AECC Comments Related to Combining SPP Zones for Schedule 11

Summary: **Under scenarios being considered, AECC will have to pay approximately $4 million more per year. AECC believes it is today not receiving benefits commensurate with current Schedule 11 costs. To shift additional costs to Schedule 11 would only worsen this inequity.**

Thank you for the opportunity to provide comments related to the SPP HITT Team's recommendation to consider combining zones for Schedule 11 purposes.

AECC has load in three SPP zones with peak loads of approximately 900 MW in the American Electric Power zone, 200 MW in the Oklahoma Gas & Electric zone, and 75 MW in the Southwestern Power Administration zone. If zones are merged, AECC has considerable concern that it will pay higher transmission rates. AECC already questions whether it receives today benefits commensurate with Schedule 11 payments related to the new higher voltage lines that are regionally funded in the SPP.

AECC appreciates that considerable work has been done by the HITT team and likewise by the CAWG in reviewing the HITT recommendations. The table below shows impacts from a 4-zone scenario included in a CAWG White Paper. Under this scenario, rates would increase for all the Arkansas SPP zones (including Empire). Based on AECC's 2018 demands at the times of the zonal peaks, the rate increases below would require that AECC pay an additional $3.8 million per year.

CAWG White Paper
Cost Allocation in Wind-rich Areas
Working Draft

Table V-2

Rate Impacts with Four Sub-Regions for Schedule 11

Zone	Zone Name	Sub-Region	$ / MW Change	% Change in Sch. 11	% of 9&11 Total
1	American Electric Power	South	$204	9%	4%
2	Reserved for Future Use				
3	City Utilities of Springfield	MO/KS	$725	52%	21%
4	Empire District Electric	MO/KS	$485	30%	10%
5	Grand River Dam Authority	South	$273	12%	4%
6	Kansas City Power & Light	MO/KS	$676	47%	23%
7	Oklahoma Gas & Electric	South	$583	31%	15%
8	Midwest Energy	MO/KS	($32)	-2%	-1%
9	KCP&L Greater Missouri Oper.	MO/KS	$697	49%	18%
10	Southwestern Power Admin.	South	$1,113	82%	30%
11	Southwestern Public Service	South	($918)	-27%	-16%
12	Sunflower Electric Cooperative	MO/KS	($858)	-29%	-16%
13	Western Farmers Electric Coop.	South	($578)	-19%	-15%
14	Westar Energy	MO/KS	($648)	-23%	-10%
15	Mid-Kansas Electric Co.	MO/KS	($1,847)	-46%	-36%
16	Lincoln Electric System	Neb.	$394	27%	8%
17	Nebraska Public Power District	Neb.	($280)	-13%	-7%
18	Omaha Public Power District	Neb.	$230	14%	6%
19	Upper Missouri Zone	UMZ	$0	0%	0%
	Total		$0	0%	0%

AECC has concerns whether merging of zones would appropriately reflect allocation of cost to beneficiaries. To the degree that transmission is built to serve local reliability needs, cost causation principles would have the local zone pay for the upgrades. Local planning criteria can vary across zones, and to the extent that a particular zone desires more local transmission to improve reliability, the costs today are appropriately borne by those within the zone. If zones are combined for Schedule 11, a zone that receives most of its funding from others for local transmission will have less incentive to be cost conscious and a higher incentive to add more local transmission to improve reliability.

Much of the need for combining zones has been focused on wind generation. Wind-rich areas have low LMPs, and the lower LMPs impact both the generation and load – low LMPs reduce the market cost to serve load in that area. Negative LMPs that are often seen if high-wind areas mean that load in that same area actually gets paid to take the energy!

To the degree that wind is exported across zones, it will be predominantly over the higher voltage lines that are regionally funded. Significant new 345 kV lines built in western Kansas have a thermal load carrying capability of 1,500 MW with certain segments having two 345 kV lines (3,000 MW), while 115 kV lines, zonally funded, have a load carrying capability of around 150 MW.

Higher voltage lines are regionally funded, and the Regional Cost Allocation Review (RCAR) provides an estimate of the benefit/cost of regionally funded transmission. Summary results from the 2016 report are shown below. AECC load is on the eastern edge of the AEP and OG&E zones. The adjusted production cost (APC) savings shown in the table below would vary across the zone. Of concern to AECC is that, in general, the zones that are on the eastern edge of SPP are ones that are not receiving benefits commensurate with costs. Springfield, Empire and Omaha each have B/C ratios of less than one. Generally, zones in the wind-rich areas have the higher B/C ratios. Of note, of the 1,175 MW of AECC load in the three SPP zones as discussed above, 275 MW are pseudo-tied into MISO, meaning that MISO generators serve this SPP load. AECC pays the full SPP transmission rate for this load while receiving no APC savings that would result from increased SPP transmission. Given calculations of B/C are done by zone, it is difficult to state what AECC's B/C ratio is. If the pseudo-tied load were included, it is almost certain that AECC's B/C ratio would be well below 1.

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

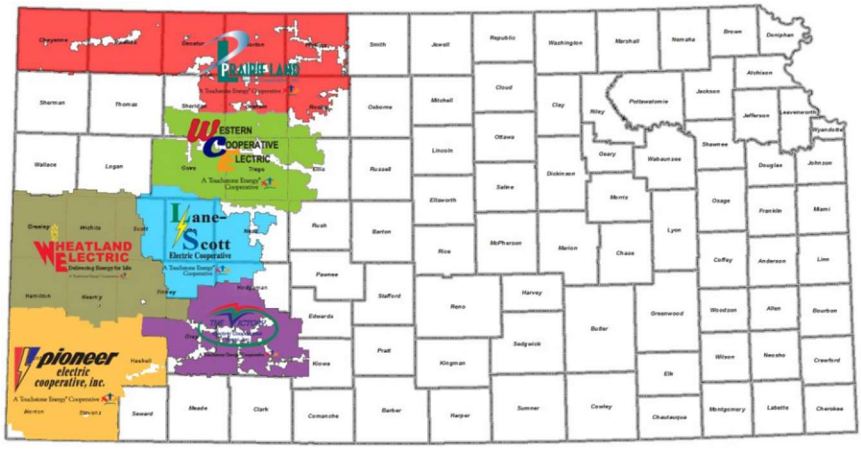
	Present Value of 40-yr Benefits for the 2015-2054 Period (2016 $million)											PV of 40-yr ATRRs (2016 $million)			
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-Peak Losses	Mitigation of Trans-mission Outage Costs	Assumed Benefit of Mandated Reliability Projects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

There are two notable exceptions to high-wind areas have high B/C ratios and eastern zones having low B/C ratios. Kansas City P&L (KCPL) is on the eastern edge of SPP and has one of the higher B/C ratio (2.97), while Mid-Kansas Electric Company (MKEC) is in a wind-rich area and has a relatively low B/C ratio (1.28).

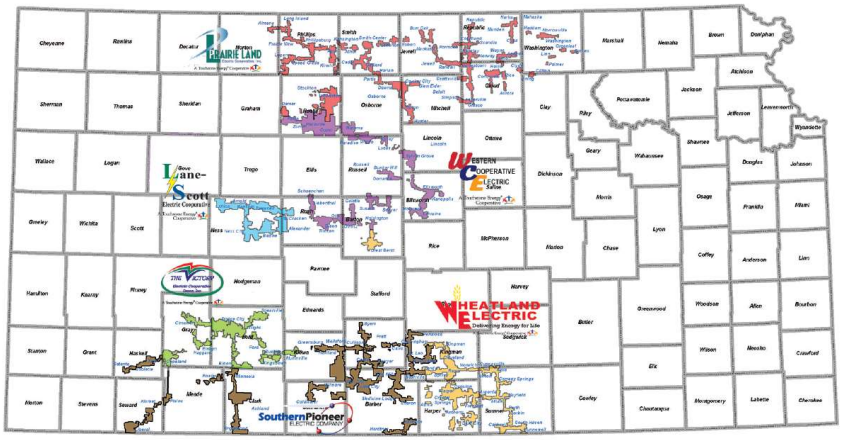
KCPL presumably receives benefits from some significant regionally-funded transmission projects located in its service area. The Iatan to Nashua 345 kV line and the Nebraska City-Mullin Creek-Sibley 345 kV line (terminating in KCPL) combined represent $400 million of new transmission investment, all regionally funded.

MKEC is owned by the same six Kansas distribution cooperatives that own Sunflower Electric Power Corporation (SEPC), and notably SEPC has the second highest B/C ratio in the table above (3.73). The service areas of the MKEC and SEPC are shown below. Given the proximity of the service territories of SEPC's and MKEC's members, with areas that are even contiguous, it is surprising that the B/C ratios of the two are so different.

SEPC Members' Service Territory



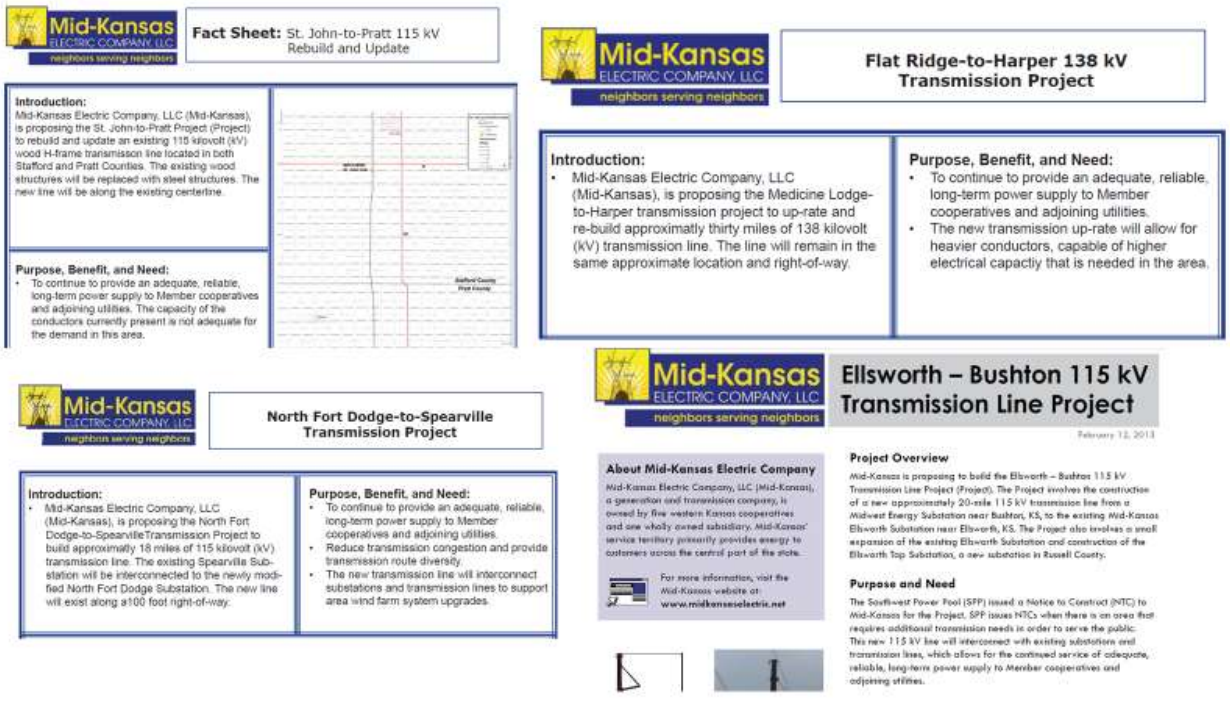
MKEC Members' Service Territory



SEPC and MKEC are two of the entities that would appear to benefit significantly from combining SPP zones for Schedule 11 purposes. Under the 4-zone scenario shown above, MKEC was by far the greatest beneficiary. As an illustrative and relevant example, it may be valuable to understand more fully what lower voltage projects currently funded by the MKEC zone alone would become more broadly funded. MKEC's website list recent transmission projects. Snips from the website (shown in Appendix A below) mostly discuss needs for upgrades based on local reliability and meeting demands. Here are some examples:

- St. John-to-Pratt 115 kV Rebuild and Update: "The capacity of the conductors currently present is not adequate for the demand in the area." Similar language is used to justify the Clifton-to-Washington County Line Rebuild and Upgrade.
- SEPC's Santa Fe to Twin Springs 115 kV project and MKEC's Ingall's to Bluejay 115 kV project (jointly called the System Backbone): "Building this project rather than constructing temporary transmission solutions will allow Lane-Scott and Wheatland [distribution electric cooperatives] to save money while addressing service constraints in their territories. Victory [distribution electric cooperative] will also benefit from this project as the project will provide a redundant feed to a large load pocket in its service territory."

Appendix A



Mid-Kansas ELECTRIC COMPANY, LLC
neighbors serving neighbors

Fact Sheet: Clifton-to-Washington County Line Rebuild and Uprade

Introduction:
Mid-Kansas Electric Company, LLC (Mid-Kansas), is proposing the Clifton-to-Washington County Line Project (Project) to rebuild and upgrade an existing 115 kilovolt (kV) wood H-frame transmisson line located in Washington County. The existing wood structures will be replaced with steel structures. The new line will be along the existing centerline.

Purpose, Benefit, and Need:
- To continue to provide an adequate, reliable, long-term power supply to Member cooperatives and adjoining utilities. The capacity of the conductors currently present is not adequate for the demand in this area.
- Decrease land-use impacts. The majority of the structures will change from a two pole H-frame structure to a single- pole steel structure, reducing the utility's footprint on the property.

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Harper-to-Milan 138 kV Transmission Line Project

Project Update

(June 2018) The Harper-to-Milan Transmission Project, which officially kicked off in the summer of 2015, has been energized on time and on budget. The project is the largest new construction transmission project undertaken by Mid-Kansas to date. Spanning three counties—Kingman, Harper and Sumner—the project involved multiple electric utilities' service territories, which required extensive communication and planning to ensure limited service disruptions occurred during construction. To read more about project completion, you can view the latest newsletter.

Project Update

(January 2018) The Rago-to-Harper portion of the Harper-to-Milan 138 kV line has already been energized. As of December 2017, foundation work was completed, poles were set and anchors and guyed lines were installed. Some clean-up remains.

The next segment that will likely be energized is the Harper-to-Anthony segment. Nearly all the foundation work is finished, structures are being set, and the stringing of conductor has begun. The same level of completion has been achieved on the Anthony-to-Bluff Creek segment.

(November 2017) Right-of-way clearing has been completed along the Harper-to Milan Project route. Poles have been set on portions of the line. Conductor is being strung from Rago to Harper. The project's 75-mile, 115 kV line, scheduled to be energized by late spring or mid-2018, will help bring reliable electricity to Kingman, Harper and Sumner counties.

(May 2017) Final negotiations were underway with property owners during late spring and early summer. Right-of-way clearing, which began in early spring, will be completed by fall 2017 in preparation for construction. The project remains on schedule and should be in service by March 2018. The 70-mile long project will create a reliable "loop" of service in the Kingman, Harper and Sumner Counties, an area that has been in need for additional infrastructure. The project will assist with reducing power outages in the area.

https://www.sunflower.net/wp-content/uploads/2018/06/System-Backbone-April2018-Abby-edits-002.pdf

Project Need & Development - System Backbone

The System Backbone Project, aptly named as it will provide a boost in load-serving capability and reliability in the vicinity, includes the construction of a 25-mile, 115 kilovolt (kV) transmission line and three substations in Finney and Gray counties.

The project was developed through the local planning process and will provide many benefits. Building this project rather than constructing temporary transmission solutions will allow Lane-Scott and Wheatland to save money while addressing service constraints in their territories. Victory will also benefit from this project, as the project will provide a redundant feed to a large load pocket in its service territory.

In August of 2017, public information meetings were held in Garden City and Cimarron to explain the project's purpose and potential routes. Based on the public's feedback gathered at those meetings and routing constraints of the area—homes, businesses, agricultural areas, active oil leases and river crossings—a preferred route was identified (see map).

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Ingalls-to-Bluejay

Project In Service

In August, the new Victory Electric Substation, Bluejay Substation, was energized, and the Ingalls-to-Bluejay 115 kV line was placed into service.

Project planning for the Ingalls-to-Bluejay 115 kV line, located in Gray County, began in 2015 and required coordination with many state agencies to ensure the best possible project. The Ingalls-to-Bluejay line, Phase I of the three-phase System Backbone Project, enhances reliability in the Gray County and surrounding area. Construction of the 9.5-mile-long line began in January of 2017. It was placed in service in late September 2017.

Beginning in the summer of 2017, planning for the construction of Phases II and III of the System Backbone Project was underway. Phases II and III, which are projects of Sunflower Electric Power Corporation, include the construction of 24 miles of single-pole, steel structures to support 115 kV transmission line Gray and Finney Counties, along with three new substations, two in Gray County and one in Finney County. Phases II and III are scheduled for completion by late 2019.

To learn more about the System Backbone project visit the project site here.

Project Nearing Completion

September 2017

Construction of the Ingalls-to-Bluejay line, which began in late 2016, was completed in January of 2017. The transmission line will be energized upon the completion of the new Bluejay Substation, which is scheduled to be energized September 2017. The Ingalls-to-Bluejay line was designed to provide the necessary infrastructure for additional projects, including the System Backbone Project, which is needed in Gray and Finney counties. To learn more about the System Backbone Project, visit https://www.sunflower.net/system-backbone-project/.

Addendum 1 to AECC Comments Related to Combining SPP Zones for Schedule 11

Addendum Summary: **Wind-rich zones have lower costs to serve load. The lower cost to serve load more than offsets the increased cost of transmission in these zones.**

AECC made the statement in its original comments that, "Wind-rich areas have low LMPs, and the lower LMPs impact both the generation and load – low LMPs reduce the market cost to serve load in that area."

LMPs are public information, and AECC calculated LMPs for certain load zones for the 12-month period ending July 31, 2018. Please see the table below. As expected, Arkansans are in SPP zones that have higher LMPs than zones that are in wind-rich areas. AECC's average hourly * day-ahead LMP for its load zone was $28.32/MWh. As a comparison, the SECI-SECI load zone (believed by AECC to be a combination of both the Sunflower Electric Power Corporation and Mid-Kansas Electric Company loads[1]) was an hourly average of $22.39/MWh.

* Not load-weighted for this purpose, which should provide a conservative computation of total costs (i.e., does not take into account that LMPs tend to be higher when loads are higher than average).

Average Day-Ahead LMPs for Certain SPP Load Zones

Time Period:	August 2018 - July 2019				
On Peak:	HE 7-22	(all days)			
Off Peak:	HE 1-6, 23-24	(all days)			
	Average Day Ahead LMPs ($/MWh)				
Load Zone	All Hours	On-Peak	Off-Peak		Notes
Load zones in or including areas in Arkansas:					
AECC_CSWS	28.32	32.13	20.71		AECC load
AEPM_CSWS	27.64	31.40	20.12		AECC believes this is AEP (SWEPCO & PSO) load
EDE_EDE	29.78	33.70	21.95		AECC believes this is Empire District Electric load
OKGE_OKGE	26.37	30.35	18.43		AECC believes this is OG&E load
Examples of load zones in wind-rich areas:					
GSEC_SPS	22.75	26.41	15.43		AECC believes this is Golden Spread EC load
SECI_SECI	22.39	26.31	14.57		AECC believes this is Sunflower & Mid-Kansas EC load
SPS_SPS	23.35	26.73	16.59		AECC believes this is Southwestern Public Service load
WR_WR	22.99	26.92	15.13		AECC believes this is Westar load

[1] The Mid-Kansas Electric Company 2018 Annual Report, Notes to Consolidated Financial Statements, Note 3, states, "Sunflower has been directed by the Mid-Kansas and Sunflower boards to serve as the SPP Integrated Market Participant (MP) on behalf of Mid-Kansas." Further details in the note indicate that the loads are combined in a single load zone for SPP settlement purposes. Note 10 of the report also states that Sunflower and Mid-Kansas have requested from regulators that the entities merge, effective January 1, 2020.

So as not to rely on AECC's calculations and to broaden the information, it may be worthwhile to have SPP staff calculate values for all its load zones.

Example Comparing Energy and Transmission Costs

AECC provides the following example to illustrate the value of lower cost energy relative to transmission costs.

Please see the calculation in the table below. If Sunflower were to have the same cost of load as AECC based on the hourly average day-ahead LMPs for the load zones, its load costs would be $13 million higher per year. If Sunflower were to have the same Schedule 11 zonal transmission rate as the AEP rate, savings to Sunflower would be approximately $6 million per year. Within the computation, Sunflower receives approximately a net benefit of $7 million per year by being in a low-energy cost (high-wind) area.

Sunflower Energy Benefit vs. Transmission Cost Comparison

Energy Cost Comparison				
				note
AECC Load Zone LMP		$28.32	/MWh	from table above
SECI Load Zone LMP	-	$22.39	/MWh	from table above (value is for Sunflower and MKEC)
		$5.93	/MWh	
Sunflower's Sales	x	2,200,000	MWh	2018 Sales to Members, from Sunflower's 2018 Annual Report
Value of lower energy cost		**$13,046,000**		
Transmission Cost Comparison				
				note
Sunflower's Sch 11 Zonal Rate		$24,202.59	/MW-year	from SPP's Rate Postings, snippet shown below
AEP's Sch 11 Zonal Rate	-	$8,657.32	/MW-year	from SPP's Rate Postings, snippet shown below
		$15,545.27	/MW-year	
Sunflower's avg demand	x	385.167	MW	from SPP's Rate Postings, snippet shown below
Cost of higher transmission		**$5,987,524**		

SPP Rate postings can be found at found at https://www.spp.org/spp-documents-filings/?id=18251

Values from the previous table are found in the following snippets:

Southwest Power Pool, Inc.

Calculation of Base Plan Point-To-Point Rates
Zonal Point-To-Point Rate

Sunflower Electric Power Corporation Zone

Description	Amount	Notes
Base Plan Zonal ATRR	$9,322,029	
12 CP Average Transmission System Load (MW)	385.167	
Firm Point-To-Point Transmission Service		
Annual Rate / MW	$24,202.586	

Southwest Power Pool, Inc.

Calculation of Base Plan Point-To-Point Rates
Zonal Point-To-Point Rate

American Electric Power West Zone

Description	Amount	Notes
Base Plan Zonal ATRR	$74,077,075	
12 CP Average Transmission System Load (MW)	8,556.583	
Firm Point-To-Point Transmission Service		
Annual Rate / MW	$8,657.319	

AECC Specific Recommendations for CAWG Consideration with C2

Based on a review of the Sunflower Presentations to CAWG, AECC offers some specific recommendations for C2, building upon Sunflower's recommendations.

Sunflower presentation to CAWG on September 10, 2019:

HITT Recommendation – C2

1. "Under this recommendation, costs for a byway-funded transmission upgrade could be funded using a region-wide allocation after meeting certain criteria under a narrow review process. Projects eligible for this narrow and limited process must be base plan upgrade costs eligible for cost allocation under the SPP tariff. This could include new or existing Schedule 11 facilities.
2. Costs that are directly assigned shall not be eligible for this review.
3. This process could be administered through a request for waiver of the cost allocation that otherwise would be applicable. Information concerning the specific upgrade(s) must be submitted to SPP for such costs to be considered for full region-wide allocation. The process for review and approval of the requests could **conceptually** follow the current processes for addressing waiver requests related to upgrades for transmission service and for transformers, as described in Section III of Attachment J." (Emphasis added)

Building a Criteria Based on Attachment J Waiver Concept

- Waiver for cost allocation purposes based on the anticipated utilization of the transformer.
- Any waiver request submitted shall be evaluated based on the following general factors, including but not limited to:

  (1) whether the power flows through the transformer predominantly are from the lower voltage to the higher voltage;

  (2) whether the transformer is not necessary for the support of, or does not substantially benefit, the lower voltage system in the host zone to which it is connected.

Assuming this language is to be the starting point for the language adopted by the CAWG, AECC would recommend the following (AECC Comments in Red):

- Waiver for cost allocation purposes based on the ~~anticipated~~ utilization of the transformer.
- Any waiver request submitted shall be evaluated based on the following general factors, including but not limited to:
    1) Whether the power flows through the transformer predominantly are from the lower voltage to the higher voltage;
    2) Whether the transformer is not necessary for the support of, or does not substantially benefit, the lower voltage system in the host zone to which it is connected. This is to be established with a "but for" test - the modeling that resulted in the notice to construct shows that the upgrades were not needed "but for" the generators causing the flows onto the higher voltage transmission.
    3) Generators affiliated with the entity submitting the waiver request shall not contribute to justification for a waiver request.

Alternative/Additional Factors for Consideration

If the CAWG were willing to fund less than 100% of qualifying projects regionally, AECC would recommend that RCAR results be used to establish the additional amount to fund. AECC recommendation:

- If transmission is accepted through the waiver process to receive additional regional funding, the regional funding percent will be according to the following formula:
    1) 1/3 + [2/3 * Average of the 3 zones that have the lowest RCAR ratios / RCAR of zone where transmission is located]
    2) Maximum of 100% regional funding
    3) RCAR at the time of waiver request will be used

Example: Zone A had an RCAR of 1.28 in the most recent study. Average of 3 lowest RCAR zones is 0.76.

0.76/1.28 = 0.59;
Additional regional funding (above current 1/3) for Zone A transmission that qualifies: 2/3 * 0.59 = 0.39;
New regional funding percent for Zone A transmission that qualifies: 1/3 + 0.39 = 0.73%

One rationale for this approach is to provide an incentive for SPP Members that support C2 an incentive to support transmission that benefits the low RCAR zones. The most recently approved projects from the SPP Integrated Transmission Plan provides benefits primarily to zones in the east that have lower RCARs. It was opposed/not supported by some of the SPP Members that support C2 and/or are in wind-rich zones (please see below).

Excerpt from the Minutes of the SPP Board of Directors' Meeting, October 29, 2019:

Agenda Item 7 – Markets and Operations Policy Committee

Ms. Holly Carias (NextEra Energy Resources, LLC) provided an update on the MOPC (MOPC Presentation – Attachment 14). Ms. Carias began by discussing an overview of the 2019 ITP. She thanked staff members Antoine Lucas and his team for their hard work, for the great job explaining the information, and for putting it together. This was a very collaborative stakeholder process. There are 44 projects worth $336M. The benefit-to-cost ratio is very high. (2019 ITP Report – Attachment 15).

Mr. Nick Brown moved to approve the 2019 ITP assessment report and associated issuance of NTC's (2019 ITP Recommendation – Attachment 16). Mr. Mark Crisson seconded the motion. The Members Committee voted in favor with one no vote (Sunflower Electric Power Corporation) and four abstentions (Golden Spread Electric Cooperative, Tri-County Electric Cooperative, Oklahoma Gas & Electric, and Oklahoma Municipal Power Authority). The Board voted; the motion passed.

If this proposal were adopted by CAWG, AECC would recommend that RCAR continue to include all current zones for which a ratio is calculated, though AECC would not oppose MKEC and Sunflower combining. AECC would also seek to have Southwestern Power Administration be included as an RCAR zone. As was discussed in Southwestern's presentation at CAWG, loads (including certain AECC loads) that are classified as non-Federal transmission are charged Schedule 11 costs. Without inclusion as a zone in the RCAR review, there is no visibility into "unintended consequences," as was part of SPP's filing to FERC that resulted in approval of the current highway/byway cost allocation.

If C2 is to be a "narrow and limited process," consideration may also be given to limiting its impact. AECC recommendation:

- Transmission funded through the C2 process will be limited:
  1) Additional regionally funded portion ($) of C2 projects in total will represent no more than 1% of regional funding ($) for all transmission
  2) Submission of waiver requests will establish priority if the limit is reached

The intent with this item is to recognize that this process is intended to be limited. Alternate solutions should be investigated if the costs rise above this level.

1. We don't support retroactive rate making and we believe that changing the cost allocation for past NTC's will be problematic at FERC. The tariff already has contemplated remedies available to SPP and the RSC through the RCAR process but to date the two RCAR analysis don't show that any of the wind rich zones mentioned so far (sunflower, OGE, SPS, MKEC, MIDW) below a .8 B/C or even below 1.0. In fact, all of them except MKEC are above the AEP B/C of 1.75.

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		
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		
GMO	$174	$1	$3	$38	$180	$0	$19	-$2				$412	$207	$15	$192	2.15		
GRDA	$82	$0	$1	$19	$70	$0	$13	-$6				$179	$114	$8	$106	1.68		
KCPL	$642	$1	$6	$76	$308	$0	$37	$51				$1,122	$407	$29	$378	2.97		
LES	$115	$0	$1	$19	$64	$0	$8	$15				$223	$106	$8	$98	2.27		
MIDW	$76	$0	$11	$8	$93	$0	$5	-$3				$190	$71	$5	$66	2.89		
MKEC	$60	$0	$17	$13	$171	$0	$14	$30		Not Monetized		$306	$259	$20	$239	1.28		
NPPD	$158	$1	$53	$58	$275	$0	$38	-$9				$574	$404	$29	$375	1.53		
OGE	$1,428	$2	$65	$131	$635	$0	$66	-$64				$2,262	$838	$60	$777	2.91		
OPPD	$24	$1	$3	$48	$150	$0	$23	$9				$257	$320	$23	$297	0.87		
SEPC	$83	$0	$12	$9	$159	$0	$8	$11				$283	$82	$6	$76	3.73		
SPS	$3,537	$12	$357	$115	$1,024	$0	$90	-$13				$5,122	$1,402	$102	$1,301	3.94		
UMZ	$281	$1	$47	$96	$595	$0	$55	$191				$1,266	$397	$45	$352	3.60		
WFEC	$159	$0	$77	$34	$222	$0	$20	$56				$568	$295	$21	$274	2.08		
WR	$996	$1	$5	$105	$710	$0	$94	$100				$2,011	$1,002	$73	$930	2.16		
TOTAL	$8,974	$41	$743	$1,014	$5,759	$0	$641	$427				$17,599	$7,760	$579	$7,180	2.45		

2. As a point of reference, of all the costs assigned to the AEP zone since HW/BW began, only a small fraction of those costs have been associated with projects built within our zone. To say that we are not contributing to the transmission build out of other zones in the region isn't correct.
3. If we do re-allocate BW costs, we would rather see SPP analysis on the beneficiaries paying rather than a general uplift to the whole region. I believe during the HITT meetings, SPP said they could determine which BW facilities we being used to support regional (HW) flows and allocating those costs to the beneficiaries would be more appropriate. Using a narrow process to reallocate these facilities through the ITP process would be more appropriate.
4. If the CAWG decides to follow a process outlined by the sunflower presentation then they should consider these items:
    a. The CAWG should discuss whether it makes sense for economic, reliability, or both types of BW projects to be elevated.
    b. To the extent sunflower's assertion is correct that reliability project costs are being driven from generator interconnections in their zone, then the CAWG should find ways to address that problem rather than simply shifting costs to other zones.
    c. When determining whether a zone is considered wind rich they should exclude all affiliated generation and PPA's.
    d. All NTC's associated with firm transmission requests (TSR's), GI's, and AQ request should be excluded. Any upgrades build through TSR's in the wind rich zone for wind leaving the zone already have 33% of the cost directly assigned to the off taker. Those parties should be held harmless due to the wind rule.

e. Be cognizant that several other HITT recommendations are at play here which all compound. Z2 will be removed and therefore there isn't a feedback loop going forward where directly assigned upgrades due to the GI process will ultimately make their way back to become base plan funded by the local zone.

HITT RECOMMENDATION C-2
CAWG DISCUSSION ITEMS

The HITT Report suggests that the process for review and approval of a waiver, as described in HITT Recommendation C-2, could conceptually follow the current process for addressing waiver requests related to upgrades for transmission service and for transformers as described in Section III of Attachment J. During its August 2019 meeting, the CAWG discussed utilizing the waiver criteria contained in Attachment J, III as a starting point.

The relevant transformer waiver language in Attachment J, III states:

> A waiver may be requested to use a transformer's higher voltage level instead of the lower voltage level for the purposes of cost allocation under this Attachment J based on the anticipated utilization of the transformer. Such request must be made in writing with supporting analysis and submitted to the Transmission Provider not less than one hundred eighty (180) days following the inclusion of the transformer in an approved SPP Transmission Expansion Plan. Any waiver request submitted shall be evaluated based upon the following general factors, including but not limited to: (i) whether the power flows through the transformer predominantly are from the lower voltage to the higher voltage; (ii) whether the transformer is not necessary for the support of, or does not substantially benefit, the lower voltage system in the host zone to which it is connected. The Transmission Provider shall make a recommendation to accept or deny the waiver, on a non-discriminatory basis, to the Markets and Operations Policy Committee. The Markets and Operations Policy Committee will consider the waiver request and the Transmission Provider's recommendation regarding such waiver to the SPP Board of Directors. Barring unusual circumstances, the recommendation to approve or reject such waiver request will be submitted to the SPP Board of Directors within one hundred twenty (120) days following the receipt of the waiver request.

LES General Comments: LES believes that the onus for proving a need for highway funding on a byway project remains on the entity seeking a waiver. Additionally, although the CAWG is seeking consistency in how the waiver process might be approached and applied, LES believes that the most important thing to consider is the fact that this should be a narrow process for potential approvals. Nearly all byway projects approved under the ITP process should remain byway projects. This means that a methodology used to show a need for highway funding for a byway project within one ITP may not necessarily be a good guideline for the next or other ITP's, simply because it might apply to too many projects in that ITP. There needs to be flexibility within the process to recognize this.

The CAWG seeks comment on the following:

1. Would it be appropriate to modify the evaluation language to read as follows: "Any waiver request submitted shall be evaluated based upon the following general factors, including but not limited

to: (i) whether the power flows ~~through the transformer~~ on the transmission facility predominantly ~~are from the lower voltage to the higher voltage~~ support the export of power from the zone; and (ii) whether the ~~transformer~~ transmission project is not necessary for the support of, or does not substantially benefit, ~~the lower voltage system in~~ the host zone to which it is connected." Other suggestions?

LES: LES doesn't believe this language is inappropriate. However, again, this may be too broad if left by itself. There should only be 1-2 (if any) projects per ITP that should qualify for a waiver.

2. How could a Transmission Owner demonstrate that the power flows on the transmission facility predominantly support the export of power from the zone?

LES: This should be at the discretion of the entity seeking the waiver and the approval of the MOPC.

3. How could a Transmission Owner demonstrate that the transmission facility is not necessary for the support of, or does not substantially benefit, the host zone? How should "does not substantially benefit" be defined?

LES: This should be at the discretion of the entity seeking the waiver and the approval of the MOPC.

4. Should we look at all generation that exceeds XX% and the local zone exports greater that 50% of the hours in a year? Other suggestions?

LES: Greater than 50% seems low. Additionally, if there was adequate demonstration that met the purposes of items 2 and 3 above, this might not be necessary.

5. The HITT C-2 recommendation anticipates including existing NTCs in the waiver process. Are the current timeframes in J, III appropriate for existing NTCs? Are the timeframes appropriate for future NTCs? If not, what should the timeframes be for waiver request filings and review?

LES: There may need to be a one-time exemption for existing facilities that allows them to go beyond the 180 day limitation. However, this should be a limited time period for these requests.

6. The Attachment J, III waiver process directs the MOPC to consider the waiver request and provide a recommendation to the SPP Board of Directors. Should the RSC be included in the review process and, if so, to what extent?

LES: Perhaps only in previously approved projects, due to the fact that there may be some cost shifts.

7. Attachment J, Section III transformer waiver process requires the request to be made in writing with supporting analysis not later than 180 days following the inclusion of the transformer in the approved SPP Transmission Expansion Plan. Instead of the "approved SPP Transmission Expansion Plan", should it be limited to the ITP? Other suggestions?

LES: Yes, limited only to the ITP process.

NPPD Comments

The proposal attempts to correct an issue that has been caused by the Interconnection Planning Process which fails to identify necessary upgrades during the interconnection study process. The Interconnection study process utilizes ERIS assumptions and dispatch assumptions that "stack the deck" in favor of the interconnection facility where by no network upgrades are identified. Then when a subsequent Aggregate Study is processed the Aggregate Study, using a more stringent criteria, identifies the necessary upgrades that were caused by the interconnection customer during the GI process.

The requested change to the waiver process attempts to correct the issue via a very indirect allocation process. When the cause of the issue is the planning process.

Most zone would not be eligible for the waiver so it discriminates against the majority of the zones.

The allocation to the regional schedule 11 bucket only masks the issue causing other customer to pay for upgrades that provide no benefit to those customers. Those that cause the costs (interconnection projects) should bare the costs of the upgrades.

SPS Comments

HITT RECOMMENDATION C-2
CAWG DISCUSSION ITEMS

The HITT Report suggests that the process for review and approval of a waiver, as described in HITT Recommendation C-2, could conceptually follow the current process for addressing waiver requests related to upgrades for transmission service and for transformers as described in Section III of Attachment J. During its August 2019 meeting, the CAWG discussed utilizing the waiver criteria contained in Attachment J, III as a starting point.

The relevant transformer waiver language in Attachment J, III states:

> A waiver may be requested to use a transformer's higher voltage level instead of the lower voltage level for the purposes of cost allocation under this Attachment J based on the anticipated utilization of the transformer. Such request must be made in writing with supporting analysis and submitted to the Transmission Provider not less than one hundred eighty (180) days following the inclusion of the transformer in an approved SPP Transmission Expansion Plan. Any waiver request submitted shall be evaluated based upon the following general factors, including but not limited to: (i) whether the power flows through the transformer predominantly are from the lower voltage to the higher voltage; (ii) whether the transformer is not necessary for the support of, or does not substantially benefit, the lower voltage system in the host zone to which it is connected. The Transmission Provider shall make a recommendation to accept or deny the waiver, on a non-discriminatory basis, to the Markets and Operations Policy Committee. The Markets and Operations Policy Committee will consider the waiver request and the Transmission Provider's recommendation regarding such waiver to the SPP Board of Directors. Barring unusual circumstances, the recommendation to approve or reject such waiver request will be submitted to the SPP Board of Directors within one hundred twenty (120) days following the receipt of the waiver request.

The CAWG seeks comment on the following:

1. Would it be appropriate to modify the evaluation language to read as follows: "Any waiver request submitted shall be evaluated based upon the following general factors, including but not limited to: (i) whether the power flows ~~through the transformer~~ on the transmission facility predominantly ~~are from the lower voltage to the higher voltage~~ support the export of power from the zone; and (ii) whether the ~~transformer~~ transmission project is not necessary for the support of, or does not substantially benefit, ~~the lower voltage system in~~ the host zone to which it is connected." Other suggestions?

   As an initial matter, if you are going to create larger zones, we don't need the waiver process.

   On the phrase "support the export of power from the zone", if this applies to everyone, SPS would support the modification. However, SPS would oppose the modification if it is only applicable to a narrow definition applicable to "high wind rich area" zones.

On (ii), the term "substantially benefit", the determination should not be a benefit test; rather, whether the the project would have not been built but for the definition in part (i).

2. How could a Transmission Owner demonstrate that the power flows on the transmission facility predominantly support the export of power from the zone?

The TO should not perform the analysis – it should be up to the SPP. Further, it should be a documented and replicable process.

3. How could a Transmission Owner demonstrate that the transmission facility is not necessary for the support of, or does not substantially benefit, the host zone? How should "does not substantially benefit" be defined?

As mentioned in response to Question 2, this analysis should be performed by the SPP. If it wasn't for this flow, we wouldn't be building the project and therefor, substantially benefit does not need to be defined.

4. Should we look at all generation that exceeds XX% and the local zone exports greater that 50% of the hours in a year? Other suggestions?

No. This provision should not be included. If this suggestion were included, the process would be only applicable to two zones.

5. The HITT C-2 recommendation anticipates including existing NTCs in the waiver process. Are the current timeframes in J, III appropriate for existing NTCs? Are the timeframes appropriate for future NTCs? If not, what should the timeframes be for waiver request filings and review?

SPS supports the HITT recommendation of going-forward NTCs, where going-forward applies to future NTCs only. That is, existing NTCs would not qualify. This approach is administratively much cleaner and much easier to administer and implement.

6. The Attachment J, III waiver process directs the MOPC to consider the waiver request and provide a recommendation to the SPP Board of Directors. Should the RSC be included in the review process and, if so, to what extent?

The RSC should set the policy, but they are not an operational/implementation body, so the waiver review process itself should be left to the MOPC.

7. Attachment J, Section III transformer waiver process requires the request to be made in writing with supporting analysis not later than 180 days following the inclusion of the transformer in the approved SPP Transmission Expansion Plan. Instead of the "approved SPP Transmission Expansion Plan", should it be limited to the ITP? Other suggestions?

SPS would support limiting the process to the ITP because that is where the issues are going to be identified.

CAWG REQUEST FOR COMMENTS ON SUNFLOWER/MIDWEST ENERGY DRAFT PROPOSAL TO IMPLEMENT HITT RECOMMENDATION C-2

Background:

The HITT recommended pursuing zonal consolidation as its preferred cost allocation modification to address, among other things, wind-rich cost allocation. The HITT also recommended developing a limited cost allocation review process.

The SPP Board of Directors, in recommendation C-2 of the HITT Report, recommended that SPP evaluate creating a narrow process through which costs for specific projects between 100 kV and 300 kV can be fully allocated prospectively on a region-wide basis. According to the Report, the process should take into consideration regional benefits resulting from the facilities, including energy exports from the transmission pricing zone where each project is located.

Under this recommendation, costs for a byway-funded transmission upgrade could be funded using a region-wide allocation after meeting certain criteria under a narrow review process. Projects eligible for this *narrow* and *limited* process must be base plan upgrade costs eligible for cost allocation under the SPP tariff. This could include new or existing Schedule 11 facilities. Costs that are directly assigned shall not be eligible for this review.

The HITT report suggested that this process could be administered through a request for waiver of the cost allocation that otherwise would be applicable. Information concerning the specific upgrade(s) must be submitted to SPP for such costs to be considered for full region-wide allocation. The process for review and approval of the requests could conceptually follow the current processes for addressing waiver requests related to upgrades for transmission service and for transformers, as described in Section III of Attachment J.

The CAWG and RSC are tasked with leading this recommendation. The ESWG and RTWG are the assigned secondary working groups.

Sunflower and Midwest Energy's Draft Proposal for the C-2 Byway Waiver Process

1. In order to be eligible to seek a waiver, the following criteria must be met:
    a. Renewable generation in local zone exceeds 100% of 12 CP; **and**
    b. Local zone exports >50% of the hours in a year.

As an initial matter, consistent with determinations made by the courts and FERC, there needs to be a rough equivalence between costs and benefits – and this doesn't seem to be the case here.

SPS does not support either of these. The waiver determination should be more general – if the driver was economics outside of your zone, then you should be eligible to apply for a waiver. The determination as to whether a waiver should be granted should be determined by the SPP.

2. If the criteria in item 1 have been met, then a TO in that Zone may seek a waiver to regionally allocate the remaining costs of an NTC for a byway facility that was issued on or after June 19, 2010 that the TO demonstrates was built to primarily support the exports of renewables in its Zone. The waiver request must include supporting documentation to satisfy the applicable test for the facility as follows:
3. Tie-Line Test:
    a. For Tie-Lines between Zones that have been in service for 1 year or longer Provide at least 1 year of real-time data to demonstrate that the tie-line exports more than 50% of the hours of the year.
    b. For Tie-Lines that have been in service for less than one year or for new Tie-Line NTCs that upgrade or will create a new tie-line between Zones: Provide analysis to demonstrate the anticipated flow will predominantly be out of the pricing zone (or "exporting" out of the Zone) using ITP economic models.

As already discussed, the ability to apply for a waiver should be more general and not limited to a definition of a "wind rich area".

4. Transformer Test:
    a. For existing transformer NTCs: Provide at least 1 year of real-time data to demonstrate that the transformer exports[1] more than 50% of the hours of the year.
    SPS does not support application to existing projects; therefore, this is not needed.
    b. For new transformer NTCs: Provide analysis to demonstrate anticipated flow will predominantly export[2] out of the pricing zone using ITP economic models.
    Agree; the determination should be made by the SPP.

5. Embedded Byway Test:
    Transmission owner must provide data to satisfy one of the following two options, Option 1 or Option 2:

        a. Option 1: Conduct ITP reliability analysis to determine whether the NTC is needed for local zonal reliability. There must be no resulting voltage or thermal violations at current load levels in ITP models under the following conditions:

[1] An export for transformers consists of the power flow from the low voltage side of the transformer which is < 345 kV (byway system) to the high voltage side which is greater or equal to 345 kV of the transformer (Highway system).

[2] See footnote 1.

i. New construction or previously constructed Facility NTC – Take out the NTC and run N-1 analysis using latest ITP models; or
ii. Rebuild Existing Facility NTC – Reverse the upgrade to its original size and configuration and run N-1 analysis using latest ITP models.

b. Option 2: Transfer Distribution Factor (TDF) ITP Analysis: By incrementing the output of renewable generating resources and evaluating the PTDF (Power Transfer Distribution Factor) or the OTDF (Outage Transfer Distribution Factor) determine the impact on the flow on the NTC. If the impact of the TDF (PTDF or OTDF) exceeds a set threshold then the NTC is deemed necessary to continued exports and qualifies for a waiver. (Note that a Transfer Distribution Factor is the measure of responsiveness or change in electrical loading on system facilities due to an increase in electric power output from specific identified generator(s) and expressed in per cent (up to 100%) of the change in power flow on NTCs (monitored facility.)
SPS does not support application to existing projects; accordingly, this is not needed.

6. Economic Project Test: For an NTC that is byway funded and is classified as an economic project in a Zone that meets the criteria in Item 1 , the cost of such project will be regionally funded if the project is not needed to support the reliability of the local byway system.
SPS supports this provision, assuming the application of the waiver process is generally applied, based on the economics of the project, not a narrow application based on the definition of a "wind rich area".

Sunflower Comments

HITT RECOMMENDATION C-2
CAWG DISCUSSION ITEMS

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The relevant transformer waiver language in Attachment J, III states:

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The CAWG seeks comment on the following:

1. Would it be appropriate to modify the evaluation language to read as follows: "Any waiver request submitted shall be evaluated based upon the following general factors, including but not limited to: (i) whether the power flows ~~through the transformer~~ on the transmission facility predominantly ~~are from the lower voltage to the higher voltage~~ support the export of power from the zone; and (ii) whether the ~~transformer~~ transmission project is not necessary for the support of, or does not substantially benefit, ~~the lower voltage system in~~ the host zone to which it is connected." Other suggestions?

   ~~1.~~

2. How could a Transmission Owner demonstrate that the power flows on the transmission facility predominantly support the export of power from the zone?

   a. Could we use Sunflower's proposal step 1 here to demonstrate the flows support exports?

b. Excerpt:

In order to be eligible to seek a waiver, the following criteria must be met:

i. Renewable generation in local zone exceeds 100% of 12 CP; **and**

ii. Local zone exports >50% of the hours in a year.

~~2.~~c.

3. How could a Transmission Owner demonstrate that the transmission facility is not necessary for the support of, or does not substantially benefit, the host zone? How should "does not substantially benefit" be defined?

a. Let's look at this from a "decision tree" standpoint. If the project is economic, we can look at the project benefits used to approve the project and see how many of them accrue to the host zone. If that's below some threshold, then it is not substantially benefitting the host zone.

~~3.~~b. If the project is a reliability project, let's compare the impact of the host zone's contracted generation serving its load versus the rest of the generation in the zone exporting out of the host zone on the initial problem. [1]

4. Should we look at all generation that exceeds XX% and the local zone exports greater that 50% of the hours in a year? Other suggestions?

a. I'm in favor of the "all generation" rather than the proposals which have been singling out renewables.

~~4.~~b. Let's call it "nameplate generation in a zone exceeds 150% of the peak load in the 5 year planning case."

5. The HITT C-2 recommendation anticipates including existing NTCs in the waiver process. Are the current timeframes in J, III appropriate for existing NTCs? Are the timeframes appropriate for future NTCs? If not, what should the timeframes be for waiver request filings and review?

a. No. There needs to be a window that allows for older NTC's to be reviewed, some kind of "catch-up" period

b. For future ones, the timelines are probably ok. I suspect that how these projects come out of the planning process should largely determine whether this waiver will be sought. A sensitivity akin to Sunflowers 5a or 5b could be run by either SPP or the TO during the ITP process (excerpted below)

c. Embedded Byway Test:

Transmission owner must provide data to satisfy one of the following two options, Option 1 or Option 2:

a. Option 1: Conduct ITP reliability analysis to determine whether the NTC is needed for local zonal reliability. There must be no resulting voltage or

[1] Calculate the DF of host zone DNRs to host zone NITS load on the reliability problem the project solves and compare that to the DF of ERIS or external DNR generation to the rest of the market or the contracted NITS load, respectively.

thermal violations at current load levels in ITP models under the following conditions:

i. New construction or previously constructed Facility NTC – Take out the NTC and run N-1 analysis using latest ITP models; or

ii. Rebuild Existing Facility NTC – Reverse the upgrade to its original size and configuration and run N-1 analysis using latest ITP models.

b. Option 2: Transfer Distribution Factor (TDF) ITP Analysis: By incrementing the output of renewable generating resources and evaluating the PTDF (Power Transfer Distribution Factor) or the OTDF (Outage Transfer Distribution Factor) determine the impact on the flow on the NTC. If the impact of the TDF (PTDF or OTDF) exceeds a set threshold then the NTC is deemed necessary to continued exports and qualifies for a waiver. (Note that a Transfer Distribution Factor is the measure of responsiveness or change in electrical loading on system facilities due to an increase in electric power output from specific identified generator(s) and expressed in per cent (up to 100%) of the change in power flow on NTCs (monitored facility.)

~~5.~~

6. The Attachment J, III waiver process directs the MOPC to consider the waiver request and provide a recommendation to the SPP Board of Directors. Should the RSC be included in the review process and, if so, to what extent?

~~6.~~a. From a practical standpoint, no. Each member of the RSC has a responsibility, often statutory, to fight for lower rates for their state's ratepayers. The purpose of evaluating these waivers is to shift costs from one area to another which naturally puts that group at odds with each other.

7. Attachment J, Section III transformer waiver process requires the request to be made in writing with supporting analysis not later than 180 days following the inclusion of the transformer in the approved SPP Transmission Expansion Plan. Instead of the "approved SPP Transmission Expansion Plan", should it be limited to the ITP? Other suggestions?

~~7.~~a. No. Should some other driver cause for an extra-ordinary transmission plan to be developed (HPILs, MVPs, CREZ, etc.) then you don't want this waiver option excluded.