SOUTHWEST POWER POOL
ECONOMIC STUDIES WORKING GROUP MEETING

March 5, 2020
AEP Offices – Dallas, TX

SUMMARY OF MOTIONS AND ACTION ITEMS

General:

- Approved February ESWG meeting **minutes**.
- Approved **RR 391** as it has no impact in ESWG

SOUTHWEST POWER POOL
ECONOMIC STUDIES WORKING GROUP MEETING
March 5, 2020
AEP Offices – Dallas, TX

MINUTES

AGENDA ITEM 1 – ADMINISTRATIVE ITEMS

Economic Studies Working Group (ESWG) Chair Alan Myers called the meeting to order at 10:00 a.m. The following members were in attendance or represented by proxy:

Al Tamimi, SUNC
Alan Myers, ITC
Anita Sharma, AEP
Bennie Weeks, Xcel
Calvin Daniels, WFEC
Gayle Nansel, WAPA
Jeremy Severson, BEPC
Jody Holland, SCMCN
Jon Iverson, OPPD
John Olsen, Evergy
Kurt Stradley, LES
Kyle McKinney, GSEC
Michael Watt, OMPA
Randy Collier, CUS
Tim Owens, NPPD
Zac Hager, OGE

Proxies:
Bob Tallman for Zac Hager
JP Meitner for John Olsen

(Attachment 1 – Attendance) (Attachment 2 – Proxy)

Amber Greb (SPP) confirmed there was a quorum and provided the antitrust statement. Alan Myers reviewed the agenda for any changes. (Attachment 3 – Agenda)

> **Kurt Stradley made a motion, seconded by Calvin Daniels to approve the agenda. The motion was approved unanimously.**

AGENDA ITEM 2 – CONSENT AGENDA

The consent agenda included the following items:

Meeting Minutes – February 5th-6th, 2020 (Attachment 4 – February 5-6 2020 ESWG Minutes)

Tim Owens made the motion, seconded by Calvin Daniels, to approve the minutes.

The motion was approved unanimously.

AGENDA ITEM 3 – REVIEW OF PAST ACTION ITEMS

Amber Greb (SPP) reviewed past action items. (Attachment 5 – Past Action Items)

AGENDA ITEM 4 – HITT T5

Amber Greb (SPP) reviewed information on the benefit-to-cost ratio for economic projects with the goal for ESWG to evaluate and make a recommendation to the MOPC. There was discussion on information that could be provided to help understand the issue. (Attachment 6 – HITT T5)

Anita Sharma made the motion, seconded by Calvin Daniels, to approve for ESWG to recommend to the MOPC the B/C ratio for economic projects should remain at 1.0. The motion failed with 7 votes in favor, 7 votes against, and 1 abstention.

Voting Rational:

"ITC voted in favor of the motion to maintain the minimum Benefit/Cost (B/C) ratio for approval of economic projects at 1.0 in response to the HITT T5 request to evaluate raising the minimum B/C ratio to 1.05-1.25. Our vote on the motion itself was after ESWG's thorough review of the overall economic planning process, in consideration of the policy question HITT has raised. We voted in this manner for the following reasons:

1. The review of the overall economic planning process illustrates that many steps of the process are intentionally designed to be conservative in calculating benefits. Examples of this include using only adjusted production cost benefits up to the point of selecting successful projects – which have consistently averaged 80 percent of the total calculated benefits when all monetizable benefits are considered. This amounts to applying a functional 1.25 B/C ratio test to projects on average. In fact, it is our opinion that at each decision point, stakeholders have made conservative decisions in identifying and calculating economic project benefits.

2. SPP's analysis also indicated that as a region we have consistently overestimated project costs at the study stage over the last several planning cycles. This has the affect of reducing evaluated project B/C ratios to provide additional comfort margin regarding attractiveness of approved projects.
3. Our present consolidation methodology provides sufficient information to allow decision-makers to deny approval of an individual project for which they are not confident of the value without necessarily impacting the overall portfolio.
4. Should the region choose to revise the minimum B/C ratio to a number higher than 1.0, we believe it would be appropriate to revisit a number of other assumptions imbedded in the process to determine whether they are overly conservative in combination with the revised B/C ratio.
5. We support SPP staff's recommendation to maintain the approval B/C ratio at 1.0." – Alan Myers

"AEP voted to retain the B/C ratio of 1.0 for economic projects largely because the conservative assumptions and inherent limitations imposed on the benefits used for calculating the B/C ratio is equivalent to a B/C threshold greater than 1.0 as explained below:

- **Currently, only the APC (Adjusted Production Cost) savings benefit metric is included in the benefit-cost (B/C) ratio used to determine whether to proceed with the economic project in ITP assessments. These savings represent only a portion of the overall economic benefits provided by transmission projects and do not capture the multiple transmission–related benefits calculated after selecting the final portfolio of transmission projects. In fact, SPP Staff's analysis illustrates that these APC savings averaged 79% of the total benefit package in the last three assessments.**
- **Production cost simulations used to calculate APC savings are based on simplified modeling approaches and assumptions that tend to understate congestion and likely APC savings of transmission projects. For example, such simulations are based on perfect foresight of real time market conditions, weather-normalized load and an unrealistic fully intact transmission system (i.e. no planned or unplanned transmission outages). In contrast, it is our understanding from SPP that they are operating under "N-40" transmission system conditions on a regular basis making the market cost of congestion paid by customers markedly higher than the planning model suggests.**
- **Furthermore, by excluding the APC benefits of any unaffiliated wind from benefit calculations of transmission projects being evaluated, the APC benefit metric itself is even more restrictive now. To put this into perspective, by adopting this methodology the APC benefit to the SPP region was reduced by a factor of 2 in the 2019 ITP assessment. This also helps ensure we are not developing projects for uncommitted wind.**

- **While benefits of transmission projects are estimated over 40 years, the benefits are extrapolated out to year 15 only and then held constant in inflation-adjusted terms until the 40th year. Additionally, the inflation rate used to escalate benefits after year 15 was recently reduced from 2.5% to 2%.**
- **The 40-year costs used for B/C ratio calculations are based on SPP average net plant carrying charge (NPCC) which has historically been higher than the actual zonal net plant carrying charge of recommended projects. While this is subject to change, calculated B/C ratios of transmission projects have been conservative in past planning studies. By way of example, the 2019 ITP Economic portfolio costs based on SPP average NPCC of 17.44% resulted in $200+ million additional costs when factoring in the incumbent TO NPCC of 14.64%.**
- **An increase in benefit-cost threshold could potentially eliminate some economic projects from consideration at early stages of the solution evaluation process which may prove to be otherwise highly beneficial projects during project optimization and portfolio development. Consequently, sub-optimal projects may be recommended in the planning process.**
- **To reiterate, by holding the B/C ratio at 1.0, we will ensure that projects having benefits are identified and considered through all the phases of the ITP study process . But as we have seen over time, simply identifying projects in the study process does not mean they will necessarily be approved by the SPP BOD. Raising the B/C ratio will deprive the organization from the opportunity of even considering such projects.**
- **It is our understanding that SPP Economic Planning Staff recommends a B/C threshold of 1.0 and we support Staff's recommendation for reasons summarized above." – Anita Sharma**

"WFEC voted to maintain the 1.0 BC (Benefit/Cost) ratio because the current calculations of Benefits and Costs have been determined over time and changing the BC ratio will negate those decisions. The calculation of Benefits and Costs needs to be considered holistically before deciding to change the BC ratios in the ITP process. Until the Benefits and Costs used in the ITP have been reviewed the BC ratio should not be changed. Also, the decisions on the Benefits and Costs were originally decided by other working groups and those other groups should consider the entire BC picture.
Previous decisions that must be considered holistically include, for example:
1) The NPCC used (see slide 9, from presentation at ESWG March 5, 2020 meeting) resulted in 66% {=(541.2/326.7)-1} higher costs.
2) The Adjusted Production Cost (APC) benefit in the same slide is only 79% of the total benefits of projects.
Just considering these two factors and not the other conservative factors changes a 1.0 BC to a 2.10 BC {=(1/0.79)/(1*(326.7/541.2))} and a 1.25 BC to a 2.62 BC {=(1.25/0.79)/(1*(326.7/541.2))}." – Calvin Daniels

"Evergy voted to leave the B/C ratio for economic projects at the current 1.0 level. SPP was asking for a vote on the B/C ratio only, without addressing any of the other considerations (e.g. NPCC, discount rate, inflation, duration). It is inappropriate and uninformed to vote on changing the B/C ratio without discussing all the other factors. We believe the ESWG should evaluate all parameters together to determine what changes, if any, are needed." – John Olsen

"OPPD supports raising the B/C ratio used for portfolio selection to meet economic needs in the ITP process to a value in the range of 1.05 to 1.25. By the very nature of being projects to decrease the adjusted production costs of the SPP region (economic projects), such projects should inherently bring a better benefit versus cost outcome than the choice of not doing the projects at all. Inputs to the B/C calculation such as inflation rate and NPCC should be set based on accurate information while minimizing subjectivity towards outcomes." – Jon Iverson

"LES voted yes on the HITT T5 motion, "ESWG recommends to the MOPC the B/C ratio for economic projects should remain at 1.0", due to there being no compelling reason presented during the ESWG meeting discussion to warrant a change from the present 1.0 B/C ratio for economic projects." – Kurt Stradley

Golden Spread Electric Cooperative-"We support a higher than 1.0 Benefit to Cost ratio for economic justified projects in the ITP for the following reasons:

1. Transmission projects are a 40 year cost for consumers throughout the footprint, and while the costs are well known, the benefits are not.
2. Benefits are projected, costs are very well known. This is an inherently risky proposition. Unfortunately, we don't have the luxury to true up the benefits at the 10 – 20 – 30 year point in time.
3. A higher ratio than 1.0 gives a cushion for decision makers at the SPP to ensure they do not approve projects that will not be cost effective with better than a 50% probability.
4. It is important not to approve projects that could be cost beneficial equivalent to a flip of a coin.
5. The variables going into the calculation are estimates, too. Although, an attempt is made to make these estimates on the conservative side, there is no way to know. For example, natural gas prices are negative in some regions now.
6. With the large transmission buildout finished in the SPP we now have $10 billion of investment approved. This was the "low hanging fruit" and much of that could have been justified several different ways. We needed to tie together all the old Balancing Authorities and provide significant intertie capability for reliability and market operations. This has been done.

7. Going forward, approval of transmission and the risk of it not being cost effective over the 40 year time horizon is significantly more likely and potentially regrettable.
8. Until we get a "Decision Quality" process developed at SPP, for these very risky decisions, it is imperative we become more conservative in our estimation of the projected benefit to cost ratio for economically justified transmission projects.
9. Similar issues at other RTOs/ISOs have resulted in their processed requiring higher than 1.0 margins, too.
10. Although the issue was not unanimous at the HITT, the recommendation had a majority support to seriously look at raising the bar for economic projects to protect those who ultimately pay the price for them – the consumer." – Kyle McKinney

"City Utilities supports keeping the benefit to cost ratio for economic projects at 1.0. We believe the current b/c ratio is already very conservative due to the following:
• The average Net Plant Carrying Cost used in the evaluation of projects is ~17.44%. The typical projects in the areas being evaluated are ~14%. This would lead to higher cost being used in the evaluation (and lower b/c ratios).
• A limited amount of benefit metrics (primarily Adjusted Production Cost) are used in the current process, likely understating the total benefit.
• A discount rate of 8% is being used in project evaluation, which is conservative." – Randy Collier

"NPPD voted in favor of the motion. After reviewing the information presented and listening to the discussions of the ESWG over the past several months, I didn't find sufficiently strong evidence to support the need for an increase in the B/C ratio for economic projects. Particularly compelling was information presented by SPP Staff indicating that applying a more conservative (i.e., higher) B/C ratio would not have changed the economic projects selected in the recently completed 2019 ITP assessment. While the overall B/C ratio threshold appears to be adequate for SPP as a whole, NPPD does continue to have concerns that the ultimate allocation of these benefits may be overstating the benefits assigned to individual zones, relative to the allocation of costs." – Tim Owens

AGENDA ITEM 5 – 2020 ITP ASSESSMENT

AGENDA ITEM 5A – SCHEDULE

Sherri Maxey (SPP) presented the 2020 ITP Assessment schedule and reviewed upcoming milestones. (Attachment 7 – 2020 ITP Schedule)

AGENDA ITEM 6 – 2021 ITP ASSESSMENT

AGENDA ITEM 6A – SCHEDULE

Sherri Maxey (SPP) presented the 2021 ITP Assessment schedule and reviewed upcoming milestones. (Attachment 8 – 2021 ITP Schedule)

AGENDA ITEM 6B – RESOURCE PLAN PHASE 2

This item was not discussed.

AGENDA ITEM 6C – SITING PLAN & SITING MANUAL UPDATES

Joshua Norton (SPP) discussed the changes to the siting manual and received feedback from the group on some additional language needed. An update will be brought back to the group. (Attachment 9 – ITP Resource Siting Manual)

AGENDA ITEM 6D – MOPC AI 305: CONSOLIDATION

Amber Greb (SPP) reviewed the 2021 consolidation survey results and voting rationale that will be presented to MOPC. (Attachment 10 – 2021 ITP Portfolio Consolidation-Scope) (Attachment 11 – ESWG-TWG 2021 ITP Scope Recommendation – Rationale)

Kyle McKinney named Mike Wise as his proxy.

AGENDA ITEM 6E – MOPC AI 304: ECONOMIC MUST RUN

Kelsey Allen (SPP) reviewed economic must run criteria, previously approved must run exceptions, and discussed a draft proposal for must run exception criteria. (Attachment 12 – MOPC AI 304 Economic Must Run Exceptions)

AGENDA ITEM 6F – LOAD AND GEN REVIEW

Brooke Keene (SPP) presented the load and gen review schedule and changes since the latest posting. She reviewed information about the heat rate curve and laid out a timeline for feedback and approval. (Attachment 13 – 2021 Generation and Load Review)

A recommendation was sent out by email on March 12, 2020.

Tim Owens made the motion, seconded by Calvin Daniels, to approve the 2021 ITP Economic Generation and Load Reviews. The motion was approved on March 16, 2020, with 11 affirmative votes and 3 abstentions.

AGENDA ITEM 7 – RR 391: ZONAL PLANNING CRITERIA – HITT T2

Micha Bailey (SPP) presented the zonal planning criteria recommendation report. (Attachment 14 – RR391 Recommendation Report)

Jeremy Severson made the motion, seconded by Calvin Daniels, to approve RR 391 as it has no impact in ESWG. The motion was approved unanimously.

AGENDA ITEM 8 – SEAMS STEERING COMMITTEE UPDATE

Clint Savoy (SPP) gave an update on the seams steering committee.

AGENDA ITEM 9 – RISK-BASED PLANNING

Chris Jamieson (SPP) presented on the MOPC action item 302 and risk-based planning in the ITP. (Attachment 15 – MOPC AI 302 & Risk Based Planning)

ECONOMIC STUDIES WORKING GROUP MINUTES

March 5, 2020

AGENDA ITEM 15 – CLOSING ITEMS

There were no action items taken.

Respectfully Submitted,

Amber Greb

Secretary

Name	Company/Email	Attendance
aaron dingmann	aaron.p.dingmann@xcelenergy.com	Webex
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Adam Schieffer (OPPD)	ajschieffer@oppd.com	Webex
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Al Tamimi	atamimi@sunflower.net	Webex
Alan Decker	Alan.Decker@grda.com	Webex
Alan Myers	ITC	In-person
Amber Greb	SPP	In-person
Andy Berg	andrew.berg@mrenergy.com	Webex
Anita Sharma	AEP	In-person
Antonio Barber	abarber@spp.org	Webex
Ben Abing	babing@itctransco.com	Webex
Bennie Weeks	Xcel	In-person
Bill Leung	NPRB	In-person
Bob Tallman	OGE	In-person
Brian Johnson	AEP	In-person
Brian Rounds (AESL)	brian.rounds@aeslconsulting.com	Webex
BROOKE KEENE	BKEENE@SPP.org	Webex
Calvin Daniels	WFEC	In-person
Casey Cathey	ccathey@spp.org	Webex
Chris Cranford	ccranford@spp.org	Webex
Chris Davis	SPP	In-person
Chris Jamieson	cjamieson@spp.org	Webex
Chris Matthes	camatthes@aep.com	Webex
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Jacob Pannell	jpannell@spp.org	Webex
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Jason Mazigian (BEPC)	jmazigian@bepc.com	Webex

Jason Shook (GDS/ETEC)	JASON.SHOOK@GDSASSOCIATES.COM	Webex
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Jeremy Severson	BEPC	In-person
Jody Holland	SCMCN	In-person
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Joe Fultz	jfultz@grda.com	Webex
Joel Berger	jberger@ces-ltd.com	Webex
John Olsen	Westar	Phone
John Stephens	john.stephens@cityutilities.net	Webex
John.Turner	john.turner@wfec.com	Webex
Jon Iverson	OPPD	Phone
Jordan Schmick	SPS/Xcel	In-person
Joshua Norton	jnorton@spp.org	Webex
Josie Daggett	daggett@wapa.gov	Webex
JP Meitner	james.meitner@evergy.com	Webex
Kelsey Allen	kallen@spp.org	Webex
Kirk Hall	khall@spp.org	Webex
Kurt Stradley	LES	In-person
Kyle McKinney(GSEC)	kmckinney@gsec.coop	Webex
Liz Gephardt	lgephardt@spp.org	Webex
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matthews	matthews@mwec.com	Webex
Micha Bailey (SPP)	mcbailey@spp.org	Webex
Michael Odom	modom@spp.org	Webex
Michael Watt	OMPA	In-person
Mike Kraft (BEPC)	mkraft@bepc.com	Webex
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Sherri Maxey	smaxey@spp.org	Webex
Simon Mahan	simon@southernwind.org	Webex
Steve Gaw	APA	In-person
tac0908	tbright@spp.org	Webex
tallmarj	tallmarj@oge.com	Webex
Tim Owens	NPPD	In-person

Proxy Statements

Member	Proxy	Note
Zac Hager	Bob Tallman	
John Olsen	JP Meitner	John on phone, JP proxy if needed

Good Afternoon,

I will not be able to attend the March ESWG meeting on this Thursday but Bob Tallman will have my proxy.

Thanks,

Zac

Zachary C. Hager, P.E.

Resource Planning

Oklahoma Gas & Electric

321 N. Harvey, M/C 802

Oklahoma City, OK 73101

(405) 553-3635

SOUTHWEST POWER POOL, INC.
ECONOMIC STUDIES WORKING GROUP MEETING

March 5th, 2020
AEP Offices – Dallas, TX

AGENDA

Thursday, 10:00a.m. – 5:00p.m.

1. Administrative Items ..... Alan Myers (15 minutes)
   - A. Call to Order, Introductions ..... Alan Myers
   - B. Receipt of Proxies ..... Amber Greb
   - C. Review of Agenda[1] ..... Alan Myers
   - D. Antitrust Reminder ..... Amber Greb
2. Consent Agenda[1]
   - A. Meeting Minutes – February 5-6, 2020
3. Review of Past Action Items[1] ..... Amber Greb (10 minutes)
4. HITT T5[1] ..... Amber Greb (30 minutes)
5. 2020 ITP Assessment ..... (20 minutes)
   - A. Schedule[1] ..... Sherri Maxey (20 minutes)
6. 2021 ITP Assessment ..... (135 minutes)
   - A. Schedule[1] ..... Sherri Maxey (10 minutes)
   - B. Resource Plan Phase 2[1] ..... Kirk Hall (20 minutes)
   - C. Siting Plan & Siting Manual Updates (Approval Item)[1] ..... Joshua Norton (30 minutes)
   - D. MOPC AI 305: Consolidation (Approval Item)[1] ..... Amber Greb (45 minutes)
   - E. MOPC AI 304: Economic Must Run ..... Kelsey Allen (15 minutes)

[1] Background Material Included

F. Load and Gen Review (Approval Item)[1] ..... Brooke Keene (30 minutes)

7. RR 391: Zonal Planning Criteria – HITT T2 (Approval Item)[1] ..... Micha Bailey (45 Minutes)
8. Seams Steering Committee Update ..... Clint Savoy (10 minutes)
9. Risk-based Planning[1] ..... Chris Jamieson (30 minutes)
10. Closing Items ..... All (10 minutes)

A. Summary of Action Items (Amber Greb)

B. April Meeting Agenda Items

C. Future Meetings

i) April 7-8, 2020: 41st floor AEP Office, Dallas, TX

ii) May 6-7, 2020: Evergy Offices, Kansas City, MO

iii) June 10-11, 2020: 41st floor AEP Office, Dallas, TX

SOUTHWEST POWER POOL
ECONOMIC STUDIES WORKING GROUP MEETING

February 5-6, 2020
AEP Offices – Dallas, TX

SUMMARY OF MOTIONS AND ACTION ITEMS

General:

- Approved January ESWG meeting **minutes**.
- Approved **ITP Manual Task Force Retirement.**
- Approved using existing 100 meter **wind profiles** for the 2021 ITP resource planning and economic model build
    - Continue development of 80 meter profile methodology for 2022 ITP implementation
    - Use 80 meter profiles for existing 80 meter turbines, if implemented, to perform sensitivities on 2021 ITP

2020 ITP:

- Endorsed MISO RDT as the **Target Area** for additional analysis in the 2020 ITP Study.

SOUTHWEST POWER POOL
ECONOMIC STUDIES WORKING GROUP MEETING
February 5-6, 2020
AEP Offices – Dallas, TX

MINUTES

AGENDA ITEM 1 – ADMINISTRATIVE ITEMS

Economic Studies Working Group (ESWG) Chair Alan Myers called the meeting to order at 1:00 p.m. The following members were in attendance or represented by proxy:

Al Tamimi, SUNC
Alan Myers, ITC
Anita Sharma, AEP
Bennie Weeks, Xcel
Calvin Daniels, WFEC
Gayle Nansel, WAPA
Jeremy Severson, BEPC
Jody Holland, SCMCN
Jon Iverson, OPPD
John Olsen, Evergy
Kurt Stradley, LES
Kyle McKinney, GSEC
Michael Watt, OMPA
Randy Collier, CUS
Tim Owens, NPPD
Warren Whitson, Southern Power
Zac Hager, OGE

(Attachment 1 – Attendance) (Attachment 2 – Proxy)

Amber Greb (SPP) confirmed there was a quorum and provided the antitrust statement. Alan Myers reviewed the agenda for any changes. (Attachment 3 – Agenda)

> **Anita Sharma made a motion, seconded by Kurt Stradley to approve the agenda. The motion was approved unanimously.**

AGENDA ITEM 2 – CONSENT AGENDA

The consent agenda included the following items:

Meeting Minutes – January 8th-9th, 2020 (Attachment 4 – January 8-9 2020 ESWG Minutes)

The January ESWG Minutes were amended to clarify approval language for a 2% inflation rate

Tim Owens made the motion, seconded by Calvin Daniels, to approve the amended minutes. The motion was approved unanimously.

AGENDA ITEM 3 – REVIEW OF PAST ACTION ITEMS

Amber Greb (SPP) reviewed past action items. (Attachment 5 – Past Action Items)

AGENDA ITEM 4 – ITP MANUAL TASK FORCE RETIREMENT

Amber Greb (SPP) led a discussion to evaluate retiring the ITP Manual Task Force since all sections have ownership from working groups and the task force work is done. She stepped through the next steps, which included the RR process taking care of ongoing updates and if a large undertaking is needed, the ITP Manual Task Force can be reinstated. (Attachment 6 – ITP Manual Task Force Retirement)

Tim Owens made the motion, seconded by Kurt Stradley, to retire the ITP Manual Task Force. The motion was approved unanimously.

AGENDA ITEM 5 – 2020 ITP ASSESSMENT

AGENDA ITEM 5A – SCHEDULE

Sherri Maxey (SPP) presented the 2020 ITP Assessment schedule and reviewed upcoming milestones. (Attachment 7 – 2020 ITP Schedule)

AGENDA ITEM 5B – MODEL AND CONSTRAINT UPDATES

SPP Staff reviewed updates to the short circuit, market economic, and market Powerflow models and the event file. (Attachment 8 – 2020 ITP Model and Constraint List Updates)

AGENDA ITEM 5C – MARKET POWERFLOW MODEL

Michael Odom (SPP) gave an update on the market Powerflow model.

AGENDA ITEM 5D – NEEDS ASSESSMENT

Kelsey Allen (SPP) reviewed the data staff uses for solutions, and covered general process for staff solution development and evaluation. He introduced the Standard Impedance Effort and covered next steps. He also covered another presentation reminding the group of the correlations between need categories. (Attachment 9 – 2020 ITP Staff Solutions) (Attachment 10 – 2020 ITP Needs Assessment)

AGENDA ITEM 5E – MISO RDT/POTENTIAL TARGET AREA

Adam Bell (SPP) and Neil Robertson (SPP) discussed "MISO Regional Directional Transfers (RDT)" as a potential target area in the 2020 ITP Assessment. They presented background and the reasons for needing additional analysis related to RDT. They presented staff's recommendation to included "MISO RDT" as the Target Area for additional analysis in the 2020 ITP Assessment. (Attachment 11 – 2020 ITP Target Area Discussion) (Attachment 12 – Settlement Agreement Reevaluation)

> **Motion: Calvin Daniels made the motion, seconded by Anita Sharma, to endorse inclusion of "MISO RDT" as the target area for additional analysis in the 2020 ITP Assessment. The motion was approved with 5 abstentions: Tim Owens, Bennie Weeks, Kurt Stradley, Zac Hager, and JP Meitner (Proxy for John Olsen, Evergy).**
>
> **Comments: "Evergy expected this to be an approval item at the TWG/ESWG joint call in February and not this ESWG meeting. We are still researching the impacts of this effort on other MISO / SPP agreements and proceedings. We will continue our internal review and be ready to approve or bring forth further discussion points for consideration at the joint call." – JP Meitner (Proxy for John Olsen, Evergy)**
>
> **I abstained from this vote, primarily because I felt it was premature to vote on Staff's recommendation at this meeting. This was not listed as an approval item on the meeting agenda and the TWG did not have an opportunity to fully review the presentation during their regular February meeting. Staff indicated they would be bringing additional information to the joint TWG/ESWG net-conference scheduled for February 26, which might have had a bearing on my vote. Finally, taking action on the motion during this meeting allowed no opportunity to discuss the issue internally with others at NPPD, prior to voting. – Tim Owens (NPPD)**

AGENDA ITEM 5F – DPP SUBMITTAL FORM & REQUIREMENTS

Tammy Bright (SPP) reviewed the Detailed DPP process and dates for the window. She noted where to find information about submitting DPPs and presented changes to the submission form. (Attachment 13– DPP Window)

AGENDA ITEM 6 – DPP BEST PRACTICES

Kirk Hall (SPP) gave a recap of a 2019 ITP Summit presentation and reviewed best practices when submitting DPPs. (Attachment 14 – DPP Best Practices)

AGENDA ITEM 7 – 2021 ITP ASSESSMENT

AGENDA ITEM 7A – SCHEDULE

Sherri Maxey (SPP) presented the 2021 ITP Assessment schedule and reviewed upcoming milestones. (Attachment 15 – 2021 ITP Schedule)

AGENDA ITEM 7B – RESOURCE PLAN PHASE 2

Kirk Hall (SPP) gave an overview of the Resource Plan Phase 2 process. He reviewed allocation of accredited resources and received questions on storage accreditation. Staff will bring back storage discussion in the March meeting. (Attachment 16 – ITP Resource Planning Phase II)

AGENDA ITEM 7C – SITING PLAN METHODOLOGY & ACTION ITEM 199: GI QUEUE IN SITING

Joshua Norton (SPP) reviewed work completed for action item 199 and presented an updated 2019 ITP Wind Siting Plan evaluation. He covered some updates for including baseline sites and proposed a process update for the 2021 ITP Siting Plan. The group kept action item 199 open to address questions on storage. Siting Manual language will be brought back in the March meeting. (Attachment 17 – Siting Plan & Action Item 199)

AGENDA ITEM 7D – MOPC AI 305: CONSOLIDATION

Amber Greb (SPP) led a discussion on the MOPC action item for consolidation. The group discussed what to bring to the April MOPC meeting. SPP staff requested feedback on the consolidation methodology for the 2021 ITP, specifically the 60/40 F1/F2 weighting for consideration 1 (APC benefit). Stakeholders will provide the rationale for votes in favor or against by Feb 21st, 2020.

AGENDA ITEM 7E – MOPC AI 304: ECONOMIC MUST RUN

Kelsey Allen (SPP) reviewed results from evaluating impact of economic must run coal units on congestion and presented conclusions and next steps. (Attachment 18 – MOPC AI 304 Economic Must Run)

AGENDA ITEM 8 – AI 200 ABB LOAD SHAPES

Liz Gephardt (SPP) presented the background and research related to hourly load shapes. She presented a staff recommendation to make no change to the current data source for hourly load shapes in ITP studies. (Attachment 19 – ABB Load Shapes ESWG Action Item 200)

The group closed action item 200.

AGENDA ITEM 9 – AI 202: WIND TURBINE HEIGHT

James Bailey (SPP) reviewed background for the action item, updates, and options for the 2021 ITP Assessment. He presented a recommendation to use Option 1. (Attachment 20 – Action Item 202: Evaluate Wind Turbine)

Zac Hager made the motion, seconded by Calvin Daniels, to use existing 100 meter wind profiles for the 2021 ITP resource planning and economic model build, continue development of 80 meter profile methodology for 2022 ITP implementation, and use 80 meter profiles for existing 80 meter turbines, if implemented, to perform sensitivities on 2021 ITP. The motion was approved unanimously.
The group closed action item 202.

AGENDA ITEM 10 – PROBABILISTIC PLANNING

Chris Jamieson (SPP) reviewed background and history on probabilistic planning, presented near-term and long-term strawman proposals, and discussed next steps. (Attachment 21 – Risk Based Planning in the ITP)

AGENDA ITEM 11 – AGING INFRASTRUCTURE

Jay Caspary (SPP) covered a presentation on aging transmission assets. (Attachment 22 – Aging Infrastructure)

AGENDA ITEM 12 – HITT T5

Amber Greb (SPP) reviewed past presentations on the HITT recommendation, updated cost estimate charts and tables, and upcoming schedule. (Attachment 23 – HITT Recommendation)

AGENDA ITEM 13 – JAN ESWG SURVEY RESULTS/2020 ESWG GOALS

Amber Greb (SPP) reviewed the January ESWG survey results. The group discussed prioritizing initiatives for 2020. (Attachment 24 – January ESWG Survey Results) (Attachment 25 – ESWG Survey Results Document)

AGENDA ITEM 14 – ROBERT'S RULES: ABSTENTION IMPACT ON VOTE

Amber Greb (SPP) presented on Robert's Rules and how abstentions impact votes. (Attachment 26 – Robert's Rules)

ECONOMIC STUDIES WORKING GROUP MINUTES

February 5-6, 2020

AGENDA ITEM 15 – CLOSING ITEMS

Additional Notes:

- SPP staff will provide additional details for the 2020 ITP Target Area "MISO RDT" at the Feb. 26, 2020 Joint TWG/ESWG Net-Conference.
- SPP staff requesting feedback on the consolidation methodology for the 2021 ITP, specifically the 60/40 F1/F2 weighting for consideration 1 (APC benefit). Please provide the rationale for your vote in favor or against by **Feb 21st, 2020**.

There were no action items taken.

Respectfully Submitted,

Amber Greb

Secretary

Southwest Power Pool, Inc.

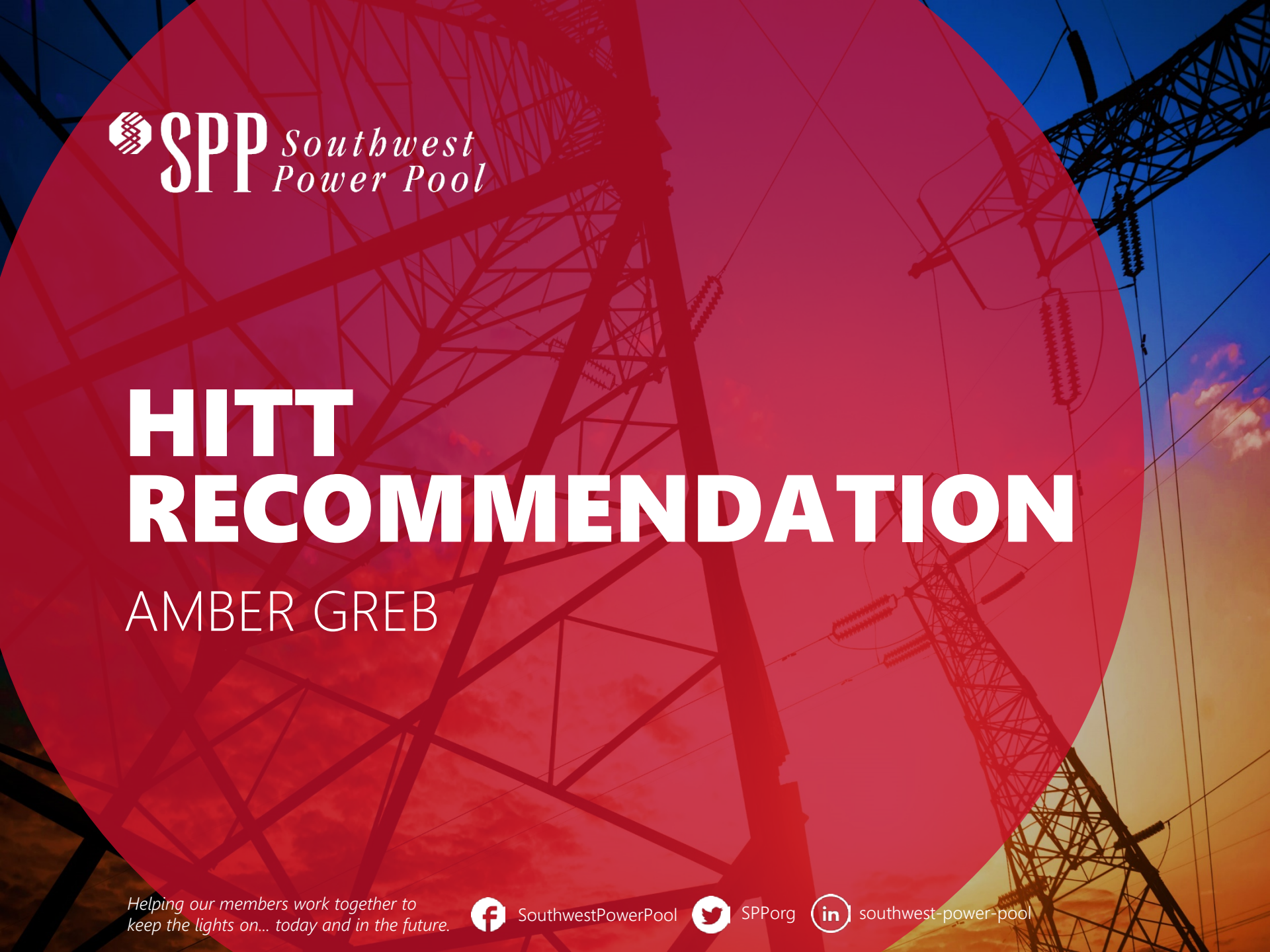
ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

March 5-6, 2020

	Action Item	Date Originated	Status	Comments
183	SPP staff to perform transmission outage analysis in the first part of 2017 to determine the appropriate APC benefit percentage to utilize for the mitigation of transmission outages benefit metric.	September 15th, 2016	In Progress SPP Staff	ESWG Approved the methodology and staff to begin analysis. Staff to bring an update by the December ESWG meeting. Working with SPP operations on additional APC benefit with outages included.
190	SPP staff to perform a full transmission outage analysis before the next RCAR	October 12th, 2017	SPP Staff	Working with SPP operations on additional APC benefit with outages included.
196	From SSC: ESWG to look into including market to market payments/settlements in the ITP Planning Process	January 9th, 2019	In Progress SPP Staff	Staff presented an education session in February, bring additional information as available
199	How we inform our Siting Plan: Research the appropriateness of relying on the GI Queue for Siting of renewables and Battery Storage and looking into other available information	April 2019	SPP Staff	Goal: to complete and implement for the 2021 ITP Assessment Continue discussing the battery storage piece
~~200~~	~~Address the Load shape issues provided by ABB~~	~~July 2019~~	~~SPP Staff~~	~~Bringing for approval in February meeting~~
201	Review the interchange methodology	July 2019	SPP Staff	Goal: To complete for the 2021 ITP Assessment
~~202~~	~~Re-Evaluate the existing wind 80/100 meter turbine height~~	~~July 2019~~	~~SPP Staff~~	~~Goal: 2021 ITP Scope~~
203	Conduct a Lessons Learned Session with the ESWG on the 2019 ITP Assessment	August 2019	SPP Staff	
204	Discuss the 2020 ITP consolidation methodology and if changes are needed in the scope.	September	~~All~~ Complete	
205	MOPC Action Item: TWG, and ESWG to recommend best way to incorporate Basin's concerns about winter peaking Bakken area load and	MOPC October 15-16, 2019	~~In Progress~~ Complete	Going to January MOPC

	generation supply issues in the 2021 ITP.			
206	MOPC Action Item: TWG and ESWG to develop approaches that address winter peaking and cold-weather driven reliability issues for incorporation in SPP's normal planning processes.	MOPC October 15-16, 2019	In Progress	
207	Review the discount rate	January 8-9, 2020		April EWSG
208	MOPC Action Item: ESWG and Staff to provide additional information, including input from the Strategic Planning Committee, to aid the MOPC in making a decision at the April 2020 meeting on the consolidation portion of the 2021 ITP Assessment Scope	MOPC January 14-15, 2020		



SPP Southwest Power Pool

HITT RECOMMENDATION

AMBER GREB

Helping our members work together to keep the lights on... today and in the future.

SouthwestPowerPool SPPorg southwest-power-pool

TRANSMISSION PLANNING RECOMMENDATION #5

- Evaluate the benefit-to-cost ratio for economic projects
  - Action: The ESWG should evaluate and make a recommendation to the MOPC on whether SPP should increase the B/C ratio for economic projects to between 1.05 to 1.25

REVIEW

- SPP Current Process
- MISO Process
- ERCOT Process
- Time Value of Money
- Why increase the threshold
- Conservative SPP assumptions

SPP'S CURRENT PROCESS

- ITP Economic Projects
  - 1.0 Benefit to Cost Ratio
    - 40yr APC benefit / 40yr NPV cost
    - Assumes an 8% discount rate
    - Based on ~17.44% NPCC
      - Typical projects in areas with ~14% NPCC

MISO'S CURRENT PROCESS

- Market Economic Projects (MEPs)
  - 1.25 Benefit to Cost Ratio
    - 20yr APC Benefit / 20yr NPV Cost
    - Assumes 7.22% Discount Rate (MTEP 19)

ERCOT'S CURRENT PROCESS

- Economic Projects
  - 1.0 Benefit to Cost Ratio
    - Levelized 1 year APC Benefit / 1st year Annual Revenue Requirement (ARR)
    - 14% ARR
    - 2 study years

*Single-year production cost savings are used for projects that only show sufficient production cost savings in the later year

THE VALUE OF MONEY

- Benefit/Cost Ratio measures how close you are to breaking even.
- Meeting the expected rate of return means a Benefit/Cost Ratio = 1.
- Because of the 8% discount rate:
  - Loaning $1,000 & getting back $100/year for ten years = Benefit/Cost ratio of .72
  - Loaning $1,000 & getting back $138/year for ten years = Benefit/Cost ratio of 1

WHY INCREASE THE B/C THRESHOLD?

- Uncertainty of Futures Assumptions
  - Load growth
  - Gas prices
  - Renewable projections
- Related requirements are less stringent
  - B/C threshold must only be realized in a single SPP future
  - 1.0 B/C threshold is based on 40yr values
- Recent stakeholder pushback of Economic Projects that meet all of the current requirements
- 2 data points and slope make up the benefit

  **Extrapolation of slope limited to 5 years beyond final data point

HOW ARE WE CONSERVATIVE?

- Net Plant Carrying Charge
  - 17.44% SPP average versus actual
  - 2019 ITP Economic portfolio 40-years costs = **$541.2M** at 17.44% NPCC
  - 2019 ITP Economic portfolio 40-years costs = **$326.7M** at incumbent TO NPCC (14.64% average)
- Additional benefit metrics not included in 1.0 threshold
  - APC has averaged 79% of the total benefit package in the last three ITP assessments
- 40 year calculation methodology
  - Terminal value 5 years after final data point
    - Inflation at 2.5%, discounted at 8%

HOW ARE WE CONSERVATIVE?

- PROMOD models idealized and/or simplified market
  - Perfect load forecasting
  - Perfect renewable forecasting
  - Assumes power system intact, no maintenance or forced transmission outages
  - Assumes perfect congestion hedging between owned generation and load
- SPP Other Bucket
  - Revenue from projected wind not included in the regional total

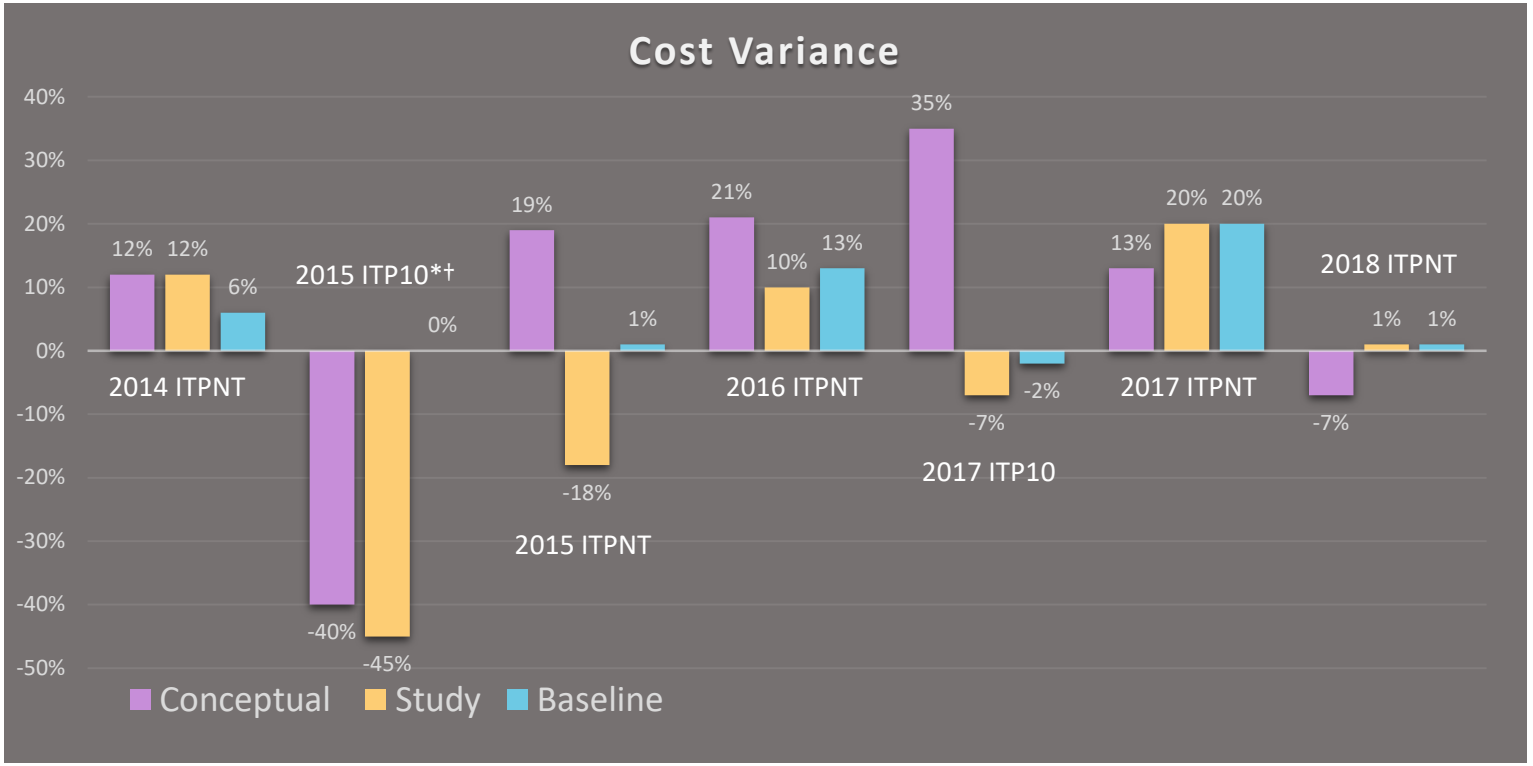
SCHEDULE

- Today
  - ESWG recommendation to MOPC
  - ESWG approval
- April
  - MOPC approval
  - SPC approval

APPENDIX

ITP COST ESTIMATES ($M)

Study Name	Conceptual	Study	Baseline	Final	Conceptual vs Final
2014 ITPNT	$482	$482	$450	$423	$59
2015 ITP10*†	$27	$25	$44	$44	$17
2015 ITPNT	$209	$145	$177	$176	$33
2016 ITPNT	$215	$195	$201	$177	$38
2017 ITP10	$15	$10	$11	$11	$4
2017 ITPNT	$17	$18	$18	$15	$2
2018 ITPNT	$3	$3	$3	$3	$0



*Different 3rd party performed study cost estimates for 2015 ITP10

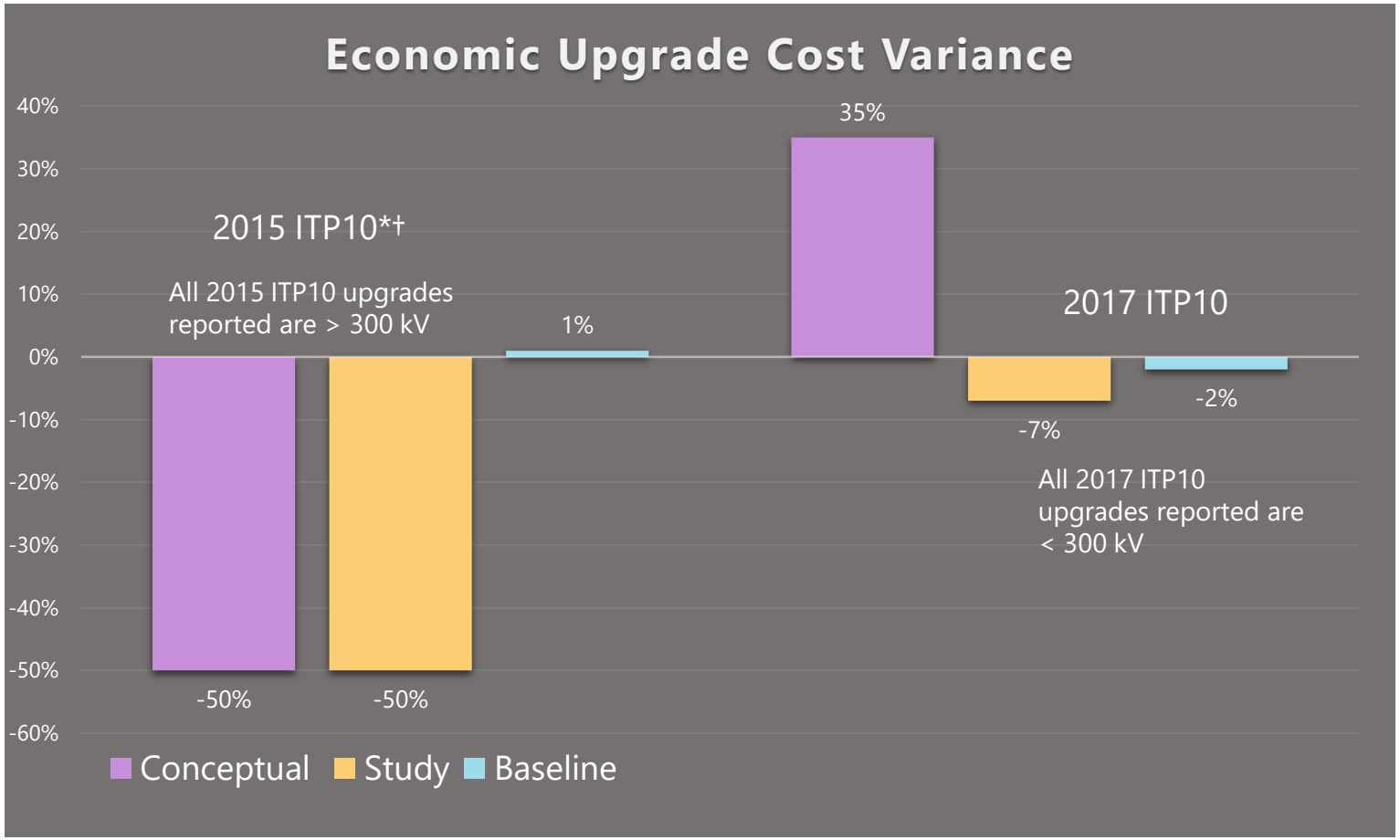
†3rd party performed all study cost estimates (not just competitive)

REVIEW OF SPP'S COST ESTIMATES

- Defined in Business Practice 7060
  - **Conceptual Estimate-** Defined by Staff using historical information. -50% to + 100% variance to final cost
  - **Study Estimate-** Generally completed by TO. +/-30% variance to final cost
  - **Baseline Cost Estimate-** Cost estimate provided by TO for NTC or NTC-C. +/- 20% variance to final cost

ITP ECONOMIC COST ESTIMATES ($M)

Study Name	Conceptual	Study	Baseline	Final	Conceptual vs Final
2015 ITP10*†	$16	$16	$32	31	$17
2017 ITP10	$15	$11	$11	$11	$4



*Different 3rd party performed study cost estimates for 2015 ITP10
†3rd party performed all study cost estimates (not just competitive)

OPERATIONS

- SPP staff is working on evaluating the operational benefit of a set of previously approved ITP projects through SPP's Value of Transmission Tool
- Operational benefit compared to to estimated values in planning studies will help inform the B/C discussion

SPP Southwest Power Pool

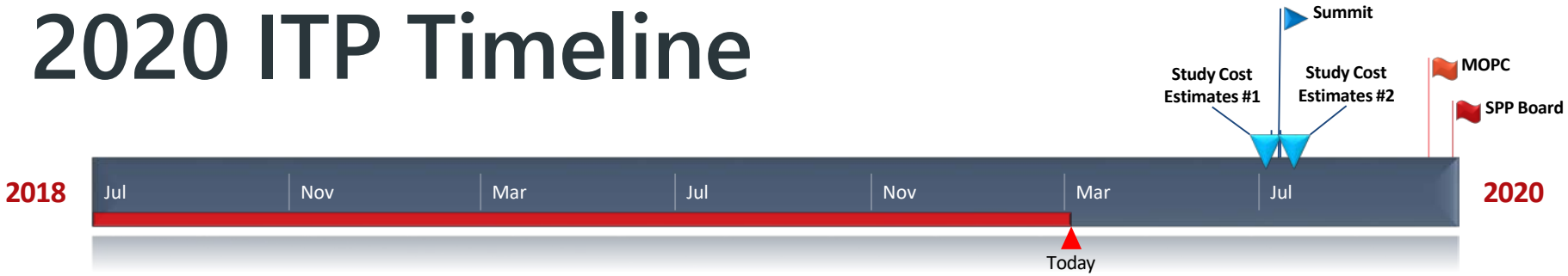
2020 ITP

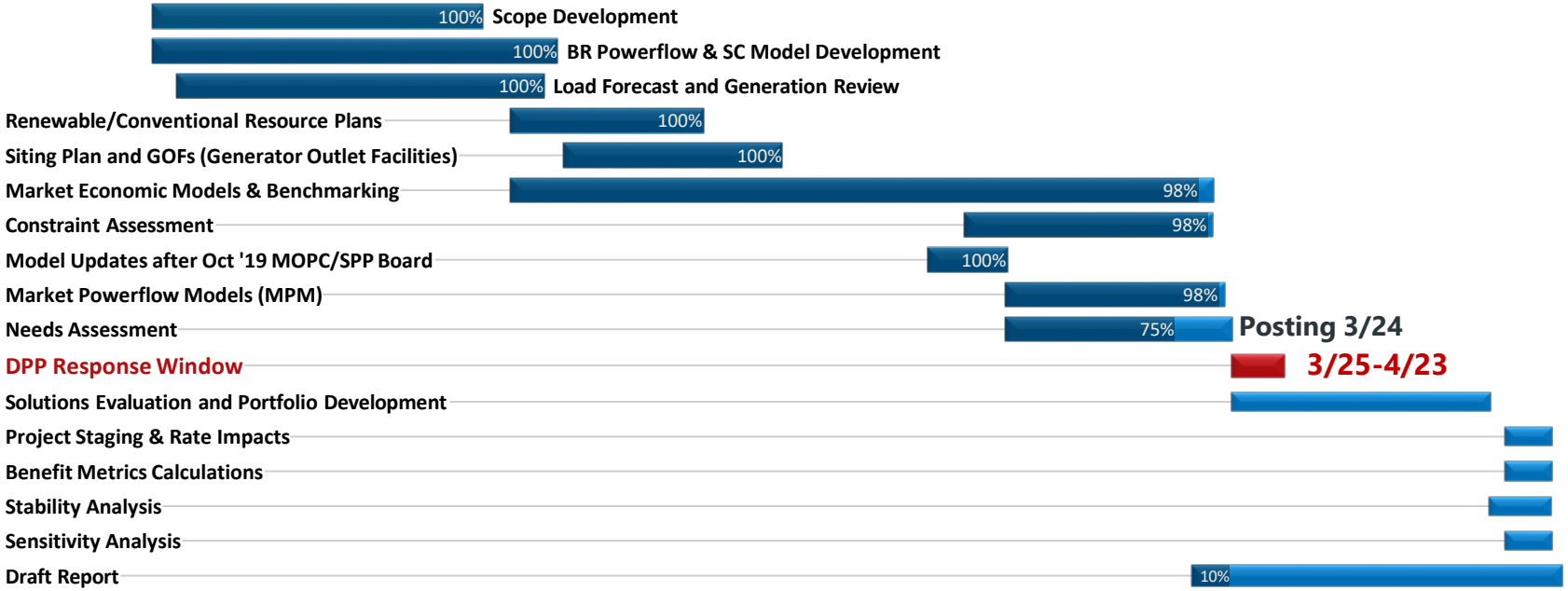
2020 ITP SCHEDULE

SHERRI MAXEY

MARCH 5, 2020

2020 ITP Timeline





MARKET ECONOMIC MODEL BUILD

- Start: 2/01/2019
- End: 1/08/2020 (Member's Initial Final Approval)
- Updated End: 3/13/2020 (Member's Re-Approval)
- Member Review Time:
  - *Post 1: 6/13/2019 – 6/28/2019 (12 days)*
  - *Post 2: 9/30/2019 – 10/07/2019 (5 days)*
  - *Post 3: Post for Approval (Constraint Assessment): 10/22/2019 – 10/29/2019 (5 days)*
  - *ESWG Approved for use in Constraint Assessment via email on 11/01/2019*
  - *Final Posting for ESWG Member Approval: 12/31/2019 – 1/08/2020 (5 days)*
  - *Final ESWG Approval: 1/08/2020*
  - Final Posting for ESWG Member Approval: 3/04/2020 – 3/11/2020 (5 days)
  - Final ESWG Approval via email by: 3/13/2020
- Staff Leader: Kelsey Allen (kallen@spp.org)
- Working Group Approval: ESWG

CONSTRAINT ASSESSMENT

- Start: 10/22/2019
- End: 1/07/2020 (Member's Initial Final Approval)
- Updated End: 3/13/2020 (Member's Re-Approval)
- Member Review Time:
  - *Post for Stakeholder Review: 12/12/2019 – 12/19/2019 (5 days)*
  - *Final Posting for TWG Member Approval: 12/30/2019 – 1/07/2020 (5 days)*
  - *Final TWG Approval: 1/07/2020*
  - Final Posting for TWG Member Approval: 3/04/2020 – 3/11/2020 (5 days)
  - Final TWG Approval via email by: 3/13/2020
- Staff Leader: Kirk Hall (khall@spp.org)
- Working Group Approval: TWG

MARKET POWERFLOW MODELS (MPM)

- Start: 10/18/2019
- End: 2/05/2020 (Member's Final Approval)
- Updated End: 3/19/2020 (Member's Re-Approval)
- Member Review Time:
  - *Pass 1 (Reactive System Adjustments): 1/07/2020 – 1/14/2020 (5 days)*
  - *Pass 2: 1/22/2020 – 1/27/2020 (3 days)*
  - *Final Posting for TWG Member Approval: 1/28/2020 – 2/04/2020 (5 days)*
  - *Final TWG Approval: 2/05/2020*
  - Final Posting for TWG Member Approval: 3/10/2020 – 3/17/2020 (5 days)
  - Final TWG Approval via email by: 3/19/2020
- Staff Leader: Michael Odom (modom@spp.org)
- Working Group Approval: TWG

BASE RELIABILITY NEEDS ASSESSMENT

- Start: 11/04/2019
- End: 3/24/2020

- Staff Leader: Joshua Pilgrim (jpilgrim@spp.org)

MARKET POWERFLOW RELIABILITY NEEDS ASSESSMENT

- Start: 1/22/2020
- End: 3/24/2020

- Staff Leader: Joshua Pilgrim (jpilgrim@spp.org)

ECONOMIC/POLICY NEEDS ASSESSMENT

- Start: 12/20/2019
- End: 3/24/2020

- Staff Leader: James Bailey (jbailey@spp.org)

SHORT CIRCUIT NEEDS ASSESSMENT

- Start: 11/04/2019
- End: 3/24/2020

- Staff Leader: Jason Terhune (jterhune@spp.org)

DPP WINDOW

- Start: 3/25/2020 12:00 a.m.
- End: 4/23/2020 11:59 p.m.
- Member Review Time:
  - Transmission-planning response window (30 calendar days)
    - Caveat: This start date is dependent upon the following milestones completing on time as scheduled:
      - MEM and Constraint Assessment re-approved by 3/13/2020
      - MPM re-approved by 3/19/2020
      - Completed needs assessments posted for reliability, short-circuit, economic, policy and consideration of persistent operational needs by 3/24/2020
- Staff Leader: Tammy Bright (tbright@spp.org)

SOLUTIONS DEVELOPMENT & TECHNICAL VALIDATION

- Start: 3/25/2020
- End: 6/08/2020

- Staff Leader: Kelsey Allen (kallen@spp.org)

SOLUTIONS EVALUATION

- Start: 4/13/2020
- End: 6/08/2020

- Staff Leaders:
  - Reliability: Neeya Toleman (ntoleman@spp.org)
  - Economic/Policy: Adam Bell (abell@spp.org)
  - Operational: Will Tootle (wtootle@spp.org)
  - Short Circuit: Jason Terhune (jterhune@spp.org)

RELIABILITY PORTFOLIO DEVELOPMENT

- Start: 6/01/2020
- End: 8/12/2020

- Staff Leader: Kelsey Allen (kallen@spp.org)

ECONOMIC PORTFOLIO DEVELOPMENT (INCLUDES PROJECT GROUPING)

- Start: 6/01/2020
- End: 8/12/2020

- Staff Leaders: Liz Gephardt (lgephardt@spp.org)

STUDY COST ESTIMATES – ROUND 1*

- Start: 7/01/2020
- End: 7/14/2020

- Staff Leader: John O'Dell (jodell@spp.org)

* Dates subject to change

PLANNING SUMMIT

- Start: 7/15/2020
- End: 7/24/2020
- Member Review Time:
  - Summit Materials (7 days prior to meeting) – Date TBD
- Staff Leader: Tammy Bright (tbright@spp.org)

STUDY COST ESTIMATES – ROUND 2*

- Start: 7/29/2020
- End: 8/12/2020

- Staff Leader: John O'Dell (jodell@spp.org)

* Dates subject to change

FINALIZE RELIABILITY PORTFOLIOS

- Start: 8/13/2020
- End: 8/17/2020

- Staff Leader: Kelsey Allen (kallen@spp.org)

OPTIMIZATION & PORTFOLIO CONSOLIDATION

- Start: 8/18/2020
- End: 9/03/2020

- Staff Leaders:
  - Liz Gephardt (lgephardt@spp.org)
  - Joshua Pilgrim (jpilgrim@spp.org)

PROJECT STAGING

- Start: 9/03/2020
- End: 9/16/2020

- Staff Leader: Liz Gephardt (lgephardt@spp.org)

BENEFIT METRICS CALCULATION

- Start: 9/03/2020
- End: 9/25/2020

- Staff Leader: Antonio Barber (abarber@spp.org)

STABILITY ANALYSIS

- Start: 9/03/2020
- End: 9/25/2020

- Staff Leader: Joshua Pilgrim (jpilgrim@spp.org)

SENSITIVITY ANALYSIS

- Start: 9/03/2020
- End: 9/25/2020

- Staff Leader: James Bailey (jbailey@spp.org)

FINAL RELIABILITY ASSESSMENT

- Start: 8/13/2020
- End: 9/25/2020

- Staff Leader: Neeya Toleman (ntoleman@spp.org)

RATE IMPACTS/ATRR

- Start: 9/16/2020
- End: 9/25/2020

- Staff Leader: Antonio Barber (abarber@spp.org)

FINAL REPORT

- Start: 8/1/2020
- End: 9/27/2020
  - Final ESWG/TWG Approval in Sept. 2020
- Staff Leader: Tammy Bright (tbright@spp.org)

TWG/ESWG FINAL APPROVALS

- Start: 9/21/2020
- End: 10/2/2020

- Staff Leaders:
  - TWG – Adam Bell (abell@spp.org)
  - ESWG – Amber Greb (agreb@spp.org)

MOPC AND SPP BOARD

- Start: 9/14/2020
- End: 10/27/2020

- Member Review Time:
  - MOPC: 10/2/2020 – 10/13/2020 (7 days)
  - SPP Board: 10/20/2020 – 10/27/2020 (5 days)

SPP Southwest Power Pool

2021 ITP

2021 ITP SCHEDULE

SHERRI MAXEY

MARCH 5, 2020

SCOPE DEVELOPMENT – APPROVED PENDING ONE ITEM

- Start: 7/08/2019
- End: 1/14/2020 (Member's Final Approval)
  - *MOPC Approval: 1/14/2020*
  - Final MOPC Review for Consolidation section: 4/15/2020
  - Final MOPC Approval for Consolidation section: 7/15/2020
- Member Review Time:
  - *Stakeholder review: 12/03/2019 – 12/11/2019 (8 days)*
  - *Approved by ESWG: 12/11/2019*
  - *Stakeholder review: 12/10/2019 – 12/18/2019 (8 days)*
  - *Approved by TWG: 12/18/2019*
  - Stakeholder Review: 3/31/2020 – 4/07/2020 (5 days)
  - Approval by ESWG: 04/07/2020
- Staff Leader: Amber Greb (agreb@spp.org)
- Working Group Approvals: ESWG and TWG

POWERFLOW & SHORT CIRCUIT MODELS

- Start: 7/09/2019
- End: 3/20/2020 (Final Approval)
- Member Review Time:
  - *Pass 0 – Trial 1: 7/22/2019 – 7/26/2019 (5 days) (complete) – Powerflow only*
  - *Pass 0 – Trial 2: 8/12/2019 – 8/30/2019 (15 days) (complete) – Powerflow only*
  - *Pass 1 – Trial 1: 9/30/2019 – 10/18/2019 (15 days) (complete) – Powerflow only*
  - *Pass 1 – Trial 1: 10/4/2019 – 10/18/2019 (10 days) (complete) – Short Circuit*
  - *Pass 1 – Trial 2: 11/18/2019 – 12/13/2019 (20 days)*
  - *Last Chance Data Submission Deadline: 12/13/2019**
  - *Pass 2: 1/20/2020 – 2/07/2020 (15 days)*
  - *Final Chance Data Submission Deadline: 2/07/2020***
  - Final Initial ITP: 3/09/2020 – 3/20/2020 (10 days)
  - Final ITP Approval with Oct. 2020 Board approved projects in Nov. 2020
- Staff Leader: David Duhart (dduhart@spp.org)
- Working Group Approval: TWG

*** Last Chance** - Data Submitters provide final Transmission Service Inputs (AG1) Data, review Pass 2 models/data submission through MOD, update load and generation reports/reconcile transaction discrepancies.
**** Final Chance** - Data Submitters submit final generation dispatch, DocuCheck corrections and topology data updates through MOD and EDST.

LOAD REVIEW

- Start: 7/19/2019
- End: 3/13/2020 (Member's Final Approval)
- Member Review Time:
  - *Load Pass 1 – Trial 1: 9/30/2019 – 10/18/2019 (15 days)*
  - *Load Pass 1 – Trial 2: 11/18/2019 – 12/06/2019 (15 days)*
  - *Load Pass 2: 1/20/2020 – 1/24/2020 (5 days)*
  - Final Posting for Approval: 3/06/2020
  - Final Load Pass – Stakeholder Review: 3/09/2020 – 3/13/2020 (5 days)
  - Final ESWG Approval requested via email: 3/13/2020
- Staff Leader: Liz Gephardt (lgephardt@spp.org)
- Working Group Approval: ESWG

GENERATION REVIEW

- Start: 7/19/2019
- End: 3/13/2020 (Member's Final Approval)
- Member Review Time:
  - *Generation Pass 1 – Trial 1: 9/30/2019 – 10/18/2019 (15 days)*
  - *RAR & Waiver Request to Stakeholders: 9/30/2019 – 10/18/2019 (15 days)*
  - *Generation Pass 1 – Trial 2: 11/18/2019 – 12/06/2019 (15 days)*
  - *Generation Pass 2: 1/20/2020 – 1/24/2020 (5 days)*
  - Final Posting for Approval: 3/06/2020
  - Final Generation Pass – Stakeholder Review: 3/09/2020 – 3/13/2020 (5 days)
  - Final ESWG Approval requested via email: 3/13/2020
- Staff Leader: Liz Gephardt (lgephardt@spp.org)
- Working Group Approval: ESWG

RENEWABLE POLICY REVIEW

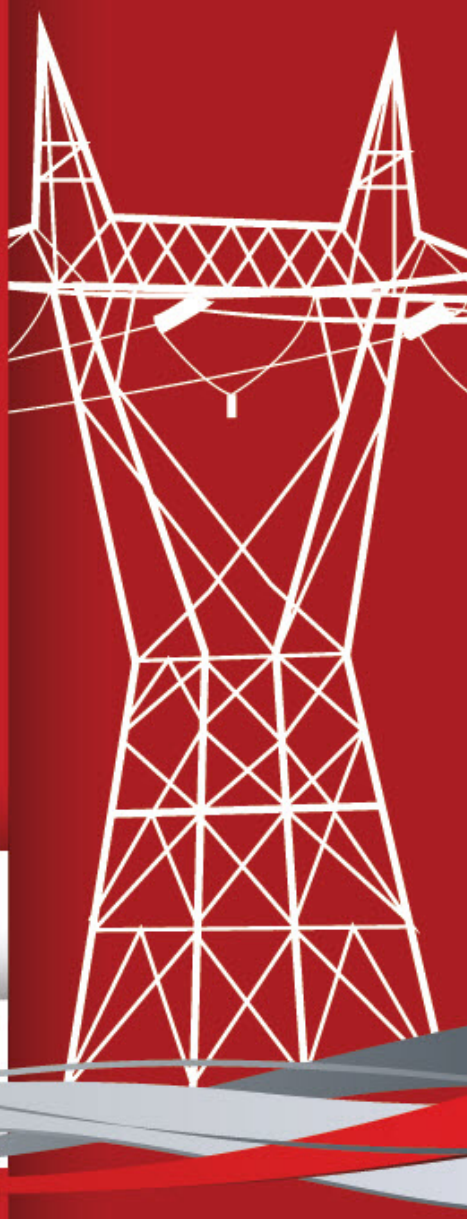
- Start: 1/07/2020
- End: 3/20/2020 (Member's Final Approval)
- Member Review Time:
  - Posting: 3/13/2020
  - Stakeholder Review: 3/16/2020 – 3/20/2020 (5 days)
  - Request ESWG Final Approval via email vote: 3/20/2020
- Staff Leader: Ahmed M. Al Azzawi (AAlAzzawi@spp.org)
- Working Group Approval: ESWG

RENEWABLE RESOURCE PLAN – PHASE 1

- Start: 2/03/2020
- End: 3/20/2020 (Member's Final Approval)
- Member Review Time:
  - Posting: 3/13/2020
  - Stakeholder Review: 3/16/2020 – 3/20/2020 (5 days)
  - Request ESWG Final Approval via email vote: 3/20/2020
- Staff Leader: Ahmed M. Al Azzawi (AAlAzzawi@spp.org)
- Working Group Approval: ESWG

INTEGRATED TRANSMISSION PLAN RESOURCE SITING MANUAL

SPP Southwest Power Pool



REVISION HISTORY

Date	Author	Change Description
06/20/2017	SPP staff	Initial Creation
10/4/2018	SPP Staff	Incorporation of approved siting methodology
3/6/2019	SPP Staff	ESWG Action Item 199 Updates

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SECTION 1:INTRODUCTION

As part of the Integrated Transmission Plan (ITP) assessments, SPP staff, with feedback from stakeholders, will create resource expansion siting plans for each future to ensure public policy compliance and resource adequacy in long-range planning models. These resources will be sited in order to meet study objectives in areas with appropriate potential pursuant to the guidelines established herein. The sites will be developed utilizing sites selected in previous studies, the generator interconnection (GI) queue, and sites developed by SPP staff and stakeholders using specific resource technology information. SPP staff will give stakeholders ample opportunities to provide feedback throughout the process and will directly engage stakeholders as needed to ensure siting assumptions are reasonable. The siting effort will be conducted as a screening-level exercise to identify sites that generally comply with the criteria and will not be intended to provide or replace a fully-scoped power plant siting study. A physical spatial location and electrical point of interconnection (POI) for each new resource within the SPP region will be selected.

A priority-based approach to siting new resources will generally be used to provide a logical order to locating generation. The source of prospective new resource sites will be the GI queue, stakeholders, SPP staff, and publicly-available information. The prioritization and ranking criteria and siting results will generally follow guidelines documented in this Manual. However, this process may be changed from study to study to meet the study-specific objectives to best deal with evident risks and uncertainties presented by trapped generation potential, load pockets, bulk transfers, and other transmission limits of interest on a case-by-case basis. Any such changes will be vetted by the ESWG.

The final resource siting plan should result in a practical balance of resource additions across SPP in such a way that the study can investigate and solve transmission limitations to best benefit the region. The prioritization and ranking criteria is based on both objective and subjective information and approved by the ESWG.

SECTION 2:GENERAL SITING PHILOSOPHY

The siting philosophy for new resources will incorporate the following general guidelines:

- Understand study objectives and how best to select practical sites to enable a study's ability to assess transmission system limitations
- Avoid excessive concentration of generation in one unit, at one physical or electrical location, or in one area in order to maintain a balanced design of the electric system
    - Limit conventional resource capacity to 1,500 MW at each site
- Recognize assumptions for proxy generation and generator outlet facilities (GOFs) can unintentionally mask critical transmission needs and can hinder the study's ability to assess transmission system limitations
- Site new jointly-owned resources in the pricing zone or state of operation of entities with the highest capacity need unless it hinders the study's ability to assess transmission system limitations or there is substantiating evidence to support otherwise, such as a limited amount of suitable sites or more attractive sites elsewhere
- Use transmission availability and resource deliverability to rank site alternatives and minimize GOF assumptions
- Maintain a reasonable balance of remaining renewable technical potential across SPP system
    - Consider areas of the system with insufficient transmission availability to prevent trapped generation potential

SECTION 3:PROCESS FLOW

The siting process will generally adhere to the following steps:

- Update the site repositories with the latest power flow and GI queue information to account for actual resource development between planning cycles
- Post repositories and request applicable stakeholders to provide feedback and additional sites for consideration and supportive rationale
- Assess whether the site repositories include adequate and diverse amount of sites to fulfill the requirements of the resource plan and are representative of remaining technical renewable potential across SPP
- Develop additional conventional resource sites and conceptual solar and wind resource sites as needed
- Rank and select sites
- Post site prioritization and selections for review
- Make any necessary adjustments and repost for approval

SECTION 4:SITE REPOSITORY

A site repository will be developed and maintained for each resource type to track sites, usage, suitability attributes, prioritization, and stakeholder feedback from study to study. The repository will be provided to stakeholders throughout the siting process for review to provide additional sites for consideration and targeted feedback. The repository will include sites from prior studies, the GI queue, and additional conceptual sites. Each site will be classified by technology type and include applicable qualitative and quantitative site suitability attributes and qualifications to rank and choose sites and build confidence in the siting plan. The repository will consider existing and retired generation sites, GI queue sites, and conceptual greenfield sites that will periodically be removed or adjusted to account for actual resource development.

The site repository could include the following site-specific information:

- Spatial or physical location
- Electrical location (bus, bus kV, and bus name)
- Pricing zone, state, nearest town, and county location
- Capacity and date of expected generation retirements
- First-contingency incremental transfer capability (FCITC) analysis results that prescreen generator outlet capability and/or deliverability of new resource to the SPP footprint
- GI queue number, POI, status, interconnection costs, and available capacities
- Stakeholder survey results
- Site classification such as brownfield, retired, or greenfield
- Data source (GI queue, SPP staff, SPP stakeholder, or publicly-available data)
- SPP staff and stakeholder prioritization and rationale
- Location in relation to modes of fuel transportation (railroad, navigable waterway, gas pipeline, etc.)
- Location in relation to frequently constrained areas (FCA), load pockets, load centers, and historical congestion
- Renewable resource capacity factors
- Fuel supply, substation interconnection, and air permitting feasibility
- Available land and feasibility of changes in land use
- Historical LMPs
- SPP staff and stakeholder feedback and comments

- Other items as needed to ensure sites have been properly vetted by SPP staff and stakeholders

SECTION 5:SITE PRIORITIZATION BY TECHNOLOGY

Sites will generally be ranked by the following criteria for initial review by the ESWG. Stakeholder-requested exceptions to the results of these technology-specific rankings will be reviewed by the ESWG for potential inclusion to account for additional information not captured by this ranking. Any sites approved as exceptions will generally replace lowest rank of corresponding GI cluster group. If no other sites were originally selected in a given cluster group, the lowest ranked site overall will be replaced.

As part of the initial selection of sites, a set of baseline sites will be automatically included in the siting plan. A baseline site will be identified when either of the following apply:

- The site resource is existing and in service.
- The site resource has an effective GIA that is not on suspension or an effective interim GIA and one of the following:
    - Has approved long-term firm transmission service with an effective transmission service agreement, or
    - Will have a firm contract for delivery through ownership and operation of the resource or procurement of a purchase power agreement (PPA) from the generation owner

Generator outlet capability will be considered at some point for each technology. Generator outlet capabilities of individual sites may be exceeded, but the goal in any case would be to minimize the number and size of GOFs required by the siting plan. GI cluster group limits may be developed and used to inform site selection. Sites would be selected by rank until GI cluster group limits are exceeded or individual FCITC limit is reached. If more sites are needed after all group limits are met, sites will be selected by rank, balancing incremental additions to groups across the footprint.

Although the primary types of resources added to the ITP assessments will be gas-fired conventional, wind, and solar; other types may be considered for future policy standards, technological advancements, or other drivers. If resources falling into categories outside of those discussed above are added through the ITP resource plan, coordination between SPP staff and stakeholders will drive where these resources are sited.

5.1: Utility-Scale Solar Photovoltaic

Due to a somewhat limited, but increasing quantity of solar PV sites requested in the SPP GI queue, the initial set of utility-scale solar sites to be considered will include (in order of preference) those from multiple site sources: the SPP GI queue, additional sites identified by stakeholders during the repository review, previous ITP sites, and other NREL conceptual sites. Utility-scale solar sites will

initially be narrowed to those within the zone of majority ownership (as assigned in the resource expansion plan). If there are no sites within the zone or only sites with limited generator outlet capability, this list will be expanded to sites within zones adjacent to the zone with majority ownership. Within each site source, starting with the most preferred (as mentioned above), the sites with the highest capacity factors and generator outlet capabilities will be selected until the sites for the given source are exhausted. The formula for this ranking is as follows:

$$Site\ Ranking\ Index\ (MWh) = FCITC\ \times 8{,}760\ Hours\ \times Capacity\ Factor$$

If a zone's resulting average capacity factor for projected solar is less than one standard deviation below the SPP average, sites with higher capacity factors in other zones may be considered.

5.2: Wind

Due to the large quantity of wind sites requested in the SPP GI queue, the initial set of wind sites to be considered are those requested in the queue that are not withdrawn~~,~~ or on suspension~~., or are past their active GIA commercial operation date.~~ This set of sites will be ranked from least to greatest according to the most current network upgrade costs per MWh:

$$Site\ Ranking\ Index\ \left(\frac{\$}{MWh}\right) = \frac{Currently\ Assigned\ Network\ Upgrades}{MW\ Requested\ \times 8{,}760\ Hours\ \times Capacity\ Factor}$$

~~of capacity requested; t~~These assigned amounts would include consideration of potentially-directly assigned upgrades needed, unknown third-party system impacts, and the generator outlet capability and corresponding GOF(s) needed to accommodate the interconnection.

When the generator outlet capability of the requests with assigned costs are trending to values less than that of requests without costs yet assigned, these interconnection requests in DISIS/PISIS (ranked ~~from highest generator outlet capability to the lowest~~by MWh) will be considered for wind siting. This set of sites will be ranked from greatest to least energy capability:

$$Site\ Ranking\ Index\ (MWh) = FCITC\ \times 8{,}760\ Hours\ \times Capacity\ Factor$$

In addition to generator outlet capability, recurring issues and/or significant upgrades within GI groupings will be taken into consideration as they relate to requests in DISIS or PISIS study at the time.

This wind ranking methodology was developed during a study where projected wind was generally assumed a non-firm energy resource without zonal ownership, thus this criteria does not consider siting within the zone of majority ownership.

5.3: Natural Gas-Fired Conventional

Conventional sites will initially be narrowed to those within the zone of majority ownership (as assigned in the resource expansion plan). If there are no sites within the zone or only sites with limited generator outlet capability, this list will be expanded to sites within zones adjacent to the zone with majority ownership. Barring any restrictions in generator outlet capability, the ranking of sites will be based on any stakeholder rankings provided during the repository review. If there are limited or no rankings for the applicable zone(s), preference will then be given to retirement sites then previous ITP sites, within the sites' generator outlet capabilities.

Due to the increased NERC CIP-002-5.1 implications of interconnections totaling 1,500 MW or more of conventional generation, total conventional generation at a single site (including existing and projected) will be capped at this amount.

SECTION 6:SITING FOR EXTERNAL REGIONS

The resource siting plan for each of the modeled regions external to SPP will be based on the corresponding company's resource plan in their most current regional planning study, as available and appropriate. If this data is not available or appropriate, as determined by SPP and the ESWG, SPP will coordinate with the corresponding entity to closely resemble the same logic as those sited through the SPP siting plan.

Publicly-known efforts to site future generation at particular locations would be the most reliable source for external siting information. For consistency across planning studies, locations utilized in other regional planning processes will also be considered.

If these sources do not result in sufficient siting information for resource plan generation, EHV buses near or at existing generation in the appropriate company's footprint will be used with the assumption that transmission capacity in these areas are sufficient for adequate power transfer without in-depth transfer analysis. For siting of resources in these external regions, the following priority will be used:

- Publicly available siting data from company integrated resource plans (IRPs)
- Locations utilized in other external regional processes
- EHV buses near other generation

SECTION 7:SITE ATTRIBUTE BACKGROUND

The general prioritization of sites are based on varying site attributes, some of which are associated with additional data that may not be incorporated (whether fully or in part). For example, the load pocket analysis was considered for the current methodology, however, the trend of requests in the GI queue indicate generation developers are taking advantage of areas of the system that would likely be avoided as a result of the load pocket analysis documented in this section. Thus, the current process does not consider this, however, there could be value in this analysis if and when trends change in the future.

This section documents background on the attributes leveraged in the approved methodology, as well as areas that may warrant consideration in future ITP studies. Any changes to the general prioritization of sites documented in this Manual will be vetted through the ESWG.

7.1: GI Queue

The GI queue prescreens obstacles such as transmission capacity availability, land availability, and customer interest due to incentives or opposition. Listed below are the queue statuses, listed from those generally indicating the most to least mature:

- Interconnection Agreement (IA) Fully Executed/Commercial Operation – The Generator Interconnection Agreement (GIA) is executed and the project has achieved commercial operation. In terms of this siting process, this status indicates the generator is operating at its requested capacity.
- IA Fully Executed/Commercial Operation Not Fully On-Line – This is not an official SPP GI queue status. The GIA is executed and the project has achieved commercial operation for a portion of the requested capacity. Subsequent phases of the project may have a later operational date.
- IA Fully Executed/On-Schedule – The GIA is executed and the agreement milestones are being met.
- IA Fully Executed/On-Suspension – The GIA is executed; however, the GI customer has requested that facility construction work be suspended.
- IA Pending – The facility study is completed for the GI request. SPP, the interconnection customer, and the transmission owner(s) (TOs) are negotiating and drafting the GIA.
- Facility Study Stage – The system impact study has been completed for the GI request. The TOs are further studying the required facilities.
- Definitive Interconnection System Impact Study (DISIS)
- Preliminary Interconnection System Impact Study (PISIS)
- Withdrawn

GI customers and/or applicable TOs will be surveyed, as needed, to gather information regarding prospective generation in the GI queue in order to better understand the likelihood of a resource proceeding to full commercial operation and aid in the prioritization.

7.2: Site Development Categories

Each site's development will be categorized as follows:

1. Existing brownfield sites
    1.1. With scheduled retirements
    1.2. With projected retirements
    1.3. Without retirements
2. Mothballed or retired brownfield sites
3. Greenfield sites
    3.1. Cancelled or postponed projects
    3.2. Conceptual projects

Existing brownfield sites include existing power plants in operation that are expandable and may have some or all units scheduled or projected for retirement. Retired/mothballed brownfield sites include power plants which have not been reused and could be recommissioned. Not all of these brownfield sites may be ideal for new capacity or differing technology. GIS information and stakeholder feedback will be used to help assess feasibility and prioritization of these sites. Generators needed for the study that would require a change in technology at brownfield sites will be given less priority than those where the technology would be the same. Greenfield sites are conceptual sites with no existing or planned development. Generators analyzed in the GI process at greenfield sites that were cancelled or postponed will be given more priority. The reasons why a project was cancelled will be investigated to determine the site's viability relative to other sites.

7.3: Generator Outlet Capability

Generator outlet capability will be used to rank sites and to limit GOF assumptions. GOF assumptions can be avoided by either selecting another site of equal status or changing the POI to one with greater available transfer capability. The siting process will include performing DC FCITC analysis as needed to help develop conceptual sites, prescreen GOF requirements, and prioritize sites.

7.4: Site Assignment

Conventional and renewable sites could be ranked by pricing zone, state, sub-region, and region. The sites will be assigned based on the origin of a need for a new resource and criteria that can be applied uniformly across SPP and adjusted as needed to meet study objectives. Resource needs are generally determined by pricing zone, and generation will be located in an entity's pricing zone or state(s) of operation. However, attractive sites in other areas can and will be used if they present a cost effective

advantage to sites within the entity's zone or state(s) of operation or to balance new resource additions across SPP. This matching of need to site is performed with the goal of spreading out the best sites and meeting study objectives. The criteria and exceptions to assumed ownership and selection of sites will be discussed with the ESWG and directly impacted stakeholders to determine the reasonableness and impact of assumptions.

7.5: Load Pocket Analysis

A ranked list of load pockets will be developed and maintained using information from historical studies and system operation, load density maps, and stakeholders. Generation, load, and generation to load profile ratios of the top ranked load pockets will be reviewed as needed to ensure reasonable balances in generation and load. Criteria will be developed and approved by stakeholders to determine when not to site new generation near these load pockets. Both conventional and renewable resource additions and sites may be adjusted to prevent from having potential load pocket issues and allow the study to assess transmission solution alternatives. Adjustments may include but not limited to:

- Selecting a site remote from a load pocket over a site near a load pocket
- Excluding a new resource addition
- Changing the technology of a new resource addition near a load pocket
- Assuming less aggressive growth in renewable resource additions near a load pocket

These adjustments may require additional analysis to be scoped as part of the study such as comparing transmission solutions to new generation as a non-transmission solution. Careful consideration will be given to a load pocket's real and reactive power requirements to identify any need for new generation to provide local voltage support.

7.6: Additional Considerations

Stakeholders and SPP staff will supply new generation sites for consideration along with site suitability information and ranking relative to other sites in the site repositories. A combination of brownfield and greenfield sites will be selected to ensure balance and diversity in site types and locations. Other quantitative and qualitative information such as expected costs, impact to the system, market impact, and likelihood of commercial operation will be considered in prioritizing and ranking sites. Information gathered from stakeholders will include, but is not limited to, preferred ranking and applicable site suitability qualities. Conventional site suitability should include information such as access to land, air permitting, cost effective fuel delivery and supplies, cooling water, substation interconnection feasibility, and site construction logistics to limit interruptions to current site operations.

SPP Southwest Power Pool

2021 **ITP**

2021 ITP PORTFOLIO CONSOLIDATION-MOPC AI

AMBER GREB

MOPC ACTION ITEM

- ESWG and Staff to provide additional information, including input from the Strategic Planning Committee, to aid the MOPC in making a decision at the April 2020 meeting on the consolidation portion of the 2021 ITP Assessment Scope

OBJECTIVE

- Review Consolidation Survey Results and rationale for votes
- Discuss direction for the MOPC action item

2021 CONSOLIDATION SURVEY RESULTS

No	Consideration	Possible Points	Threshold	Average	Keep	Up	Down
1	40-yr (1-year) APC B/C in Selected Future	Threshold Only	1.0 (0.9)	10.8	7	6	n/a
	40-yr (1-year) APC B/C in Opposite Future		0.8 (0.7)				
	40-yr (1-year) APC Net Benefit in Selected Future ($M)	50	N/A	45.8	4	3	6
	40-yr (1-year) APC Net Benefit in Opposite Future ($M)		N/A				
2	Congestion Relieved in Selected Future (by need(s), all years)	10	N/A	8.8	10	0	3
	Congestion Relieved in Opposite Future (by need(s), all years)	10	N/A	8.8	10	0	3
3	Operational Congestion Costs or Reconfiguration ($M/yr or hrs/yr)	10	>0	10	11	1	1
4	New EHV	7.5	Y/N	6.7	7	2	4
5	Mitigate Non-Thermal Issues	7.5	Y/N	4.8	7	0	6
6	Long Term Viability (Eg 2013 ITP20) or Improved ARR	5	Y/N	4.2	7	2	4

Confidence in Futures	Average	Preference	Equal	%
Confidence level in Future 1	4.3	7	5	57%
Confidence level in Future 2	3.3	1		43%

PREVIOUS ACTIVITIES

- Grouping Reminder
  - Grouping process selected the Cost Effective portfolio for Future 1 and the Highest Net portfolio for Future 2
  - Unknown what will be selected for the 2021 ITP
- Testing
  - Staff believes that the current methodology provided the best solutions to address the 2019 ITP needs
  - Testing showed that incorporating the survey feedback would not have changed the portfolio recommendations for the 2019 assessment
- Recommendation
  - SPP Staff recommended consolidation methodology consistent with the 2019 ITP
  - Motion made to keep the existing point scale for the considerations; but weight the Net benefit for consideration 1 at 60% for Future 1 and 40% for Future 2

RATIONALE SUPPORTING 60/40

- The current 50/50 methodology may favor large EHV solution over smaller less costly alternatives.
  - The Emerging Technologies Future 2 was designed to stress the system
    - Has higher energy demand growth rates due to EV growth, faster age related fossil fuel plant retirements, higher levels of distributed solar generation, utility scale solar and wind The Future 1 wind forecast in the 2021 ITP has been adjusted to make it more realistic in terms of wind generation growth than in past years and is the more likely future. Future 2 is a higher than expected wind output case.
- The 60/40 weighting reflects the ESWG's confidence level in each future based on survey results viewed during the December 2019 meeting.
- 60/40 weighting responds to concerns over favoring EHV solutions without making a major change in the consolidation process.
- A lot of scrutiny has been placed on the "installed capacity" of wind and how the ITP levels are lagging current trends. However, the "energy" from the wind in the model is "more than" the current energy trends. Therefore, the Future 1 ITP models are in line with (maybe even leading) current wind energy trends.
- Energy storage may not expand to 35% of projected solar. There is also an uncertain future for the role and market products available for Energy storage. Until this has been worked through, it is presumptuous to infer such a large share of energy storage will expand to these capacities.
- Projects with higher B/C ratios were more prevalent for the competing projects selected in Future 1 of the 2019 ITP, so a 60/40 weighting give more opportunity to award projects with a higher B/C ratio.

RATIONALE SUPPORTING 50/50

- ITP 2021 futures assumptions and consolidation criteria were debated thoroughly over a few ESWG meetings and different aspects were voted on many times to collectively develop these futures. The group agreed upon including a third future with an aggressive wind build-out that was subsequently scrapped by MOPC. During these discussions, the comments and discussion around the futures centered around these being equally weighted futures. If we are going to weight futures less than equal then we should re-visit the entire futures assumptions and consolidation methodology. F1 and F3 would have been viewed as the study bookends and F2 would have been somewhere in the middle.
- 50/50 weighting aligns with the ESWG direction to consolidate future-specific portfolios into a single set of projects by evaluating each project individually.
- Concerns with "overbuilding transmission" for uncommitted renewable resources are addressed across both futures because benefits are conservatively limited to APC benefits only and generation revenues associated with uncommitted wind are excluded from regional APC.
- We've been through only one ITP process (2019 ITP) that uses the new consolidation process developed by the ESWG. This process anticipated equal futures weighting and this methodology should be utilized for a few more ITP studies to determine whether modifications are actually warranted.
- According to SPP's own analysis, the traditional conservative forecasting model (Future 1) has significantly under-represented actual renewable energy growth. By under-forecasting renewable generation, SPP has also under-forecasted the amount and size of reliable transmission to meet customer needs.
- The AWEA "SPP ITP21 Futures Whitepaper" shows 6 independent analyst projections, all showing wind build peaking in 2020 but continuing into the future at a much higher rate than F1 contemplates.
  - On December 17, 2019 (after this decision was made at the ESWG on 12/11), Congress extended the PTCs for wind facilities for which construction begins in 2020 to be required to be in-service by 1/1/2024, likely increasing the amount of wind that will be brought on-line in 2021-2023.

NEXT STEPS

- Providing supporting information to MOPC in April

SOUTHWEST POWER POOL, INC.
Transmission and Economic Studies Working Group

RECOMMENDATION TO THE MARKETS AND OPERATIONS POLICY COMMITTEE
January 14, 2020
2021 Integrated Transmission Planning Assessment Scope

ORGANIZATIONAL ROSTER

The following persons are members of the Transmission Working Group (TWG):

Travis Hyde (Chairman), OG&E
Nathan McNeil (Vice Chairman), MIDW
Daniel Benedict, IP&L
Scott Benson, LES
John Boshears, CUS
Derek Brown, Evergy
Jarrod Cooley, SPS
Cliff Franklin, SUNC
Joe Fultz, GRDA
James Ging, KPP
Kalun Kelley, WFEC
John Knofczynski, East River
Randy Lindstrom, NPPD
Jim McAvoy, OMPA
Matt McGee, AEP
Shane McMinn, GSEC
Nate Morris, EMDE
Michael Mueller, AECC
Gayle Nansel, WAPA
John Payne, KEPCo
Chris Pink, Tri-State
Jason Shook, GDS Associates
Josh Verzal, OPPD
Michael Wegner, ITC
Phil Westby, BEPC
Noman Williams, GHP

The following persons are members of the Economic Studies Working Group (ESWG):

Alan Myers (Chairman), ITC Great Plains
Tim Owens (Vice Chairman), NPPD
Randy Collier, CUS
Calvin Daniels, WFEC
Zac Hager, OG&E
Jody Holland, GHP
Jon Iverson, OPPD
Kyle McKinney, GSEC
Gayle Nansel, WAPA
John Olsen, Evergy
Jeremy Severson, BEPC
Anita Sharma, AEP
Kurt Stradley, LES
Al Tamimi, SEPC
Michael Watt, OMPA
Bennie Weeks, Xcel Energy
Warren Whitson, Southern

BACKGROUND

The Integrated Transmission Planning (ITP) assessment is a regional planning process built to leverage knowledge of the transmission system's reliability, public policy, operational, and economic needs, as well as compliance, generator interconnection, and transmission service request impacts to develop a cost-effective transmission portfolio over a 10-year planning horizon.

The objective of the 2021 ITP Assessment is to develop a regional transmission plan that provides reliable and economic delivery of energy and facilitates achievement of public policy objectives, while maximizing benefits to the end-use customer. This 2021 ITP Scope contains assumptions to be utilized in the 2021 ITP Assessment that are not standardized in the ITP Manual. These documents should be reviewed together for a comprehensive view of the 2021 ITP process and assumptions.

The ESWG and TWG are the business owners of the 2021 ITP Scope, which entails the review and approval of methodologies and assumptions to be utilized within the study, and the scope language.

During the October 2019 Markets and Operations Policy Committee (MOPC) meeting, the MOPC reviewed and approved the futures to be assessed in the 2021 ITP.

ANALYSIS

Pursuant to SPP OATT Attachment O, the scope includes sections covering the following: an overview of the 2021 ITP assessment, assumptions to be utilized (including the two futures to be analyzed), the methodologies by which solutions will be evaluated and portfolios developed, assessments under which the final portfolio will be tested, a study timeline, and information on the process by which changes to assumptions or methodologies should be made.

The 2021 ITP Assessment will also include a needs assessment, identifying reliability, public policy, operational, and economic needs. Solutions will be evaluated for these needs and will come from Detailed Project Proposals, Transmission Service Studies, Generation Interconnection Studies, previous ITP studies, and other solutions proposed by stakeholders or staff. A portfolio of projects will be developed for each future. The projects in the future-specific portfolios will then be consolidated into a single, final portfolio.

The final portfolio will be assessed for its flexibility under varying system conditions, its benefits according to the ESWG-approved benefit metrics, and its impact on overall system reliability.

The 2021 ITP assessment began in July 2019 and will be completed by October 2021. The study scope was approved by the ESWG on December 12th, 2019, and the TWG on December 18, 2019.

Additionally, the 2021 ITP Scope includes a waiver of the ITP Manual requirement to use resource expansion software in the development of the conventional resource plan. The waiver is recommended in an effort to save time and resources based upon previous use of the resource expansion software. For the 2019 and 2020 ITP assessments, the resource expansion software determined combustion turbines as the only optimal prototype for the conventional resource plan.

RECOMMENDATION

1. The ESWG recommends a waiver of the ITP Manual's requirement to use resource planning software in the 2021 ITP Assessment.
2. The TWG and ESWG recommend the Markets and Operations Policy Committee approve the 2020 ITP Scope.

Approved:	ESWG (Waiver) Passed Unanimously	November 6, 2019
Approved:	ESWG (Scope) Passed Unanimously	December 12, 2019
Approved:	TWG (Scope) Passed Unanimously	December 18, 2019

Action Requested: Approve Recommendation

Supportive Rationale

LES	LES voted for the 60/40 F1/F2 weighting for consideration 1 (APC benefit) in the 2021 ITP consolidation at the December 2019 meeting. The results from the 2019 ITP consolidation process with the larger EHV projects being favored over possible less costly solutions caused a number of ESWG members to evaluate whether changes are warranted in the 2021 consolidation process. The Emerging Technologies Future 2 case in the 2021 ITP with the higher energy demand growth rates due to EV growth, faster age related fossil fuel plant retirements, higher levels of distributed solar

	generation, and utility scale storage, wind and solar will stress the SPP transmission system much more than Future 1 thus causing more congestion and the likelihood that Future 2 projects would be given an advantage due to higher scores in the consolidation methodology process. The Future 1 wind forecast in the 2021 ITP has been adjusted to make it more realistic in terms of wind generation growth than in past years and is the more likely future. Future 2 is a higher than expected wind output case. There were various opinions amongst the ESWG members on going forward with some wanting the status quo of equal future ratings. The consolidation process used in the 2019 ITP has only been used once and thus we do not know how future project results will fare. LES also has a small preference for Future 1 over Future 2, thus we feel it is appropriate at this time to make a slight change to the weighting process from 50/50 to 60/40 for F1/F2 to incorporate that preference.
NPPD	**Vote for 60/40 F1/F2 weighting for consideration 1 (APC benefit) in the 2021 ITP (December 2019 meeting)** – I voted for this motion. Results from the 2019 ITP consolidation caused a number of ESWG members to question whether the current methodology was favoring large EHV solutions vs. smaller less costly alternatives, based on their ability to mitigate the increased congestion resulting from the additional renewable generation buildout assumed in Future 2. The ESWG revisited the consolidation methodology over several meetings last fall as part of the scope development for the 2021 ITP and included a survey of ESWG members regarding the relative weighting of considerations in the consolidation methodology, as well as their relative level of confidence in both futures. Results of the survey, as reviewed during the December 2019 ESWG meeting, indicated a slight preference for Future 1 over Future 2, although a number of ESWG member thought that keeping the equal weighting was appropriate. Given that the consolidation methodology has only been used once so far, it didn't seem appropriate to make significant changes until we have a few more ITP assessments under our belt. At the same time, I felt it was important to respond to the concerns expressed regarding the equal weighting in the current methodology. The 60/40 weighting of the APC net benefit (consideration #1) seemed to be a measured response to those concerns and a reasonable compromise.

OGE

Below is the rationale for my vote in favor of the 2021 ITP 60/40, F1/F2 weighting in the consolidation methodology for the APC benefit.

OG&E voted for the 2021 ITP 60/40 F1/F2 weighting for the APC benefit calculation in the portfolio consolidation for the following reasons:

- The second future is designed to stress the system
  - Future 2 contains additional load from higher electric vehicle adoption whereas Future 1 uses the assumptions contained in each company's 50/50 demand forecast
  - Future 2 has lower retirement dates that cannot be adjusted by generator owners unless unit is planned for repowering upgrades
  - Future 2 has higher levels of Distributed Generation (Solar), utility scale solar and wind.
- A lot of scrutiny has been placed on the "installed capacity" of wind and how the ITP levels are lagging current trends. However, the "energy" from the wind in the model is "more than" the current energy trends. Therefore, the Future 1 ITP models are in line with (maybe even leading) current wind energy trends.
- Congestion is expected to be higher in the second future by design. The removal of that congestion will therefore lead to higher scores. This will automatically give projects from Future 2 an advantage in the consolidation methodology.

For these reasons I believe Future 1 should have a much higher weighting but settled on the 60/40 split to be more in line with survey of member confidence (scores) of the futures.

OPPD

OPPD's response to the ITP 2021 consolidation consideration survey was submitted to SPP on 11/12/2019. In this response we indicated we would like a specific Consideration based on the B/C ratio achieved by competing projects in separate futures.

To further explain, the OPPD suggestion is to take part of the 50 points awarded based on APC net benefits and award those points (x of 50) based on APC B/C ratio. OPPD suggested giving a possible 25 points to APC net benefits and a possible 25 points to APC B/C ratio.

At the December ESWG meeting the group decided to stay with the existing 50 possible points based on APC net benefits. In other words, no change to the existing consolidation used in the 2019 ITP.

Given that OPPD's proposal was to better reward projects with higher B/C ratios than competing projects with lower B/C ratios, and that higher B/C ratios were more prevalent for the competing projects selected in Future 1 of the 2019 ITP, OPPD supported a higher weighting of 60% (based on APC benefits) to Future 1 of the 2021 ITP.

OPPD also supports the 60/40 weighting of F1 and F2 based on the confidence level results of the 11/12/19 survey.

GSEC

Golden Spread Electric Cooperative, Inc. (GSEC) supports a 60% weighting for Future 1 and a 40% weighting for Future 2. As discussed in prior meetings, we do not want to make any sweeping changes to this process at this point due to only completing one ITP cycle. This is the exact reason we need to begin, in the early years of this process, to stay more conservative until we have additional history to lead us in a different direction. There is not a market or reliability need to simulate larger build-outs of transmission, and by doing so, market participants can incur higher transmission costs than are necessary. However, GSEC also supports defining and the implementation of annual reporting of actual data relative to the 'Key Assumptions" that are made– particularly the review of data points that the ITP has assumed inputs for during its model run. These annual reviews should provide ESWG the opportunity to vote each year for different weightings between the two futures. This gives flexibility for future model runs to adjust based on actual data and trends that are realized.
GSEC supports the slightly stronger weighting of Future 1 over Future 2 for the following reasons:

1. The simulation of large amounts of wind and solar beyond what a forecast that is deemed conservative leaning risks the unneeded overbuild of transmission.
2. Energy storage may not expand to 35% of projected solar. There is also an uncertain future for the role and market products available for Energy storage. Until this has been worked through, it is presumptuous to infer such a large share of energy storage will expand to these capacities.

SPS	F1 includes a significant amount of additional wind, solar and batteries. F2 assumes emerging technologies will drive even more additional wind, solar and batteries. There are differing opinions on how fast and what impact emerging technologies will have in the future. For that reason SPS supports the 60/40 F1/F2 weighting.

Unsupportive Rationale

AEP	**AEP rationale to maintain equal "50/50" futures weightings in ITP 2021 Study** • The ITP Futures are being mischaracterized during this F1/F2 weighting debate as "F1 is the expected future and F2 is a stretch future". It is more accurate to consider futures as "bookends" where the expected results will end up somewhere in the range between the futures. ESWG intended for three futures for the 2021 ITP including a Future 3 which anticipated a carbon tax and greater EV penetration, and as such F1 and F3 would have been viewed as the study bookends and F2 would have been somewhere in the middle. Due to concerns over additional costs to evaluate F3, this future was ultimately abandoned without subsequent adjustment to the F1 or F2 assumptions that would have rightly adjusted these bookends. As such, F2 in the 2021 ITP does not represent a typical study bookend but is closer to a midpoint, lending credence to maintaining the 50/50 weighting. • SPP Staff has been directed by the ESWG to consolidate future-specific portfolios into a single set of projects by evaluating each project individually and using a 50/50 weighting aligns well with meeting the objective of evaluating the project on an individual basis. Also, Staff and stakeholders agreed that although this methodology is a reasonable approach to measure the project effectiveness, it will not be the only input to project selection and Staff has the ability to use engineering judgement and oppose the results of this systematic approach based on project drivers. • Concerns with "overbuilding transmission" for uncommitted renewable resources are addressed across both futures because ▪ Benefits are conservatively limited to APC benefits only

- Generation benefits associated with uncommitted wind are excluded for the benefits calculations for transmission projects included in the ITP

- We've been through only one ITP process (2019 ITP) that uses the new consolidation process developed by the ESWG. This process anticipated equal futures weighting and this methodology should be utilized for a few more ITP studies to determine whether modifications are actually warranted.
- The 50/50 weighting used in the consolidation methodology for the two futures in the 2019 ITP Assessment produced a portfolio of transmission projects that provided significant and near-term benefits to loads in the SPP Region while addressing the transmission system needs.
- In addition, ESWG is currently considering modifications to long-standing b/c input parameters (inflation rate and discount rate) that will affect study results. The cumulative effect of these plus changing futures weightings may result in unintended consequences when multiple new variables are applied concurrently.

Evergy

Evergy's concern with the unequal 60/40 weighting is it suggests the "status quo" future 1 is more likely than future 2. There is no data that suggests future 1 outcomes are any more likely than the future 2. Historically, future 1 tends to underestimate the change that the SPP members are likely to experience. In Evergy's opinion, Future 2 has done a better job of representing the final state of the system in the outer years. For example, the amount of wind that was connected to the SPP footprint at the end of 2019 (22.5 GW) nearly equals the amounts listed in the 2019 ITP Assessment Scope for future 1 (24.2 GW Year 5, 24.6 GW Year 10). Future 2's assumptions (27 GW Year 5, 30 GW Year 10) would seem more likely given the current trajectory of wind expansion. Additionally, the weightings were arbitrarily rounded up from the survey results of 57%/43%, which was the basis for the original motion to change the weighting. At this time, Evergy sees no need to deviate from the current 50/50 weighting.

ITC

ITC voted against the 12/11/19 ESWG consolidation proposal that weights F1 APC benefits at 60 percent versus 40 percent for F2 APC benefits in the 2021 ITP study. ITC's reasons for our vote include the following:

1. We support the staff analysis and recommendation which would have maintained an implied 50/50 weighting of APC benefits between F1 and F2 when evaluating the value of individual projects.
2. ITC believes that across the totality of the assumptions in the respective futures, neither future represents an "expected case" worthy of greater weight than the other. In fact, as the assumptions on renewable resources were developed, we would assert that F2 is at least as probable as F1.
3. The consolidation methodology in total provides an appropriate level of individual project detail for SPP's decisional bodies to make appropriate judgements and alterations as necessary without changing the formula used in the 2019 ITP study (and, which will be used in the 2020 ITP study).

NextEra

Per SPP's request the following rationale is behind the NextEra votes against the 60/40 Future 1/Future 2 proposal:

According to SPP's own analysis, the traditional conservative forecasting model (Future 1) has significantly under-represented actual renewable energy growth. By under-forecasting renewable generation, SPP has also under-forecasted the amount and size of reliable transmission to meet customer needs.

NextEra believes that Southwest Power Pool should be utilizing the most statistically correct methodology when forecasting Future scenarios. Of the two methods available today, Future 2 is more accurate and is a better method for forecasting transmission needs across the footprint. NextEra sees no need to change the current methodology of 50/50 weighting for this ITP cycle to a method that is less accurate.

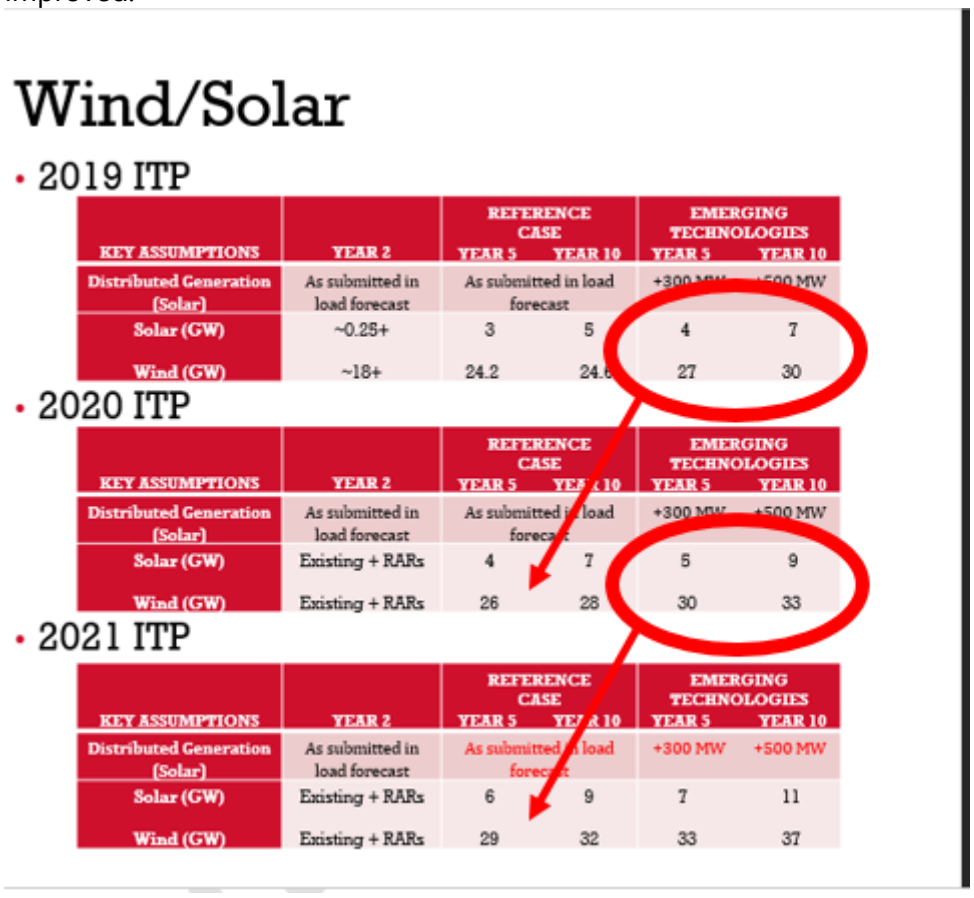
NextEra also recommends that SPP evaluate a stronger emphasis on Future 2 for future scenarios and recommends a review on other methods that may provide SPP with more statistically accurate growth assumptions.

Southern Power

Following is Southern Power's rationale for voting no on the 60/40 Futures weighting. We did not originally provide comments, but wanted to get the following on the record, per the discussion and request for additional feedback at the last ESWG meeting:

Southern Power **opposes** weighting net benefit for consideration 1 at 60% for Future 1 and 40% for Future 2 primarily for the following reasons:

1. The rationale given in discussion at ESWG for weighing Future 1 higher is that some members feel that the future wind build-out in that future is more likely than that in Future 2. We disagree with this rationale for several reasons. Over the past few years (as has been presented by AWEA at ESWG meeting on 9/5/2019) SPP ESWG's F1 has consistently under-estimated wind build-out, with F2 wind assumptions (emerging technologies) becoming F2 (Reference Case) for the following year's ITP process. Also, by the time the ITP studies are completed, the wind build-out has consistently not only project to exceed F1, but operating and committed wind build-out has already exceeded the Year 10 assumption for F1. Under-forecasting was prevalent enough that even senior SPP leadership has publicly acknowledged this is an item that needs to be improved.



1.

2. This AWEA "SPP ITP21 Futures Whitepaper" also shows 6 independent analyst projections, all showing wind build peaking in 2020 but continuing into the future at a much higher rate than F1 contemplates.

2. Much of the arguments around why wind build is going to slow down is based around the expiration of the federal PTCs for wind. On December 17, 2019 (after this decision was made at the ESWG on 12/11), Congress extended the PTCs for wind facilities for which construction begins in 2020 to be required to be in-service by 1/1/2024, likely increasing the amount of wind that will be brought on-line in 2021-2023. As a large wind developer/owner/operator in SPP, Southern Power is very familiar with wind facility economics and PTC dynamics. SPC does not believe that wind development will almost completely stop even when PTCs expire, as F1 contemplates.

The entire ITP 2021 futures assumptions and consolidation criteria were debated thoroughly over a few ESWG meetings in the Fall of 2019 and different aspects were voted on many times to collectively develop these futures. The group agreed upon including a third future with an aggressive wind build-out that was subsequently scrapped by MOPC. During these discussions, the comments and discussion around the futures centered around these being equally weighted futures. If we are going to weight futures less than equal then we should re-visit the entire futures assumptions and consolidation methodology.

APA **The Advanced Power Alliance submits the following comments on the weighting of Futures 1 and 2 in the ITP 2021:**

The Advanced Power Alliance (APA)[1] believe that the two Futures in ITP 2021 represent a conservative assessment of the changes that are occurring in the SPP. The higher weighting of Future 1 results in an overly conservative and less realistic emphasis on the least likely of the two ITP 2021 Futures and should be rejected.

Over the last decade the generation mix of SPP has dramatically changed from one heavily reliant on coal and gas with only very small amounts of wind and solar to one increasingly powered by renewable energy. Wind energy is now the second most utilized energy resource in the SPP and is predicted by SPP to pass coal and take over the number one spot within the next two years. These

[1] Advanced Power Alliance (APA) is a not for profit trade organization representing wind, solar, and storage developers, generator owners, wind turbine and component parts manufacturers, and public interest organizations interested in wind and solar energy and energy storage development in the SPP and Electric Reliability Council of Texas ("ERCOT") regions of the United States.

changes have been continually underestimated in the transmission planning process. SPP's review of the estimates over this 10 year timeframe clearly show that projections for wind development alone have been extremely conservative and inaccurate. The transmission planning futures regularly projected wind development over the 10 year horizon is actually in service before the study itself is even completed. Consumers pay for not addressing the congestion costs that result from not planning and constructing cost beneficial transmission in a timely fashion. The purpose of good planning should be to assess plausible scenarios so that good investment decisions can be made for the benefit of consumers. We should not put blinders on our planning of transmission needs so that the benefits and costs of building or not building transmission can be assessed more accurately. Because SPP has chosen to only examine two Futures it is important that they represent reasonable scenarios that appropriately weight the likelihood of their occurrence.

The initial proposal of three futures for the ITP 2021 included an additional Future that assumed additional wind and solar development beyond that assumed in Future 1 and 2. There was general support for looking at this third scenario before the cost of that effort led its abandonment. Some stakeholders including APA and the MMU, believed that Future 3 was a very plausible scenario that should be examined in the ITP 2021. An analysis including Future 3 would have meant that Future 2 would represent the moderate case between two bookend futures. When that Future was removed APA believed that the remaining Future 2 was the most likely scenario of the two remaining. The current proposal to further diminish the impact of the more likely Future 2 at this point is repeating the failures of the past transmission planning studies that have vastly underestimated the development of wind and solar resources in the footprint. If any difference in weighting of the two remaining futures should occur it would be more reasonable to increase the importance of Future 2, rather than diminish it.

While it is a very conservative approach, we do not object to staff's original recommendation for the futures to have equal weighting or in the alterative to allow consideration of the additional information that becomes available at the time decisions are made on transmission project recommendations in the latter stages of the study. We believe it is time for the ITP process more accurately reflect the changes that are occurring in SPP and to avoid the pitfalls of past studies that have continually underestimated generation development. At a minimum the remaining futures in the ITP 2021 should be equally valued.

SPP Southwest Power Pool

2021 ITP

MOPC AI 304 ECONOMIC MUST RUN EXCEPTIONS

KELSEY ALLEN

MARCH 5-6, 2020

OVERVIEW

- Review general economic must run criteria
- Review previously approved must run exceptions
  - Review SPP comments on previous cases made (red text)
- Discuss draft proposed must run exception criteria

MUST RUN CRITERIA

- Methodology for must run units in the ITP:
  - All nuclear and hydro units
  - Identified co-generation units based on EIA 860 data as well as any co-generation units in ABB data that were not identified in EIA 860 data
  - If a unit was originally identified as a must run in a previous ITP, but was removed as an exception, it will not be identified as a must run in the current ITP.
- Exceptions approved by ESWG

MUST RUN EXCEPTIONS (2021 ITP)

- Sheldon (NE):2
  - Sheldon (NE):2 is being converted to utilize hydrogen gas. NPPD is expecting a 75-90% capacity factor and is requesting Sheldon (NE):2 to be operated as a must-run beginning in 2021 in order to fully utilize the hydrogen from the Monolith process.
    - Allow exceptions for units that will be converted to co-generation operation in the future

MUST RUN EXCEPTIONS (2021 ITP)

- Holcomb
  - Sunflower has unaffiliated confidential supply-chain contracts that require Holcomb to operate at an approximate 50% capacity factor through the term of the 2021 ITP study period (term extends thru 2034). Market Economic study models, especially those that include winter and summer months, should identify that Holcomb is a must-run unit during non-shoulder periods.
    - Current must run rules exclude self-scheduled commitments attempting to reflect current day operational practice
    - Some fuel supply contracts are both must pay and must take
    - Allow exceptions for must pay and must take supply contracts ending beyond the study horizon
  - Holcomb (350-MW) is Sunflower's flagship unit, placed into service in 1983, and is the only EGU operated on a continuing basis by Sunflower.

MUST RUN EXCEPTIONS (2021 ITP)

- Plum Point
  - The portion of Plum Point sinking in SPP is not large enough to meet minimum load requirements for the plant to operate and allow SPP to make commitment decisions.
    - Allow exceptions for units that are jointly-owned/purchased by multiple entities in different markets
  - MISO Economic models typically reflect the must run status, and the unit has been (and will likely continue to be) self-scheduled on a commitment basis.
    - SPP does not unilaterally model MISO must run data. SPP rules are typically followed for external systems.
    - Current must run rules exclude self-scheduled commitments attempting to reflect current day operational practice
  - Empire has a must take portion of 50 MW (out of total 100 MW) when the plant is in online.
    - Plum point minimum capacity in economic models is 268MW and EMDE will get a minimum 40MW~ share when the unit is online, regardless of must run status

MUST RUN EXCEPTION CRITERIA (DRAFT PROPOSED)

- The unit is expected to be converted to a co-generation unit (operating with an industrial process) within the study horizon
- The unit has a must pay and must take fuel supply contract that ends beyond the 10-year study horizon
- The unit is jointly owned/purchased across multiple markets (i.e. SPP/MISO)

2021 **ITP**

APPENDIX

FEBRUARY 5TH MUST RUN PRESENTATION

OBJECTIVE

- Review impact of economic must run coal unit status on flowgate/system congestion
  - 2020 ITP models
  - Units fully or partially owned/contracted by SPP entities
- Determine next steps to address MOPC AI 304

MUST RUN COAL UNITS EVALUATED

- Holcomb
  - Zone: Sunflower Electric Power Corp. (SPP)
  - Must run status in 2020 ITP: On
  - Ownership: 100% SPP
- Big Stone
  - Zone: Otter Tail Power Company (MISO)
  - Must run status in 2020 ITP: On
  - Ownership: 23% SPP
- Plum Point
  - Zone: Entergy Arkansas (MISO)
  - Must run status in 2020 ITP: Off*
  - Ownership: 24% SPP

*Flagged as must run in 2021 ITP generation review

CONGESTION RESULTS

- Must Run Off->On

	Max Congestion Score Change on any 1 Flowgate by Scenario ($/MW)				
Unit	***Y2***	***F1Y5***	***F2Y5***	***F1Y10***	***F2Y10***
Holcomb	(5,538)	(9,251)	(5,906)	(4,604)	(13,304)
	14,574	8,985	14,531	2,882	8,007
Big Stone	(4,507)	(8,117)	(13,008)	(9,983)	(10,910)
	54,597	87,262	85,168	86,310	156,371
Plum Point	(6,167)	(4,269)	(9,966)	(8,805)	(5,284)
	7,411	7,273	6,461	8,348	4,752

CONGESTION RESULTS

- Must Run Off->On

	Max Congestion Score Change on any 1 Flowgate by Scenario ($/MW)				
Unit	***Y2***	***F1Y5***	***F2Y5***	***F1Y10***	***F2Y10***
Holcomb	(5,538)	(9,251)	(5,906)	(4,604)	(13,304)
	14,574	8,985	14,531	2,882	8,007
Big Stone*	(4,507)	(8,117)	(13,008)	(9,983)	(10,910)
	7,860	4,131	16,967	8,986	27,607
Plum Point	(6,167)	(4,269)	(9,966)	(8,805)	(5,284)
	7,411	7,273	6,461	8,348	4,752

*1 Flowgate removed from Big Stone calculations

CONGESTION RESULTS

- Must Run Off->On

	Sum Total System Congestion Score Change by Scenario ($/MW)				
Unit	***Y2***	***F1Y5***	***F2Y5***	***F1Y10***	***F2Y10***
Holcomb	8,931	15,731	33,519	(12,483)	10,491
Big Stone	67,365	77,982	156,117	93,593	243,760
Plum Point	1,955	18,617	11,959	10,692	19,864

CONGESTION RESULTS

- Must Run Off->On

	Sum Total System Congestion Change by Scenario ($/MW)				
Unit	***Y2***	***F1Y5***	***F2Y5***	***F1Y10***	***F2Y10***
Holcomb	8,931	15,731	33,519	(12,483)	10,491
Big Stone*	12,767	(9,280)	70,949	7,284	87,389
Plum Point	1,955	18,617	11,959	10,692	19,864

*1 Flowgate removed from Big Stone calculations

IMPACT ON FLOWGATES

- Holcomb
  - 2 new flowgates above $50k congestion score
    - 1st: mon was already above $50k threshold
    - 2nd: marginal change in score ($215)
- Big Stone
  - No new flowgates over $50k
  - Data aligns more with Holcomb/Plum Point with 1 flowgate removed from calculations (see appendix)
- Plum Point
  - No new flowgates over $50k

CONCLUSION/DISCUSSION

- Current economic must run coal units are generally un-impactful to flowgate/system congestion and potential needs
- System impact of economic must run units can be situational depending on changing system conditions and must run exceptions
- SPP currently sees no need to change ongoing study methodology/data (2020/2021 ITP)

  NOTE: Big Stone currently identified as a cogeneration unit

- Next steps

SPP Southwest Power Pool

2021 **ITP**

GENERATION AND LOAD REVIEW

BROOKE KEENE

MARCH 5-6, 2020

OBJECTIVE

- Review 2021 ITP Generation and Load schedule
- Review changes since last posting

SCHEDULE

- Final Generation Review Posting: March 6
- Anticipated Final Generation Review Approval: March 13
  - SPP will solicit approval via email vote March 12

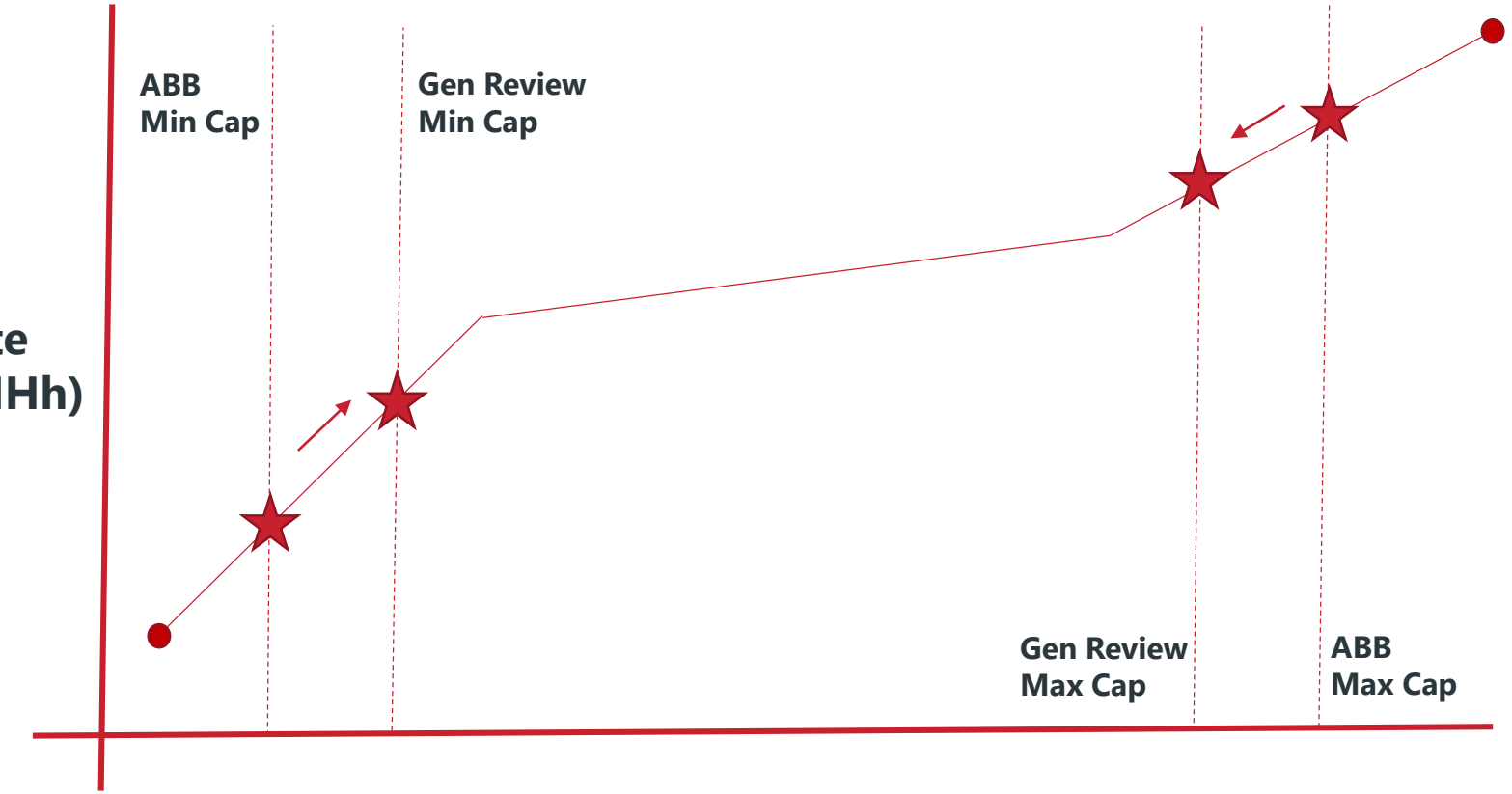
CHANGES SINCE POSTING

- Added missing TWG and ESWG approved waivers and RARs
- Updated Station Service Load IDs
- 2021 ITP BR updates will continue to be made for approval by the TWG on March 20
  - Topology changes
  - Dispatch changes
  - DocuCheck updates
  - Unit ID changes

ABB HEAT RATE CURVE & MIN/MAX CAPACITY

- A heat rate curve is a function of capacity output
- Majority of heat rate curves automatically adjust with minimum and maximum capacity adjustments
  - Flat: heat rate doesn't vary with unit output
  - Polynomial: heat rate recalculated based on input/output curve
  - Incremental: heat rate is first derivative of input/output curve
    - Some steam units are associated with heat rate values specific to the original capacity segments, which do not adjust according to the minimum and maximum capacity adjustments

HEAT RATE CURVE EXAMPLE



RECOMMENDATION

On March 12, SPP Staff will solicit a motion to approve:

- 2021 ITP Load and Generation Reviews with submitted maximum capacity changes, but without minimum capacity % changes
- The 2021 ITP MEM Benchmark will include an effort to investigate minimum capacity % changes and refine incremental heat rate curve changes
  - Will allow for stakeholder feedback for adjustments

Revision Request Recommendation Report

RR #: 391	Date: 12/18/2019
RR Title: HITT T2 – Uniform Local Planning Criteria	
SUBMITTER INFORMATION	
Submitter Name: Micha Bailey	**Company:** Southwest Power Pool
Email: mcbailey@spp.org	**Phone:** 501.688.2522

EXECUTIVE SUMMARY AND MOTION FOR RECOMMENDED MOPC/BOD ACTION

(Executive summary is high-level explanation of what the revision request will accomplish and should include a summary of voting records and opposition. The motion for recommended MOPC/BOD action should be written such that the organization group "recommends" the action needed.)

RR391 proposes a change to the way Local Planning Criteria is submitted to SPP for consideration of Zonal Reliability Upgrades. Instead of each individual TO submitting their Local Planning Criteria to SPP, a Facilitating Transmission Owner can submit a single Zonal Planning Criteria for their Zone. The Zonal Planning Criteria will be use in the individual Zone for all entities in that Zone for consideration of Zonal Reliability Upgrades. The proposed changes mandate a single Zonal Planning Criteria per Zone, but does not mandate that a Zonal Planning Criteria has to be created or submitted.

TWG recommends that MOPC and BOD approve RR391.

OBJECTIVE OF REVISION

(Ensure the objective has been updated to reflect the intent of the revisions presented for approval)

Transmission Planning Recommendation #2

Establish uniform Schedule 9 local planning criteria for each zone[27]

SPP should establish uniform local planning criteria within each Schedule 9 pricing zone. The criteria can vary between zones, but all TOs within each zone should be subject to the same local criteria in determining the need for zonal reliability upgrades within the zone. The HITT also recommends that the host TO invite TOs and transmission customers (TCs) of that zone to participate when developing the zonal criteria before submitting to SPP.

Additional information

Zonal reliability upgrades are defined in the tariff as "upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan to ensure the reliability of the Transmission System identified because of application of a TO's company-specific planning criteria." Attachment O of the tariff then requires TOs to provide to SPP their "company-specific planning criteria in order for the need for Zonal Reliability Upgrades to be assessed…" [28]

Under the current tariff language, zones that have multiple TOs can have multiple sets of local planning criteria. In such situations, the cost of a zonal reliability upgrade can be allocated to all load in the zone, regardless of which TO's criteria resulted in construction of the upgrade. A TO can establish very stringent criteria without having its network load bear the full cost of the resulting upgrades.
Conversely, in this situation, the network load of a TO that does not have local criteria more stringent than SPP's criteria can be allocated costs for upgrades that its criteria do not require.

Establishment of consistent local criteria applicable to all TOs within each zone would address this issue. The host TO in each Schedule 9 zone should be designated to take the lead in facilitating the establishment of consistent local criteria and invite any other TOs and TCs in that zone to participate. The host TO should facilitate a process that is designed to solicit meaningful input from other TOs and TCs in the zone to reach consensus-driven local planning criteria. The criteria would be submitted to SPP as the basis for considering zonal reliability upgrades pursuant to the requirements of the SPP tariff.

Under Attachment O, SPP determines the appropriateness of the application of local planning criteria to authorize zonal reliability upgrades.

Action

SPP staff should propose a timeline and process to the stakeholders and host TOs to initiate the implementation process. The HITT recognizes that developing local planning criteria as a result of this recommendation cannot be mandated. Staff's focus should be on guiding and facilitating the process for developing local planning criteria.

[27] Approved at April 3-4, 2019 HITT meeting by a unanimous vote of 15-zero. Motion by Greg McAuley (OG&E) and second by Denise Buffington (KCP&L/Evergy).
[28] Section II of Attachment O of the SPP tariff.

SPP STAFF COMMENTS

SPP Supports RR391.

IMPACT ANALYSIS
(See RR Impact Analysis Form for complete impact details)

System Changes ☒ No ☐ Yes

Process Changes? ☐ No ☒ Yes

Impact Analysis Required? ☒ No ☐ Yes | **If no, but system or process changes are expected please explain why an Impact Analysis will not be performed** (e.g. FERC Order, work included in another Impact Analysis for a related RR):

The Facilitating Transmission Owner will submit the Zonal Planning Criteria for use when determining a Zonal Reliabilty Upgrade. No system changes are needed.

Estimated Vendor Cost: *ROM based on information available at the time of the estimate* ***Cost Categories: A>0-20k, B>20-60k, C>60-100k, D>100-300k, E>300k – 600k, F>600k – 1mm, *G>1mm*** **If greater than 1mm an upper limit will also be provided.*	**Estimated Implementation Staff Hours: N/A** *ROM based on information available at the time of the estimate*
Estimated Implementation Time: N/A *ROM based on information available at the time of the estimate*	**Primary Working Group Priority: N/A**

SPP DOCUMENTS IMPACTED		
☐ **Market Protocols**	**Protocol Section(s):**	**Protocol Version:**
☐ **Operating Criteria**	**Criteria Section(s):**	**Criteria Date:**
☐ **Planning Criteria**	**Criteria Section(s):**	**Criteria Date:**
☒ **Tariff**	**Tariff Section(s):** Section 1 and Attachment O Section II	
☐ **Business Practice**	**Business Practice Number:**	
☐ **Integrated Transmission Planning (ITP) Manual**	**Section(s):**	
☐ **Revision Request Process**	**Section(s):**	
☐ **Minimum Transmission Design Standards for Competitive Upgrades (MTDS)**	**Section(s):**	
☐ **Reliability Coordinator and Balancing Authority Data Specifications (RDS)**	**Section(s):**	
☐ **SPP Communications Protocols**	**Section(s):**	

ORGANIZATIONAL GROUP ACTION *(Action = Approved, Approved Unanimously, or Rejected)*	
Primary Working Group: TWG	**Date: 12/18/2019** **Motion: To approve RR391 as discussed at the TWG** **Action: Approved** **Abstained: GridLiance High Plains, OPPD, Western Area Power Adminstration, Kansas Power Pool** **Opposed: Midwest Energy, Evergy, Empire District Electric, GDS Associates**
Reason for Abstention/Opposition:	

Primary Working Group: TWG	**Date: 2/4/2020** **Motion: To approve RR391 as edited at the 2/4/2020 TWG meeting with the understanding that Zonal Planning Criteria shall be applied comparably to all load in the applicable Zone. When developing the Zonal Planning Criteria, it is appropriate for the Zonal Planning Criteria to consider the specific equipment reliability requirements of the transmission system in that Zone.** **Action: Approved** **Abstained: Western Area Power Adminstration** **Opposed: Kansas Power Pool, Nebraska Public Power District, Oklahoma Municipal Power Authority, GDS Associates, Inc., Tri-State Generation and Transmission Association, Inc., GridLiance High Plains LLC**

Reason for Abstention/Opposition:

NPPD:

RR 391: Zonal Planning Criteria HITT T2 – NPPD voted NO since we do not support the proposed tariff language currently being developed in RR 391 to address HITT Recommendation T2. The new tariff language establishes new specific requirements and processes on the Facilitating Transmission Owners which was not specified in the original HITT recommendations regarding the establishment of uniform Schedule 9 local planning criteria. Further, NPPD is concerned with the new directives to engage transmission customers into the development of zonal planning criteria. NPPD is no longer a Transmission Service Provider under the SPP Tariff, so NPPD does not study, approve, or allocate costs to any of the so called transmission customers which were identified as transmission customers in the NPPD pricing zone. NPPD does not have any formal relationships with these SPP transmission customers and the zonal planning criteria will not even apply to their local distribution facilities which are not under the SPP tariff.

WAPA-UGPR:

WAPA-UGPR abstained from the TWG vote to approve the"RR391: Zonal Planning Criteria HITT T2" language as modified at the SPP TWG 04 Feb 2020 meeting. WAPA-UGPR is in agreement with the application of ZPC but believes it is essential to have language in this RR to require the FTO to obtain consensus within the zone on the ZPC. If no consensus is reached, then the Zone would default to only using the SPP Criteria.

KEPCo:

KEPCo voted to approve RR 391 as amended at our recent TWG meeting. The revisions specifically address HITT item T2 by enabling a Zonal Planning Criteria process. However, we feel that T2 does not go far enough to ensure that the local planning process used by the Transmission Owners is a process open to all stakeholders in the Zone, as intended by FERC Order 890 and related filings. We'd like to see more SPP effort in this area.

KPP:

Below are the KPP comments for the "No" vote of RR391 in the Feb 4th TWG meeting.

- The Tariff language as drafted does not reflect the HITT initiative where the Zonal Planning Criteria is developed by all impacted parties with the facilitating TO simply taking the lead.
- The Zonal Planning Criteria does not require agreement between FTO, customers, and other TO's in zone.
- The HITT report assigns the FTO a facilitation role only. In RR391, the FTO has unilateral control over Zonal Planning Criteria. While the FTO must hold open meeting(s) over proposed criteria, they can choose what becomes criteria or whether to have a Zonal Criteria.
- There is no obligation for an FTO to create any criteria at all. And does not require the FTO to reconsider criteria once it is submitted to SPP or to hold additional meetings on zonal criteria unless the FTO itself desires to make a change to the criteria. This forces other TOs and customers in the zone to forfeit their local planning rights in SPP's process. This was made very clear in the Feb 4th meeting that some FTO's will not include other TO's beyond the first round of criteria development.
- The revisions reduce SPP's coordination requirements on upgrades.

GridLiance & OMPA:

Here are the reasons GridLiance and OMPA opposed RR391 in its vote at the Feb 4, 2020 TWG meeting:

- The Tariff language as drafted does not embody the spirit of the HITT where the Zonal Planning Criteria is developed by all impacted parties with the facilitating TO simply taking the lead role.
    - The ZPC does not require agreement between FTO, customers, and other TOs in zone.
    - The HITT report assigns the FTO a facilitation role only. The proposed tariff revision provides the FTO unilateral control over Zonal Planning Criteria. While the FTO must hold an open meeting(s) over proposed criteria, they can choose what becomes criteria or whether or not to have a Zonal Criteria.
    - There is no obligation for an FTO to create any criteria at all. It does not require the FTO to reconsider criteria once it is submitted to SPP or to hold additional meetings on zonal criteria unless the FTO itself desires to make a change to the criteria. This forces other TOs and customers in the zone to forfeit their local planning rights in SPP's process.
- The revisions reduce SPP's coordination obligations and requirements on upgrades.

ETEC:

ETEC voted no on RR391 because the proposed language does not require consensus on the zonal criteria. The HITT report very clearly sets consensus-driven development of Zonal Planning Criteria as a goal, and that goal was ignored in the proposed tariff language. In the proposed language, the criteria submitted by the FTO to SPP sets the zonal criteria. Additionally, the decision to have zonal planning criteria rests solely with the facilitating transmission owner. Finally, if an entity has local planning criteria today and is unable to have that criteria included in the zonal criteria, then the entity loses its local planning criteria.

Secondary Working Group: RTWG	**Date:** **Motion:** **Action:** **Abstained:** **Opposed:**
Reason for Abstention/Opposition:	
Secondary Working Group: RCWG	**Date:** **Motion:** **Action:** **Abstained:** **Opposed:**

Reason for Abstention/Opposition:	
Secondary Working Group: ESWG	**Date:** **Motion:** **Action:** **Abstained:** **Opposed:**
Reason for Abstention/Opposition:	
MOPC	**Date:** **Motion:** **Action:** **Abstained:** **Opposed:**
Reason for Abstention/Opposition:	
BOD/Member Committee	**Date:** **Motion:** **Action:** **Abstained:** **Opposed:**
Reason for Abstention/Opposition:	

SUMMARY OF COMMENTS
(See comment forms in the RR folder on SPP.org for full comment details)

1. **Comment Form Date and Submitter:** 12/11/2019, Micha Bailey, SPP

Summary of Comments: After presenting to various working groups, SPP proposes the following item changes.

Add Schedule 9 in the definition of Facilitating Transmission Owner and Local Planning Criteria.

Change the name of Local Planning Criteria to Zonal Planning Criteria in support of adopting one Planning Criteria per Schedule 9 Zone.

Organizational Group Review Results *(e.g. Reviewed and accepted, reviewed but not accepted, reviewed with partial acceptance – provide details to explain)***:** TWG reviewed the comments

2. **Comment Form Date and Submitter:** 12/13/2019, Shawn Geil, KEPCo

Summary of Comments: KEPCo believes that transmission projects affecting zonal and/or regional revenue requirements should be subjected to a thorough planning and approval process that complies with FERC Order 890 and, importantly, involves all relevant stakeholders. The implementation of HITT recommendation T2 will help strengthen the planning process and provide more transparency but only if all relevant stakeholders are allowed to fully participate in the development and approval process.

Without appropriate and meaningful stakeholder involvement, transmission projects cannot receive adequate scrutiny from the Transmission Customers that ultimately bear the associated costs. FERC's guidance on the implementation of Order 890 includes expectations for a coordinated, open, and transparent planning and approval process involving all relevant stakeholders for both zonal and regional transmission projects. The development of the Local Planning Criteria will have a significant impact on future zonal transmission projects and, therefore, warrants active involvement and participation of all relevant stakeholders. This revision request should make clear that the Facilitating Transmission Owner is obligated to include other Transmission Owners and Transmission Customers in the zone, as well as other relevant stakeholders, in the development and approval of the Local Planning Criteria. Doing so will ensure a better, more efficient process and, in turn, greater assurance that the transmission projects are necessary and prudent for zonal reliability.

Organizational Group Review Date and Results *(e.g. Reviewed and accepted, reviewed but not accepted, reviewed with partial acceptance – provide details to explain)***:** TWG reviewed the comments

3. Comment Form Date and Submitter: 12/17/2019, Derek Brown, Evergy

Summary of Comments: Evergy offers the following comments.

Organizational Group Review Date and Results *(e.g. Reviewed and accepted, reviewed but not accepted, reviewed with partial acceptance – provide details to explain)***:** TWG reviewed the comments

4. Comment Form Date and Submitter: 12/18/2019, Steve Sanders, WAPA

Summary of Comments: WAPA suggested edits and comments to latest version submitted by SPP Staff based upon Zone 19 UMZ Coordination Group (UMZCG) discussions on 12/17/19.

Organizational Group Review Date and Results *(e.g. Reviewed and accepted, reviewed but not accepted, reviewed with partial acceptance – provide details to explain)***:** TWG reviewed and incorporated some of the comments in their TWG comments

5. Comment Form Date and Submitter: 12/18/2019, Micha Bailey on behalf of TWG, SPP

Summary of Comments: The TWG recommends the following changes as presented in the TWG meeting.

Organizational Group Review Date and Results *(e.g. Reviewed and accepted, reviewed but not accepted, reviewed with partial acceptance – provide details to explain)***:** TWG approved the comments as presented.

6. Comment Form Date and Submitter: 02/04/2020, Micha Bailey on behalf of TWG, SPP

Summary of Comments: After reviewing RR391 with the RTWG, the TWG submits the following changes based upon the RTWG feedback.

1. Updated definition of Facilitating Transmission Owner
2. Clarified the FTO shall hold opening meeting and shall invite all applicable parties in the Zone
3. Other modifications as needed for clarity

Organizational Group Review Date and Results *(e.g. Reviewed and accepted, reviewed but not accepted, reviewed with partial acceptance – provide details to explain)***:** TWG approved the comments as presented.

PROPOSED REVISION(S) TO SPP DOCUMENTS

SPP Tariff (OATT)

F - Definitions

Facilitating Transmission Owner: The Facilitating Transmission Owner is responsible for the Zonal Planning Criteria responsibilities as described in Attachment O of this Tariff. The Network Customer with the largest total Network Load in the Zone, computed in accordance with Sections 34.4 and 34.5 of the Tariff on an average calendar year basis for the prior calendar year, shall designate a Transmission Owner with Zonal Annual Transmission Revenue Requirement for facilities in the Zone as the Facilitating Transmission Owner for the Zone each year. For Zone 10, the Facilitating Transmission Owner shall be Southwestern Power Administration.

Facilities Study: An engineering study conducted by the Transmission Provider in collaboration with the affected Transmission Owner(s) to determine the required modifications to the Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or Generator Interconnection Service. The Transmission Provider shall have the ultimate responsibility for any such studies. However, the Transmission Provider's final decision must be consistent with Good Utility Practice. Facilities studies for any facilities not under the operational control of the Transmission Provider shall be performed by the Transmission Owner or any entity it designates to perform the studies.

Feasibility Study: A coordinated preliminary determination by the Transmission Provider and the affected Transmission Owner(s) of the Attachment Facilities, other Direct Assignment Facilities, and system upgrades that are needed to accept power into the grid at the

interconnection receipt point, that will be necessary to accommodate a Generator Interconnection Request made under Attachment V.

Federal Power-Southwestern: All power and energy generated at reservoir projects under the control of the Department of the Army in the marketing area of the Southwestern Power Administration (Southwestern) plus power and energy delivered to Southwestern from other sources for the purpose of fulfilling Southwestern's contractual obligations for the sale of power and energy pursuant to Southwestern's Federal power allocations.

Federal Power–Western-UGP: All power and energy generated at reservoir projects under the control of the Department of the Army or the Bureau of Reclamation in the marketing area of the Western-UGP for the purpose of fulfilling Western-UGP's Statutory Load Obligations for the sale of power and energy. This shall also include any power and energy delivered to or from Western-UGP under the grandfathered bi-directional agreement with Southwestern Power Administration through Associated Electric Cooperative, Inc. ("AECI") for delivery and receipt at AECI's Maryville Substation. Western-UGP's deliveries to Southwestern shall be considered part of Western-UGP's Statutory Load Obligations, and receipts from Southwestern to Western-UGP will be considered as coming from Federal resources. Federal Power-Western-UGP resources shall be eligible to be considered as Designated Resources.

Federal Power Marketing Agency: This term shall include the term "Federal Power Marketing Administration" and have the same definition that is set forth in the Federal Power Act at 16 U.S.C. § 796(19), which defines "Federal power marketing agency" as "any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy[.]"

Federal Service Exemption: Western-UGP's exemption from certain charges described in Section 39.3(e) of this Tariff.

Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

L - Definitions

Load Ratio Share: Ratio of a Transmission Customer's Network Load in a Zone to the total load in that Zone computed in accordance with Sections 34.4 and 34.5 of the Network Integration Transmission Service under Part III of this Tariff and calculated on a calendar year basis, for the prior calendar year. Customer loads used to determine the Load Ratio Share shall be adjusted for real power losses in accordance with the provisions set out in Section 28.5 of this Tariff.

Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to Transmission System or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

Long-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

Long-Term Service: Long-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service of one year or longer.

…

Zonal Planning Criteria: In each Zone, the set of measuring systems and performance standards that is used for assessing the actual or projected ability of the Transmission System to deliver power to load reliably.

Zonal Reliability Upgrades: Those upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System identified because of application of ~~a~~ Zonal ~~Transmission Owner's company-specific~~ ~~p~~Planning ~~c~~Criteria.

Attachment O

II. Roles and Responsibilities

References to the "stakeholder working group" is a generic term that references those working group(s) as defined in the SPP Bylaws, Sections 3 through 6 that are charged with the transmission planning process. The current names of all the working groups shall be posted on the SPP website.

1) Division of Responsibilities

a) The rights, powers and obligations for planning are set forth in the SPP Membership Agreement in (i) Article 2.0 for the Transmission Provider and (ii) Article 3.0 for the Members. The division of responsibility between the Transmission Provider and the Members is set forth in the SPP Criteria and in this Attachment O. The SPP Membership Agreement, the SPP Criteria and the Tariff shall be posted on the SPP website.

b) The Transmission Provider shall be responsible for developing the list of projects in accordance with the stakeholder process set forth in Sections II, III and V of this Attachment O, and including interregional coordination set forth in Section VIII of this Attachment O.

c) The Transmission Provider shall perform transmission planning studies to assess the reliability and economic operation of the Transmission System in accordance with Section III of this Attachment O.

d) As inputs to the planning process, the Transmission Provider shall include and maintain requirements to serve existing commitments for long-term transmission service and Generator Interconnection Service in accordance with Section III.5 of this Attachment O and any applicable roll-over rights as set out in Section 2.2 of this Tariff. The Transmission Provider shall also take into account all

previously approved projects in accordance with Section III of this Attachment O.

e) In accordance with Section II.5 of this Attachment O, the Transmission Provider shall review, and include as appropriate, all local area upgrades ~~to meet local area reliability criteria~~ as proposed by the Transmission Owners to meet Zonal Planning Criteria, including such ~~those~~ plans developed by Transmission Owners that have their own FERC approved local planning process, to ensure coordination of the projects set forth in such plans with the potential solutions developed in the regional planning process.

f) The Transmission Provider shall review and include, as appropriate, all reasonably expected demand resource, transmission, or generation options identified by stakeholders in accordance with Section III of this Attachment O.

g) The Transmission Provider shall describe the details regarding expansion planning methodology, criteria, assumptions and data in the Integrated Transmission Planning Manual, which shall be developed by the Transmission Provider, in consultation with stakeholders, and approved by the Markets and Operations Policy Committee. The Transmission Provider shall post the Integrated Transmission Planning Manual on its website.

h) The Transmission Provider shall conduct an annual survey of stakeholders to identify Public Policy Requirements in accordance with Section III of this Attachment O.

i) In accordance with its NERC reporting requirements, the Transmission Provider shall publish an annual reliability report that shall include a list of the following:

i) Regional upgrades required to maintain reliability in accordance with the NERC Reliability Standards and SPP Criteria;

ii) Zonal upgrades required to maintain reliability in accordance with more stringent ~~individual Transmission Owner~~ Zonal ~~p~~Planning ~~c~~Criteria; and

iii) Upgrades developed with neighboring Transmission Providers, including results from the coordinated system plans.

j) Using the data provided in Section VII of this Attachment O, the Transmission Provider shall develop the planning model(s) in accordance with the Integrated Transmission Planning Manual to be used for the transmission planning processes in this Attachment O. The schedule for the model development will be posted on the SPP website.

2) Stakeholder Working Groups

a) The purpose of the stakeholder working groups is to provide technical advice, assistance and oversight to the Transmission Provider in all aspects of the regional and local planning process, including but not limited to:

i) Review and development of coordinated planning among the Transmission Provider and the Transmission Owners including accepted Network Upgrades developed by those Transmission Owners that have their own FERC approved local planning process to meet Zonal Planning Criteria~~local area reliability criteria~~;

ii) Review and development of regional planning criteria;

iii) Review and development of Available Transfer Capability related calculation criteria as specified in Attachment C of this Tariff;

iv) Review and development of transmission rating criteria;

v) Compliance with NERC Reliability Standards concerning transmission assessment, transfer capability and ratings of transmission facilities;

vi) Review and development of the list of transmission needs driven in whole or in part by Public Policy Requirements for which transmission solutions will be evaluated; and

vii) Review of Interregional Projects in accordance with Section IV.7 of this Attachment O.

b) All the stakeholder working group representation shall be appointed and chaired in accordance with Article 3.0 of the SPP Bylaws. All meetings of the stakeholder working groups are open to all entities.

c) Voting in the various stakeholder working groups shall conform to Article 3.9 of the SPP Bylaws.

d) The data, information, and technical support necessary for the Transmission Provider to perform studies as required by the planning process and to develop the regional reliability projects are provided by the Transmission Owners, Transmission Customers and Generator Interconnection Customers and other entities in accordance with Section VII of this Attachment O.

e) Stakeholder working groups that work with the Transmission Provider on transmission planning shall meet at least quarterly and additional meetings, web conferences and teleconferences shall be scheduled as needed. Teleconference capability will be made available for stakeholder working group meetings. Notice of meetings of the stakeholder working groups shall be posted on the SPP website and distributed via email distribution lists. Meeting agendas and minutes shall be posted on the SPP website.

3) Participation by State Regulators

In accordance with the SPP Bylaws, any regulatory agency having utility rates or services jurisdiction over a Member may participate fully in all SPP planning activities.

4) Adherence to Regional Planning Criteria

i) The regional planning criteria are comprised of the NERC Reliability Standards and SPP Criteria.

ii) The regional planning criteria may change from time to time based upon the then current process for changing reliability criteria.

iii) The individual Transmission Owners shall be obligated under the NERC Reliability Standards and SPP Criteria to resolve reliability violations and compliance needs identified by the Transmission Provider or by the individual Transmission Owners themselves in accordance with these standards and criteria.

5) Use of Local Planning Criteria

i) ~~Individual~~ A Facilitating Transmission Owner~~s~~ in each Zone within the SPP Region may develop ~~company-specific~~ Zonal ~~p~~Planning ~~c~~Criteria that, at a minimum, conform to the NERC Reliability Standards and SPP Criteria. There shall be only one set of Zonal Planning Criteria per Zone. The Facilitating Transmission Owner within the Zone shall hold open meeting(s) to discuss the development of the Zonal Planning Criteria and shall invite all other Transmission Owners and customers taking Long-Term Service within that Zone. Any initial development of and subsequent modification(s) to the Zonal Planning Criteria shall be discussed through open meeting(s).

ii) ~~For each annual planning cycle,~~ The Facilitating Transmission Owner~~s~~ in each Zone~~, including those Transmission Owners that have their own FERC approved local planning process,~~ must provide to the Transmission Provider at least once a year, by April 1st, ~~their~~ the ~~company-specific~~ Zonal ~~p~~Planning ~~c~~Criteria, if a set of Zonal Planning Criteria has been developed in accordance with Section II(5)(i) of this Attachment O, in order for the need for Zonal Reliability Upgrades to be assessed and included in the SPP Transmission Expansion Plan. If the Facilitating Transmission Owner does not provide Zonal Planning Criteria by April 1st, then the Transmission Provider's criteria will be used for that Zone.

iii) ~~Transmission Owner~~ The Zonal ~~p~~Planning ~~c~~Criteria and assumptions may be modified at any time provided that, if the planning criteria are made more stringent, the increased requirements will not apply retroactively to studies previously completed or studies already underway by the Transmission Provider. Access to the Zone-specific~~individual Transmission Owner's~~ Zonal ~~p~~Planning ~~c~~Criteria shall be made available via an electronic link on the SPP website.

iv) The ~~individual~~ Zonal ~~p~~Planning ~~c~~Criteria of each ~~Transmission Owner~~ Zone~~, including those Transmission Owners that have their own FERC approved local planning process,~~ shall be the basis for determining whether

a reliability violation exists for which a need for a new Zonal Reliability Upgrade should be considered.

v) ~~The~~ All Transmission Owners within the Zone shall apply ~~its~~ the Zonal~~local~~ ~~p~~Planning ~~c~~Criteria comparably to all load ~~in its service territory~~ in the applicable Zone.

vi) ~~Transmission Owners' company specific~~Zonal ~~p~~Planning ~~c~~Criteria and Transmission Owners' local planning processes must provide for: (a) the identification of transmission needs driven in whole or in part by Public Policy Requirements; and (b) the evaluation of potential solutions to meet those needs.

6) Planning Summits

i) The Transmission Provider shall conduct, at a minimum, a planning summit once a year.

ii) The purpose of a planning summit is for the Transmission Provider and the stakeholders to share current SPP transmission network issues, provide solution alternatives and review study findings. Summits also provide an open forum where all stakeholders have an opportunity to provide advice and recommendations to the Transmission Provider to aid in the development of the SPP Transmission Expansion Plan.

iii) Each planning summit shall be open to all entities.

iv) The Transmission Provider shall chair and facilitate the planning summits.

v) Teleconference capability will be made available for planning summits. Planning summit web conferences shall be held as needed.

vi) Notice of an upcoming planning summit and web conferences shall be posted on the SPP website and distributed via email distribution lists.

III. The Integrated Transmission Planning Assessment

The Integrated Transmission Planning Assessment evaluates the system upgrades, at all applicable voltage levels, identified in the ten-year planning horizon.

1) Commencement of the Process

Upon the commencement of the process, the Transmission Provider shall: (i) post the study schedule and information relating to the study process on the SPP website; and (ii) provide notice of the posting via email distribution lists. The schedule shall include a timeline and process for stakeholder submission of transmission needs, including transmission needs driven by Public Policy Requirements, and solutions to such needs as described in this Section III of this Attachment O.

2) Preparation of the Integrated Transmission Planning Assessment

a) The Integrated Transmission Planning Assessment shall review the system for a ten-year planning horizon. This assessment is not intended to review each consecutive year in the planning horizon.

b) The Integrated Transmission Planning Assessment shall identify solutions required to meet the criteria defined in Section III.3 of this Attachment O and assess the cost effectiveness of proposed solutions over a forty-year time horizon.

c) The Transmission Provider shall develop the Integrated Transmission Planning Assessment study scope with input from the stakeholders, in accordance with the parameters in the Integrated

Transmission Planning Manual. The study scope and the Integrated Transmission Planning Manual shall specify the methodology, criteria, assumptions, and data to be used, including how transmission needs will be identified, and how the input requirements described in Section III.3 of this Attachment O will be incorporated. The study scope shall include an explanation of which Public Policy Requirements will be evaluated for potential solutions in the Integrated Transmission Planning Assessment. The final Integrated Transmission Planning Assessment study scope shall be posted on the SPP website.

d) Notice of the transmission needs being evaluated in the Integrated Transmission Planning Assessment will be provided pursuant to Section III.6 of this Attachment O. In accordance with the study scope and the Integrated Transmission Planning Manual, the Transmission Provider shall analyze potential solutions pursuant to Section III.7 of this Attachment O.

3) Policy, Reliability, and Economic Input Requirements to the Integrated Transmission Planning Assessment

In accordance with the Integrated Transmission Planning Manual, the Transmission Provider shall incorporate, as appropriate, the following as part of its planning studies:

a) NERC Reliability Standards;

b) SPP Criteria;

c) Zonal~~Local~~ ~~p~~Planning ~~c~~Criteria as set forth in Section II;

d) Previously identified and approved transmission projects;

e) Zonal Reliability Upgrades developed by Transmission Owners, including those that have their own FERC approved local planning process, to meet Zonal Planning Criteria~~local area reliability criteria~~;

f) Long-term firm transmission service;

g) Load forecasts, including the impact on load of existing and planned demand management programs, exclusive of demand response resources;

h) Capacity forecasts, including generation additions and retirements;

i) Existing and planned demand response resources;

j) Congestion within SPP and between the SPP Region and other regions and balancing areas;

k) Renewable energy standards;

l) Fuel price forecasts;

m) Energy efficiency requirements;

n) Other relevant environmental or government mandates;

o) Public Policy Requirements identified through the annual survey of stakeholders and additional Public Policy Requirements as determined by the Transmission Provider and stakeholders;

p) Operational experience gained from markets operated by the Transmission Provider;

q) Other input requirements identified during the stakeholder process and included in the Integrated Transmission Planning Assessment scope; and

r) Identified persistent operational issues.

4) Inclusion of Generation and Demand Response Resources in the Integrated Transmission Planning Assessment

In developing the long term capacity forecasts, the Integrated Transmission Planning Assessment will include generation and demand response resources capable of providing any of the functions assessed in the SPP planning process, and that can be relied upon on a long-term basis. Such generation and demand response resources shall be permitted to participate in the planning process on a comparable basis. Stakeholders may also propose any combination of demand resources, transmission, or generation as alternate solutions to identified needs.

5) Additional Information to be Included in the Integrated Transmission Planning Assessment

a) The studies performed under this Section III of Attachment O shall accommodate and model the specific long-term firm transmission service of Transmission Customers upon the completion of the associated Aggregate Facilities Study in accordance with Attachment Z1 of this Tariff and specific interconnections of Generation Interconnection Customers in accordance with the schedule for Generator Interconnection Agreements and Generation Interconnection Service upgrades in the Integrated Transmission Planning Manual.

b) Transmission upgrades related to requests for transmission service that are described in Sections 19 and 32 of this Tariff and Attachment Z1 of this Tariff. Upgrades associated with the accepted long-term firm

transmission service are included in the Transmission System planning model upon the completion of the associated Aggregate Facilities Study in accordance with Attachment Z1 of this Tariff. Transmission upgrades related to an approved request for transmission service may be deferred or supplemented by other upgrades based upon the results of subsequent studies. Changes in planned upgrades do not remove the obligation of the Transmission Provider to have adequate transmission facilities available to start or continue the approved transmission service.

c) Interconnection facilities and other transmission upgrades related to requests for Generator Interconnection Service are described in Attachment V of this Tariff. Upgrades associated with the modeled Generator Interconnection Service are included in the Transmission System planning model upon the execution of a Generator Interconnection Agreement with the Generator Interconnection Customers or filing of an un-executed Generator Interconnection Agreement with the Commission. Transmission upgrades related to an approved interconnection agreement may be deferred or supplemented by other upgrades based upon the results of subsequent studies. Changes in planned upgrades do not remove the obligation of the Transmission Provider to have adequate transmission facilities available to start or continue the approved interconnection service.

d) A Sponsored Upgrade will be included in the Transmission System planning model upon execution of the Agreement for Sponsored Upgrade in Schedule 1 to Attachment J of this Tariff.

e) Projects approved in accordance with Section IV of this Attachment O will be included in the Transmission System planning model upon approval for construction.

6) Identification of Needs and Detailed Project Proposals

After the study scope has been finalized, the Transmission Provider shall identify potential transmission needs, including any needs driven by Public Policy Requirements, in accordance with the Integrated Transmission Planning Assessment scope and the Integrated Transmission Planning Manual. The Transmission Provider shall notify stakeholders of identified transmission needs and provide a transmission planning response window of thirty (30) days during which any stakeholder may propose a detailed project proposal (DPP). The Transmission Provider shall track each DPP and retain the information submitted pursuant to Section III.6(a) of this Attachment O. If the project described in a DPP is approved by the SPP Board of Directors as an ITP upgrade, the submitting stakeholder may qualify for incentive points as described in Section III of Attachment Y of this Tariff.

a) The information supplied by the stakeholder must be sufficient to allow the Transmission Provider to evaluate the project described in the DPP. At a minimum, the DPP must include the following information:

i) description of the project including one-line diagrams, configuration(s), proposed line routing, preliminary transmission line and substation engineering and design data;

ii) description of the need(s) identified in the Integrated Transmission Planning Assesment to be addressed;

iii) proposed project schedule including, at a minimum timelines for completing regulatory, right-of-way, environmental, engineering, procurement and construction activities;

iv) description of any known or anticipated risks to the project schedule and any recommended mitigation plans;

v) description of any known or anticipated environmental impacts;

vi) engineering and modeling data required by the Transmission Provider;

vii) identification and justification of any changes in modeling assumptions from those used in the current Integrated Transmission Planning Assessment;

viii) results of transmission project economic or reliability analysis, if applicable; and

ix) any other information available to support the evaluation of the project.

b) Any stakeholder providing a DPP that meets the requirements set forth in Section III.6(a) of this Attachment O will be recorded by the Transmission Provider for the Integrated Transmission Planning Assessment for which the DPP was submitted, including the contact information of the stakeholder that submitted the DPP.

c) If the Transmission Provider, in its sole discretion, determines that the information provided in a DPP is incomplete, the Transmission Provider shall provide written notice to the stakeholder that submitted the DPP. The stakeholder shall be permitted to cure such deficiency by the later of the end of the transmission planning response window or 10 days after the Transmission Provider issues such notice. Failure to cure the deficiency shall result in the submission being disqualified as a DPP.

d) The Transmission Provider shall hold all DPPs in confidence until the thirty (30) day transmission planning response window has closed. Subsequent to the close of the transmission planning response window,

information contained in a DPP shall be disclosed to stakeholders only as the Transmission Provider determines it is necessary for the review of the DPP during the planning process and for documentation of the reason(s) why the DPP was or was not chosen in the current Integrated Transmission Planning Assessment. The remaining information in the DPP will remain confidential.

e) A stakeholder that submits a DPP is eligible for incentive points, in accordance with Section III of Attachment Y of this Tariff, for the current Integrated Transmission Planning Assessment.

7) Process to Analyze Transmission Solutions and Alternatives for the Integrated Transmission Planning Assessment

a) The Transmission Provider shall perform the required studies to analyze the potential solutions for improvements to the Transmission System, provided by the Transmission Provider and by the stakeholders, in order to address the final Integrated Transmission Planning Assessment study scope which shall consider the current and anticipated future needs of the SPP Region within the parameters of the Integrated Transmission Planning Manual. The analysis shall also consider the value brought to the SPP Region by incremental changes to the proposed solutions.

b) For all potential solutions provided by the stakeholders, including reliability upgrades that Transmission Owners (which includes those Transmission Owners that have their own FERC approved local planning process), propose to address violations of ~~company-specific~~ Zonal ~~p~~Planning ~~c~~Criteria pursuant to Section II.5 of this Attachment O, and upgrades to address transmission needs driven in whole or in part by identified Public Policy Requirements, the Transmission Provider shall determine if there is a more comprehensive regional solution to address the reliability needs, economic needs, and needs driven by Public Policy Requirements identified in the assessment.

c) The Transmission Provider will consider, on a comparable basis, any alternative proposals which could include, but would not be limited to, generation options, demand response programs, “smart grid” technologies, and energy efficiency programs. Solutions will be evaluated against each other based on a comparison of their relative effectiveness of performance and economics.

d) The Transmission Provider shall assess the cost effectiveness of proposed solutions. Such assessments shall be performed in accordance with the Integrated Transmission Planning Manual. This analysis shall take into consideration the following:

i) The financial modeling time frame for the analysis shall be 40 years (with the last 20 years provided by a terminal value).

ii) The analysis shall include quantifying the benefits resulting from dispatch savings, loss reductions, avoided projects, applicable environmental impacts, reduction in required operating reserves, interconnection improvements, congestion reduction, and other benefit metrics as appropriate, in accordance with this Attachment O and the Integrated Transmission Planning Manual.

iii) The analysis shall identify and quantify, if possible, the benefits related to any proposed transmission upgrade that is required to meet any regional reliability criteria.

iv) The analysis scope shall include different scenarios to analyze sensitivities to load forecasts, wind generation levels, fuel prices, environmental costs, and other relevant factors. The Transmission Provider shall consult the stakeholders to guide the development of these scenarios.

v) The results of the analysis shall be reported on a regional, zonal, and state-specific basis.

vi) The analysis shall assess the net impact of the transmission plan, developed in accordance with this Attachment O, on a typical residential customer within the SPP Region and on a $/kWh basis.

e) The Transmission Provider shall make a comprehensive presentation of the preferred solutions, including the results of the analysis above, to the stakeholder working groups and at a planning summit meeting or web conference. The presentation shall include a discussion of all the Transmission Provider and stakeholder alternatives considered and reasons for choosing the particular preferred solutions.

f) The Transmission Provider shall solicit feedback on the solutions from the stakeholder working groups and through the stakeholders attending the various planning summits. The Transmission Provider will also include feedback from stakeholders through other meetings, teleconferences, web conferences, and via email or secure web-based workspace.

g) Upon consideration of the results of the cost effectiveness analysis and feedback received in the subsequent review process, the Transmission Provider shall prepare the annual Integrated Transmission Planning Assessment report, which shall include a draft list of projects for review and approval in accordance with Section V of this Attachment O. The report shall also include an explanation of which transmission needs driven by Public Policy Requirements were evaluated for potential solutions in the Integrated Transmission Planning Assessment, as well as an explanation of why other transmission needs driven by Public Policy Requirements were not evaluated.

MOPC AI: 302 COLD-WEATHER DRIVEN RELIABILITY ISSUES AND RISK BASED PLANNING IN THE ITP

CHRIS JAMIESON & ADAM BELL

MARCH, 2020

OBJECTIVE

- Discuss MOPC Action Item 302
  - Previously Discussed Options
  - SPP Staff Proposal
- Discuss high-level strawman proposal for incorporating Risk-Based Planning in ITP
- Provide high-level proposal to MOPC and SPC in April 2020

MOPC ACTION ITEM 302

MOPC ACTION ITEM 302

- SPP MOPC: October 15-16, 2019
  - Action Item 302: TWG and ESWG to develop approaches that address winter peaking and cold-weather driven reliability issues for incorporation in SPP's normal planning processes.

PREVIOUSLY DISCUSSED OPTIONS

1. Include additional contingencies in the Base Reliability needs assessment of the current ITP Winter Peak Models
2. Include an additional Base Reliability Model as a part of future ITP analysis that better captures this scenario
3. Utilize the existing Winter Peak ITP Base Reliability Model to better capture this scenario
4. Continue with status-quo (do nothing) and rely on current Winter Peak Models in the ITP to address these concerns

Additional Information in Appendix

STAKEHOLDER FEEDBACK

- ESWG
  - Preferred the TWG initially provide a recommendation on how to address this MOPC AI, as it primarily deals with addressing reliability issues
  - Would weigh in after the TWG provides direction to see if additional economic analysis is warranted
- TWG
  - Comments supporting the inclusion of an informational only approach (sensitivity) in the 2021 ITP
  - Comments in support of including additional contingencies and additional models

SPP STAFF RECOMMENDATION

- Evaluate additional contingencies and sensitivities in the Base Reliability needs assessment of the current ITP Winter Peak Models
  - Utilize additional appropriate contingencies to reflect extreme winter peak conditions
    - SPP staff to work with stakeholders to develop application criteria
    - Potentially member submitted contingencies
      - Including generation contingencies
  - Evaluate sensitivities to adequately reflect generation levels experienced in extreme winter events
- Used for Informational Purposes Only
- Pending finalizing SPP Staff resource assessment

NEXT STEPS

- Discuss SPP Staff Recommendation
  - March / April – TWG & ESWG
    - What Additional Information is Needed?
    - Do Stakeholders Support this Approach?
  - Update MOPC in April 2020
- Seek approval from TWG and ESWG
  - May / June 2020
- Seek MOPC Approval in July 2020
- Include the Informational Only Sensitivity in the 2021 ITP
  - If SPP Staff recommendation is supported by Working Groups
- Assess whether further / permanent changes to the ITP process are warranted for the 2022 ITP

RISKED BASED PLANNING IN THE ITP

BACKGROUND

- SPP Strategic Plan
  - Maintain an Economical, Optimized Transmission System
- 2019 TWG Goal
  - Develop an approach to evaluating risk and value-based transmission planning
- ESWG Action Item
  - Futures Weight
- MOPC Action Items
  - Action Item 301-TWG and ESWG to recommend best way to incorporate Basin's concerns about winter peaking Bakken area load and generation supply issues in the 2021 ITP
  - Action Item 302: TWG and ESWG to develop approaches that address winter peaking and cold-weather driven reliability issues for incorporation in SPP's normal planning processes.

HISTORY

- SPP
  - Economic Planning Studies
  - Loss of Load Expectation (LOLE) Studies
  - Project Plan for Probabilistic planning at SPP (2012/2013)
  - EPRI Risk-based transmission planning program
- NERC
  - Probabilistic Assessment Working Group (PAWG)
  - Probabilistic Assessment Technical Guideline Document (2016)
- Current Efforts of Other RTO/ISOs

HIGH-LEVEL STRAWMAN PROPOSAL (NEAR-TERM)

- Investigate options, cost, and data requirements to develop a process to perform, identify, and rank TPL only planning events with high impacts on ITP Base Reliability needs assessment Winter Peak Models and Market Powerflow Models (2020 ITP/TPL)
- Investigate options, cost, and data requirements to perform Risk-Base Planning pilot on Bakken (2021 ITP/TPL)
  - Provide stakeholder information on EPRI Risk-based transmission planning program
  - Investigate cost in building additional ITP Market Powerflow Model for Winter Peak reliability hour and sensitivities
  - Identify Bakken uncertainties and sensitivities

HIGH-LEVEL STRAWMAN PROPOSAL (LONG-TERM)

- Work with TWG and ESWG to develop a planned approach for incorporating Risk-Based Planning in ITP and other planning processes
  - Review prior Project Plan for Probabilistic planning at SPP (2012/2013)
    - Understand relevance of implementation Level 1, 2 and 3 Benefits and Cost
    - Identify and refresh as needed implementation project plan requirements
  - Identify education opportunities for staff and stakeholders
    - Provide stakeholder information on current efforts of NERC and other RTO/ISOs
  - Identify governing documents and other working group impacts and revision requests needed for incorporating Risk-Based Planning in ITP
  - Develop and recommend a long-term implementation project plan

OTHER THOUGHTS AND FEEDBACK

- Identify and understand risks and frequency of other ITP Market Economic Model regional, inter-regional, by load center operating points of interest for additional Market Powerflow Model reliability hour consideration

NEXT STEPS

- March ESWG/TWG
  - Incorporate stakeholder feedback into high-level proposal and schedule
  - Provide additional background on prior Project Plan for Probabilistic planning at SPP (2012/2013)
- April MOPC/SPC
  - Provide High-level proposal and schedule

APPENDIX

POTENTIAL APPROACHES – OPTION 1

- Include additional contingencies in the Base Reliability needs assessment of the current ITP Winter Peak Models
  - Utilize additional appropriate contingencies on Winter Peak ITP Models
    - Potentially member submitted contingencies
    - Potentially P3 contingencies on Winter Peak ITP Models
      - Entails the removal of a generator, a system adjustment, then a second contingency after that
      - Currently P3 contingencies are only evaluated on Summer Peak and Light Load Models for TPL purposes

POTENTIAL APPROACHES – OPTION 2

- Include an additional Base Reliability Model as a part of future ITP analysis that better captures this scenario
  - "Cold Snap" Model in addition to Summer, Winter, & Light Load
    - Account for generation and load affected by extreme winter conditions via a TBD criteria
      - Ambiguity of the definition of a cold-weather driven reliability issue makes the development of a footprint wide criteria difficult
    - Footprint wide approach

POTENTIAL APPROACHES – OPTION 3

- Utilize the existing Winter Peak ITP Base Reliability Model to better capture this scenario
  - Utilize the existing ITP process and model set (via the Winter Peak Models) to more accurately represent extreme cold-weather driven reliability issues
    - Allow for additional member submitted generation data to be incorporated in the ITP Winter Peak Models
      - Leverage existing modeling processes
      - Explore the need for changes to the current process

POTENTIAL APPROACHES – OPTION 4

- Continue with status-quo (do nothing) and rely on current Winter Peak Models in the ITP to address these concerns
  - Winter Peak Models already take into account expected conditions during a winter peak hour
    - Currently model and contingency sets align with TPL requirements for events that don't allow for Interruption of Firm Transmission Service (ITFS) or Non-Consequential Load Loss (NCLL)