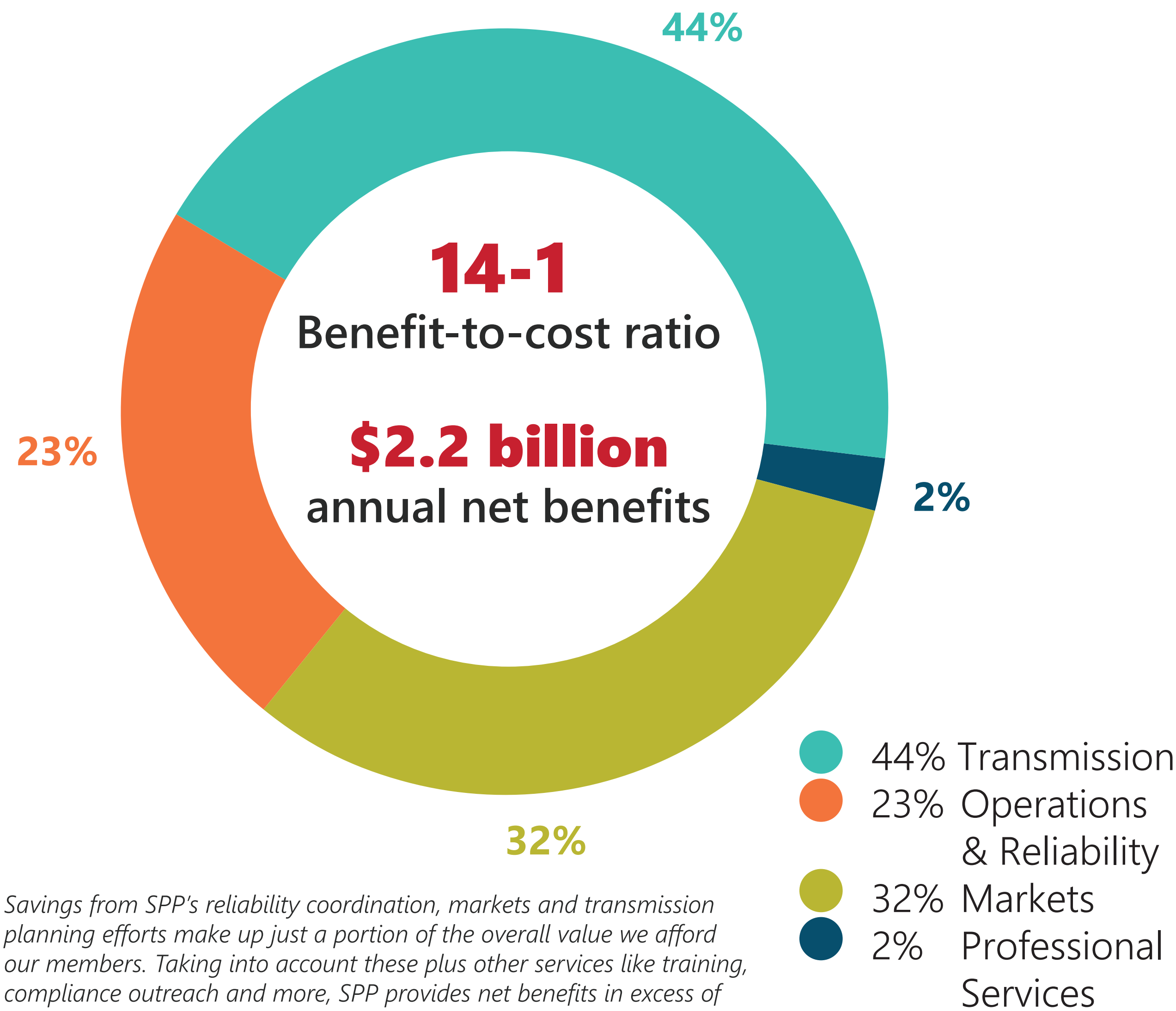
For every dollar our members invest in SPP, we save them 14. That's tremendous value, and it's just one of the reasons our stakeholders trust us to manage their transmission assets, coordinate the modernization of the bulk power grid and ensure the lights stay on for more than 17 million people in our service territory.

SPP’s Peace-of-Mind Promise

The electric utility industry is evolving at a previously unimaginable rate. Our stakeholders face significant and daily risks to both electric reliability and financial security. Changes in customer behavior, the rapid emergence of advanced technology, political uncertainty and threats to the security of physical and cyber assets are just a few of the obstacles electricity providers face every day.

Our expert staff understands these challenges, and we’re ready and able to help. Our stakeholder-driven, regionally holistic approach to planning, problem-solving and decision-making protects the interests of our members and their customers.

We work with our diverse member companies to produce mutually beneficial and cost-effective solutions that provide our customers—and *their* customers—peace of mind.

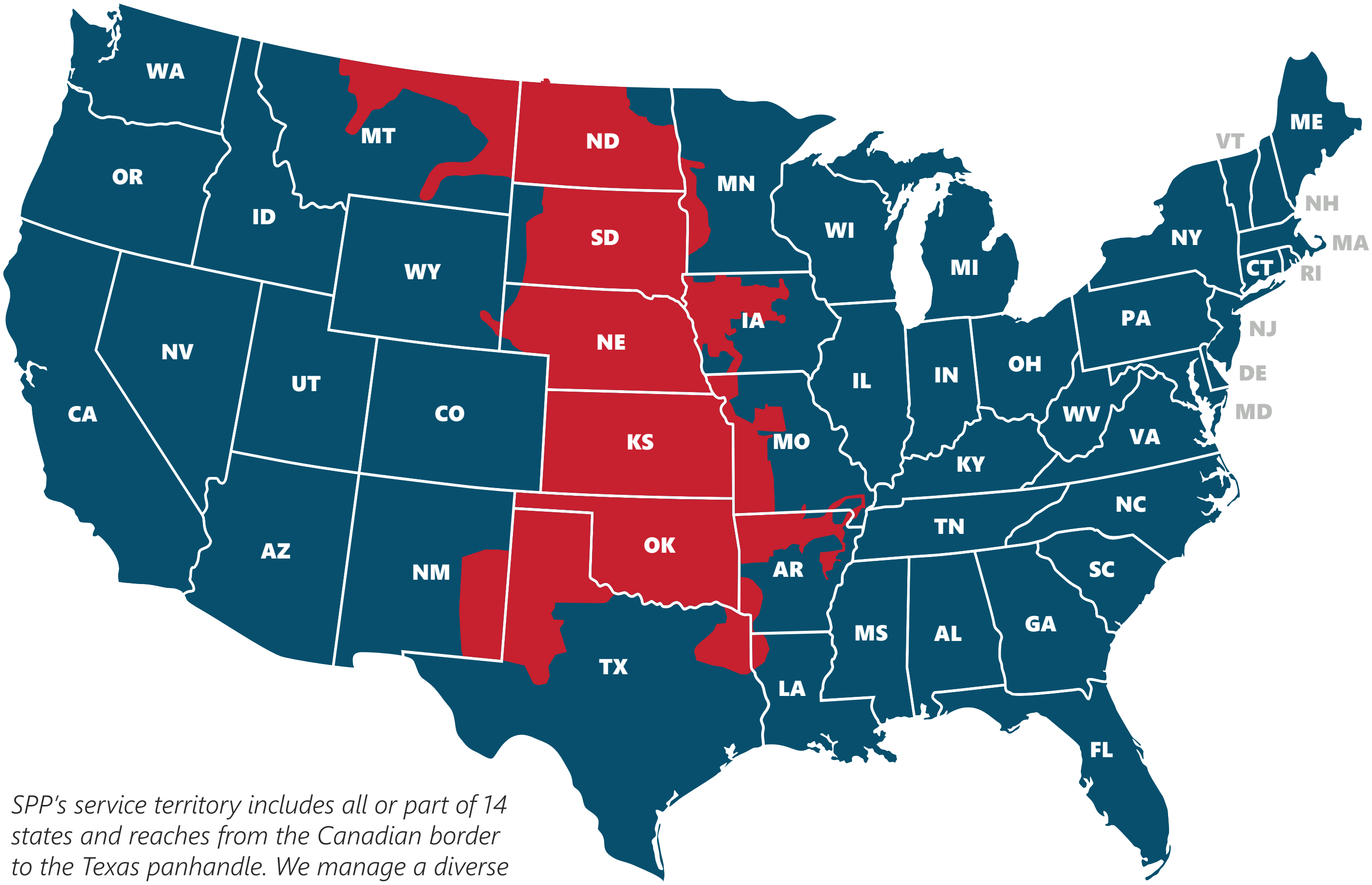


Savings from SPP's reliability coordination, markets and transmission planning efforts make up just a portion of the overall value we afford our members. Taking into account these plus other services like training, compliance outreach and more, SPP provides net benefits in excess of $2.2 billion annually at a benefit-to-cost ratio of 14-to-1.

THE VALUE OF SPP

SPP is devoted to good stewardship of our members' resources. We maintain efficient processes, effective controls and business practices, and a culture that promotes doing the right thing for the right reason in the right way. All of this contributes to the **14-to-1 return on every dollar members contribute to our mission.** That's real value our customers can depend on.

SPP is a 501(c)(6) not-for-profit service organization with voluntary membership. We exist because of our member companies and to serve them. As approved by the Federal Energy Regulatory Commission, we collect from our members an administrative fee that funds the performance of our critical functions and achievement of collaboratively set goals for the collective good of our region.



SPP's service territory includes all or part of 14 states and reaches from the Canadian border to the Texas panhandle. We manage a diverse roster of members and geographically expansive footprint.

Operations and Reliability

Most end-use customers have no idea how many people and complex machines and systems work in sync to ensure electricity is there when it's needed. SPP has been helping our members orchestrate this critical mission for more than 75 years. We coordinate the dispatch of generating resources, manage the region's transmission system and forecast and adjust to changing load minute-by-minute.

SPP is certified as a reliability coordinator (RC) by the North American Electric Reliability Corporation. As an RC, we're tasked with ensuring reliable delivery of electricity to consumers by maintaining a wide-area view of the grid's current state and future conditions. RCs act as air-traffic controllers overseeing the interconnected operations of the power grid. We keep watch for potential contingencies; collaborate with our members and neighboring systems to prepare and implement solutions; and, when reliability events occur, work to quickly and effectively return the grid to normal operation.

We act today as RC for a territory that includes all or part of 14 states and reaches from the Canadian border to the Texas panhandle. We manage the diversity of a broad roster of members and geographically expansive footprint, both of which pose unique and numerous operational, regulatory, environmental and political challenges that have helped shape and hone our transmission system, processes and tools.

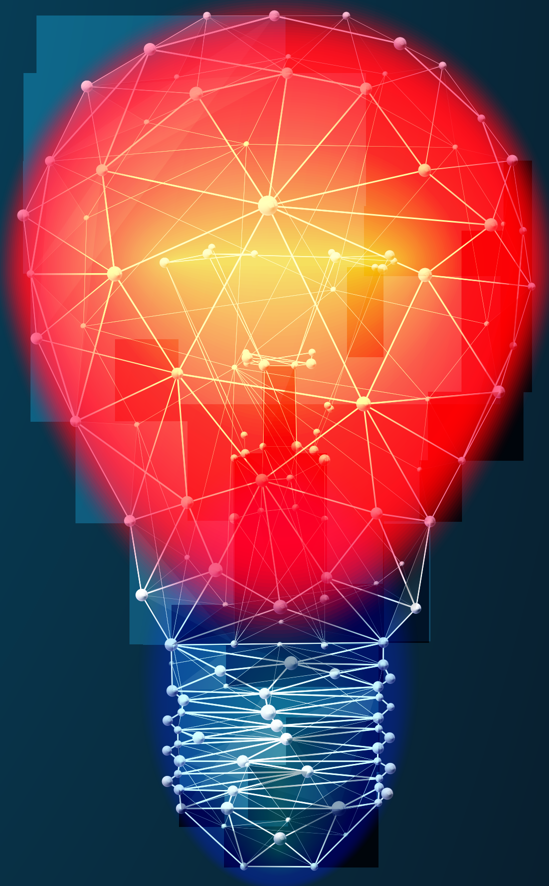
Our calculations of the value of reliability services are conservative and exclude many hard-to-quantify but very real benefits, like avoided costs associated with reliability events. The 2003 Northeast blackout, for example, contributed to at least **11 deaths and cost an estimated $7 billion**[1].

1. ICF Consulting, "The Economic Cost of the Blackout: An Issue Paper on the Northeastern Blackout, August 14, 2003."

MARKETS ENABLE ACCESS TO RENEWABLES

In 2008, wind energy made up just 3 percent of SPP's annual energy production: about six terawatt-hours (TWh) of the 176 TWh produced that year. In 2018, SPP produced 276 TWh of energy, of which wind made up 23 percent or 65 TWh.

At a given moment, SPP has reliably met as much as 71 percent of its load with renewables and 67 percent with wind alone: a level that was unthinkable just a few years ago.



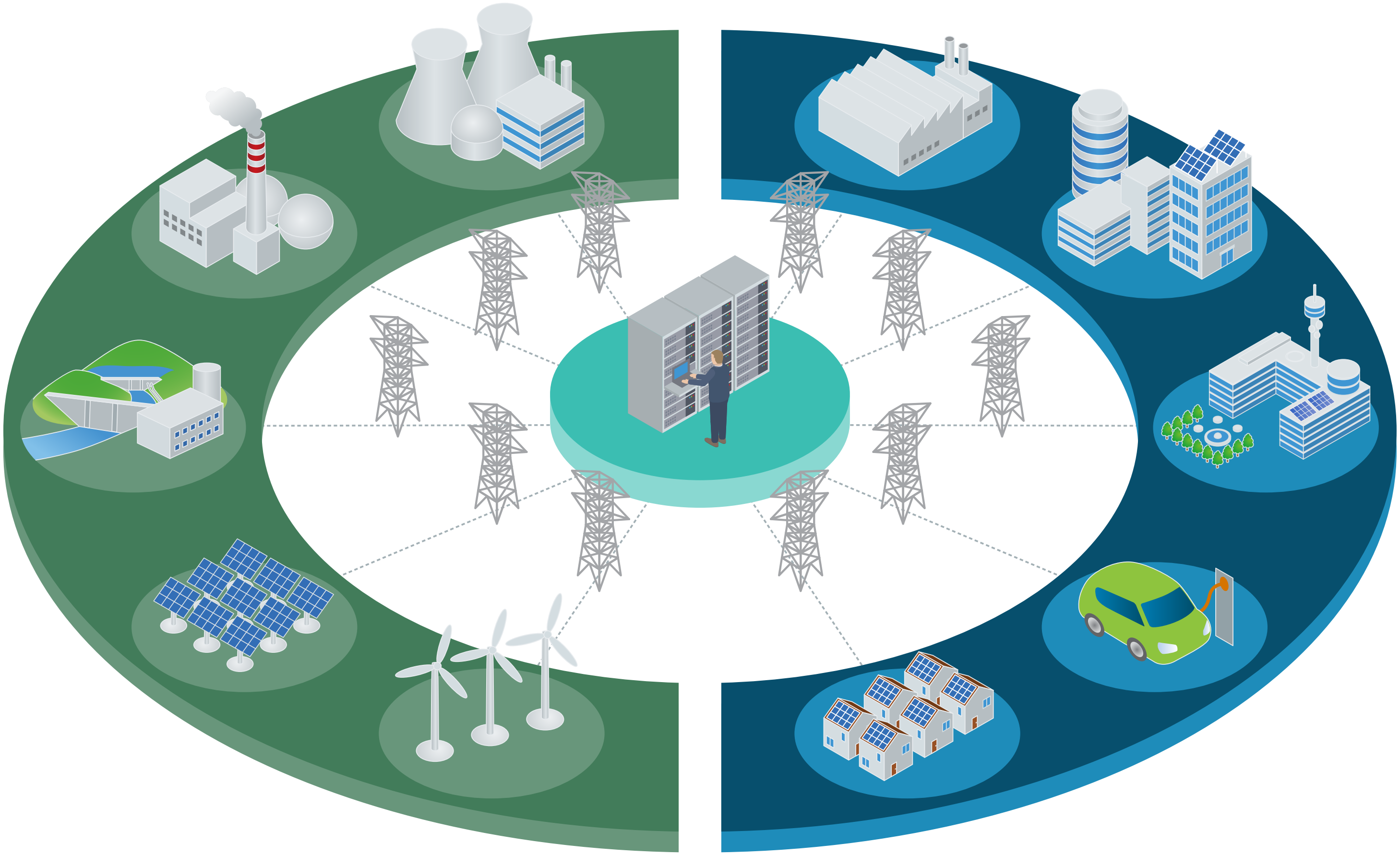
Markets

Working in tandem with SPP's other services, **our Integrated Marketplace has produced the lowest wholesale electricity costs in the nation, saved SPP's market participants cumulatively more than $2.7 billion and enabled access to renewables at a degree previously unimaginable,** among providing other benefits like enhanced reliability to SPP's stakeholders and the region as a whole.

Since it launched in 2014, our **Integrated Marketplace has yielded an average of $570 million in annual savings** derived from lower wholesale electricity costs, reductions to excess capacity requirements and other efficiencies facilitated by SPP's robust market processes. In testimony to Congress in March 2019, Mark Gabriel, CEO and administrator of the Western Area Power Administration, cited "financial and operational benefits exceeding our conservative assumptions" and surplus generation sales facilitated by SPP's markets "that accrued more than $48 million of additional net market value."

SPP's markets select the most cost-effective generation to meet customer demand and mitigate grid congestion in real time. This enables operations staff more time to monitor and prepare for unusual circumstances that require manual intervention and critical thinking. Our Integrated Marketplace also determines days in advance the resources needed to economically ensure reliability. It does so more effectively and efficiently than methods available to most individual utilities working by themselves to ensure the reliability of their systems.

Based on calculations reported by the Federal Energy Regulatory Commission in October 2018, **wholesale electricity prices in the SPP region were the lowest in the nation.** SPP's year-to-date spot power prices averaged $29/megawatt-hour (MWh).



Transmission Planning

SPP also serves as a planning coordinator. We ensure the dependability of our stakeholders' transmission investments no matter what the future holds through our relationship-based and member-driven approach to transmission planning. We direct transmission upgrades to ensure the region's transmission system meets reliability and economic needs today and in the future.

A recent study based on real-world data showed every dollar SPP directs toward transmission expansion returns $3.50 in benefits. Over the last decade, SPP has directed nearly $10 billion in transmission construction and upgrades that are modernizing the grid and will enhance reliability and reduce electricity costs for decades.

Professional Services

In addition to the core products described above, **SPP provides a suite of professional services that benefit stakeholders through economies of scale and cost savings.** Our stakeholders recieve from us industry-best training, project management, strategic planning, counsel and representation in regulatory and government affairs, and more. We do these things at a fraction of the cost of outside agencies, and because we address needs at a regional level our solutions are more cost-efficient than those achievable by members' in-house resources.

HELPING OUR MEMBERS HELP THEIR CUSTOMERS

Our service territory is becoming more attractive to businesses and increasing in economic development potential. **Our Integrated Marketplace and robust transmission network have enabled access to both the lowest-cost electricity in the nation and a diverse portfolio of generating resources.** Businesses and investors are taking note.

In September 2017, social-media giant Facebook announced it would locate a planned 200-megawatt server farm in Nebraska after working with SPP member Omaha Public Power District to ensure its demand could be met with 100 percent renewable energy. Beer-maker Anheuser-Busch similarly entered into a renewable energy partnership with Enel Green Power to purchase power from the Thunder Ranch wind farm in Oklahoma. Retail giant and SPP member Walmart has committed to getting 100 percent of its energy supply from renewable sources. EDP Renewables, another SPP member, is contracted to provide a portion of Walmart's renewable portfolio and notes that such procurements are on the rise thanks to the declining cost of power.

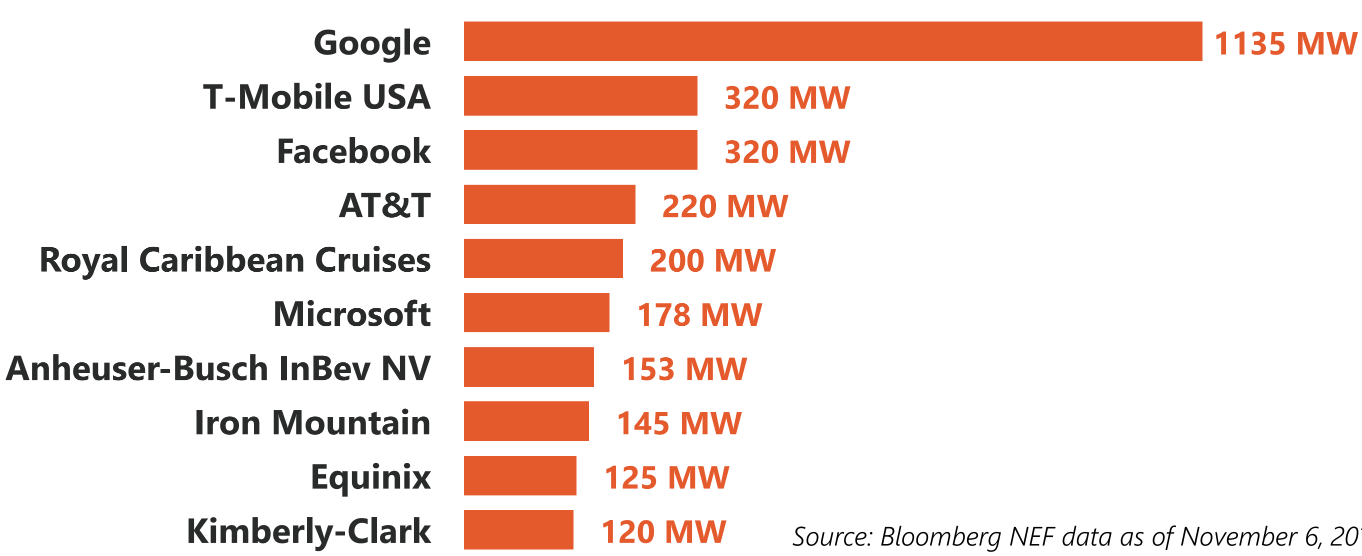
These are just a few examples of non-energy companies capitalizing on the open nature of the market. The benefits of SPP's services extend to residential ratepayers, too. **A typical residential customer in the SPP footprint who uses 1,000 kilowatt-hours saves $7.63 per month because of the services SPP provides.**

GEOGRAPHIC AND FUEL DIVERSITY

The SPP region is geographically diverse, stretching from the Canadian border to the Texas panhandle. Such a large footprint, with nearly 800 generating units at our disposal, gives us access to a diverse portfolio of fuel sources. This has enabled us to serve as much as 67 percent of our load with wind, made possible by fossil fuel and other resources standing at the ready to meet demand when the wind stops blowing.

Top 10 Corporate Buyers of Clean Energy in SPP's Market
(MW in Power Purchase Agreements)

The SPP region is increasing in economic development potential. Businesses and investors are taking note of the low-cost electricity and access to diverse fuel sources facilitated by our markets and transmission network.



Source: Bloomberg NEF data as of November 6, 2018

THE SPP DIFFERENCE

SPP is governed through a transparent and collaborative stakeholder process. Our independent board of directors oversees dozens of committees, working groups and task forces. In these groups' meetings — nearly all of which are open to the public — member representatives and SPP staff work toward consensus on our organization's strategic direction, financial decisions, processes, procedures and more. Everyone who wants to participate in the process can.

We don't take for granted the trust and responsibility given to us by our members. We don't base our decisions on assumptions of their wishes or our own understanding of what's best for the region, but rather we include them in the planning and execution of our corporate strategy. We manage change by building regional consensus, not strong-arming them into following our lead. A stakeholder prioritization process gives the people whose support and input we depend on the chance to provide direct input into our prioritization of project work and changes to market protocols, governing documents and more.

This consensus-building and relationship-based approach to business is unique, and it provides immeasurable value. It ensures the whole of our customer base has the opportunity to make its voice heard in decisions both big and small.

ALWAYS GETTING BETTER

SPP embraces a strategy of continuous improvement. We strive to always innovate, question the status quo and take every chance to cut costs, improve outcomes and work more efficiently. It's a practice that yields big returns for our stakeholders.

Through process improvements, efficiencies and the constant maturation of our business practices, SPP has expanded our territory and service offerings, adapted to changing requirements and circumstances and saved our members billions of dollars, and we've done it all while helping them achieve their own goals of providing affordable and reliable electricity to their customers.

SPP Southwest Power Pool

Learn more at SPP.org.

KCP&L and GMO
RTO Participation Cost/Benefit Study
Draft Scope
June 5, 2019

Purpose: Evaluate KCP&L and GMO's continued participation in the SPP RTO per the Stipulation and Agreements in MPSC Docket EO-2012-0135 and EO-2012-0136

Schedule:

- 06/30/19 Provide preliminary study plan to MPSC Staff ("Staff) and Office of Public Counsel ("OPC") for input
- 09/30/19 Finalize study plan after consultation with Staff and OPC
- 06/30/20 Final report filed with the MPSC along with a pleading concerning KCP&L and GMO's continued RTO participation or having another entity serve as an Independent Controller of Transmission ("ICT") after September 30, 2021

Study Components:

Analysis Period: 5-10 year benefit/cost projection. Assume any transition from SPP would be complete as of 1/1/2023

Entities: KCP&L and GMO evaluated separately

Participation Options:

(1) SPP
(2) MISO
(3) An ICT

Global Uncertainties:

(1) Future CO_2 restrictions (no restrictions, significant restrictions)
(2) Natural Gas Prices (low, mid, high natural gas prices)
(3) No change in current wholesale market structures

Cost/Benefit Considerations:

(1) Fuel, Purchased Power, Off-System Sales
(2) Ancillary service revenues and costs
(3) Emission costs
(4) Transmission congestion costs, TCR/FTR revenues
(5) Transmission service costs, including wheeling costs (if any)
(6) Transmission revenues
(7) RTO/ICT Administration Fees
(8) FERC FEE impacts (if any)
(9) Internal cost impacts (labor, systems, etc.)
(10) SPP exit fees
(11) Market power impacts (if any)
(12) Transition costs (SPP to MISO, or SPP to ICT)
(13) Planning reserve margin requirements