Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 21st, 2016

OGE Offices, Oklahoma City, OK

• SUMMARY OF ACTIONS TAKEN •

1. Approved RR 160 – Generation and Transmission service in the ITP.

Southwest Power Pool

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

April 21st, 2016

OGE Offices, Oklahoma City, OK

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:00 AM, welcomed those in attendance, and asked for introductions.

There were 20 in-person participants and 39 web conference participants, representing 17 of 17 ESWG members. (Attachment 1 – April 21st, 2016 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. Two proxies were identified; Jon Iverson (OPPD) named Kurt Stradley (LES) as his proxy and Al Tamimi (Sunflower) named Wayne Penrod (Sunflower) as his proxy. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. SPP Staff requested rearrangement of items to accommodate personnel schedules. (Attachment 3 – April 21st, 2016 ESWG Agenda)

> **Kurt Stradley (LES) made a motion; seconded by Tim Owens (NPPD) to adopt the agenda as modified. The motion was approved unanimously.**

Agenda Item 2 – Review of Past Action Items

Kelsey Allen (SPP Staff) reviewed the list of past action items. Juliano Freitas (SPP) suggested that action item 057 regarding SPP resource siting methodology could be removed and rolled into an overall effort to implement expected recommendations from the TPITF. After discussion, the group decided to leave the item as listed. (Attachment 4 – Past Action Items)

Agenda Item 3 – Consent Agenda

The consent agenda included the following items:

Meetings Minutes – March 17th, 2016 (Attachment 5 – March 17th, 2016 ESWG Minutes)
Meetings Minutes – March 29th, 2016 (Attachment 6 – March 29th, 2016 ESWG Minutes)

Alan Myers (ITC Great Plains) asked if any items should be removed from the consent agenda.

> **The consent agenda was approved unanimously.**

Agenda Item 4 – RR160 - Generation and Transmission Service in the ITP

Liz Gephardt (SPP Staff) reviewed the proposed Tariff changes outlined in RR160 regarding the inclusion of service and upgrades related to Generator Interconnections and Transmission Service studies in the ITP study process. The proposed changes will help to provide clarity and point to the ITP Manual for specifics on the modeling of new Generator Interconnections and Transmission Service. Liz also reviewed the proposed ITP Manual changes that detail the approved Resource Addition Request (RAR) process utilized for the 2017 ITP10. The group agreed with the changes proposed in RR160 but wanted more clarity in some of the language describing the inclusion of resources as a base assumption in an ITP10/20 model as well as detail regarding the notification process for RAR submittal. (Attachment 7 –

Tariff RR160 Generation and Transmission Service in the ITP Recommendation Report) (Attachment 8 – 2015 ITP Manual_Append_ProposedGenEdit_rev)

Jody Holland (SCMCN) made a motion; seconded by Pat McCool (KCPL) to approve RR 160. The motion was approved unanimously.

ACTION ITEM: SPP Staff to adjust the proposed ITP manual changes regarding the Resource Addition Request process for the ITP10/20 to provide clarity to the resources addressed and notification process.

Agenda Item 5 – Transmission Planning Improvement Task Force (TPITF) Discussion

Kelsey Allen (SPP Staff) gave an overview of the preliminary recommendations detailed in the TPITF whitepaper and focused review on the recommendations to standardize the study scope and establish common models for planning assessments as well as the proposed transition to the new process. The group discussed the need to make formal comments on the whitepaper and determined that none were necessary. The group also acknowledged the work that will need to be done to standardize the study scope and ITP manual and agreed to begin work on identifying items to begin prioritizing and discussing in upcoming meetings. (Attachment 9 – TPITF Whitepaper Discussion) (Attachment 10 – TPITF_Recommendations_Draft_White_Paper_4-5-2016_April_2016_MOPC)

ACTION ITEM: SPP Staff and members to prepare for discussion on scope standardization and prioritization of discussion items.

Agenda Item 6 – 2017 ITP10 Economic Needs Assessment Process

Kelsey Allen (SPP Staff) gave an overview of the economic needs assessment process SPP Staff will be implementing. This details the steps that Staff will use to implement the economic criteria approved by the ESWG as well as additional analysis to develop the list of congested flowgates that will be posted as official economic needs for the 2017 ITP10. (Attachment 11 – 2017 ITP10 Economic Needs Assessment Process)

Agenda Item 7 – RCAR II Update

Josh Ross (SPP Staff) and Amber Greb (SPP Staff) reviewed the implementation of the load pocket and trapped generation approaches in the RCAR models. There was also a discussion of the detailed decisions made by Staff regarding the net CONE (Cost of New Entry) analysis used to monetize the Reduced Capacity Costs Due to Reduced Losses On-Peak metric, and the loading threshold utilized to filter projects in implementing the Avoided or Delayed Reliability Projects metric. SPP Staff requested members to submit their feedback about the presented topics. (Attachment 12 – RCAR II Metrics Update)

Agenda Item 8 – Study Schedules

Agenda Item 8a – 2017 ITP10

Juliano Freitas (SPP Staff) gave an update on the status of the 2017 ITP10. Staff has discovered an issue regarding implementation of the approved transmission constraints that is currently being investigated with the vendor, ABB. The simulations are not properly honoring all of the constraint ratings. At this time the opening of the DPP window will be delayed but until the issue is resolved Staff does not have a new projected date.

ACTION ITEM: SPP Staff to send out notice to Stakeholders when the transmission constraint issue is corrected and when the DPP window will be open for the 2017 ITP10.

Agenda Item 8b – RCAR II

Juliano Freitas (SPP Staff) gave an update on the status of the RCAR II. It was Staff's intent to begin bringing metric results to the group for review, but with recent delays and the desire to report on all metrics as a whole, Staff will be bringing results to the group for review at the May meeting. (Attachment 13 – RCAR II Schedule)

Closing Items

Chair Alan Myers (ITC Great Plains) requested other items meriting discussion.

List of action items from the meeting:

1. SPP Staff to adjust the proposed ITP manual changes regarding the Resource Addition Request process for the ITP10/20 to provide clarity to the resources addressed and notification process.
2. SPP Staff and members to prepare for discussion on scope standardization and prioritization of discussion items.
3. SPP Staff to send out notice to Stakeholders when the transmission constraint issue is corrected and when the DPP window will be open for the 2017 ITP10.

The meeting was adjourned at 2:00 PM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

April 21, 2016

OG&E Office/Oklahoma City, OK

• ATTENDANCE LIST •

Name	Company
Kelsey Allen	SPP
Michael Wegner	ITC
Tim Soles	OXY
Josh Ross	SPP
Michael Massery	AECC
Amber Gres	SPP
Leon Howell	OTE
Juliano Freitas	SPP
Alan Myers	ITC
Kurt Stradley	LES
Tim Owens	NPPD
Wayne Penrod	Sunflower
Bethany King	EDE
Jody Holland	SCMCN
Don Le	NEET
Jeremy Severson	BEPC

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

April 21, 2016

OG&E Office/Oklahoma City, OK

• ATTENDANCE LIST •

Name	Company
Aaron Pypa	LS Power
Wayman Smith	AEP
ZAC HAGER	OGE
Tom Burke	ESEC

Name	Email	Company	Attendance
Aaron Pupa		LS Power	In Person
Akarsh Sheilendranath	akarsh.sheilendranath@brattle.com		Webex
Alan Myers		ITC	In Person
Alex Schneider	aschneider@quanta-technology.com		Webex
Amber Greb		SPP	In Person
Baseem	baseem@notrhwestern.com		Webex
Bennnie Weeks	bennie.weeks@xcelenergy.com		Webex
Bethany King		EDE	In Person
Bill Leung (NPRB)	bleung@bjleung.com		Webex
brenda harris	brenda_harris@oxy.com		Webex
Bret Toplyn	bret.toplyn@us.abb.com		Webex
Brian Rounds (AESL)	brian.rounds@aeslconsulting.com		Webex
Bryan Ramler (Xcel Energy)	bryan.ramler@xcelenergy.com		Webex
Chris Jamieson	cjamieson@spp.org		Webex
Clifford Franklin	clifford.franklin@westarenergy.com		Webex
David Burnham	david.burnham@eversource.com		Webex
Don Le		NEET	In Person
ed pfeiffer (quanta)	epfeiffer@quanta-technology.com		Webex
H. Lao	hlao@aep.com		Webex
Jamie Hajek	jamie.hajek@northwestern.com		Webex
Jason Shook (GDS/ETEC)	jason.shook@gdsassociates.com		Webex
Jeff Knottek	jeff.knottek@cityutilities.net		Webex
Jeremy Harris (WERE)	jeremy.harris@westarenergy.com		Webex
Jeremy Severson		BEPC	In Person
Jerry Bradshaw	jerry.bradshaw@cityutilities.net		Webex
Jody Holland		SCMCN	In Person
Joe Fultz	jfultz@grda.com		Webex
John Boshears	john.boshears@cityutilities.net		Webex
Jordan Schmick	jordan.h.schmick@xcelenergy.com		Webex
Josh Ross	jross@spp.org	SPP	In Person
joshua phillips	jphillips@spp.org		Webex
Juliano Freitas		SPP	In Person
Justin Radl (Xcel Energy)	justin.w.radl@xcelenergy.com		Webex
Kelsey Allen	kallen@spp.org	SPP	In Person
Kirk Hall	khall@spp.org		Webex
Kurt Stradley		LES	In Person
Leon Howell		OGE	In Person
Liz Gephardt (SPP)	lgephardt@spp.org		Webex
Michael Massery		AECC	In Person
Michael Watt (OMPA)	mwatt@ompa.com		Webex
Michael Wegner		ITC	In Person
Nikki Roberts	nroberts@spp.org		Webex
Pat Hayes	phayes@ameren.com		Webex
Prashanth Buyanni	prashanth.reddy.buyanni@dnvgl.com		Webex
Randy Collier (CUS)	randy.collier@cityutilities.net		Webex
Ross Hohlt	dhohlt@ameren.com		Webex

Ryan Yokley	ryokley@sunflower.net		Webex
sam loudenslager (SPP)	sloudenslager@spp.org		Webex
Sandeep Baidwan (Continuum)	sbaidwan@continuum-associates.com		Webex
Shawnee Claiborn-Pinto	shawnee.claiborn-pinto@puc.texas.gov		Webex
Steve Gaw	rsgaw1@gmail.com		Webex
Steve Hohman (OPPD)	shohman@oppd.com		Webex
Tim Owens		NPPD	In Person
Tim Soles		OXY	In Person
Todd Tadych (DATC)	ttadych@atcllc.com		Webex
Tom Burke		GSEC	In Person
Wayman Smith		AEP	In Person
Wayne Penrod		Sunflower	In Person
Zac Hager		OGE	In Person

1. **Jon Iverson (OPPD) proxy to Kurt Stradley (LES)**

From: IVERSON, JON S [mailto:jiverson@oppd.com]
Sent: Wednesday, April 20, 2016 12:35 PM
To: Kelsey Allen; Myers, Alan
Cc: Stradley, Kurt
Subject: **External Email** OPPD Proxy for ESWG meeting; 4/21/16

Kelsey, Alan,
Due to me having to participate in a day of training tomorrow at OPPD, I will not be able to attend the ESWG meeting.
Kurt Stradley will have my proxy for the ESWG meeting on 4/21/16.
Thanks,
Jon

your energy partner®
OPPD
Omaha Public Power District

2. **Al Tamimi (Sunflower) proxy to Wayne Penrod (Sunflower)**

From: Tamimi, Al [mailto:atamimi@sunflower.net]
Sent: Thursday, April 21, 2016 2:25 AM
To: Myers, Alan K.
Subject: Proxy

Wayne Pernod has my proxy for today's meeting.

Sent from my iPhone

ECONOMIC STUDIES WORKING GROUP

April 21st, 2016

OGE Offices – Oklahoma City, OK

• A G E N D A •

8:00am – 3:00pm

1. Administrative items
   a. Call to Order, Introductions...Alan Myers (5 minutes)
   b. Receipt of Proxies ....Kelsey Allen (1 minute)
   c. Review of Agenda[1] ....Alan Myers (1 minute)
2. Review of Past Action Items[1] .... Kelsey Allen (5 minutes)
3. Consent Agenda[1] (Approval Item)...Alan Myers (5 minutes)
   a. Approval of Meeting Minutes – March 17th, 2016
   b. Approval of Meeting Minutes – March 29th, 2016
4. RR 160 - Generation and Transmission Service in the ITP[1] (Approval Item) Liz Gephardt (30 minutes)
5. Transmission Planning Improvement Task Force (TPITF) Discussion .... All (60 minutes)
6. 2017 ITP10 Economic Needs Assessment Process .... Kelsey Allen (15 minutes)
7. RCAR II Update .... SPP Staff (60 minutes)
8. Study Schedules .... Juliano Freitas (45 minutes)
   a. 2017 ITP10
   b. RCAR II
9. Closing Items .... All (5 minutes)
   a. Summary of Action Items (Kelsey Allen)
   b. Future Meetings
      i. April 21st, 2016: OGE Offices, Oklahoma City, OK
      ii. May 18th-19th, 2016: Embassy Suites, Omaha, NE
      iii. June 16th, 2016: 8th Floor AEP Offices, Dallas, TX

---

[1] Background Material Included

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

April 21st, 2016

	Action Item	Date Originated	Status	Comments
057	SPP staff will write a straw-man procedure or portion of the ITP manual that deals with conventional and wind generation planning and siting within the ITP process. The process should be in place by the Spring of 2015.	August 23rd, 2012	In Progress Staff	A draft resource siting whitepaper will be developed for review mid-2016.
151	Staff to look into optional software tools for use in ITP studies.	May 20th, 2015	In Progress Staff	Staff is meeting with software vendors and users and expects to have a recommendation on any potential resource planning software changes by 4th quarter 2016.
160	SPP Staff and the ESWG are to formalize standard procedures for data requests and member review of information related to ITP studies.	January 21st, 2016	In Progress Staff/ESWG	Combined item representative of AI148 and AI149.
161	Staff to report on carbon emissions as the 2017 ITP10 study moves forward through the different milestones.	February 24th-25th, 2016	In Progress Staff	

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

March 17th, 2016

8th Floor AEP Offices, Dallas, TX

• SUMMARY OF ACTIONS TAKEN •

1. Approved the completion and results of the Benchmarking milestone of the 2017 ITP10.
2. Approved the 2017 ITP10 economic models as posted on TrueShare with adjustments to 2020 carbon prices for Future 1 and Future 2 detailed in the Economic Model presentation at the 3/17 ESWG meeting, including direction to be given by the ESWG on modeling of carbon costs for APC calculation.
3. Endorsed the Wind Integration Study recommendation #5 to begin accelerating the approved ITP projects with issued NTCs, specifically PID 30843 (Cimarron – Draper 345 kV Terminal Upgrades) and PID 30844 (Amoco – Sundown 230 KV Terminal Upgrades).
4. Approved the Staff recommendation for reflecting the price of carbon in the CPP Futures of the 2017 ITP10.
    a. Include a carbon cost in the model for all fossil units as a means to affect dispatch
    b. Reflect the cost of carbon in the energy costs of affected EGUs [to be regulated under the CPP]

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

March 17th, 2016

8th Floor AEP Offices, Dallas, TX

• MINUTES •

<u>Agenda Item 1 – Administrative Items</u>

<u>Agenda Item 1a - Call to Order, Introductions</u>

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:00 AM, welcomed those in attendance, and asked for introductions.

There were 14 in-person participants and 54 web conference participants, representing 16 of 17 ESWG members. (Attachment 1 – March 17th, 2016 Attendance List)

<u>Agenda Item 1b – Receipt of Proxies</u>

Alan Myers (ITC Great Plains) asked for any proxy statements. One proxy was identified; Gayle Nansel (WAPA) named Josie Daggett (WAPA) as her proxy. (Attachment 2 – Proxy Statements)

<u>Agenda Item 1c – Review of Agenda</u>

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – March 17th, 2016 Agenda)

> **Kurt Stradley (LES) made a motion; seconded by Tim Owens (NPPD) to adopt the agenda as modified. The motion was approved unanimously.**

<u>Agenda Item 2 – Review of Past Action Items</u>

Kelsey Allen (SPP Staff) reviewed the list of past action items. (Attachment 4 – Past Action Items)

<u>Agenda Item 3 – Consent Agenda</u>

The consent agenda included the following items:

> Meetings Minutes – February 24th – 25th, 2016 (Attachment 5 – ESWG 02.24-25.16 Minutes)

Alan Myers (ITC Great Plains) asked if any items should be removed from the consent agenda.

> **The consent agenda was approved unanimously.**

<u>Agenda Item 4 – Transmission Planning Improvement Task Force (TPITF) Update</u>

Alan Myers (ITC Great Plains) gave an update on the activities of the TPITF. There is currently a draft whitepaper that will be going to the MOPC for review in April and for final approval in July. The members discussed the need to make formal comments on the whitepaper prior to MOPC approval as well as beginning discussion on the impacts that the TPITF recommendations will have on items under ESWG purview.

ACTION ITEM: Staff to include and item on the April meeting agenda to discuss details on the TPITF whitepaper and provide comments as necessary.

<u>Agenda Item 5 – Study Schedules</u>

<u>Agenda Item 5a – 2017 ITP10</u>

Juliano Freitas (SPP Staff) gave an update on the status of the 2017 ITP10. This update focused on the recent determination of the schedule impacts of including additional TPL-001-4 contingencies (beyond P0 and P1) that were approved by the MOPC. Staff proposed current options being considered by the TWG regarding the technical implementation of these events in the reliability needs assessment. Current options range from an additional 8-12 weeks needed to complete the needs assessment. The modified schedule also contains additional time that would be needed to re-perform the constraint assessment, adding 7 weeks, for a total of 15-19 weeks needed in the schedule. This would require that the end of the study be pushed to potentially April or July MOPC/BOD approval. The group discussed the need to re-perform the constraint assessment in order to mitigate some of the additional schedule impacts. It was mentioned that the current market engine may not consider these additional TPL contingencies when determining redispatch after system event and the ITP10 should be consistent with that process. Staff requested that members continue to review the options proposed and supply additional comments. (Attachment 6 – TPL in the 2017 ITP10 Schedule)

ACTION ITEM: Members to supply comments to Staff on TPL impacts to the 2017 ITP10 in preparation for discussion on a future conference call.

Agenda Item 5b – RCAR II

Juliano Freitas (SPP Staff) gave an update on the status of the RCAR II. Staff plans to begin bringing results to the group for consumption at the April face-to-face meeting. (Attachment 7 – RCAR II Schedule)

Agenda Item 6 – SPP-MISO IPSAC Update

Brett Hooton (SPP Staff) gave a report on activities at the latest SPP-MISO IPSAC meeting. There was discussion on performing another joint study starting in 2016. SPP and MISO Staff will be sending out a questionnaire to their respective stakeholders to gather feedback on potential types of transmission issues to evaluate and any suggested improvements to the previous study process.

Agenda Item 7 – RR156 (BP7650 Modifications – DPP Clarification)

Tony Green (SPP Staff) reviewed RR156 which details a request to modify BP7650, specifically relating to the criteria for determining when a project submitted via a DPP is equivalent to a transmission project in a recommended portfolio. The group had several comments and questions on the redlined portion of the “Proposed Revision(s) to SPP Documents” section. The group requested clarification where the changes discuss “similar termination points that are located no more than 1 station (sub-station, switching station, or other station as identified in the SPP Model) away”, noting that the SPP Model does not identify types of stations. While not an approval item for the ESWG, Alan Myers stated that ITC will vote no on this RR in the appropriate groups because of the timing of implementation, clarifying that these changes should be made at the end of an ITP study cycle, not in the middle. Sunflower supported ITC’s comments. (Attachment 8 – RR 156 Recommendation Report 20160218)

Agenda Item 8 – 2017 ITP10 Benchmarking

Nikki Roberts (SPP Staff) reviewed results of the benchmarking effort for the 2017 ITP10. This effort focused on comparisons of the 2017 ITP10 simulation outputs to other data sets such as SPP Operations data, EIA data, and 2015 ITP10 data. The group was generally comfortable with the results and also requested more discussion to include in the report on the factors that are driving the differences in items such as system LMPs and generation capacity factors. (Attachment 9 – 2017ITP10 Benchmarking Update)

> **Jody Holland (SCMCN) made a motion; seconded by Kurt Stradley (LES) to approve the completion of the Benchmarking milestone of the 2017 ITP10. The motion was approved unanimously.**

Agenda Item 9 – SPP Wind Integration Study – NTC Project Acceleration

Jason Tanner (SPP Staff) reviewed recommendation #5 of the SPP Wind Integration Study to accelerate those projects with NTCs that resolve issues identified in the study and can be completed prior to the previously identified need date. Jason discussed the costs of acceleration and the potential benefits realized by accelerating the projects and asked for approval from the group. (Attachment 10 - SPP Wind Integration Study)

Jody Holland (SCMCN) made a motion; seconded by Kurt Stradley (LES) to endorse the Wind Integration Study recommendation #5 to begin accelerating the approved ITP projects with issued NTCs, specifically PID 30843 (Cimarron – Draper 345 kV Terminal Upgrades) and PID 30844 (Amoco – Sundown 230 KV Terminal Upgrades). The motion was approved with two opposed, Al Tamimi (Sunflower) and Jon Iverson (OPPD), and one abstention, Alan Myers (ITC Great Plains).

Alan Myers abstained for the following reason: "I have a lingering concern over how the benefits of the project accelerations were calculated. I don't think the benefit calculations were done in a manner consistent with present SPP practice."

Al Tamimi opposed for the following reason: "I do not think the tariff supports a reevaluation or acceleration of an NTC outside of the ITP process (Business Practice 7160). If we deviate from that, then SPP board must approve the reevaluation before it starts and to allow for accelerated study if not going through the ITP process."

Jon Iverson opposed for the following reason: "

My no vote regarding SPP accelerating certain NTCs out the Wind Integration Study (WIS) is due to the following reasons:

- **There was no indication if firm transmission service has been requested or approved for the wind generators that were causing the need to accelerate the NTC projects**
- **The presentation didn't provide sufficient detail to fully understand the how the benefits were calculated and which zones were receiving the benefits"**

Agenda Item 10 – 2017 ITP10 Study Assumptions

Agenda Item 10a – CPP Considerations

Kelsey Allen (SPP Staff) reviewed the options for reflecting the price of carbon the Future 1 and 2 of the 2017 ITP10. Staff recommended to include a carbon cost in the model for all fossil units as a means to affect dispatch and reflect the cost of carbon in the energy costs of affected EGUs [to be regulated under the CPP]. (Attachment 10 – 2017 ITP10 Analysis Methodology)

Don Le (NextEra) made a motion; seconded by Jody Holland (SCMCN) to approve the Staff recommendation for reflecting the price of carbon in the CPP Futures of the 2017 ITP10. The motion was approved with one abstention, Pat McCool (KCPL).

Agenda Item 10b – Portfolio Consolidation Methodology

[This item was not covered]

Agenda Item 10c – Metrics and Sensitivities

[This item was not covered]

Agenda Item 11 – 2017 ITP10 Economic Model

Liz Gephardt (SPP Staff) gave a brief update on the latest posting of the 2017 ITP10 economic model. Chris Jamieson (SPP Staff) reviewed the carbon prices and emissions outputs of the Future 1 and Future 2 models. Staff had to make adjustments to the 2020 carbon prices and leave some of the external regions/states outside of SPP above their 2020 emissions targets due to the lack of renewables in the external resource plan. (Attachment 12 – 2017 ITP10 Economic Model)

Kurt Stradley (LES) made a motion; seconded by Jody Holland (SCMCN) to approve the 2017 ITP10 economic models as posted on TrueShare with adjustments to 2020 carbon prices for Future 1 and Future 2 detailed in the Economic Model presentation at the 3/17 ESWG meeting, including direction to be given by the ESWG on modeling of carbon costs for APC calculation. The motion was approved with one abstention, Bethany King (EDE).

Bethany King abstained for the following reasons: "

- **The requirements needed to receive an exception for the retirement of a coal unit (Futures 1 and 2) are unclear.**
- **Exceptions have not been allowed for coal units in other aspects to the 2017 ITP10 (Example: No coal units were allowed a Must Run status even when the unit and majority ownership is outside the SPP footprint).**
- **It is EDE's belief the exceptions invalidate the retirement ranking list independently created by SPP staff and previously approved."**

Agenda Item 12 – 2017 ITP10 Scope

[This item was not covered]. (Attachment 13 – 2017 ITP10 Scope) (Attachment 14 – 2017 ITP10 Scope_Draft updates for April MOPC)

Agenda Item 13 – MOPC Action Item 255

Kelsey Allen (SPP Staff) reviewed the strawman proposal for MOPC Action Item 255. The group added a conclusion section and made some suggestions for adjustments to the recommendation section. (Attachment 15 - ESWG MOPC AI 255 Strawman_ESWG redline)

ACTION ITEM: Staff to draft a new recommendation for MOPC Action Item 255 based on member comments and send out for review and email approval.

Agenda Item 14 – 2016 ESWG Meeting Schedule

Kelsey Allen (SPP Staff) reviewed the ESWG Meeting Schedule for the second half of 2016. (Attachment 16 – 2016 ESWG Meeting Schedule)

Closing Items

Chair Alan Myers (ITC Great Plains) requested other items meriting discussion. A conference call will be scheduled the week of March 28th to complete the items on the agenda.

List of action items from the meeting:

1. Staff to include and item on the April meeting agenda to discuss details on the TPITF whitepaper and provide comments as necessary.
2. Members to supply comments to Staff on TPL impacts to the 2017 ITP10 in preparation for discussion on a future conference call.
3. Staff to draft a new recommendation for MOPC Action Item 255 based on member comments and send out for review and email approval.

The meeting was adjourned at 3:00 PM.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

March 29th, 2016

Net Conference

• SUMMARY OF ACTIONS TAKEN •

1. Approved the RCAR II economic models to be used in the metric analysis.
2. Accepted Staff's recommendation to develop portfolios for Future 1 and Future 2 of the 2017 ITP10 following the normal solution development processes, and Staff identify potential additional projects needed to meet emission targets for informational purposes.
3. Accepted Staff's recommendation on 2017 ITP10 portfolio consolidation methodology to develop two plans, a Future 3 plan and a consolidated CPP plan that will be composed of economic projects meeting the 0.9 B/C criteria based on a weighted sum 1-year APC B/C with Future 1 having a 75% weight and Future 2 having a 25% weight.
4. Accepted Staff's recommendation on 2017 ITP10 metrics and sensitivities analysis to calculate the approved benefit metrics and demand and gas sensitivities on two final plans, assessing the CPP plan in the Future 1 model and the non-CPP plan in the Future 3 model, and calculate peak and energy demand sensitivity at a 67% confidence interval (1 standard deviation) and gas sensitivity at a 95% confidence interval (2 standard deviations).
5. Approved the 2017 ITP10 scope document as posted, scope language changes based on previous approvals, and changes to the economic needs ranking to reflect congestion score.

Via email vote

6. Approved the ESWG recommendation to the MOPC on Action Item 255

Southwest Power Pool

Southwest Power Pool

ECONOMIC STUDIES WORKING GROUP

March 29th, 2016

Net Conference

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC Great Plains) called the meeting of the Economic Studies Working Group (ESWG) to order at 8:30 AM, welcomed those in attendance, and asked for introductions.

There were 63 web conference participants, representing 17 of 17 ESWG members. (Attachment 1 – March 29th, 2016 Attendance List)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC Great Plains) asked for any proxy statements. Two proxies were identified; Al Tamimi (Sunflower) named Wanye Penrod (Sunflower) as his proxy and Randy Collier (CUS) named Kenny Hale (CUS) as his proxy. (Attachment 2 – Proxy Statements)

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC Great Plains) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – March 29th, 2016 Agenda)

> **Tim Owens (NPPD) made a motion; seconded by Kurt Stradley (LES) to adopt the agenda as modified. The motion was approved unanimously.**

Agenda Item 2 – RCAR II Economic Model

Josh Ross (SPP Staff) gave an overview of the RCAR II economic models, updated the group on the implementation of the load pocket and trapped generation issues, and asked for approval of the models. (Attachment 4 – RCAR II Economic Model)

> **Natasha Henderson (GSEC) made a motion; seconded by Jody Holland (SCMCN) to approve the RCAR II economic models to be used in the metric analysis. The motion was approved with one abstention, Tim Owens (NPPD).**
>
> > **Tim Owens abstained for the following reason: NPPD abstained from this vote for the following reason. We discovered an issue resulting in overlapping maintenance outages for three of NPPD's fossil generating units in the year 2020 model, which we believe is unrealistic. Although NPPD provided timely feedback to SPP after the models were posted, it was unfortunately not possible to fully resolve the issue prior to the March 29, 2016 ESWG vote.**

Agenda Item 3 – 2017 ITP10 Study Assumptions

(Attachment 5 – 2017 ITP10 Analysis Methodology)

Agenda Item 3a – CPP Considerations

Kelsey Allen (SPP Staff) reviewed the options for meeting emissions targets with the portfolios of Future 1 and 2. Staff recommended that the development of final plans follow the traditional reliability, economic, and policy solution development processes and in the event the model does not demonstrate compliance with emissions targets, Staff will develop any additional solutions necessary to do so for informational purposes.

Jody Holland (SCMCN) made a motion; seconded by Tim Owens (NPPD) to accept Staff's recommendation to develop portfolios for Future 1 and Future 2 of the 2017 ITP10 following the normal solution development processes, and Staff identify potential additional projects needed to meet emission targets for informational purposes. The motion was approved unanimously.

Agenda Item 3b – Portfolio Consolidation Methodology

Kelsey Allen (SPP Staff) reviewed the proposed portfolio consolidation methodology. The current proposal is to consolidate Future 1 and Future 2 into a single CPP portfolio, and continue forward with a CPP and a reference case portfolio. The group discussed the merits and likelihood of the two CPP portfolios to determine an appropriate weighting to use for the 1-year B/C weighted APC methodology. Based on comments from the last meeting, Staff is proposing a 75% weight on Future 1 and a 25% weight on Future 2. Empire and OGE believe that with the current litigation surrounding the CPP, Future 2 is a more likely. KCPL believes that Future 1 is more likely because it attempts to model a regional carbon trading market, where Future 2 does not. The CPP futures are defined as a regional approach to compliance vs. a state approach to compliance, following interpretation of the draft CPP rule and implemented as an attempt to model regional carbon markets vs. state carbon markets, following interpretation of the final CPP rule.

Wayne Penrod (Sunflower) made a motion; seconded by Kurt Stradley (LES) to accept Staff's recommendation on 2017 ITP10 portfolio consolidation methodology to develop two plans, a Future 3 plan and a consolidated CPP plan that will be composed of economic projects meeting the 0.9 B/C criteria based on a weighted sum 1-year APC B/C with Future 1 having a 75% weight and Future 2 having a 25% weight. The motion was approved with two opposed, Bethany King (EDE) and Pat McCool (KCPL).

Bethany King opposed for the following reason: "Empire voted no on the motion to weight F1 75% and F2 25% in the consolidated CPP portfolio due to different coal retirement scenarios used in the futures. Empire believes each scenario should be given equal weight. Additionally the uncertainty surrounding the outcome of litigation and regulation related to CPP makes it difficult to determine which future is more likely (considering individual states have filed differing court cases) and unlikely each state will implement CPP in the same manner. It is our belief a 50/50 weighting would be more appropriate."

Pat McCool opposed for the following reason: "KCPL voted 'No' on the motion to weight the 'CPP Portfolio Consolidation' at 75% Future 1 (Regional CPP) and 25% Future 2 (State CPP) because Future 2 does not include any trading of carbon allowances. KCPL believes that the CPP rule supports a carbon trading market and it is unreasonable to believe all states will opt out of what may be a more economical alternative to other methods of meeting the CPP requirements. Therefore, KCPL would support a 'CPP Portfolio Consolidation' of 100% Future 1 (Regional CPP) and 0% Future 2 (State CPP)."

Agenda Item 3c – Metrics and Sensitivities

Kelsey Allen (SPP Staff) reviewed Staff's proposal for calculating metrics and sensitivities.

Leon Howell (OGE) made a motion accept Staff's recommendation on 2017 ITP10 metrics and sensitivities calculations and calculate peak and energy demand sensitivity at a +/- 10% band and gas sensitivity at a +/- 25% band on 2 final plans. The motion died for lack of second.

Jody Holland (SCMCN) made a motion; seconded by Leon Howell (OGE) to accept Staff's recommendation on 2017 ITP10 metrics and sensitivities analysis to calculate the approved benefit metrics and demand and gas sensitivities on two final plans, assessing the CPP plan in the Future 1 model and the non-CPP plan in the Future 3 model, and calculate peak and energy demand sensitivity at a 67% confidence interval (1 standard deviation) and gas sensitivity at a 95% confidence interval (2 standard deviations). The motion was approved unanimously.

Agenda Item 4 – 2017 ITP10 Schedule Impacts - TPL

Kelsey Allen (SPP Staff) reviewed the schedule impacts of including the additional TPL contingencies in the 2017 ITP10 assessments. Based on Staff proposals and Stakeholder recommendations, the impact of including the additional TPL analysis could range from 2 weeks to 8 weeks. Staff will be requesting technical direction from the TWG on what option would be the best to implement. The group requested Staff to keep them informed of TWG decisions in order to understand how the schedule might change. (Attachment 6 – TPL in the 2017 ITP10)

Agenda Item 5 – 2017 ITP10 Scope

Kelsey Allen (SPP Staff) reviewed the updates to the 2017 ITP10 Scope. The updates added language around previous ESWG and TWG approvals to flesh out the areas of the scope that were described generally. Staff also requested one additional change to the scope regarding the ranking of congested flowgates to determine economic needs, specifically the use of flowgate congestion cost. Upon further investigation, Staff found that congestion costs are netted based on direction of flow on the flowgate throughout the year and recommended using a congestion score, which uses assumes no bias based on direction of flow. (Attachment 7 – 2017 ITP10 Scope) (Attachment 8 – 2017 ITP10 Scope_Draft updates for April MOPC_rev)

> **Jody Holland (SCMCN) made a motion; seconded by Don Le (NextEra) to approve the 2017 ITP10 scope document as posted, scope language changes based on previous approvals, and changes to the economic needs ranking to reflect congestion score. The motion was approved with one abstention, Wayne Penrod (Sunflower).**
>
> **Wayne Penrod abstained for the following reason:**
>
>> **"According to the Scoping document, authority for endorsement of the scope rests with MOPC. Responsibility for preparing, reviewing and recommending changes to the scope rests with ESWG. However MOPC must endorse those changes, especially if they are policy driven. While the schedules for action by MOPC are not perfectly synchronized with the ESWG, the necessary endorsement should occur as the ESWG work proceeds. Specifically in this instance there were eight scope changes sought.**
>>
>> **Changes recommended to the study scope include changes in the B/C ratio threshold identified in the original scope. These changes have the effect of increasing the number of projects for further evaluation prior to final project determination. Sunflower voted no on this scope change in the first instance. The significant changes in the final Clean Power Plan (CPP) rule, and the subsequent stay of the rule by the US Supreme Court has added uncertainty related to how and whether this rule might be implemented. At this particular time it seems inappropriate to increase the number of projects to be evaluated. Sunflower voted yes in all other scope change recommendation following ESWG deliberations."**

Closing Items

Chair Alan Myers (ITC Great Plains) requested other items meriting discussion.

List of action items from the meeting:

1. None.

The meeting was adjourned at 11:30 AM.

Email Voting 3/31/16

Natasha Henderson (GSEC) made a motion; seconded by Kurt Stradley (LES) to approve the ESWG recommendation to the MOPC on Action Item 255. The motion was approved unanimously.

Respectfully Submitted,

Kelsey Allen
ESWG Secretary

SPP Southwest Power Pool

Revision Request Recommendation Report

RR #: 160	**Date:** 3/17/2016
RR Title: Generation and Transmission Service in the ITP	
SUBMITTER INFORMATION	
Submitter Name: Liz Gephardt	**Company:** SPP
Email: lgephardt@spp.org	**Phone:** 501-482-2236
OBJECTIVE OF REVISION	
The Tariff language in Attachment O, Section III is ambiguous as to which generation interconnections and associated upgrades are required to be modeled in the Integrated Transmission Planning (ITP) assessments. SPP is currently following a process documented and approved in the Integrated Transmission Planning (ITP) Manual in this regard. Language pointing to the existing process should be clarified in the Tariff so the potential for other interpretations is minimized for upcoming ITP model builds.	
EXECUTIVE SUMMARY OF RECOMMENDATION	
IMPACT ANALYSIS REQUIRED: ☐ **Yes** ☒ **No**	
Estimated Cost: $ *Cost is a **rough order of magnitude** estimate, approx. +/-50%*	**Estimated Duration:** months *Duration is a **rough order of magnitude** estimate, approx. +/-50%*
Priority Rank for System Change: ☐ **1 – Critical** ☐ **2 – High** ☐ **3 – Medium** ☐ **4 – Low**	

SPP DOCUMENTS IMPACTED		
☐ **Market Protocols**	**Protocol Section(s):**	**Protocol Version:**
☐ **Criteria**	**Criteria Section(s):**	**Criteria Date:**
☒ **Tariff (OATT)**	**Tariff Section(s):** Attachment O Section III	
☐ **Business Practice**	**Business Practice Number:**	

WORKING GROUP REVIEWS AND RECOMMENDATIONS List Primary and any Secondary/Impacted WG Recommendations as appropriate	
Primary Working Group: **RTWG**	**Date: 3/25/2015** **Vote: Unanimously Approved** **Abstained:** **Opposed:**
Reason for Opposition:	
Secondary Working Group: **RCWG**	**Date: 4/18/2025** **Vote: Unanimously Approved** **Abstained:** **Opposed:**
Reasons for Opposition:	

Secondary Working Group:	**Date:** **Vote:** **Abstained:** **Opposed:**
Reasons for Opposition:	
Secondary Working Group:	**Date:** **Vote:** **Abstained:** **Opposed:**
Reasons for Opposition:	
MOPC Recommendation:	**Date:** **Vote:** **Abstained:** **Opposed:**
Reasons for Opposition:	
BOD/Member Committee Recommendation:	**Date:** **Vote:** **Abstained:** **Opposed:**
Reasons for Opposition:	
COMMENTS	
Comment Author:	
Description of Comments:	
Status:	describes any action taken on the comment. SS will complete this… Comments incorporated, comments rejected…
Comment Author:	
Description of Comments:	
Status:	
PROPOSED REVISION(S) TO SPP DOCUMENTS	
Market Protocols	

III. The Integrated Transmission Planning Process

The ITP process is an iterative three-year process that includes 20-Year, 10-Year and Near Term Assessments. The 20-Year Assessment identifies the transmission projects, generally above 300 kV, and provides a grid flexible enough to provide benefits to the region across multiple scenarios. The 10-Year Assessment focuses on facilities 100 kV and above to meet the system needs over a ten-year horizon. The Near Term Assessment is performed annually and assesses the system upgrades, at all applicable voltage levels, required in the near term planning horizon.

1) Commencement of the Process

At the beginning of each calendar year the Transmission Provider shall notify stakeholders as to which part(s) of the integrated transmission planning cycle will take place during that year and the approximate timing of activities required to develop the SPP Transmission Expansion Plan. Notice of commencement of the process shall be posted on the SPP website and distributed via email distribution lists. Such notice shall include a timeline indicating when stakeholders are able to submit 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) Transmission Planning Forums

The transmission planning forums include planning summits and sub-regional planning meetings and these are conducted as follows:

a) Planning Summits

i) The purpose of the planning summits is for the Transmission Provider and the stakeholders to share current SPP transmission network issues, develop the study scopes, provide solution alternatives and review study findings. These 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.

ii) The planning summits shall be open to all entities.

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

iv) Planning summits shall be held at least semi-annually, including sub-regional breakout sessions of the SPP Region. Teleconference capability will be made available for planning summits. Planning summit web conferences shall be held as needed.

v) Notice of the planning summits and web conferences shall be posted on the SPP website and distributed via email distribution lists.

b) Sub-regional Planning Meetings

i) The Transmission Provider shall define sub-regions from time to time to address local area planning issues.

ii) The purpose of the sub-regional planning meetings is to identify unresolved local stakeholder issues and transmission solutions at a more granular level. The sub-regional planning meetings shall provide stakeholders with local needs the opportunity to provide advice and recommendations to the Transmission Provider and to the Transmission Owners. The sub-regional planning meetings shall provide a forum to review local planning criteria and needs as specified in Section II of this Attachment O.

iii) The sub-regional planning meetings shall be open to all entities.

iv) The Transmission Provider shall facilitate the sub-regional planning meetings.

v) A planning meeting shall be held at least annually for each individual sub-region.

vi) The sub-regional planning meetings shall be held in conjunction with the stakeholder working group meetings. Teleconference capability will be made available for sub-regional planning meetings. Sub-regional planning web conferences shall be held as needed.

vii) Notice of the sub-regional planning meetings, teleconferences and web conferences shall be posted on the SPP website and distributed via email distribution lists.

3) Preparation of the 20-Year Assessment

a) The Transmission Provider shall perform a 20-Year Assessment once every three years. The timing of this assessment shall generally be in the first half of each three-year cycle.

b) The 20-Year Assessment shall review the system for a twenty-year planning horizon and address, at minimum, facilities 300 kV and above needed in year 20. This assessment is not intended to review each consecutive year in the planning horizon. The Transmission Provider shall work with stakeholders to identify the appropriate year(s) to study in developing the assessment study scope.

c) The 20-Year Assessment shall assess the cost effectiveness of proposed solutions over a forty-year time horizon.

d) The Transmission Provider shall develop the assessment study scope with input from the stakeholders. The study scope shall take into consideration the input requirements described in Section III.6 of this Attachment O.

e) The assessment study scope shall specify the methodology, criteria, assumptions, and data to be used.

f) The Transmission Provider, in consultation with the stakeholder working groups, shall finalize the assessment study scope including the identification of those transmission needs that will be studied, such as transmission needs driven by Public Policy Requirements, as further described in the Integrated Transmission Planning Manual.

g) The assessment study scope shall be posted on the SPP website and will be included in the published annual SPP Transmission Expansion Plan report. The assessment study scope shall include an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local and regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated.

h) In accordance with the assessment study scope, the Transmission Provider shall analyze potential solutions following the process set forth in Section III.8 of this Attachment O.

4) Preparation of the 10-Year Assessment

a) The Transmission Provider shall perform a 10-Year Assessment once every three years as part of the three year planning cycle. The timing of this assessment shall generally be in the second half of the three-year planning cycle.

b) The 10-Year Assessment shall review the system for a ten-year planning horizon and address, at minimum, facilities 100 kV and above needed in year 10. This assessment is not intended to review each consecutive year in the planning horizon. The Transmission Provider shall work with stakeholders to identify the appropriate year(s) to study in developing the assessment study scope.

c) The 10-Year Assessment shall assess the cost effectiveness of proposed solutions over a forty-year time horizon.

d) The Transmission Provider shall develop the assessment study scope with input from the stakeholders. The study scope shall take into consideration the input requirements described in Section III.6 of this Attachment O.

e) The assessment study scope shall specify the methodology, criteria, assumptions, and data to be used.

f) The Transmission Provider, in consultation with the stakeholder working groups, shall finalize the assessment study scope, including the identification of those transmission needs that will be studied, such as transmission needs driven by Public Policy Requirements, as further described in the Integrated Transmission Planning Manual.

g) The assessment study scope shall be posted on the SPP website and will be included in the published annual SPP Transmission Expansion Plan report. The assessment study scope shall include an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local and regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated.

h) In accordance with the assessment study scope, the Transmission Provider shall analyze potential solutions, including those upgrades approved by the SPP Board of Directors from the most recent 20-Year Assessment, following the process set forth in Section III.8 of this Attachment O.

5) Preparation of the Near Term Assessment

a) The Transmission Provider shall perform the Near Term Assessment on an annual basis.

b) The Near Term Assessment will be performed on a shorter planning horizon than the 10-Year Assessment and shall focus primarily on identifying solutions required to meet the reliability criteria defined in Section III.6 of this Attachment O.

c) The assessment study scope shall specify the methodology, criteria, assumptions, and data to be used to develop the list of proposed near term upgrades.

d) The Transmission Provider, in consultation with the stakeholder working groups, shall finalize the assessment study scope, including the identification of those transmission needs that will be studied, such as transmission needs driven by Public Policy Requirements, as further described in the Integrated Transmission Planning Manual. The study scope shall take into consideration the input requirements described in Section III.6 of this Attachment O.

e) The assessment study scope shall be posted on the SPP website and will be included in the published annual SPP Transmission Expansion Plan report. The assessment study scope shall include an explanation of which transmission needs driven by Public Policy Requirements will be evaluated for potential solutions in the local and regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated.

f) In accordance with the assessment study scope, the Transmission Provider shall analyze potential solutions, including those upgrades approved by the SPP Board of Directors from the most recent 20-Year Assessment and 10-Year Assessment, following the process set forth in Section III.8 of this Attachment O.

6) Policy, Reliability, and Economic Input Requirements to Planning Studies

The Transmission Provider shall incorporate, as appropriate for the assessment being performed, the following into its planning studies:

a) NERC Reliability Standards;

b) SPP Criteria;

c) Transmission Owner-specific planning criteria as set forth in Section II of this Attachment O;

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 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) Transmission needs driven by Public Policy Requirements identified through a survey of stakeholders to identify Public Policy Requirements and additional

Public Policy Requirements as determined by the Transmission Provider and stakeholders during study scope development; and

p) Other input requirements identified during the stakeholder process.

q) In developing the long term capacity forecasts, the studies will reflect generation and demand response resources capable of providing any of the functions assessed in the SPP planning process, and can be relied upon on a long-term basis. Such demand response resources shall be permitted to participate in the planning process on a comparable basis. These studies will consider operational experience gained from markets operated by the Transmission Provider.

7) Inclusion of Upgrades Related to Transmission Service and Generator Interconnection in Planning Studies

a) The studies performed under this Section III of Attachment O shall accommodate and model in accordance with the Integrated Transmission Planning Manual, the specific long-term firm Transmission Service of Transmission Customers and specific interconnections of Generation Interconnection Customers when such Service Agreements and interconnection agreements have been accepted by the Commission.

~~a~~b) Transmission upgrades related to requests for Transmission Service are described in Sections 19 and 32 of the Tariff and Attachment Z1 ~~to~~of the Tariff. ~~These~~ ~~u~~Upgrades associated with the modeled long-term firm Transmission Service are included as part of the future expansion of the Transmission System, upon the execution of the various Service Agreements with the Transmission Customers. 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.

~~b~~c) Interconnection facilities and other transmission upgrades related to requests for generation interconnection service are described in Attachment V of this Tariff. ~~These u~~Upgrades associated with the modeled generation interconnection service are included as part of the future expansion of the Transmission System upon the execution of the various interconnection agreements with the Generation Interconnection Customers. 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.

~~c) The studies performed under this Section III of Attachment O shall accommodate and model the specific long-term firm Transmission Service of Transmission Customers and specific interconnections of Generation Interconnection Customers no later than when the relevant Service Agreements and interconnection agreements are accepted by the Commission.~~

8) Process to Analyze Transmission Alternatives for each Assessment

The following shall be performed, at the appropriate time in the respective planning cycle, for the 20-Year Assessment, 10-Year Assessment and Near Term Assessment studies:

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

b) After the study scope has been approved, 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.8.b(i) of this Attachment O. If the project described in a DPP is included in the ITP plan, the submitting stakeholder may qualify for incentive points as described in Section III of Attachment Y of this Tariff. A stakeholder that submits a DPP that is equivalent to a DPP or Transmission Provider identified project submitted in a previous assessment during the current three (3) year planning cycle shall not be eligible for incentive points.

i) 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:

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

b. description of the needs identified in the ITP process to be addressed;

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

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

e. description of any known or anticipated environmental impacts;

f. engineering and modeling data required by the Transmission Provider;

g. identification and justification of any changes in modeling assumptions from those used in the current ITP process;

h. results of transmission project economic or reliability analysis, if applicable; and

i. any other information available to support the evaluation of the project.

ii) Any Stakeholder providing a DPP that meets the requirements set forth in Section III.8.b(i) of this Attachment O will be recorded by the Transmission Provider for the ITP planning assessment for the which the DPP was submitted, including the contact information of the stakeholder that submitted the DPP.

iii) 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 the 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.

iv) 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 is necessary for review and documentation of the reason(s) why the DPP was or was not chosen in the current ITP assessment. The remaining information in the DPP will remain confidential.

v) A stakeholder that submits a DPP may remain eligible for incentive points, in accordance with Section III of Attachment Y of this Tariff, for the remainder of the current three (3) year planning cycle of the ITP process. In order for the stakeholder to maintain its eligibility for incentive points in any subsequent ITP assessment within the current three (3) year planning cycle, the stakeholder must resubmit the information required by Section III.8.b(1) of this Attachment O, including identification of the need(s) in the ITP assessment that the DPP is proposed to solve. If the stakeholder does not provide the updated information, the stakeholder will not be eligible for incentive points for the DPP for that subsequent assessment; however, the stakeholder would be eligible for incentive points in any other ITP assessment during the current three (3) year planning cycle, provided that the stakeholder updates the DPP information for that assessment.

c) For all potential alternatives 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 planning 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.

d) In addition to recommended upgrades, 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.

e) The Transmission Provider shall assess the cost effectiveness of proposed solutions. Such assessments shall be performed in accordance with 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. SPP shall post this manual on its website.

f) The analysis described above 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.

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.

g) The Transmission Provider shall make a comprehensive presentation of the preferred potential 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.

h) 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. Stakeholders may propose any combination of demand resources, transmission, or generation as alternate solutions to identified reliability and economic needs.

i) Upon consideration of the results of the cost effectiveness analysis and feedback received in the subsequent review process, the Transmission Provider shall prepare a draft list of projects for review and approval in accordance with Section V of this Attachment O.

SPP Criteria

SPP Business Practices

Integrated Transmission Planning Manual

Revised: 12/15/2014

ITP Manual Task Force

Southwest Power Pool

Revision History

Date	Author	Change Description
10/13/2010	SPP Staff	Initial Draft approved by the MOPC.
1/7/2011	SPP Staff	Incorporated TWG and ESWG edits to the ITPNT and ITP20 sections.
6/27/2011	SPP Staff	Includes the TWG and ESWG approved ITP10 section and minor changes to other sections.
7/13/2011	SPP Staff	Revised Draft approved by the MOPC.
9/02/2014	SPP Staff	Revised by the ITP Manual Task Force
12/15/2014	ESWG	Accepted Task Force Edits

Table of Contents

1 ITP Introduction

1.1 Purpose

The SPP Open Access Transmission Tariff (OATT), Attachment O Section III.8.e, requires the Southwest Power Pool, Inc. (SPP) to assess the cost effectiveness of proposed transmission projects in accordance with the Integrated Transmission Planning (ITP) Manual. This manual will outline the processes for the three Integrated Transmission Planning components: 20-Year, 10-Year, and Near-Term Assessments.

The first phase of the ITP process is the 20-Year Assessment, which will be used to examine the need for additions to the SPP Extra High Voltage (EHV) backbone network over a twenty year horizon. The 20-Year Assessment is intended to study the plausible long-term high voltage transmission needs of the SPP region. Because the level of uncertainty over a 20 year horizon is higher relative to the 10-Year and Near-Term Assessments, the range of future scenarios examined will normally be broader. This study will give the SPP guidance as to the high voltage transmission needs of the region under a variety of plausible scenarios. The information learned will serve as guidance in the other shorter horizon studies so that SPP has a better understanding of which designs for solutions in those studies make sense over the longer term. In this way SPP will be better equipped to construct a system that is flexible enough to address changing needs over time while at the same time striving for a no regrets goal where the transmission authorized to be built by SPP does not result in over or under investment.

The ITP20 is a value-based planning assessment that will be employed using a diverse array of power system and economic analysis tools to thoroughly study the SPP transmission system and to identify cost-effective and robust backbone projects needed to meet each of a broad array of future scenarios and provide information as to a grid design flexible enough to reasonably accommodate all of these scenarios. Thus, the study will produce a design for each of the scenarios and provide information as to an overall design that will be flexible enough to anticipate the scenarios while taking into account the likelihood of such scenarios occurring based upon the best available information. Because the degree to which the power transmission landscape will change over this time frame is not currently known, transmission system expansion is designed with flexibility (i.e., enables the ability of the transmission grid to meet a range of possible resource futures) in mind. The projects identified in the overall design as a result of the ITP20 are expected to provide benefits to the region across multiple scenarios. Designs for each scenario and the overall design will provide information that can be used for the Year-10 and Near-Term Assessments, capturing the needs under particular scenarios that may be used if it is apparent over time that they are more likely to become reality. While Notices to Construct (NTC's) are likely not to be issued for projects identified through the ITP20, these projects will provide a "pool" of potential solutions that can be analyzed in subsequent phases of the ITP Process.

The second phase of the ITP process is the 10-Year Assessment (ITP10). The ITP10 is a value-based planning approach that will analyze the Transmission System in year 10 and identify 100 kV and above solutions to issues stemming from multiple sources including: (a) the issues that are identified in the reliability analysis of the 69 kV and above system, and (b) issues identified by the ITP20 process which are appropriate for the ITP10 study.

The ITP10 process will be similar to the ITP20 process. The ITP10 will evaluate the need for the ITP20 projects ten years out. It may also evaluate (based upon updated information) the cost effectiveness of such design including whether projects in the ITP 20 should be eliminated or changed and whether other projects should be added. Changes to the ITP 20 design should be based upon changes to the assumptions originally made in the ITP 20 that should be modified in the ITP 10 because of better information becoming available. The high voltage design will be integrated with 100 kV and above facilities that satisfy needs such as: a) resolving potential criteria violations; b) mitigating known or foreseen congestion; c) improving access to markets; d) staging transmission expansion; and e) improving interconnections. Economic and reliability analyses will be utilized as a way to further refine and establish the staging of the projects. Economic analysis will aid in determining those projects that are the best project alternatives for the 10 year plan. In the ITP10, the ITP20 futures may be used as a guide for development of the futures most likely occurring within the 10-year horizon. Generally, the array of future scenarios in the ITP 10 will be narrower than the ITP 20 and when reasonable utilize a subset of the most likely scenarios utilized in the ITP 20. This will allow the designs produced in the ITP 20 to have greater applicability and value in the ITP 10. However, judgment will be employed in varying future scenarios in the ITP 10 from the ITP 20 to take into account changes that have occurred since the ITP 20 study was performed. The primary focus of the ITP10 is to determine the needs in the horizon year. However, the 10-year assessment may also analyze the need for projects within the 10 year period as well. NTC's may be issued for projects identified through the ITP10.

The ITP Near Term (ITPNT) addresses reliability issues within the SPP system. The ITPNT is done every year in conjunction with the ITP10 and ITP20. Projects approved out of the ITPNT are for reliability purposes and have financial commitment within the next 4 years.

SPP Staff will take all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the SPP Tariff (i.e., Sections 17.2(iv) and 18.2(vii); Attachment V (Section 13.1 and Article 22 of Appendix 6); Exhibit 1 (Section 2.3); Attachment AJ (Section 8); and Attachment C-One (Clause 7)).

1.2 Process

1.2.1 ITP Planning Horizon Overview

In January of 2009, the SPP Board of Directors (BOD) created the Synergistic Planning Project Team (SPPT) to address gaps and conflicts in SPP's transmission planning processes; to develop a holistic, proactive approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities.

The SPPT recommended that the organization adopt a new set of planning principles; develop and implement an ITP process; develop a plan to monitor the construction of projects approved through the ITP process; and identify Priority Projects that continue to appear in system reviews as needed to relieve congestion on existing constraints and connect SPP's eastern and western regions. The SPPT recommended that the Regional State Committee (RSC) establish a "highway-byway" cost allocation methodology for approved projects.[1]

The SPPT created the following principles to drive development of the ITP process:

- Focus on regional needs, while considering local needs as well; long range plans (both ITP20 and ITP10) are to be updated every three years while ITPNT plans are to be updated annually.

[1] The Highway-Byway cost allocation was approved by FERC on June 17, 2010. http://elibrary.ferc.gov/idmws/nvcommon/NVintf.asp?slcfilelist=12369183:0

- Plan the backbone transmission system to serve SPP load with SPP resources in a cost-effective manner. The transmission backbone will:
    - Enhance interconnections between SPP's western and eastern regions
    - Strengthen existing ties to the Eastern Interconnection.
    - Provide options for planning and coordination to the Western Electricity Coordinating Council (WECC) and the Electric Reliability Council of Texas (ERCOT) grids in the future.
- Incorporate 20-year physical modeling and 40-year financial analysis timeframes.
- Better position SPP to proactively prepare for and respond to national priorities while providing flexibility to adjust expansion plans.

SPP began performing its planning duties in accordance with the ITP process in January of 2010.

The ITP process is SPP's approach to planning transmission needed to maintain reliability, provide economic benefits and achieve public policy goals to the SPP region in both the near and long-term. The ITP process enables SPP and its stakeholders to facilitate the development of a robust transmission grid that provides regional customers improved access to the SPP region's diverse resources.
The ITP process is an iterative three-year process that includes 20-Year[2], 10-Year, and Near-Term Assessments and targets a reasonable balance between long-term transmission investment and customer congestion costs (as well as many other benefits).

The ITP process was designed to create synergies by integrating SPP transmission planning activities which existed prior to its creation including: the EHV Overlay, the Balanced Portfolio, and the SPP Transmission Expansion Plan (STEP) Reliability Assessment. Consequently, and reaching the balance above, efficiencies are expected to be realized in the Generation Interconnection and Aggregate Transmission Service Request study processes. The ITP process works in concert with SPP's existing sub-regional planning stakeholder process, and parallels the North American Electric Reliability Corporation Transmission Planning (NERC TPL) Reliability Standards compliance process.

The Economic Studies Working Group (ESWG) was also formed in conjunction with the development of the ITP process and will identify and maintain the processes, modeling assumptions for various futures and metrics on an ongoing basis for qualifying and quantifying the transmission projects for the ITP20 and ITP10 Assessments.

The Transmission Working Group (TWG) will identify and maintain the process, model assumptions and local reliability requirement review on an ongoing basis for qualifying and quantifying the transmission projects for the ITPNT Assessment.

ITP recommendations that are reviewed and endorsed by the Market Operations and Policy Committee (MOPC) and approved by the BOD will allow staff to issue NTC letters for approved projects needed within the financial commitment horizon.

Successful implementation of the ITP process will result in a list of transmission expansion projects, projected project costs and completion dates that facilitate the creation of a cost-effective, robust, flexible and responsive transmission network in the SPP footprint.

[2] The first iteration of the 20-Year Assessment is studying only year 20. However, in the future, multiple years may be studied in addition to year 20.

1.2.2 Process

The ITP process is an iterative three-year component of the SPP Transmission Expansion Plan (STEP) that includes 20-Year, 10-Year, and Near-Term Assessments. The 20-Year and 10-Year assessments target a reasonable balance between the cost of long-term transmission investment on one hand and the benefits of reducing customer congestion costs, and meeting reliability and policy needs, on the other. As each assessment concludes, more clarity is provided concerning appropriate investments in new transmission. Finding the appropriate investments is dependent on the assumptions used to represent possible future outcomes. This targeted approach is both forward-looking and proactive by designing with an end in mind of having a cost-effective and responsive transmission network which adheres to the ITP principles and also keeps the FERC "Nine Transmission Principles" in the forefront.[3]

Generally, the ITP20 and ITP10 Assessments are conducted on alternating 18 month schedules as part of a three year cycle. The ITP20 Assessment begins in year one and is completed midway through year two. The ITP10 Assessment begins during the second half of year two and is completed at the end of year three. The ITPNT Assessment is performed each year to ensure reliability, protect the rights of long-term firm transmission customers and to incorporate local planning requirements.

Analysis will be performed following the adoption of the study assumptions and will focus upon cost-effectiveness, flexibility and robustness.

Cost-effective analysis is a form of economic analysis that allows for the most effective planning over a longer versus shorter term time frame. This is often referred to as "no regrets" analysis. The objective is to produce the most economical project planning over the longer term horizon. In effect, the benefits side of the equation is held constant at some pre-determined standard of service, and various options over various time horizons for providing that standard of service are then compared, with the least-cost method identified as the preferred option.

An evaluation of robustness involves a different perspective than does the cost effectiveness analysis. Robustness includes an evaluation of changes to cost-effective transmission plans for flexibility as well as incremental cost and benefits. Metrics of robustness may be quantitative and/or qualitative.

1.2.3 Ad-Hoc Special Studies

The SPP OATT allows for the use of 3 Ad-Hoc or Special Studies during the course of a year. The purpose of these special studies is to address new regulatory or industry changes that will significantly affect the SPP transmission system. An Ad-Hoc Study must be approved by the SPP Board of Directors with a target due date and specific scope of analysis.

1.3 Order 1000 and Interregional Coordination

SPP is responsible for coordinating transmission planning with each neighboring interconnected system. SPP will coordinate any activities and studies based on the agreements listed in Addendum 1 to Attachment O of the OATT. As part of the inter-regional coordination process, SPP will share

[3] These FERC principles are coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning (congestion) studies, and cost allocation for new projects, as described more fully in Order 890, Final Rule, pages 245 – 323.

system plans with neighboring entities and identify system enhancements on the seams. Additionally, a new competitive bidding window which includes submission of transmission ideas/solutions, review of those solutions, development of an RFP, RFP submittals and award will be used for projects that meet the Order 1000 qualifications for competitive bidding. SPPs Order 1000 page can be found here.

2 Long-Term ITP Assessments: ITP20 and ITP10

2.1 Future Development

Due to the uncertainties involved in forecasting future system conditions, a number of diverse futures or scenarios are considered that take into account multiple variables. Consideration of multiple futures or scenarios provides for a transmission expansion plan that evolves as economic, environmental, regulatory, public policy, and technological changes arise that affect the industry. Initiatives such as plug-in hybrid electric vehicles, smart grid, renewable electricity standards, environmental regulations, energy storage and conversion applications, and other future technologies change the way the electric grid is utilized. The futures are defined by the SPP Strategic Planning Committee (SPC) based on input from the ESWG.

Future scenarios for the ITP 20 will generally be of broader array because of the greater uncertainty that exits over the longer 20 year time horizon. These futures should be designed to provide valuable guidance to SPP beyond business as usual. These futures should not be constrained by what is likely but what is plausible. Futures in the ITP 10 should be narrower in scope and, unless otherwise warranted by changes in circumstances, be a subset of the immediately preceding ITP 20 Futures. The ITP 10 future scenarios should be plausible and not unlikely. Added weight may be given to those scenarios that are more likely.

Sensitivities within future scenarios may be performed to help inform decision makers on the advisability of different generation mixes and of transmission design. Sensitivities may be advisable in determining the appropriate generation mix in subsequent transmission design phases of the study. Such sensitivities can help determine trigger points when certain types of generation become more economic because of variability of fuel prices and other costs impacting the construction or use of different kinds of generation or whether certain generation may be retired. Sensitivities within future scenarios in the transmission design phase will help to illustrate how different dispatch patterns might impact the need for different upgrades within a scenario due to changes in flow patterns.

2.2 Modeling Data & Assumptions

The analysis for the ITP20 and ITP10 will consist of engineering models used to facilitate the development of long range transmission plans. The analysis will be performed utilizing both economic as well as reliability models that reflect a market based dispatch. These models require an extensive set of input assumptions that include generation resources, parameters and locations. The output of these models will allow engineers to determine the appropriate transmission needs from a regional perspective.

The major input assumptions needed to construct the models contain, but are not limited to: market structure, load forecasts, fuel pricing and availability, transmission topology, resource forecasts and parameters, and others.

Each stakeholder has the opportunity to submit data and review their individual data which is being used for the study. Stakeholders can then provide specific updates to non-sensitive data. Sensitive data, such as heat rates, will not be updated by stakeholders. Multiple Stakeholder reviews are used to coordinate the submitting and vetting of all data used in the economic analysis:

- Load Forecast Review
- Policy Survey
- Generation Resource Plan Review
- Economic Model Review
- Constraint Assessment Review

The data captured in these reviews includes generating unit information, load, renewable requirements, emission prices, etc., to be included in the study models.

The starting economic dataset to be used in the model will be a commercially available model provided by the software vendor. This data as well as the powerflow dataset will be available to SPP stakeholders for review after the appropriate non-disclosure agreements have been signed. When possible, publicly available data will be used as data for the model runs. This includes data sets such as fuel curves, common assumptions or other data designated as not proprietary or confidential.

2.2.1 Footprint

The modeling footprint includes the entire SPP region and nearby areas within the Eastern Interconnection. The non-SPP areas that may be modeled are MAPP, Midwest ISO, and the western portions of PJM and SERC. In the event of pending changes in the footprint of a region it may be advisable to utilize additional sensitivities or scenarios to anticipate and understand the impact of such changes on the transmission needs of the SPP.

2.2.2 Fuel & Emission Prices

SPP staff assists the ESWG to formulate the fuel and emission price forecasts. These forecasts are then approved by the ESWG for use in the production cost model.

2.2.3 Load Forecasts

A base load forecast used for the ITP20 Assessment and ITP10 Assessment is developed by the Model Development Working Group (MDWG) and reviewed by the Transmission Working Group (TWG) and the ESWG. Load forecast sensitivities are utilized for the ITP20 Assessment.

For load forecasts for entities outside of the SPP footprint, publicly available data will be utilized as the source of the load forecast, where available. Where not available, publicly available information on projected load growth will be extrapolated to develop a good representation for load expected in the study timeframe.

2.2.4 Resources

2.2.4.1 Conventional Resources

2.2.4.1.1 Existing Generation

Generating unit modeling data is required to perform a detailed analysis of economic upgrades. Stakeholders are asked to review the data inputs for their generating units as part of the Economic

Model Review. These data types include: Variable Operations & Maintenance (O&M), Variable O&M Escalation, Fixed O&M, Fixed O&M Escalation, Energy Bid Cost, Energy Bid Markup, Spinning Reserve Bid, Spinning Reserve Bid Escalation, Heat Rate, Startup Cost Adder, and Startup Cost Adder Escalation.

Stakeholders are asked to review and provide updated values (if necessary) for non-sensitive data items. These data items include, but are not limited to: Maximum Capacity, Minimum Capacity, Must-Run status, Minimum Up Time, Minimum Down Time, Ramp Rate, Forced Outage Rate, Forced Outage Duration, Maintenance Hours Requirement, Minimum Runtime, Startup Energy Requirement, Fuel Type, and Emission Rates. Those stakeholders that have Integrated Resource Plans (IRP) that are submitted to their state are asked to coordinate the information in their IRP plan with the ITP.

The resource planning input data is vetted by stakeholders to ensure that the modeling of stakeholder's existing generation capacity and load positions are accurate.

2.2.4.1.2 New Generation

The ESWG will develop a resource plan for each future scenario based upon expected unit retirements, unit derates, capital costs, O&M costs and other costs similar to those taken into account in data inputs for existing units, as well as other relevant factors as part of the development of a resource plan for each future. The Resource plan will be reviewed by the load serving entities for accuracy before modeling. Stakeholders have the opportunity to update their new generation data to ensure the resource plan is being implemented in a reasonable fashion. This data may include generator type and location of each new resource. The siting of Sensitivities may be employed in providing additional information to develop the final resource plan for each future scenario.

2.2.4.2 Renewable Resources

2.2.4.2.1 Existing Generation

Generating unit modeling data is required to perform a detailed analysis of economic upgrades. Stakeholders are asked to review the data inputs for their generating units as part of the Economic Model Review. These data types include: Variable O&M, Variable O&M Escalation, Fixed O&M, Fixed O&M Escalation, Energy Bid Cost, Energy Bid Markup, Spinning Reserve Bid, Spinning Reserve Bid Escalation, Heat Rate, Startup Cost Adder, and Startup Cost Adder Escalation.

Stakeholders are asked to review and provide updated values (if necessary) for non-sensitive data items. These data items include but are not limited to: Maximum Capacity, Minimum Capacity, Must-Run status, Ramp Rate, Forced Outage Rate, Forced Outage Duration, and Maintenance Hours Requirement. In addition, the most recent year's historical renewable output characteristics are developed for each resource, where applicable, namely wind and solar.

2.2.4.2.2 New Generation

Futures may require the modeling of additional wind and other renewable generation capacity above what is currently in service at the time of the assessment. The amount of renewable generation modeled is to be determined either as defined in futures identified in the scope, which is proposed by the ESWG and approved by the appropriate governing committee or through the analysis of the generation resource mix to be used in each future. The additional target renewable level is then met by including additional renewable generation sites in the modeling footprint. The size and locations of these additional renewable sites are approved by the ESWG. The ESWG will develop the locations of the renewable generation to be added taking into account the following factors: potential capacity factors as indicated by data from NREL; the SPP generation interconnection queue; known environmental obstacles to development; transmission capacity that exists in areas of SPP that are attractive for the location of renewable generation; the location of the need for the renewable generation; and other factors deemed relevant by the ESWG. The object of the generation added should take advantage of the best renewable resources within the SPP while taking into account the level of interest in development, the barriers to development, and the cost effective integration of the generation into the SPP region.

2.2.4.3 Resource Addition Requests

In order to more accurately forecast resources in these long-term assessments, the Generation Interconnection queue and Transmission Service queue will be used to add generation beyond existing resources.

Generation interconnection resources and facilities are included in the ITP models if they have an executed Interconnection Agreement (IA) that is not on suspension and has a reasonable level of commitment. Generation capacity will automatically be designated to any utility once there is an executed transmission service agreement.

Proposed resources and facilities that have a high probability of going into service (i.e. If a planned generating resource does not have a TSR filed service agreement but does have a high probability of going into service) will be designated to a utility if it meets all of the following requirements:

- A Resource Addition Request (RAR) has been sent to SPP requesting the generation capacity be included into the ITP;
- The generating resource has a FERC-filed IA not on suspension or FERC-filed interim IA; and
- The generating resource will have firm contract for delivery in one or more forms:
  - The generating resource has entered the Aggregate Study or equivalent; Transmission Owner transmission service study publicly posted on OASIS and has a completed facility study that is waiting for final results without unmitigated third party impacts; or
  - The utility to be designated will own and operate the resource or has procured a Purchase Power Agreement (PPA) from the generation owner
- If a generating resource does not meet all the above requirements, a RAR for generation capacity to be included in a long-term ITP assessment can be made to ESWG on a case by case basis. ESWG will take into account the following, but not limited to, additional points:
  - A Definitive Interconnection System Impact Study Agreement (DISIS) for the generating resource has been executed, an interim IA has been requested when the DISIS was posted and a final IA was FERC filed when applicable
  - An RFP for the generating resource has been awarded, if applicable.

All other resource expansion needs will be determined through the SPP resource planning process.

2.2.5 Import/Export Limits

Formatted: Font: 11 pt, Bold, Underline
Formatted: Indent: Left: 0.34"
Commented [LG1]: Approved as "minimal network upgrade costs"
Formatted: Normal
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Font: Not Bold
Formatted: Indent: Left: 0.25", No bullets or numbering
Formatted: Font: Not Bold
Formatted
Formatted: Normal

In determining projects that will be built as a result of the ITP process, the focus is on benefits to the SPP region. Unless otherwise called for in the assumptions of a future scenario, the interchange between SPP and other regions is set and benchmarked to historical levels using hurdle rates and expected external system conditions during the time period under study. The ESWG reviews the hurdle rates and the resulting imports/exports for both the resource planning and production cost modeling phases of the study. Different hurdle rates may be used to accommodate import and export scenarios within the futures depending on the study scope. The system representation along the "seams" is reflective of expected facilities and arrangements that are consistent with the SPP futures being modeled.

DC ties connect the SPP region to the WECC and ERCOT systems. Sold firm transmission service will be used as a basis for modeling the flow levels of the DC ties. The ESWG will evaluate whether historical flows are consistent with the service agreements. [4] If there is no sold firm transmission service on DC ties, the ESWG will consider how to model the DC ties consistent with the developed futures.

2.2.6 Environmental Regulation

During the course of the ITP Process, environmental regulations may change or be in a state of flux during the ITP assessment period. The ESWG and SPC will include key environmental regulations in their development of the futures.

2.2.7 Sensitivities

2.3 Model Development & Analysis

2.3.1 Model Development

As described in the sections below, the models used in the ITP20 and ITP10 are developed based on information accumulated from various sources. The economic model building process starts with a package utilizing commercially-available data. Data from SPP stakeholders, Tier 1 entities, and data from other entities or RTO's in the Eastern Interconnect (where available) are also incorporated into the model. In addition, an SPP powerflow model appropriate for the year(s) under study is imported into the economic model so that the transmission topology is up-to-date. Other parts of the model development include adding a generation expansion plan (resource planning) and developing a list of constraints (flowgate selection). Note that SPP does not use Transmission Operating Guides in its 20-Year or 10-Year Assessment analyses. The economic model, or a package of modeling data for those without the required software license, is made available for review by SPP members.

The powerflow model used in the ITP20 and ITP10 is based on the most recent series of MDWG models as approved by the TWG. Approved STEP projects as well as other special projects which are known by SPP staff (e.g. Entergy (MISO South), AECI projects or those at other seams) are added to the latest MDWG model as of the beginning of the study. In addition, the power flow model may be modified as required to reflect the facilities necessary to more accurately represent the topology near generating facilities that may have been simplified in the MDWG models. This powerflow is uploaded into the economic dispatch model.

For reliability analysis, the power flow models based on MDWG developed models will be used as a starting point and a market dispatch developed as part of the security-constrained economic

[4] In the 2011 ITP10, SPP used historical DC tie usage profiles as an approximation for the respective power flow across the DC tie.

analysis will be incorporated. These models will be developed for the SPP system coincident peak load and off-peak load (or other seasons/scenarios as required) using output from the economic models as a reference for load and generation dispatch.

In general, the ESWG will oversee the development of the economic models. Similarly, the TWG will oversee the development of the power flow and stability models used in this analysis and they will be developed through the existing SPP Planning Model Process via the MDWG.

2.3.1.1 Resource Expansion Plans

For each future, SPP will complete forecasts of generating resource additions to balance load and capacity reserves for zones throughout SPP based on future scenarios designed by the ESWG. Siting locations for the new resources for each of the futures will be determined under the general guidelines of this manual. The resource additions will be added to the SPP database at the sited locations and interconnected in the transmission network model at the appropriate locations.

The resource planning will be conducted in three phases as summarized below.

- **Phase I.** Develop a resource expansion plan for each future scenario. The resources will be selected using an optimal generation expansion model on a regional basis. The expansion plans will be developed from a resource list of generic prototype generators representing available future resources. The optimal generation expansion model will be constrained to maintain specified capacity margins, renewable requirements, and other parameters for each future.

- **Phase II.** The new resources will be spatially located within the SPP sub-areas with the aid of GIS databases showing locations of transmission lines, natural gas pipelines, railroads, waterways, substations, as well as environmental maps and data indicating barriers to the location of generation; NREL studies on renewable energy potential; and data relevant to other factors that are to be used in the location of new resources pursuant to this manual.

- **Phase III.** The generators will be entered into the SPP database and connected to busses in the transmission system.

2.3.1.1.1 Phase I

The data defining the generating characteristics of all existing and potential resources, demand and energy forecasts, fuel price forecasts, emission price forecasts, and other factors will be input to an optimal generation expansion model to evaluate combinations of candidate resources available to cost effectively meet future peak demand and energy requirements under the parameters of the applicable future scenario. This may include the addition of combinations of demand and supply resources as well as combinations of supply resources. Generators that are under construction or far enough along in the permitting process shall be considered for inclusion in the existing resource data. Firm retirements, to the extent known, will also be incorporated in the optimal generation expansion model.

Additionally, the parameters for each future will be entered into the optimal generation expansion model. The optimal generation expansion model will be used to determine the appropriate resources for the appropriate timeframe, maintaining the required minimum capacity margins, renewable requirements, and other parameters for each future.

Cost and performance estimates for representative generation technologies to be considered as generator resource additions will be entered into the optimal generation expansion model. An overall study estimate basis shall be developed to allow all technology costs to be presented on a consistent level. Technologies considered will include simple cycle combustion turbine configurations, combined cycle configurations, pulverized coal units, nuclear, integrated gasification combined cycle with carbon sequestration (IGCC), and renewable resources (wind, solar,…).

To capture the diversity of the geographic dispersion of wind generation in SPP's control region, hourly production profiles from several potential sites within the geographic regions that exhibit the best potential for wind installation development will be input to the optimal generation expansion model.

2.3.1.1.2 Phase II

After the sets of resources for each future are approved by the ESWG, the resources will be spatially sited. A physical spatial location for each generator will be selected based upon the siting parameters developed in collaboration with the ESWG and SPP staff. The resource sets will be provided to Transmission Owners for review. The siting effort will incorporate renewable needs, and other futures parameters, as well as physical siting criteria to determine the proper location for each resource. This siting effort will be conducted as a screening level exercise to identify site areas that generally comply with the approved criteria and will not be intended to provide or replace a full scope power plant siting study. Siting criteria could include, but not be limited to, locating the resources within a certain distance from existing natural gas pipelines, existing railways, and/or navigable waterways, etc.

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

- Do not use transmission as initial siting factor**:** Let geography and existing infrastructure guide placement of proxy generation. Existing transmission used as a weighting factor rather than a primary siting factor.
- Site proxy generation by region: Site expansion of conventional model generation in zone with highest capacity needs.
- Avoid greenfield siting for NG fired capacity: NG generation is flexible to site. Locating generally more peaking NG generation near load centers will have a tendency to reduce the impact on the transmission system.
- Limit capacity to 2,400 MW maximum per location: Limiting total capacity per location potentially minimizes the impact of contingencies removing large blocks of capacity from service.
- Site base load non-nuclear steam capacity in 600 MW increments; nuclear capacity in 1200 MW

2.3.1.1.3 Phase III

After the resource sites are approved, the new resources will be added to the SPP database and interconnected in the transmission network model at the appropriate locations. The data will be used in subsequent analyses by SPP and will allow SPP to connect the resources to specific buses for the transmission models.

2.3.1.2 Constraint Selection

The nature of the economic study tools is such that the transmission constraints are the only tool in the model which controls the flow on the transmission lines – without the transmission constraints there is no adherence to the line or transformer limits, etc. The selection of transmission constraints is generally an iterative process that starts with an initial set of constraints and is then augmented with additional constraints through analysis of resource dispatch and transmission flows under contingency conditions.

The current NERC Book of Flowgates may be used as an initial list of constraints. Through a constraint selection analysis, SPP will define additional constraints which are vetted and approved by the TWG. Using a transmission analysis tool, SPP staff may also identify additional constraints related to defined interfaces which should be monitored in the economic dispatch model. In this analysis, Power Transfer Distribution Factor (PTDF) interface constraints will be selected in order to control the flow on transmission corridors where there are thermal loading and/or voltage stability interface limits.

Each constraint identified will include normal and emergency ratings. In addition, both summer and winter ratings may be used.

For the purposes of the ITP20 study, the transmission constraint list will be limited to the following types of issues so that there is a focus on disturbances on the EHV system:

- System Intact and N-1 situations
- Existing common right-of way and tower contingencies for 300+ kV facilities[5]
- Thermal loading and voltage stability interfaces
- Contingencies of 345 kV or higher voltage transmission lines only
- Contingencies of transformers with a 345 kV or higher voltage winding only
- Monitored facilities of 115 kV and above voltages only

For the purposes of the ITP10 study, the transmission constraint list will be limited to the following types of issues so that there is a focus on disturbances on the HV and EHV systems:

- System Intact and N-1 situations
- Existing common right-of way and tower contingencies for 100+ kV facilities[6]
- Thermal loading and voltage stability interfaces
- Contingencies of 100 kV or higher voltage transmission lines only
- Contingencies of transformers with a 100 kV or higher voltage winding only
- Monitored facilities of 100 kV and above voltages only

Due to the limit on the number of constraints that can be monitored by the economic modeling tool, not every flow will always be mitigated for every hour. Overloads can occur. The constraint selection process is designed so that the constraints that would be most likely to occur during the simulated hours are mitigated.

[5] NERC Standard TPL-001-4 Table 1 includes outages of any two circuits of a multiple circuit tower as a Planning event P7, and the loss of all transmission lines on a common right-of-way as an Steady State & Stability Performance Extreme Event SS2.b.

[6] NERC Standard TPL-001-4 Table 1 includes outages of any two circuits on a common structure as a Planning event P7, and the loss of all transmission lines on a common Right-of-Way as a Steady State Performance Extreme Event SS2.b.

2.3.1.3 Project Screening Analysis

With the addition of FERC Order 1000, stakeholders will need to provide solutions for screening through the Detailed Project Proposal (DPP) process. Stakeholders have 30 days to submit solutions through the DPP process. SPP will analyze a wide variety of possible transmission projects which have been identified by staff or suggested by stakeholders. The purpose of the screening analysis is to identify the grouping of projects which meet the goals of the future cost-effectively.

Part of the data used in this screening analysis will be conceptual cost estimates developed by SPP.

2.3.1.4 Interregional Considerations

The starting point for SPP's power flow models is the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group's (MMWG) model. This model is developed with input from utilities across the Eastern Interconnection (EI) to develop a reasonable representation of the entirety of the EI. SPP's neighbors participate in the MMWG model development. In addition to incorporating the representation of SPP's neighbors systems by utilizing the MMWG modeling data, SPP staff will provide an opportunity for SPP's Tier 1 neighbors to update the power flow models SPP uses in the ITP. SPP staff will request that the Tier 1 neighbors update topology, load, generation, dispatch, and other relevant modeling data.

The starting point for the SPP SCUC/SCED model is the publicly available data compiled and provided by Ventyx. This data includes modeling information for the entirety of the EI. SPP staff will provide an opportunity for SPP's Tier 1 neighbors to update the SCUC/SCED models SPP uses in the ITP. SPP staff will request that the Tier 1 neighbors update topology, load, generation, generator parameters, and other relevant modeling data. SPP will also request that the Tier 1 neighbors provide an update to the constraint list SPP uses in the ITP.

2.3.2 Modeling Analysis

2.3.2.1 SCUC & SCED Analysis

The economic dispatch model includes stakeholder-vetted data. Generating unit cost data and heat rates are taken from commercially-available sources. Data related to the physical characteristics of generators (not related to unit costs or heat rates) is reviewed and updated as needed by the members to provide company-specific values. This data is used to produce the security-constrained economic dispatch (SCED) solution with the economic modeling software.

The SCUC/SCED solution requires dual optimization processes. The first process is the security constrained unit commitment (SCUC). Here, the hourly least cost combination of units that should be committed (turned on) is determined subject to unit-specific operational constraints (e.g., ramping, minimum output, min/max runtime, startup cost, etc.), and some critical location-specific transmission reliability constraints (e.g., must-run operational limits); but without explicit consideration of transmission grid operational costs.

The second process is the SCED solution of the units committed by the SCUC process. In the SCED process, the units are dispatched (exact unit output determined) in a least-cost manner subject to various transmission operational constraints (e.g., line thermal limits, voltage support, etc.) and transmission reliability constraints (e.g., n-1 contingencies) to produce an overall least cost solution for regional load.

The SCUC and SCED model will solve using nodal LMPs which will commit and dispatch the generation economically based on unit characteristics, load information, and transmission constraints. This analysis will determine potential issues including congestion, LMP variation and trapped generation.

2.3.2.2 Reliability Assessment

In addition to economic modeling for identification of potential congestion, SPP staff will perform a reliability assessment to identify potential needs in the study horizon. The purpose of the reliability assessment is to determine areas on the system which may require transmission upgrades in order to comply with applicable reliability standards. The reliability analysis conducted as a part of the ITP process is not intended to be a replacement for the NERC Reliability Compliance Assessment[7].

The reliability analysis will consist of an AC (thermal and voltage) contingency analysis. For the ITP20, SPP will monitor 100 kV and above facilities while considering 300 kV and above contingencies within SPP and first tier neighbors. For the ITP10, SPP will monitor 60 kV and above facilities while considering 100 kV and above contingencies within SPP and first tier neighbor systems.

The power flow model that was developed and utilized in the economic model will be modified to incorporate the unit commitment, dispatch and load level associated with the specific hour(s) to be analyzed (e.g. summer peak, winter peak, light load, etc.) as specified in the study scope. The specific cases to be analyzed will be approved by the TWG as a part of the study scope development.

A stability screening study may be performed to identify potential areas of instability. These results may influence the selection of projects for the ITP.

Those issues within SPP that are not addressed in this assessment may be passed to subsequent assessments for further evaluation.

2.4 Order 1000 Process

2.4.1 Model Review and Constraint Identification

2.4.2 Detailed Project Proposal (DPP) Open Window

As part of the Order 1000 process, the SPP OATT requires a 30 day window for stakeholders to submit DPP's. The DPP necessary information must be submitted within the prescribed 30-day transmission planning response window for DPP submittal in order to qualify as a DPP to be evaluated as a potential solution to the posted needs. The information required for a DPP submittal is included in the DPP Submittal Form. Upon receipt of the DPP submittal, SPP will verify that the DPP was received within the 30-day DPP transmission planning response window, based on the time and date of the email containing the DPP submittal, and verify that the DPP is complete. If a

[7] Adherence to NERC Reliability Standards will continue to be checked through a separate NERC Reliability Compliance Assessment.

DPP Submittal Form was received outside the 30-day transmission planning response window, SPP staff will notify the Submitter via email that its submittal has been disqualified for consideration for incentive points.

2.4.3 Solution Development

During theITP20 and ITP10, SPP staff will review issues that are identified during the various phases of the study. Those issues may include: thermal overloads, voltage violations, flowgate congestion, LMP variation and trapped generation. Staff will post these issues and open the DPP Window as previously described. At that time, stakeholders may submit DPP's to address the identified needs. In addition, SPP Staff and other stakeholders may submit non-DPP solutions for evaluation as well. Proposed solutions (both DPP and non-DPP) will then be evaluated through a screening process to determine which solution sets meet the needs of the study. The solution sets (or portfolios) that result from the screening process will be further developed and refined through more detailed analysis.

Proposed projects that pass the initial screening will be placed in the economic model, and a full economic assessment will be performed. Benefit metrics will be used to distinguish the value of one set of projects over another. The results from the economic analysis will be used to determine portfolios (groups of projects) which have higher benefits based on the benefit metrics used. Sensitivities will be defined by the ESWG as input to the decision making process in order to identify potential variations in benefits.

Seams projects will be considered as potential solutions as part of the ITP20 and ITP10 study processes and expansion plans, and SPP will collaborate with neighboring entities regarding the identified needs, benefits, potential solutions, and costs. For the neighbors that SPP has an agreement with, joint coordination will be done in accordance with that agreement.

2.4.4 RFP Process

TBD

2.5 Deliverables

2.5.1 Recommended Transmission Plans

Prior to developing the final set of projects, SPP staff expects to have a transmission plan developed for each future. Those multiple plans will be analyzed to determine which projects or combination of projects would be beneficial in multiple futures. The results of this analysis will be a single transmission plan that is robust, being adaptable for all of the futures considered, and adding greater incremental value than incremental cost.

A project implementation plan will be developed for the recommended transmission plan. The final plan will be structured such that each element can be implemented in a staged manner as actual system developments approach the assumptions resulting in the need for that element. Each element will have an economic, reliability, or policy justification. NTCs will be issued for the ITP10 plan elements in accordance with the OATT, Attachment O, Section VI and SPP written procedures (see Business Practice 1.15[8]).

2.5.1.1 **Benefit Metrics**

Following is an overview of the 10 benefit metrics that will be considered in the ITP planning process when evaluating potential transmission projects and portfolios. For further detail on these metrics, refer to the Benefit Metrics section in the appendix of this document.

1. Adjusted Production Cost (APC) Savings

   The APC metric measures the effect on production cost savings relating to energy production by generating resources within the SPP footprint by considering Locational Marginal Price (LMP) for purchases and sales of energy between each area of the transmission grid. The APC metric quantifies the monetary cost associated with fuel costs, generation dispatch, most grid congestion, energy purchases, energy sales, emissions and ancillary services. The APC benefit is calculated as the difference in the production cost simulations for the base case and the change case. These are aggregated up to a zonal level.

2. Reduction of Emission Rates and Values

   Transmission projects relieve grid congestion and change generation dispatch which may result in cost savings associated with reductions to SO2, NOx, and CO2 emissions. Allowance prices for SO2, NOx, and CO2 emissions are used as inputs to the production cost model simulations and are specific to the various generating technologies modeled. This metric captures the cost savings associated with reduced SO2, NOx, and CO2 emissions through the change in generation dispatch and the assumed allowance price for these emissions. The reduction of emission rates and values is reflected in the APC savings.

3. Savings due to Lower Ancillary Service Needs and Production Costs

   Ancillary Services (A/S) are essential to the reliable operation of the electrical system and are currently reflected in the APC savings mentioned above. A number of operating reserves and products fall into this category – spinning reserves, ramping up/down, regulation, and 10-minute quick start. The difference in APC for base case and the change case reflects the reduced costs of procuring the specified A/S needs (e.g., lower procurement cost of the same A/S needs due to reduced transmission congestion that makes lower-cost resources available to provide A/S).

4. Avoided or Delayed Reliability Projects

   If a larger project with economic or public policy benefits is pursued, the costs associated with the reliability projects that are replaced by the larger project represent the avoided or delayed reliability project benefit of the larger project. The steps taken to determine which reliability projects were replaced is outlined in the Benefit Metrics section in the appendix of this document. The avoided (or delayed) reliability project benefit is captured as the avoided cost of delaying or canceling previously approved reliability projects. The benefit is allocated in accordance with the ratios of the allocation that would have been applied for the costs of the reliability project.

---
[8] SPP.org > Org Groups > Access SPP's Governing Documents > OATT Business Practices

5. Capacity Cost Savings due to Reduced On-Peak Transmission Losses

This metric captures the value of generation capacity that may no longer be required due to a reduction in losses during the system peak. These capital savings will be calculated by applying the estimated net Cost of New Entry (CONE) to the reduction in installed capacity requirements. The net CONE is the difference between the annualized CONE and the annual energy and ancillary service profits a unit of this type is expected to earn in the energy and ancillary service markets. Monetization of the capacity cost savings will be calculated using the savings in capital attributed to the corresponding MW reduction in installed capacity requirements.

6. Assumed Benefit of Mandated Reliability Projects

This metric captures the inherent value of maintaining transmission reliability. In evaluating projects within the portfolio that would be built to meet transmission reliability standards (i.e. classified as a 'reliability project' as defined in this manual), the benefit of fixing the reliability violation should be assumed to be equal to its cost. This benefit will be mutually exclusive from any other reliability benefit applied to those same projects and will be allocated using a hybrid approach that utilizes Load Ratio Share and System Reconfiguration, depending upon project size.

7. Public Policy Benefits

This metric captures the value of meeting public policy goals or mandates related to renewable energy supplies, and the benefit is assumed to be equal to the project cost. As with mandated reliability upgrades, the assumption is that public policy makers have made a decision that public benefit is at least equal to the cost of implementing a public policy. This benefit does not apply to economic decisions made by individual utilities to acquire renewable energy supplies absent some form of legal requirement to do so. Benefits will be allocated based upon the share of unmet renewable mandates or goals and only to zone(s) within the state(s) driving the public policy project(s).

8. Increased Wheeling Through and Out Revenues

While the energy revenue benefit of increased exports is captured by the APC metric, the APC metric does not capture any increases in wheeling out or wheeling through revenues associated with increased transfer capability. These increased wheeling revenues are a benefit as they will offset part of the transmission projects' revenue requirements. A historical average wheeling charge will be utilized to monetize the value of increased wheeling through and out transactions. These benefits will be allocated according to the methodology in the Tariff for allocating wheeling revenues.

9. Marginal Energy Losses Benefit

This metric captures the reduced MWh quantity of transmission losses that results from transmission expansions. Standard production cost simulations used to estimate the APC benefits assume a fixed MWh quantity of transmission losses which does not change with transmission additions. In reality, transmission projects can result in energy loss reductions and those can be estimated on a zonal basis through post-processing simulation results.

10. Mitigation of Transmission Outage Costs

This metric captures how the availability of new transmission projects decreases congestion and increases the operational flexibility of the system to mitigate the impacts of transmission outages. Standard production cost simulations assume that transmission lines and facilities are available during all hours of the year and that no planned or unexpected outages of transmission facilities will occur. Thus, the benefit of reducing this additional congestion is not captured in the standard APC metric. To measure the savings in transmission outage costs due to transmission expansion, the production cost modeling analysis will be modified to reflect a realistic level of transmission outages using a subset of historical transmission outage events.

2.5.1.2 Consolidation Process

Projects from each Future evaluated in an ITP20 or ITP10 Assessment will be consolidated into a single recommended portfolio. The criteria for consolidation in each assessment will be approved by the TWG and ESWG and included in the scope for that assessment.

Consolidation of projects across multiple futures may consist of different types of criteria depending on the assessment and the number of futures studies. The criteria could be a weighting of futures; such that projects must meet a certain threshold by summing the weight they receive by inclusion in the final portfolio of individual futures to meet that threshold. The criteria could be based on the engineering performance of a project across futures; such that a project must meet certain engineering performance guidelines in the future(s) for which it was not selected in order to be included in the final consolidated portfolio.

2.5.2 Final Reports

The deliverable for the ITP20 Assessment will be a cost effective EHV design for each future scenario analyzed and a cost effective single transmission plan that is flexible enough to allow SPP to meet these futures while timing and staging the anticipated construction of the projects in the design in an order that will protect from under and over investment. The results of the analysis as outlined in this manual will be included in the ITP20 Report.

The deliverable for the ITP10 assessment will be a cost effective design that takes into account the likelihood of the occurrence of the futures studied. In assessing the design those elements that are common to both will be used along with additional elements that can be incrementally added when the benefits are adjusted by the probability of the futures occurrence and weighed against their incremental cost. Results from the 10-Year Assessment will be compiled into a report detailing the findings and recommendations of SPP Staff. This report will be incorporated into the STEP Report that is published on an annual basis.

3 Near-Term ITP Assessment: ITPNT

3.1 Purpose

The third phase of the ITP process is the annual Near-Term Assessment, which will be performed annually on a rolling window to be defined in the ITP study scope document. This assessment will analyze the Transmission System for solutions according to NERC Reliability Standards while incorporating individual Transmission Owner planning requirements. The assumptions for this assessment will be narrowed further than those for the ITP20 and ITP10 Assessments. This narrower focus is intended to ensure continuous adherence to NERC Reliability Standards while allowing the ITP process as a whole to focus on the creation of a Transmission System that meets the ITP planning principles.

The ITPNT Assessment determines the SPP upgrades required to meet reliability in the near-term, including those upgrades recommended to the SPP BOD to receive an NTC.

The ITP20 and ITP10 plans will be incorporated into the ITPNT Assessment annually. The plans will serve as part of a pool of solutions from which the ITPNT plans are developed to determine the best regional solution for the SPP footprint. There will also be interaction of the plans based on issued NTCs.

3.2 Modeling Data & Assumptions

Per SPP Criteria 3.5, when an entity is in the conceptual planning stages of new facilities that impact the interconnected operation of the Transmission System, it shall contact the Transmission Provider so that the optimal integration of any new facilities and potentially benefiting parties can be identified.

In preparation for the annual update of transmission planning models for each annual planning cycle, SPP Members, Transmission Customers and other stakeholders must provide to the Transmission Provider the data specified in Section VII of Attachment O of the OATT.

During the course of the annual planning cycle, if material changes to the data occur, the data owners must provide timely written notice to the Transmission Provider.

Instructions to access modeling information are posted on the SPP website.[9]

The ITPNT Assessment will be performed on an annual basis. The study will be performed on a shorter planning horizon than the ITP10 assessment and will focus on the reliability of the system. The ITPNT Assessment will take the following into account:

- NERC Reliability Standards;
- SPP Criteria;
- Transmission Owner-specific planning criteria as set forth in Section II of Attachment O;
- Previously identified and approved transmission projects;
- Zonal Reliability Upgrades developed by Transmission Owners, including those that have their own FERC approved local planning process, to meet local area reliability criteria;
- Long-term firm Transmission Service;
    - Accommodate and reflect the specific long-term firm transmission service requests of the Transmission Customers and specific interconnections of Generation Interconnection Customers no later than when the relevant Service Agreements and interconnection agreements are accepted by the Commission.
- Load forecasts, including the impact on load of existing and planned demand management programs, exclusive of demand response resources;
- Capacity forecasts, including generation additions and retirements;
- Existing and planned demand response resources; and
- In developing the long term capacity forecasts, the studies will reflect generation and demand response resources capable of providing any of the functions assessed in the SPP planning process, and can be relied upon on a long-term basis. Such demand response resources shall be permitted to participate in the planning process on a comparable basis to the service provided by comparable generation resources where appropriate.

TWG has oversight of the ITPNT Assessment.

[9] http://www.spp.org/section.asp?pageID=108

Staff will use the SPP MDWG models as a starting point for the ITPNT analysis. The MDWG creates new steady-state and dynamic models annually and updates these models throughout the year.

3.3 Model Development & Analysis

3.3.1 Model Development

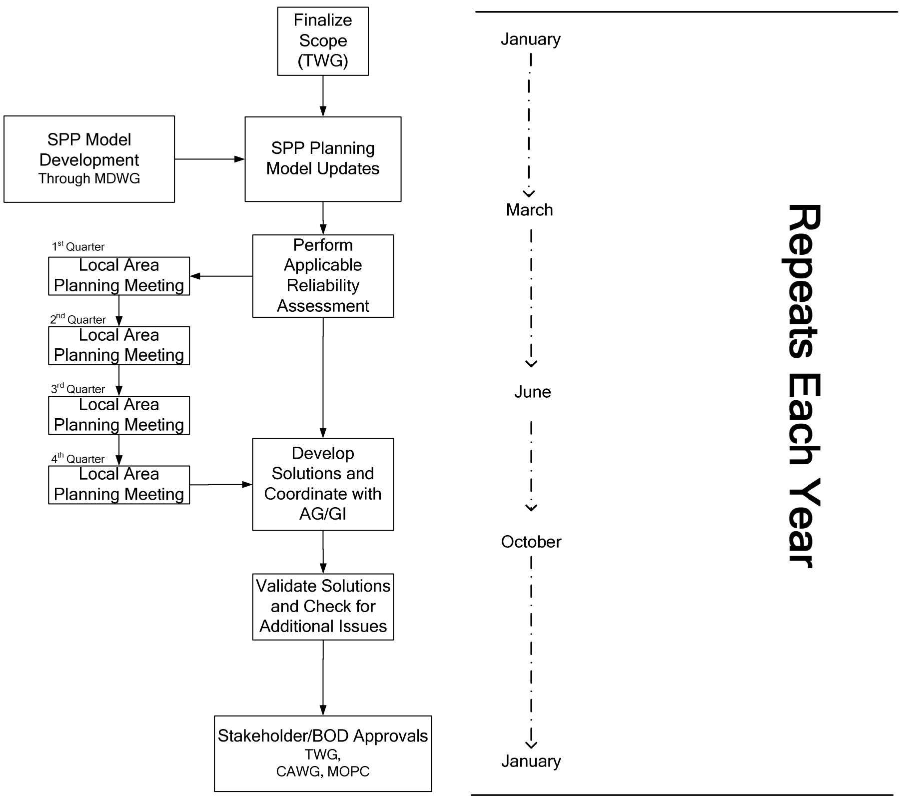
3.3.1.1 Interregional Coordination

SPP is responsible for coordinating transmission planning with each neighboring interconnected system. SPP will coordinate any activities and studies based on the agreements listed in Addendum 1 to Attachment O of the OATT. As part of the inter-regional coordination process, SPP will share system plans with neighboring entities and identify system enhancements on the seams.

3.3.1.2 Modeling Process

Planning within SPP is a collaborative process with Transmission Owners, users, and other stakeholders. The ITPNT Assessment process requires that Transmission Owners continue to develop expansion plans to meet the needs of their systems. At the same time, SPP assesses its system for the ability to meet applicable reliability standards and address stakeholder concerns, including those of regulators.

The 12-month ITPNT planning process focuses on the system’s reliability needs and the commercial and market needs for all the stakeholders in the SPP footprint. This process was developed by SPP staff in conjunction with the TWG. The process is shown in the figure below.



Details regarding key assumptions, models, project data, specific tasks, outstanding issues, progress reports, maps, and study results are available on the SPP web site.

The steady-state model building begins in January and starts with the SPP MDWG spring case topology of that same year of the study. Transmission owners and balancing authorities provide generation dispatch and load information for the years to be studied.

Transmission owners enter network changes into MOD at which time the type and status of the network upgrades is identified. The type and status of MOD projects identify into which SPP model set the network change will be entered. Appendix A of this manual provides the listing of the description of the types and statuses.

Included in the ITPNT Assessment models (i.e. ITP Reliability models) are all topology changes that have a NTC from SPP except projects that have been requested to be removed from the base ITP reliability models. These exceptions must go through a stakeholder review process as described below:

1) Stakeholder requests NTC project be removed from the base ITP reliability model along with the reason why they would like the project excluded and re-evaluated in the ITPNT.
2) If SPP Tariff Study Group identifies any Transmission Service that may be dependent upon the project, SPP Planning Group would identify any concerns in connection with removing the project from the base model and re-evaluating the need
3) The list of NTC projects to be re-evaluated is given to stakeholders for a 15 day review and comment window.

Generation interconnection facilities are included in the ITP reliability models if they have an executed Interconnection Agreement (IA) and not on suspension. Generation capacity does not get included in the assessment until there is an executed transmission service agreement.

Confirmed Long Term Firm transmission service is included in the ITP reliability models. In addition to Confirmed Firm service mentioned above, the following will also be included: 1) transactions to make generation and load match. ; 2) proposed generation stations and associated service from new generation that has a high probability of going into service; i.e. If a planned generating resource does not have a TSR filed service agreement but does have both a high probability of going into service and a high probability of obtaining an executed transmission service agreement, that new generator's service can be included in the SPP regional reliability planning models if it meets all of the following requirements:

- A formal request has been sent to SPP[10] requesting the generation capacity be included into the ITP;
- The generating resource has a FERC-filed IA not on suspension or FERC-filed interim IA;
- The generating resource has acquired the funding for major equipment;
- The generating resource has entered the Aggregate Study or equivalent; Transmission Owner transmission service study publicly posted on OASIS and has a completed facility study that is waiting for final results without unmitigated third party impacts[11];
- The generating resource has acquired air and environmental permits where applicable;
- The generating resource has started construction with major equipment procurement contracts awarded; and
- The generating resource's unit(s) must be dispatchable and committable.
  - If a generating resource does not meet all the above requirements, a formal request for generation capacity to be included in the ITPNT can be made to TWG on a case by case basis.
    - TWG will take into account the following, but not limited to, additional points:
      - An exception to include service from generation that will defer transmission expenditure(s) without a TSR filed service agreement and without a filed IA or a filed interim IA that have a high probability of going into service and also getting both an executed IA and an executed transmission service agreement must meet all of the below requirements:
      - A formal request has been sent to SPP[14] requesting the generation capacity be included into the ITP. The request should identify which transmission upgrades will be deferred
      - The generating resource has a mitigation plan for the deferred transmission upgrades until it makes a financial commitment to perform the upgrades

Commented [LG2]: David Kays (RTWG Chair): Revisit language. Possibly get with Nicole Wagner's team.

[10] Email sent to planning@spp.org
[11] Eliminates generators that may drop out as a result of changes in study results

- A Definitive Interconnection System Impact Study Agreement (DISIS) for the generating resource has been executed, an interim IA has been requested when the DISIS was posted and a final IA was FERC filed when applicable
- An RFP for the generating resource has been awarded, if applicable

If there is a shortfall between interchange, generation, and load or issues regarding reactive power support for an area in later years of the ITPNT Assessment analysis after the inclusion of all the above processes the following steps will be used sequentially to address system deficiencies[12]:

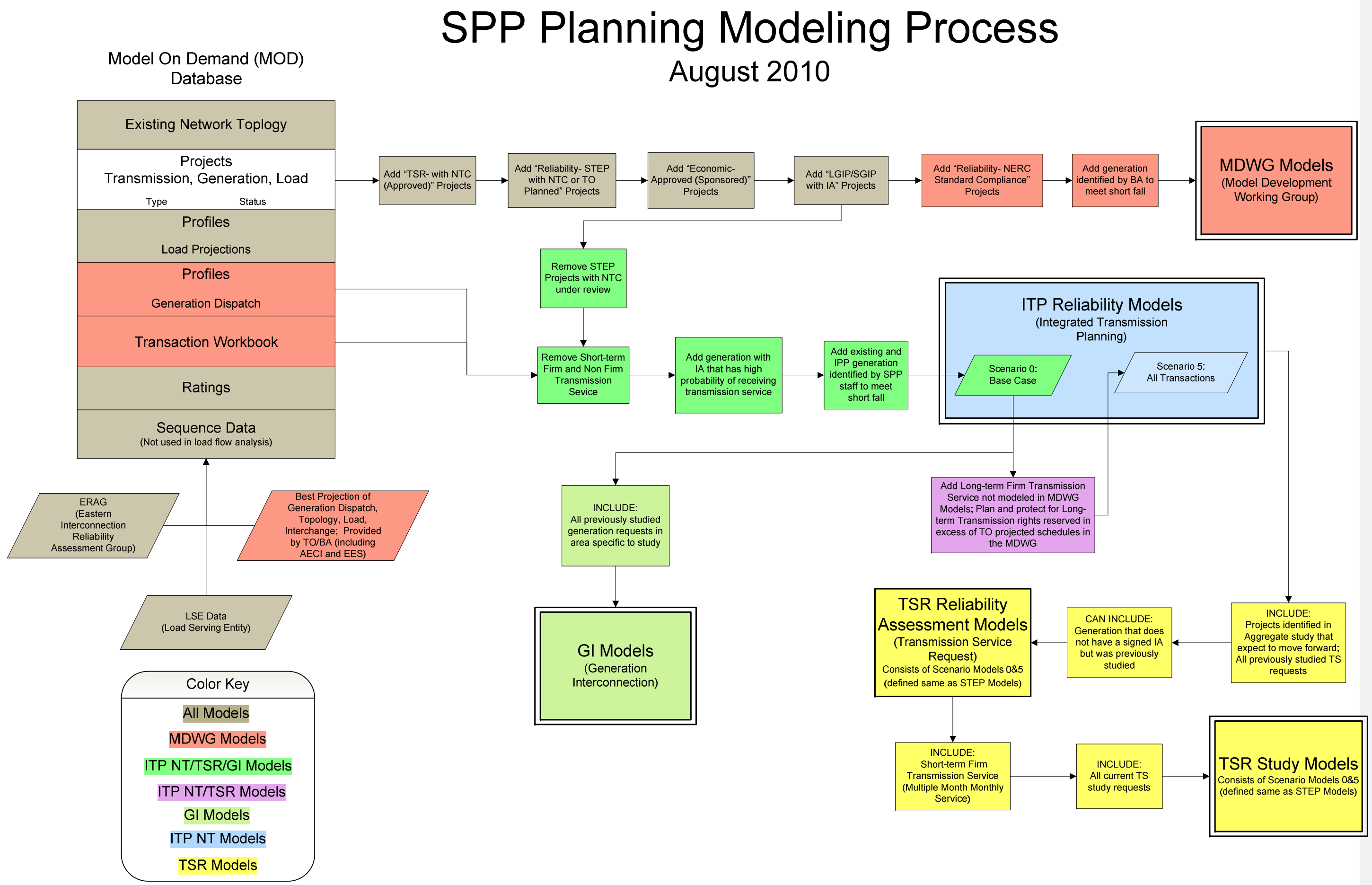
1) Exhaust the dispatchable generation of the network customer,
2) Exhaust the Independent Power Producers (IPP) dispatchable generation in the same model area,
3) Dispatch the remaining unused, dispatchable generation on a pro rata basis within SPP footprint.
4) When all other options have been exhausted, including the aforementioned formal request process, include generation resources from the most recently approved ITP10 resource plan. The addition of these ITP10 generation resources will not automatically generate NTCs.

If an ITP10 generation resource is being utilized solely for reactive support, then it will be dispatched to a minimum amount in order to remedy the situation as needed. If additional voltage support is needed, the addition of static or dynamic resources may be required and used to solve cases as needed. The addition of these devices will not automatically generate NTCs.

SPP uses scenarios to evaluate reliability. The number of scenarios is determined each year and approved by the TWG.

[12] Non-dispatchable wind generation or other generation with operating restrictions or forecasted projections shall not be used.

Below is a flow chart of the SPP planning modeling process.



3.3.2 Modeling Analysis

3.3.2.1 Transmission Operating Guides

SPP uses Transmission Operating Guides in its ITPNT Assessment analysis. Appendix B of this manual contains the SPP procedure to address use of operating guides in planning studies.

3.3.2.2 Assessment Methodology

Each year the assessment's scope is developed and approved by the TWG. The scope will contain following:

- The years and seasons to be modeled
- Treatment of upgrades in the models
- Scenario cases to be evaluated
- Description of the contingency analysis and monitored facilities
- Any new special conditions that are modeled or evaluated for the study
- Stability analysis may be performed using 5-6 year models[13]

3.3.2.3 Solution Development

After SPP performs the reliability assessment identifying the bulk power problems, SPP will present and solicit Transmission Owners and stakeholders for transmission solutions to those reliability problems. SPP solicits stakeholders in several forums including the planning summits and working group meetings. After receiving feedback from stakeholders, SPP will take current Aggregate Studies and Generation Interconnection studies into consideration to develop and validate the best regional solution for problems. Then SPP shares the proposed solutions with the members and stakeholders at various stakeholder meetings asking for additional feedback on the solutions. This process repeats for several iterations as staff refines the solutions in a set timeline.

Throughout the process, alternative solutions are proposed by stakeholders. SPP analyzes those alternatives in accordance with Section III.8 of Attachment O of the OATT.

3.4 Order 1000 Process

Under the Order 1000 Process, models will be extremely important such that submitted solutions really address issues on the SPP system. Models for the ITP will be released by SPP for a review by stakeholders with feedback provided to SPP on corrections to the models and possible enhancements. There may be 1 or more such reviews needed to address modeling issues as determined by SPP Staff. SPP will

[13] This stability analysis will be performed once per ITP cycle (i.e. every three years).

issue a final ITP model identifying key congestion issues and issues needed to be solved during the ITP process. Stakeholder will then have 30 days after the release of the final model to develop solutions as described in the DPP process and business practice. SPP will review the solutions in the course of the ITP solution development and select those DPP or solutions (non-DPP) that best provide the economic and reliability needs of the system. Upon completion of the preliminary results, a Transmission Planning Summit will be held to review the solutions for stakeholder feedback. Changes may be made based upon feedback from stakeholders. A final ITP report and plan will be presented to MOPC, Members Committee and Board for approval. Upon approval those projects that meet the Order 1000 requirements will be issued RFP's for competitive bidding purposes in compliance with the SPP OATT and business practices. The RFP evaluations will include award of any DPP points to stakeholders that have recommended solutions used by SPP staff for the ITP.

3.5 Deliverables

The deliverable for the ITPNT Assessment will be a list of 69 kV+ projects that would maintain the reliability of the SPP Region in the near term horizon.

In developing the annual STEP report, staff will include a section about the annual ITPNT Assessment. This section will summarize the regional, sub-regional and local transmission needs of the SPP Region in the near term horizon which is assessed to meet SPP's reliability needs. The ITPNT Assessment results will also contain a list of at least the following upgrades:

- Regional upgrades required to maintain reliability in accordance with the NERC Reliability Standards and SPP Criteria in the near term horizon;
- Zonal upgrades required to maintain reliability in accordance with more stringent individual Transmission Owner planning criteria in the near term horizon; and
- Inter-regional upgrades developed with neighboring Transmission Providers to meet inter-regional needs, including results from the coordinated system plans, in the near term horizon.

Throughout the ITPNT Assessment process, SPP shares, discusses, and refines proposed solutions with stakeholders. The solutions are finalized in the annual STEP report.

4 Issuance of NTCs

Once the ITP is reviewed by the MOPC and approved by the BOD, staff will issue NTC letters for approved projects in the 20-Year, ITP10, and ITPNT Assessments which are within the financial window as approved by the BOD. The NTC is sent to the incumbent Transmission Owner(s) for the project.

5 Reporting Requirements

Staff will inform the appropriate working groups throughout the year of the progress of the ITP assessments. SPP will also report on these assessments in its annual STEP report which will include a list of projects from those assessments. The STEP report will be presented to the BOD for approval.

5.1 Stakeholder Review Process

To show transparency in its planning processes, SPP holds planning summits that allow stakeholders opportunity to engage in, develop, and review SPP's on-going planning assessments and their results. SPP also has working groups meetings as another forum for stakeholders to become involved in SPP planning studies.

APPENDICES

6 Acronyms and Term Definitions

1. AECI – Associated Electric Cooperative, Inc.
2. APC – Adjusted Production Cost: APC is a dollar value calculated by adding the cost of producing energy to the cost of energy purchases and subtracting the revenue from energy sales
3. ATP – Authorization to Plan: The ATP is a status given to a project which indicates that the BOD has approved the project in the SPP ITP and it has not yet been issued an NTC because it is outside of the NTC financial commitment window.
4. BOD – SPP Board of Directors/Members Committee: The BOD is the governing body of SPP
5. DPP- Detailed Project Proposal
6. EHV – Extra High Voltage: In this document EHV refers to transmission at 300 kV or greater
7. ERCOT – Electric Reliability Council of Texas
8. ESWG – Economic Studies Working Group: The ESWG reports to the MOPC and advises and assists SPP staff, various working groups and task forces in the development and evaluation principles for economic studies
9. FERC – Federal Energy Regulatory Commission
10. IRP – Integrated Resource Plan: A Utilities resource plan that serves projected load.
11. ITP – Integrated Transmission Plan: The ITP is SPP's approach to planning transmission needed to maintain reliability, provide economic benefits, and achieve public policy goals to the SPP region in both the near and long-term
12. LMP – Locational Marginal Price: Also known as nodal pricing, the LMP is the incremental cost to the system that would result from one additional unit of energy that is demanded at a particular node
13. MAPP – Mid-Continent Area Power Pool
14. MDWG – Model Development Working Group: The MDWG is responsible for maintenance of an annual series of transmission planning models (powerflow and short circuit models and associated stability database) which represent the current and planned electric network of SPP
15. MISO – Midwest Independent Transmission System Operator
16. MOPC – Markets and Operations Policy Committee
17. MTF – Metrics Task Force: The MTF is a task force created by the ESWG to create a list of metrics for the ESWG to consider for use in evaluating projects in the ITP
18. NERC – North American Electric Reliability Corporation
19. NERC TPL – NERC Transmission Planning Standards
20. NTC – Notification to Construct: The NTC is a formal SPP document specifying approval of and notification to build specific network upgrades with specified need dates for commercial operation
21. OATT – Open Access Transmission Tariff: SPP's transmission tariff as posted on SPP's website
22. PJM – PJM Interconnection
23. PTDF – Power Transfer Distribution Factor: A PTDF is the percentage of power transfer flowing through a facility(ies) for a particular transfer when there are no contingencies.
24. ROW – Right-of-Way: The ROW identifies the strip of land which is needed for transmission purposes

25. RSC – Regional State Committee: The SPP RSC provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission
26. SERC – SERC Reliability Corporation
27. SPP – Southwest Power Pool, Inc.: SPP is a Regional Transmission Organization
28. SPPT – Synergistic Planning Project Team (SPPT): The SPPT is a team which was created to address comprehensive transmission planning processes and allocation of transmission costs associated with both existing and strategic issues including transmission service, generator interconnection, Extra High Voltage (EHV) inter-regional transmission, wind integration, etc.
29. STEP – SPP Transmission Expansion Plan: The STEP is an annual plan which summarizes activities that impact future development of the SPP transmission grid. The STEP includes projects approved in the ITP, 10 Year Reliability, Priority Projects, Aggregate Study, Generation Interconnection, etc.
30. TLR – Transmission Loading Relief: A TLR is a process which is used to reduce loading on lines which are at risk for an overload
31. TWG – Transmission Working Group: The TWG reports to the MOPC and is responsible for planning criteria to evaluate transmission additions, seasonal ATC calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations
32. WECC – Western Electricity Coordinating Council

7 Benefit Metrics

The section below provides further definition and commentary on each of the 10 benefit metrics that will be considered in the ITP planning process when evaluating potential transmission projects.

1. Adjusted Production Cost (APC) Savings

   a. Definition:

      The standard APC metric measures the impact on production cost savings by considering Locational Marginal Price (LMP) for purchases and sales of energy between each area of the transmission grid. The APC metric quantifies the monetary cost associated with fuel costs, generation dispatch, most grid congestion, energy purchases, energy sales, and other factors that directly relate to energy production by generating resources in the SPP footprint. The APC calculation also captures cost savings associated with reducing emissions and ancillary service requirements.

   b. Measurement/Monetization:

      APC estimates are usually performed for weather-normalized peak load (i.e., 50/50 peak load). The APC for an area is determined using a production cost modeling tool that captures hourly commitment and dispatch profiles for one simulation year. The hourly calculation accounts for:

      Production Costs: The fuel and non-fuel variable O&M costs of utility-owned or cost-of-service-contracted generation.
      Revenue from Sales: MWh Sold by Utility x Generation-Weighted Avg. Zonal Gen. LMP
      Cost of Purchases: MW Purchased by Utility x Load-Weighted Avg. Zonal Load LMP

      The APC benefit is then based upon the difference in the production cost simulations for the base case and the change case.

   c. Allocation:

      The APC savings are calculated in the production cost simulations on a zonal basis.

2. Reduction of Emission Rates and Values

   a. Definition:

      Allowance prices for SO_2, NO_x, and CO_2 emissions are used as inputs to the production cost model simulations and are specific to the various generating technologies modeled. Transmission projects can relieve grid congestion and change generation dispatch, resulting in cost savings associated with reductions to SO_2, NO_x, and CO_2 emissions.

   b. Measurement/Monetization:

The APC calculation captures the cost savings associated with reduced SO2, NOx, and CO2 emissions, as scoped for each particular economic study, through the assumed allowance price for these emissions.
The allowance market dynamics that take place separately from events in the energy market are not considered in this metric. Rather, a simplified approach that assumes allowances are sold and purchased at known market clearing price is applied and these allowance prices are included in the calculation of marginal production costs.

c. Allocation:

The reduction of emission rates and values is captured in the APC, which is calculated on a zonal basis.

3. Savings due to Lower Ancillary Service Needs and Production Costs
   a. Definition:

Ancillary Services (A/S) are essential to the reliable operation of the electrical system. A number of operating reserves and products fall into this category – spinning reserves, ramping up/down, regulation, and 10-minute quick start. Current production cost simulation tools account for energy costs on the system, but generally take a static approach to modeling sub-hourly A/S needs by setting aside an exogenously determined quantity of A/S reserves in each hour. However, new transmission projects can contribute to reduction in A/S system costs through either (1) a reduction in needed A/S quantities or (2) a reduction in the cost of procuring that quantity.

- Quantity Impact: At present, SPP A/S needs are determined according to the SPP Market Protocols with input from SPP staff. Findings from renewable integration studies and analyses suggest that improved transmission topology can contribute to reducing system A/S needs, which tend to increase as a function of renewable generation penetration. Therefore, system-wide A/S needs could be calculated as a function of transmission capacity and transfer capability among zones.
- Procurement Cost Impact: Conceptually, the cost of providing A/S should be captured in the APC metric if the simulation software can accurately capture and simulate A/S requirements and their deployment.

b. Measurement/Monetization:

The quantity impact will be captured as the formulaic determination of A/S needs evolves and transmission overlay begins to directly impact zonal or system-wide A/S needs. At such a point, the benefit from incremental transmission capabilities can be directly measured by calculating A/S needs in production cost simulations for the base and change cases.

Similarly, improved production cost modeling of sub-hourly A/S procurement and deployment can enable the measurement of the cost impacts directly within the APC calculations.
Monetization of the quantity and cost benefits will be reflected in the overall APC savings. The production cost simulation will be conducted using the initial A/S needs for the base case and the same (or possibly reduced) A/S needs for the change case. The difference in APC for the simulations will then reflect the reduced costs of procuring the specified A/S needs (e.g., lower

procurement cost of the same A/S needs due to reduced transmission congestion that makes lower-cost resources available to provide ancillary services).

c. Allocation:

Benefits will be calculated in the production cost simulations and will be assigned to the SPP region as a whole and re-allocated to each of the zones on a load ratio share basis.

4. Avoided or Delayed Reliability Projects

a. Definition:

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

b. Measurement/Monetization:

The methodology to determine which reliability projects were replaced with economic projects follows these steps:

i. Reliability need identified.
ii. Reliability mitigation provided and tested to ensure successful mitigation.
iii. Congestion in the system identified.
iv. Congestion near and related to reliability needs paired to compare alternative projects.
v. The value of resolving the congestion with an economic project that also mitigated the reliability need is measured and compared with the difference in costs between the projects.
vi. Where cost effective, the economic project was selected to mitigate the reliability need and relieve the congestion.

The avoided (or delayed) reliability project benefit is then captured as the avoided cost of delaying or canceling previously approved reliability projects.

c. Allocation:

The benefit is allocated in accordance with the ratios of the allocation that would have been applied for the costs of the reliability project.

5. Capacity Cost Savings due to Reduced On-Peak Transmission Losses

   a. Definition:

   This metric captures the value of generation capacity that may no longer be required due to a reduction in losses during the system peak.

   b. Measurement/Monetization:

   These capital savings will be calculated by applying the estimated net Cost of New Entry (CONE) to the reduction in installed capacity requirements. The net CONE is the difference between the annualized CONE and the annual energy and ancillary service profits a unit of this type is expected to earn in the energy and ancillary service markets. The CONE value includes the levelized investment costs and fixed operating costs of a combustion turbine as reported in the latest version of the Department of Energy Annual Energy Outlook report or other comparable public source. The following sources may be used to estimate the average annual energy and ancillary service profits for a combustion turbine:

   - Historical market revenues net of fuel and variable non-fuel operating costs for combustion turbines in SPP or similar market(s).

   - Revenues net of fuel and variable non-fuel operating costs for combustion turbines obtained from production cost simulations of the SPP or similar market(s).

   Monetization of the capacity cost savings will be calculated using the savings in capital attributed to the corresponding MW reduction in installed capacity requirements.

   c. Allocation:

   The capacity cost savings calculations will be performed zone-by-zone and allocated accordingly.

6. Assumed Benefit of Mandated Reliability Projects

   a. Definition:

In evaluating projects within the portfolio that would be built to meet transmission reliability standards (i.e. classified as a 'reliability project' as defined in this manual), the benefit of fixing the reliability violation should be assumed to be equal to its cost. This benefit will be mutually exclusive from any other reliability benefit applied to those same projects.

b. Measurement/Monetization:

Mandated reliability project benefits are set equal to costs with other economic benefits, such as APC savings, being additive (or subtractive in the case of losses). It is important to note that any transmission project with APC savings that result in a benefit-to-cost (B/C) ratio greater than 1.0 will be considered an 'economic project' with no additive reliability benefit, even if it fixes a reliability violation.

c. Allocation:

These benefits will be allocated using a hybrid approach that utilizes Load Ratio Share and System Reconfiguration, depending upon project size. The System Reconfiguration approach looks at the flows on all lines in the SPP system, both with and without the reliability upgrade. All lines with an increase in flow after the reliability upgrade is placed on outage are identified as having flows relieved by the reliability upgrade. The allocation of benefits is then based upon the increase in line flows across the system when the upgrade is on outage. The allocation will vary as follows, based upon the project size:

i. If the project is < 100 kV, allocate 100% based upon System Reconfiguration.
ii. If the project is 100-300 kV, allocate 2/3 System Reconfiguration, 1/3 Load Ratio Share.
iii. If the project is > 300 kV, allocate 1/3 System Reconfiguration, 2/3 Load Ratio Share.

7. Public Policy Benefits

a. Definition:

This metric captures the value of meeting public policy goals or mandates related to renewable energy supplies. Public policy can be met through state law, settlement agreement, or a regulatory determination made by a state regulatory authority. It does not include economic decisions made by individual utilities to acquire renewable energy supplies absent some form of legal requirement to do so.

b. Measurement/Monetization:

As with mandated reliability upgrades, the assumption is that public policy makers have made a decision that public benefit is at least equal to the cost of implementing a public policy. Therefore, the objective is finding the most cost effective method in meeting that goal, and the benefit in achieving the goal or mandate is assumed to be equal to the project cost. It is important to note that any transmission project with APC savings that result in a benefit-to-cost (B/C) ratio greater than 1.0 will be considered an 'economic project' with no additive public policy benefit.

c. Allocation:

Benefits will be allocated based upon the share of unmet renewable mandates or goals and only to zone(s) within the state(s) driving the public policy project(s).

8. Increased Wheeling Through and Out Revenues

a. Definition:

Increasing ATC with a neighboring region improves import and export opportunities outside of the footprint. Increasing inter-regional transmission capacity that causes an increase in through and out transactions will also increase SPP wheeling revenues. While the energy revenue benefit of increased exports is captured by the APC metric, the APC metric does not capture any increases in wheeling out or wheeling through revenues associated with increased transfer capability. These increased wheeling revenues are a benefit as they will offset part of the transmission projects' revenue requirements.

b. Measurement/Monetization:

The quantity impact will be determined by calculating the incremental long-term wheeling service that SPP was able to sell due to upgrades and using that historical ratio to calculate wheeling MW and revenues for export-ATC changes from new projects in the future. Reduced ratios, or scaling factors, will be considered based upon additional analyses for very large future ATC increases.

Wheeling revenue calculations as proposed here will not result in double-counting of benefits with respect to APC calculations. The reason is that in the APC methodology, imports are priced at the importing region's internal load LMP, while exports are valued at the exporting region's internal generation LMP. As a result, even if part of the difference is payable as a wheeling charge, the revenues collected are not counted in either the exporting or importing region's APC.

An average wheeling charge will be utilized to monetize the value of increased wheeling through and out transactions. The average SPP wheeling charge will be calculated by using the actual wheeling revenues divided by the MWh exports scheduled the previous year.

c. Allocation:

These benefits will be allocated according to the methodology in the Tariff for allocating wheeling revenues.

9. Marginal Energy Losses Benefit

    a. Definition:

    This metric captures the reduced MWh quantity of transmission losses that results from transmission expansions. Standard production cost simulations used to estimate the APC benefits do not reflect that transmission expansions may reduce the MWh quantity of transmission losses. To simplify simulations and make run-times of the simulations manageable, load is 'grossed up' for average transmission losses. The simulations then assume that the MWh quantity of losses is fixed and does not change with transmission additions. However, the production cost savings due to such energy loss reductions can be estimated through post-processing simulation results.

    b. Measurement/Monetization:

    The benefits of the reduced MWh losses will be calculated post-processing by capturing the Marginal Loss Component (MLC) for the LMP to calculate loss factors. The actual loss-related energy cost savings will be reduced by the energy cost savings already in the APC to arrive at the marginal energy cost savings not captured in the simulations.

    c. Allocation:

    The marginal energy loss calculations will be performed zone-by-zone and allocated accordingly.

10. Mitigation of Transmission Outage Costs

    a. Definition:

    Standard production cost simulations assume that transmission lines and facilities are available during all hours of the year and that no planned or unexpected outages of transmission facilities will occur. In practice, however, planned and unexpected transmission outages impose non-trivial additional congestion costs on the system. Thus, the benefit of reducing this additional congestion is not captured in the standard APC metric. The availability of new transmission projects decreases congestion and increases the operational flexibility of the system to mitigate the impacts of transmission outages.

    b. Measurement/Monetization:

    To measure the savings in transmission outage costs due to transmission expansion, the production cost modeling analysis will be modified to reflect a realistic level of transmission outages using a subset of historical transmission outage events.

The benefits will be calculated as the difference between 1) the APC savings due to the transmission upgrades for a system considering transmission outages and 2) the standard APC savings due to the transmission upgrades which are calculated for a system without any transmission outages.

c. Allocation:

These benefits will be calculated on an SPP-wide basis and allocated to zones based on the load ratio share.

8 Appendix A

Type	Status	Description	MDWG	STEP/ Tariff	Special Study
TSR	w/NTC (Approved)	Projects identified through Aggregate Study with an executed Transmission Service Agreement and an issued Notice To Construct	X	X	X
	Proposed (No NTC)	Proposed projects that do not have an NTC			X
LGIP	w/GIP	Projects identified through the Large or Small Generator Interconnection Procedures (LGIP, SGIP) with an executed Large Generator Interconnection Agreement and not on suspension	X	X	X
	w/GIP on Suspension	Projects identified through the Large or Small Generator Interconnection Procedures (LGIP, SGIP) with an executed Large Generator Interconnection Agreement and on suspension			X
	No GIP	Projects without an executed Large or Small Generator Interconnection Agreement (LGIP, SGIP)			X
Reliability	STEP (w/NTC) or TO Planned	Appendix B Projects that have a Notice to Construct or Transmission Owner Planning Criteria with an issued Notice To Construct	X	X	X
	STEP Proposed (No NTC)	Appendix A Projects and projects that are being studied as part of the current STEP process, or are under consideration			X
	NERC Standard Compliance	Projects needed to comply with NERC Reliability Standards or SPP Criteria that are not part of STEP	X		X
Economic	Approved (Sponsored)	Projects identified through Attachment O identified that have been shown to provide regional economic benefit that have a contract that financially commits a Project Sponsor	X	X	X
	Approved (Not Sponsored)	Projects identified through Attachment O identified that have been shown to provide regional economic benefit that have no contract to build			X
Requested	Stakeholder Driven	Transmission upgrades, requested by a Transmission Customer or other entity, which do not meet the definition of any other category of Network Upgrades.	X		X
	Alternative	Projects that are alternatives to any TSR, STEP, or Economic Project. i.e. differed projects			
Network	Energized	Projects that are in-service from a previous MOD Type & Status. Constructed facilities that are in-service.	X	X	X
Network	Outage	Projects that change network topology status. Constructed facilities that are out-of-service or normally open.	X	X	X
Network	Update	Projects that updates network data	X	X	X

9 Appendix B

SPP Transmission Operating Guides Review Procedure

This procedure documents the process of how a Transmission Operating Guide (TOG) shall be included in the ITP and SPP Aggregate Transmission Service Studies (ATSS). In most cases TOGs are not intended to indefinitely defer needed Transmission System upgrades. Effective TOGs shall be utilized in all transmission tariff service functions and OATT planning processes.

For a TOG to be considered for use in the ITP and ATSS as a possible mitigation plan, it shall be on file with SPP. An effective TOG must state the system conditions under which the TOG is to be used and describe, in detail, the action the operators will take. The TOG must be signed by someone in charge of operations from the Transmission Owner or transmission operator submitting the TOG.

An effective TOG shall continue to be used in evaluation of the ITP and ATSS unless the facility-owning Transmission Owner or transmission operator withdraws the TOG. In cases where the TOG is withdrawn before the TOG becomes ineffective, any Transmission System Upgrades lie with the Transmission Owner.

A new TOG provided as interim mitigation for an SPP-required project shall automatically be withdrawn when the project is completed.

A TOG is considered an effective solution for facilities that are not listed in the TOG if, in the act of implementing the TOG for the elements listed, other overloads or voltage violations are corrected.

Service Upgrades associated with new Transmission Service Requests or Designated Resources that cause a TOG to be ineffective will be classified as Base Plan Upgrades in accordance with Attachment J.

Transmission System upgrades that become necessary because a TOG has been identified to be ineffective in order to maintain the reliability of the Transmission System shall be categorized as Reliability Upgrades, utilizing the procedures of Attachment O of the OATT.

The upgrade(s) proposed to address an ineffective TOG may work towards either eliminating the TOG or the ineffectiveness of the TOG.

Effective TOGs

1. A TOG addressing Transmission System loading must include a short-term emergency rating which allows sufficient time to implement the TOG.
2. A TOG requiring generation redispatch must indicate if generator location is critical and, if so, must state in detail which units or plants will be re-dispatched. Absence of such specificity means location is not critical and generators may be selected from the fleet the entity has authority to run. The ramp rate of the generation must be capable of relieving the overload or voltage issue within the time allowed as specified in the TOG.
3. A TOG must not cause a violation elsewhere on the Transmission System.
4. A TOG addressing a voltage violation must provide for restoring minimum acceptable voltage conditions within a time frame so as not to cause permanent equipment damage.

A TOG shall identify the means by which system control is implemented. That is, if supervisory control is utilized it must so state.


SPP
75th Anniversary
75
SEVENTY-FIVE YEARS OF
RELIABILITY THROUGH RELATIONSHIPS

Transmission Planning Improvement Task Force (TPITF) Whitepaper

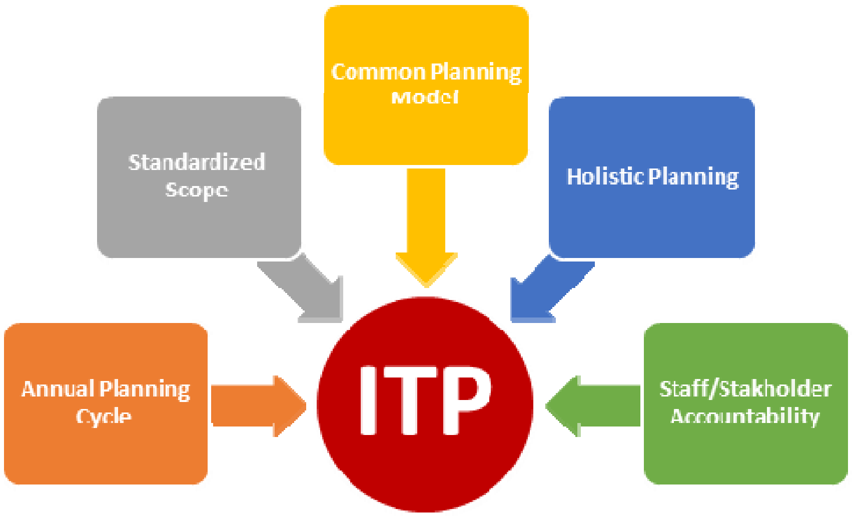
ESWG

April 21, 2016

TPITF Recommendations

- Implement annual ITP planning cycle
- Standardized study scope
- Establish common reliability planning model for all SPP planning assessments
- Utilize a holistic approach to planning
- Create a Staff/Stakeholder accountability program

*Today's discussion topics



Standardized Scope

Standardized ITP Assessment Scope

- **Current State**
  - ITP Manual
    - Comprehensive document describing the model building and assessment processes of the ITPNT, ITP10, and ITP20 studies
    - Leaves several scope items open for a range of interpretation
    - Working group review and approval for study scope items associated with each ITP assessment cycle
  - ITPNT Study Scope
    - Includes process details for each item and finalized upon stakeholder approval
  - ITP10 Study Scope
    - Includes high-level process description where details may be determined by stakeholders during the study process

Standardized ITP Assessment Scope

- **TPITF Issues Related to Study Scopes**
  - Inconsistency scope implementation from study to study
    - Scope can change mid-process due to a change in the expectations of members or conflicting expectations among members
    - Causes difficulty with building consensus toward the approval of resultant transmission plans
  - Scope review and approval by working groups can take a long time and cause delays in the process
    - Scope approval, including individual scope items, can take several working group meetings before approval is granted creating a bottleneck in the study schedule.
  - Lack of scope standardization makes it difficult to estimate Staff and stakeholder resources needed to complete the study

Standardized ITP Assessment Scope

- **Desired State**
  - Standardized Scope
    - Review and approval of methodologies and criteria that guide study processes
    - Simplify scope development process; eliminate need to review and approve items annually
    - Help provide the consistency members seek for the planning studies
  - Assumptions Document
    - Fully outline and describe scope items that require Stakeholder review and approval with each new study
    - Maintain flexibility to make needed changes for those specific scope items

TWG and ESWG will review and approve the scope items that will be standardized and the scope items that will be a part of the assumptions document and update the ITP Manual accordingly

Standardized ITP Assessment Scope

- **Desired State**
  - Leverage SPP's Revision Request (RR) Process for scope changes
    - Request Management System (RMS); tracking and reporting of scope revision submissions
    - Govern how the submitted changes will be received, reviewed, approved, and implemented
    - Proper Stakeholder vetting and approval
    - Decrease mid-process disruptions; approved revisions incorporated into scope of subsequent study
    - Retain flexibility by granting appropriate working group the ability to provide guidance on specific scope items

Common Planning Model

Common Planning Model

- **Current State**
  - 38 total study models

Description	Year 1	Year 2	Year 5	Year 10	Total
ITPNT Reliability (MDWG)	----	Scenario 0: ITPNT SP & WP Scenario 5: ITPNT SP & WP CBA: ITPNT SP & WP	Scenario 0: ITPNT SP & WP Scenario 5: ITPNT SP & WP CBA: ITPNT SP & WP Scenario 0, 5, & CBA (off-peak): ITPNT L	----	15
ITP10 Economic	----	----	Futures (1/2/3): 8760 hrs	Futures (1/2/3): 8760 hrs	6
ITP10 Reliability	----	----	DC/AC Future (1/2/3): S & L	DC/AC Future (1/2/3): S & L	12
TPL - Steady State Assessment (MDWG)	R2.1.1 Y-1 Peak: MDWG S (base) & ITPNT SP5 (sensitivity) R2.1.2 Y-1 Off-Peak: MDWG L (base) & ITPNT L5 (sensitivity)	----	R2.1.1 Y-5 Peak: MDWG (base) & ITPNT SP5 (sensitivity)	R2.2.1 Y-10 Peak: MDWG S (base)	4
TPL - Series Short Circuit (MDWG)	S Max Fault				1

SPP 75

Common Planning Model

- **Current State**
  - MDWG
    - Powerflow, TPL Steady State and Short Circuit
  - ITPNT
    - Reliability
      - MDWG powerflow base
      - Scenario 0 and Scenario 5 bookends
  - ITP10
    - ITPNT Scenario 0, summer peak base
    - Economic
  - CBA Reliability
    - ITPNT Scenario 0 base
    - ITP10 economic data
    - Security constrained economic dispatch (SCED)

Common Planning Model

- **TPITF Issues Related to Current Modeling Practices**
  - Models not constructed in a consistent manner across the planning processes. Fundamentally different between the processes
  - Separate model builds for the different planning processes place additional burdens on members to submit and review data several times throughout the year
  - Models are not indicative of what is happening in real-time under the new Integrated Marketplace.
    - SPP Market and SPP Operations feedback should be reflected in the model development process

Common Planning Model

- **Desired State**
  - 30 total study models

Description	Year 2	Year 5	Year 10	Total
Reliability: CBA (TPL Sensitivity Case)	One Future Coincident Peak On/Off-Peak (2)	Up to Three Futures Coincident Peak On/Off-Peak (6)	Up to Three Futures Coincident Peak On/Off-Peak (6)	14
Reliability: Base Scenario TPL: Powerflow	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	9
Economic	One Future Coincident Peak 8760 (1)	Up to Three Futures Coincident Peak 8760 (3)	Up to Three Futures Coincident Peak 8760 (3)	7

Common Planning Model

- **Desired State**
  - Base Reliability Model
    - Reduce bookend scenario model sets to single expected case scenario
    - Represents SPP load responsible entities serving network load with firm network resources only
      - Meets NERC requirements or firm resource modeling
    - Non-coincident peak load forecasts
    - Assumed long-term firm transmission service
    - Block dispatch of firm conventional and renewable resources at projected output levels
    - Utilize as the base model(s) for ATSS, GI, TPL Steady State and Short Circuit

Common Planning Model

- **Desired State**
  - Economic Model
    - Identify and assess solutions to economic and public policy needs of the SPP system
    - Developed for three study years (Years 2, 5, and 10)
    - Single economic model for one future in Year 2
    - Up to three economic models will be developed for the reference case future in Years 5 and 10
  - CBA Reliability Model
    - Represents SPP load responsible entities serving network load with both firm and non-firm resources under market based construct
    - Built from Economic model
      - Coincident peak load forecasts for the SPP region
      - Security constrained commitment and dispatch
      - Interchange between SPP and Tier 1 will be determined based on LMP differentials

Transition Plan

Transition

The TPITF recommends a transition to the new 2019 ITP planning process starting in September 2017 with the ITP model builds and scope development leading to the initial ITP planning assessment that will be completed in July of 2019

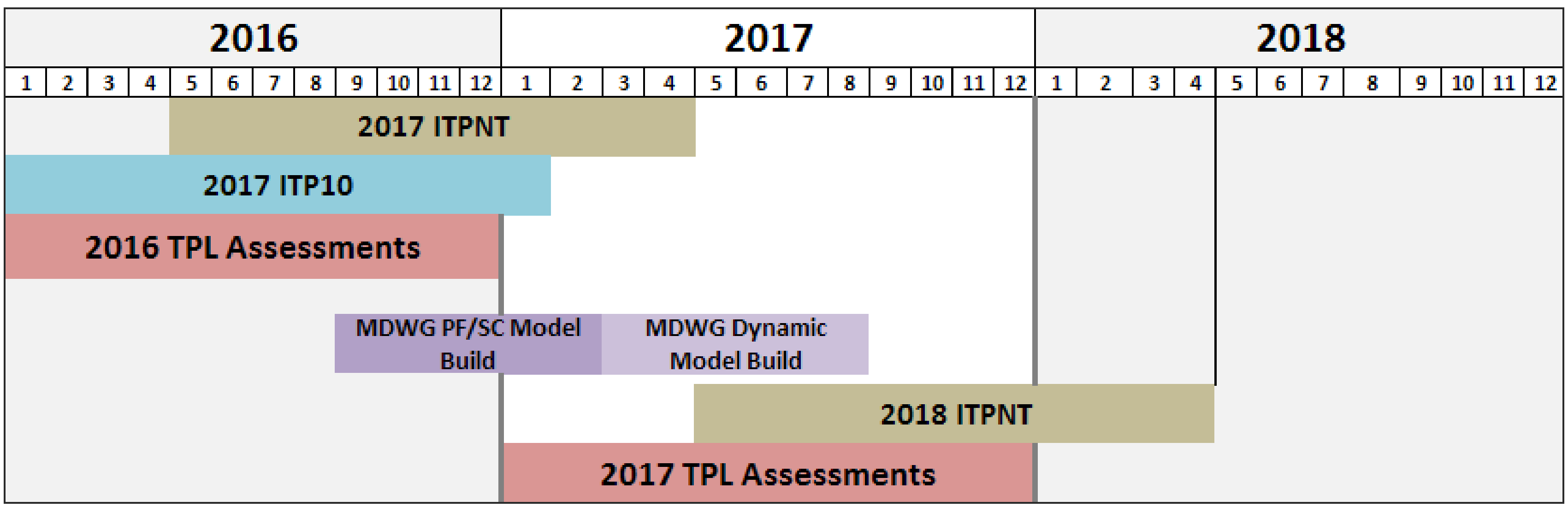
Transition to the new planning process will require two preliminary steps:

1. Current planning cycle will need to be completed
2. Stakeholders/Staff will need to implement all changes necessary to allow the new process to move forward. These changes will include, but are not limited to:
   - Modifications to the SPP tariff and other appropriate governing documents
   - Establishment of the details of the new processes and procedures for the new planning study by the applicable SPP working groups
   - Procurement of resources and tools necessary to implement the process

Transition

The current ITP planning cycle has two remaining studies, the 2017 ITP10 and the 2017 ITPNT

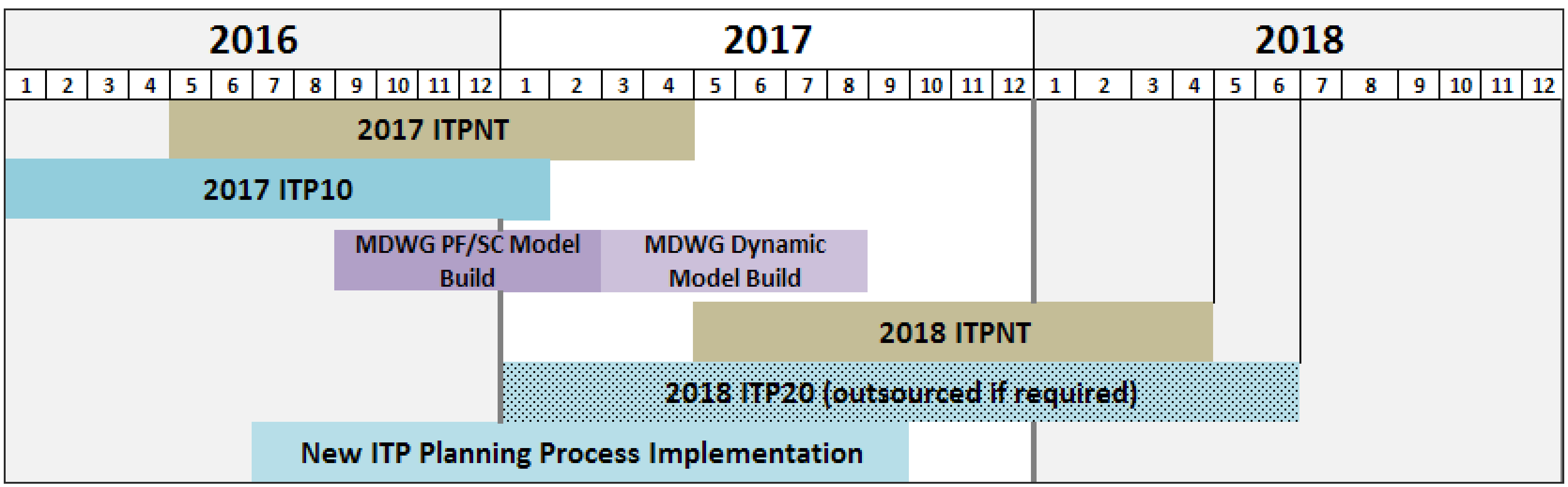
- The 2017 ITP10 is scheduled to be completed in January 2017
- The 2017 ITPNT is scheduled to begin in April 2016 and be completed in April 2017
- The next ITP planning cycle under the current process would begin with an ITP20 assessment that commences in 2017, as well as the 2018 ITPNT that would begin in April 2017 and end in April of 2018



Transition

The TPITF recommends the suspension of the ITP20 for 2017

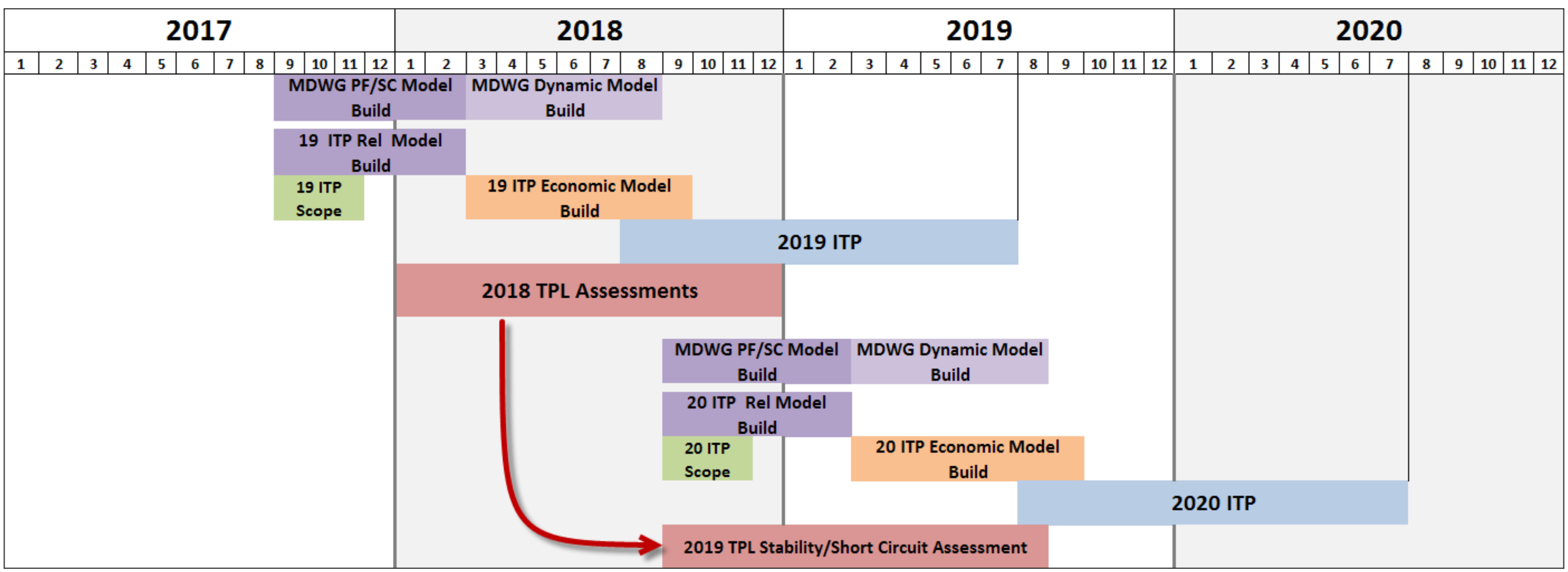
- TPITF believes SPP Stakeholder and Staff resources would be better utilized by focusing their efforts on initiatives necessary to facilitate the successful implementation of the new ITP Planning process
- 2018 ITPNT assessment is necessary to for continued reliability planning during the transition
  - If the study is required by the SPP BOD, the TPITF recommends outsourcing the performance of the study to free up the resources necessary for implementation of the new planning process

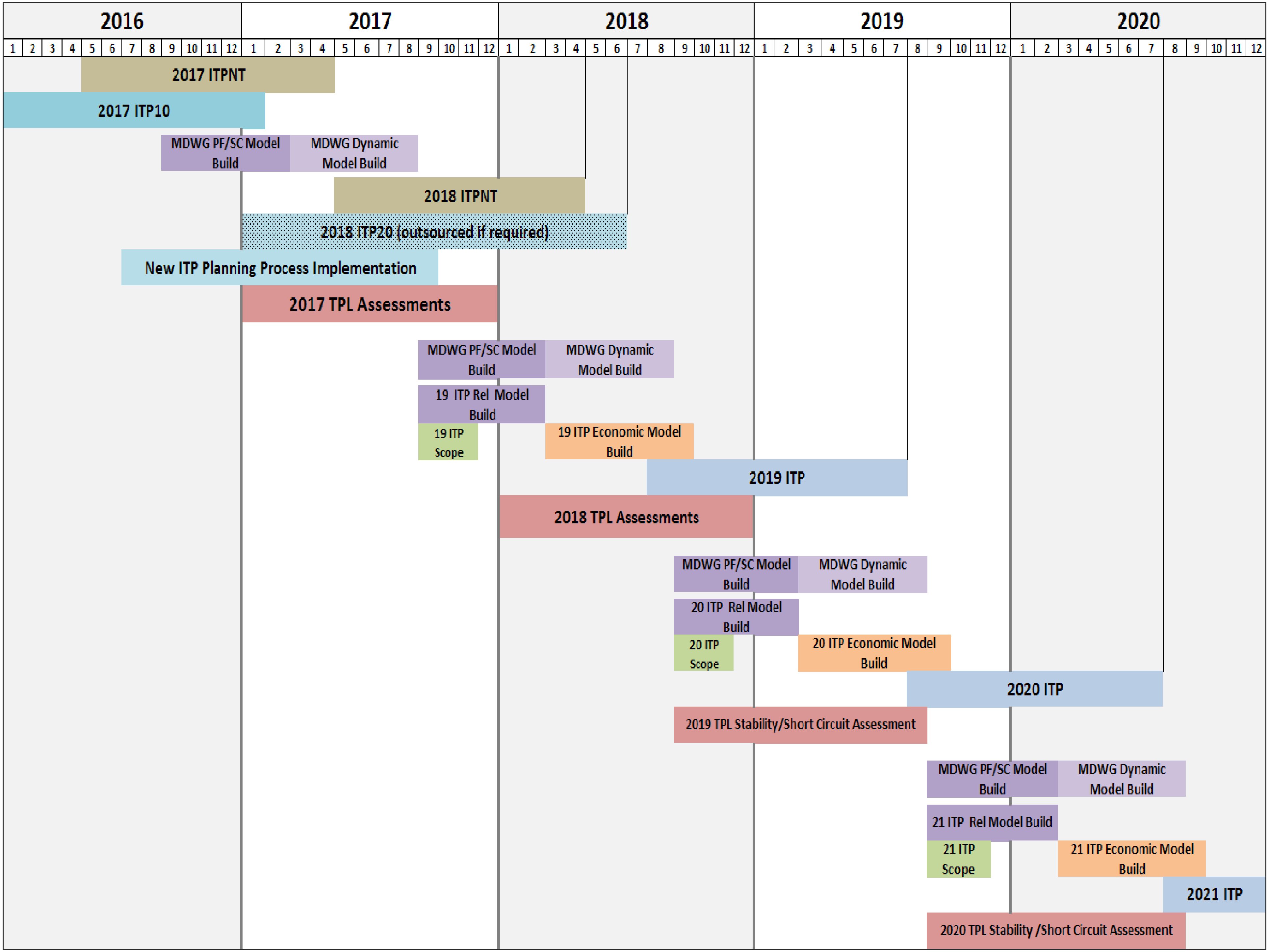


Transition

There will be three more TPL assessments performed under the current processes, prior to the inclusion of TPL power flow and short circuit assessments into the new ITP planning process

- These assessments are the 2016, 2017, and 2018 TPL assessments and will be completed in December 2016, December 2017, and December 2018 respectively
- The 2019 TPL stability assessment will commence in the latter half of 2018 rather than January of 2019 to align with the 2019 ITP assessment timeframe.
- In essence, the TPL assessments will be performed twice in 2018 in order to facilitate alignment with and inclusion in the 2019 ITP assessment and meet annual NERC posting requirements




2016
2017
2018
2019
2020
1 2 3 4 5 6 7 8 9 10 11 12
2017 ITPNT
2017 ITP10
MDWG PF/SC Model Build
MDWG Dynamic Model Build
2018 ITPNT
2018 ITP20 (outsourced if required)
New ITP Planning Process Implementation
2017 TPL Assessments
MDWG PF/SC Model Build
MDWG Dynamic Model Build
19 ITP Rel Model Build
19 ITP Scope
19 ITP Economic Model Build
2019 ITP
2018 TPL Assessments
MDWG PF/SC Model Build
MDWG Dynamic Model Build
20 ITP Rel Model Build
20 ITP Scope
20 ITP Economic Model Build
2020 ITP
2019 TPL Stability/Short Circuit Assessment
MDWG PF/SC Model Build
MDWG Dynamic Model Build
21 ITP Rel Model Build
21 ITP Scope
21 ITP Economic Model Build
2021 ITP
2020 TPL Stability /Short Circuit Assessment

ESWG Discussion

- **General comments on TPITF work and recommendations**
- **Questions regarding recommendations not reviewed today**
- **Document specific comments on recommendations whitepaper to take back to TPITF**
- **Topics of discussion for scope standardization**

Appendix

Annual Planning Cycle

Annual ITP Planning Cycle

- **Current State**
  - ITP20
    - Strategic economic study
    - Address reliability needs, support policy initiatives, and enable economic opportunities in 20-year horizon
    - Wide range of future system scenarios
    - No NTCs
  - ITP10
    - Develop a transmission expansion portfolio containing primarily 100 kV and above projects
    - Address reliability needs, support policy initiatives, and enable economic opportunities in 10-year horizon
    - NTCs issued
  - ITPNT
    - Focuses exclusively on the reliability needs of the system associated with forecasted load growth and maintenance of long-term firm transmission service in 5-year horizon

SPP 75

Annual ITP Planning Cycle

- **TPITF Issues Related to Current Planning Cycle**
  - 3-year planning cycle is too long and is inflexible in addressing system needs
  - Frequency of the 10-year planning assessment (once every 3 years) is inadequate
  - ITP20 is performed too frequently based on practical value compared with the time and cost to perform the assessment
  - Performing the planning assessments separately reduces opportunities for synergy in addressing the reliability, public policy, compliance, and economic needs of the SPP system with NTCs

<table>
<tr><th colspan="4">Year 1</th><th colspan="4">Year 2</th><th colspan="4">Year 3</th></tr>
<tr><td>1</td><td>2</td><td>3</td><td>4</td><td>1</td><td>2</td><td>3</td><td>4</td><td>1</td><td>2</td><td>3</td><td>4</td></tr>
<tr><td colspan="4">ITPNT</td><td colspan="4">ITPNT</td><td colspan="4">ITPNT</td></tr>
<tr><td colspan="6">ITP20</td><td colspan="6">ITP10</td></tr>
</table>

Annual ITP Planning Cycle

- **Desired State**
  - Single ITP planning study incorporating near- and long-term views
    - Annual planning report and NTC recommendations
  - Remove ITP20 from planning cycle
    - Perform separately no more than once every five years unless directed by the SPP Board
  - Annual 10-year assessment
    - Combines the ITPNT, ITP10, and portions of the TPL-001-4 into one assessment
  - Overlapping planning cycles
    - Three 10-year assessments over a three year period

Year 1				Year 2				Year 3			
1	2	3	4	1	2	3	4	1	2	3	4
ITP Assessment				ITP Assessment				ITP Assessment			

Holistic Planning

Holistic Planning Process

- **Current State**
  - ITP20, ITP10, and ITPNT studies performed separately on different cycles.
  - ITP20 is an economic study performed in the first half of the 3 year planning cycle (No NTCs)
    - Higher level public policy and reliability considerations
  - ITP10 is an economic study performed in the second half of the 3 year planning cycle (NTCs)
    - Detailed public policy and reliability analysis
  - ITPNT is a reliability study performed each year of the 3 year planning cycle (NTCs)
    - Detailed reliability analysis
  - GI and TSS performed on separate cycles and leverage ITPNT models (NTCs)
  - TPL compliance studies performed on separate cycles with different non ITP Models (No NTCs)

Holistic Planning Process

- **TPITF Issues with Parallel Planning Processes**
  - Chronic operational issues not addressed in the long-term planning process
  - Project evaluation and selection does not consider all factors necessary for comprehensive engineering economic analysis.
  - Planning process has no regional funding mechanism for projects necessary to mitigate higher depth contingency planning required for NERC compliance
  - Planning processes are disconnected and do not inform one another

Holistic Planning Process

- **Desired State**
  - Reliability and Compliance Assessments
    - Reliability needs produced from base reliability and CBA reliability models; model set
      - Base model reliability needs based on a block dispatch
      - CBA reliability needs based on a market dispatch
    - Compliance needs produced from the TPL base reliability and short circuit models
      - NTCs for TPL-001-4 contingencies that do not allow for non-consequential load loss or interruption of firm transmission service (P0-P3)
      - Mitigations, at a minimum, developed for TPL-001-4 contingencies that do allow for non-consequential load loss or interruption of firm transmission service (P4-P7)
  - Public Policy Assessments
    - Public policy needs considered to be any system deficiency that prohibits attaining renewable energy mandates or goals in the economic model runs for each Future in Years 2, 5, and 10

Holistic Planning Process

- **Desired State**
  - Economic Assessments
    - Economic needs determined based on congestion in the SPP region
    - Economic needs represent most congested flowgates in each Futures
  - Generation Interconnection Assessments
    - No change in needs determination from current process

Holistic Planning Process

- **Desired State**
  - Transmission Service Request Assessments
    - TSS needs produced from the base reliability models
    - TSS needs will represent transmission system overloads caused or impacted by the requested transfer(s).
    - NITS requests modeled as generation to load transfers in addition to generation to generation transfers. PTP requests modeled as generation to generation transfers
  - Seams Coordination
    - Each of the process changes envisioned should be further evaluated for opportunities to align or leverage similar activities occurring in interregional processes

Holistic Planning Process

- **Desired State**
  - Operational Assessments
    - *Chronic* operational issues with a significant financial or reliability impact identified in the operation of the integrated marketplace
      - Develop criteria around *chronic* operational issues
    - Operations identifies economic and reliability operational needs
    - ITP portfolio tested as solutions to operational needs using operational models
    - For needs not mitigated by the proposed portfolio,
      - Develop candidate projects to address the needs
      - Candidate projects presented to the TWG, ESWG, and ORWG
      - Endorsed projects submitted to MOPC/BOD for approval following approval of the ITP project portfolio

Holistic Planning Process

- **Desired State**
  - Solution Development
    - A single Detailed Project Proposal (DPP) window
      - Compliance needs, such as TPL-001-4 P4-P7 events, GI, and TSS needs addressed outside of the DPP window
    - Staff will evaluate DPPs and Staff solutions to develop the most cost-effective solutions to all needs
    - Short-term: needs identified in the early portion of the 10-year planning horizon evaluated to determine the anticipated changes in system conditions or topology mitigating the need in the long-term
      - System changes that mitigate needs in the long-term will be documented
      - Short-term need evaluated with the use of short-term mitigations or least-cost solutions until the need is permanently displaced with the longer-term solution

Holistic Planning Process

- **Desired State**
  - Solution Development cont.
    - Long-term: needs identified in the latter portion of the 10-year planning horizon addressed with the use of cost-effective long-term transmission solutions
      - Solutions evaluated in the 10-year regional planning process will also be evaluated as possible candidate solutions to needs identified in the GI and TSS evaluation

Accountability

Staff/Stakeholder Accountability

- **Current State**
  - Stakeholders responsible for:
    - Scope of the studies and guidance for study methodologies
    - Provide required data necessary reviews
  - Staff responsible for:
    - Facilitation of the Stakeholder process
    - Implementation of the study scope
    - Develop project schedules identifying timelines and assigned responsibilities of Staff/Stakeholders
  - Data exchange/review deadlines often breached leading to inefficient and costly project schedule mitigation actions
    - Project schedule mitigations may reduce time for Staff to perform study work and reduce Stakeholder review time
    - Threatens Stakeholder satisfaction and the overall quality of the study

Staff/Stakeholder Accountability

- **Desired State**
  - Stakeholders/Staff implement an *accountability assurance program*
    - Mechanisms designed to promote timely data exchanges, reviews, and approvals within the transmission planning process
    - Program will identify all entities responsible for providing data to the process and include actions that will be taken in the absence of timely data exchanges, reviews, and approvals
    - Program will describe options available to entities that would like to submit study data after the data exchange deadlines or request changes to data after the data review deadlines
  - Staff develop a *project schedule* along with study scope
    - Identify timing, duration, and responsible parties for all data exchanges, data reviews, and approvals
    - Coordinate with Stakeholders for schedule development and finalize within one month of completion of study scope and assumptions document

Staff/Stakeholder Accountability

- **Desired State cont.**
  - *Project Schedule*....
    - Single point of contact to support the modeling process
    - Proxy data for Stakeholder supplied data in the event the data is not supplied by the data exchange deadline
    - MOPC report card listing any deadlines breached by Stakeholders or Staff
    - Any entity that does not meet prescribed data exchange, review, or approval deadlines and wants to add or change data used in the study may make a request for a waiver of the deadline to the MOPC
      - Staff will provide the MOPC with the project schedule impacts, schedule mitigation plans, and an estimate of any costs associated with accommodating the waiver to support the MOPC decision making process
      - Upon approval of the waiver and associated schedule mitigations and costs, Staff will incorporate the Stakeholder data into the planning process
      - In the event the waiver is not approved, Staff will make no changes to the study process and will continue moving forward with the current study schedule

Implementation

Final set of recommendations to the MOPC, SPC, and SPP BOD in July 2016 for approval.

- Forward recommendations to the appropriate Stakeholder groups for process development and implementation
- TPITF will work with impacted Stakeholder groups to develop timelines for the development, review, and implementation of the changes to the planning process
  - Implementation plan outlining deliverables and timelines required to meet the start date of the new ITP planning process
- TPITF will work with Staff and Stakeholders to determine potential resource and other budgetary impacts of the recommended process improvements
- Workshops will be held to inform and educate Stakeholders on the proposed improvements prior to July 2016 MOPC

Recommendations Summary

Annual Planning Cycle

- The TPITF recommends the reduction of the three-year Integrated Transmission Plan assessment cycle to an annual planning cycle that will produce a 10-year transmission expansion plan each year.

Standardized ITP Study Scope

- The TPITF recommends standardizing ITP study scope items and the development of a streamlined assumptions document.

Common Planning Model

- The TPITF recommends the development of a single, base reliability powerflow model that will be used for all SPP planning processes including Transmission Service and Generation Interconnection as well as the TPL Steady State assessment.

Holistic Planning Process

- The TPITF recommends combining the ITPNT, ITP10, and the TPL Steady State and Short Circuit assessments into a single, 10-year ITP study that will produce an integrated transmission expansion plan addressing reliability, economic, policy, and compliance needs in Years 2, 5, and 10.

SPP Staff/Stakeholder Accountability

- The TPITF recommends development of an accountability assurance program that consists of mechanisms designed to promote timely data exchanges, reviews, and approvals within the transmission planning process.

Transition and Implementation

- The TPITF recommends a transition to the new 2019 ITP planning process starting in September 2017 with the ITP model builds and scope development leading to the initial ITP planning assessment that will be completed in July of 2019.

TRANSMISSION PLANNING IMPROVEMENT TASK FORCE (TPITF)

SPP Planning Process Improvement Recommendations

Published on April 5, 2016

Revision History

Revision Date	Author	Change Description	Comments
4/5/2016	TPITF	Initial Draft	

Contents

Transmission Planning Improvement Task Force (TPITF) Recommendations Whitepaper

Purpose

Since the adoption of the Integrated Transmission Planning process, there has been an improvement in the planning of needed transmission. The ITP process has helped to determine the transmission needs for the SPP region and facilitated investment in over $5.5 Billion of cost effective transmission. SPP has now completed two cycles of the ITP and is now in the midst of the 2017 ITP10. The experience of stakeholders and the SPP has shed light on the strengths of the ITP process as well as potential improvements that could be made.

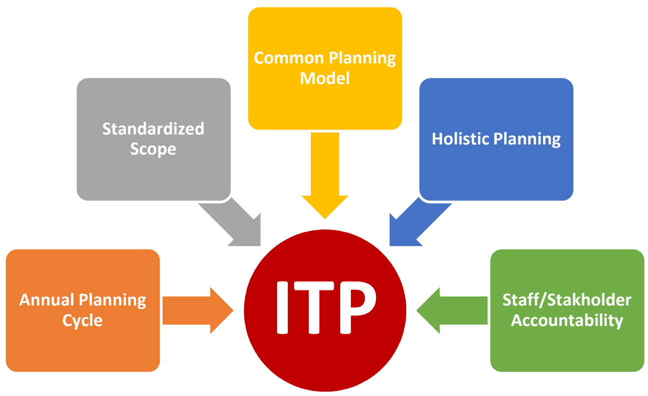
The Transmission Planning Improvement Task Force (TPITF) was assembled by the SPP Strategic Planning Committee (SPC) and the Market and Operations Policy Committee (MOPC) and given the responsibility for developing recommendations that will improve the regional planning processes. The objective was to make the SPP transmission planning process more responsive to the effects of the continued growth of SPP's transmission system, changes in the SPP markets, as well as the challenges and opportunities presented by changing federal and state energy and environmental regulations, and NERC compliance requirements. The TPITF recommendations are intended to represent a consolidated, coordinated approach in planning, managing, and maintaining the SPP transmission system, and improve the existing processes, with a particular emphasis on any progress that may be made to increase the availability of transmission service to SPP's customers without unduly compromising system reliability. The recommendations in this report are intended to enable the cost-effective use of capital-intensive generating resources for the benefit of all end-use customers in the SPP footprint and to further develop and enhance policies, tools, and practices to optimize the use of the transmission system. The TPITF was tasked with reviewing, evaluating, and proposing recommendations on the following:

1. The methodologies and modeling practices used in the Generator Interconnection Studies; Aggregate Transmission Service Studies; Integrated Transmission Planning (Near Term, 10, and 20), SPP TPL Compliance Assessments and the MDWG model development process to ensure effectiveness, consistency, and to determine if any gaps exist between the various processes. Where appropriate, the TPITF will collaborate with the SPP committees and working groups involved in the development and approval process for SPP planning.
2. Utilization of data, including data collected by operations that will benchmark, to the best ability, the real-time and planning horizon assessments to ensure consistency in the planning process.
3. The appropriateness of the planning cycle and assessments, including but not limited to, the effectiveness of using production cost modeling in more assessments; development, use, and weighting of futures, scenarios and sensitivities; the metrics used to evaluate proposed projects, in particular those that evaluate the impact on rate payers, and planning the transmission system beyond the traditional planning criteria of first contingency ("N-1") in accordance with the approved NERC Standard TPL-001-4[1].

[1] A copy of NERC Standard TPL-001-4 can be found at the following location: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-001-4&title=Transmission System Planning Performance Requirements&jurisdiction=United States

The TPITF has developed a set of five recommendations to accomplish this scope of work that will be discussed in detail throughout this whitepaper. These five recommendations are as follows.

1. Replace the current ITP schedules with an annual planning cycle
2. Create a standardized scope
3. Establish a common planning model for use across the various SPP planning process
4. Utilize a holistic approach to planning
5. Create a Staff/Stakeholder accountability program



Annual ITP Planning Cycle

Purpose

The current ITP planning cycle consists of the ITPNT, ITP10, and ITP20 assessments performed over the course of three years. The TPITF sees value in performing a single ITP planning study that incorporates near- and long-term views with the study producing a planning report and transmission project recommendations on an annual basis. The efficiencies gained through the combination of the ITPNT and ITP10 assessment processes and the increased frequency of the completion of a forward-looking, annual planning study will help address members' requests for additional synergy and flexibility within SPP's planning process.

Current State

Planning Cycle

Section III of Attachment O of SPP's Open Access Transmission Tariff (Tariff) describes the Integrated Transmission Planning (ITP) process as "...an iterative three-year process that includes the 20-Year, 10-Year, and Near Term Assessment." The 20-Year (ITP20) and 10-Year Assessments (ITP10) are each performed once every three years as part of the three-year planning cycle with the ITP20 generally performed in the first half of each planning cycle. The Near Term Assessment (ITPNT) is performed on an annual basis to maintain system reliability in the short-term. In aggregate, these assessments evaluate the cost-effectiveness of proposed solutions needed in Years 2, 5, 10, and 20 over a 40-year horizon. The cycle is shown below and iterated every three years.

<table>
<tr><th colspan="2">Year 1</th><th colspan="2">Year 2</th><th colspan="2">Year 3</th></tr>
<tr><td colspan="2">ITPNT</td><td colspan="2">ITPNT</td><td colspan="2">ITPNT</td></tr>
<tr><td colspan="3">ITP20</td><td colspan="3">ITP10</td></tr>
</table>

The ITP20 is performed in the first half of the 3-year planning cycle to guide the development of plans for the ITP10 and ITPNT assessments. The ITP20 is primarily a strategic economic study designed to identify a transmission expansion portfolio containing Extra High Voltage (EHV) projects that would provide the flexibility to address reliability needs, support policy initiatives, and enable economic opportunities in the SPP transmission system under a wide range of future system scenarios within the studied 20-year horizon. The ITP20 portfolio is not likely to result in the issuance of Notifications to Construct (NTCs) for specific projects, but rather is a longer-term strategic vision expected to better inform planning decisions in the 5-10 year horizon including the "right-sizing" of projects in support of potential system needs observed in the 20-year horizon.

The ITP10 is performed in the second half of the 3-year planning cycle. The ITP10 is intended to study in further detail a subset of future scenarios studied in the ITP20. The ITP10 is designed to develop a transmission expansion portfolio containing primarily 100 kV and above projects needed to address reliability needs, support policy initiatives, and enable economic opportunities in the SPP transmission system within the studied 10-year horizon. This portfolio of projects is likely to be recommended for NTCs.

The ITPNT is performed annually over the 3-year planning cycle. Unlike the ITP20 and ITP10, the ITPNT does not assess economic or public policy needs, but instead focuses exclusively on the reliability needs of the system associated with forecasted load growth and maintenance of long-term firm transmission service within the studied 5-year horizon.

TPITF Issues Related to Current Planning Cycle

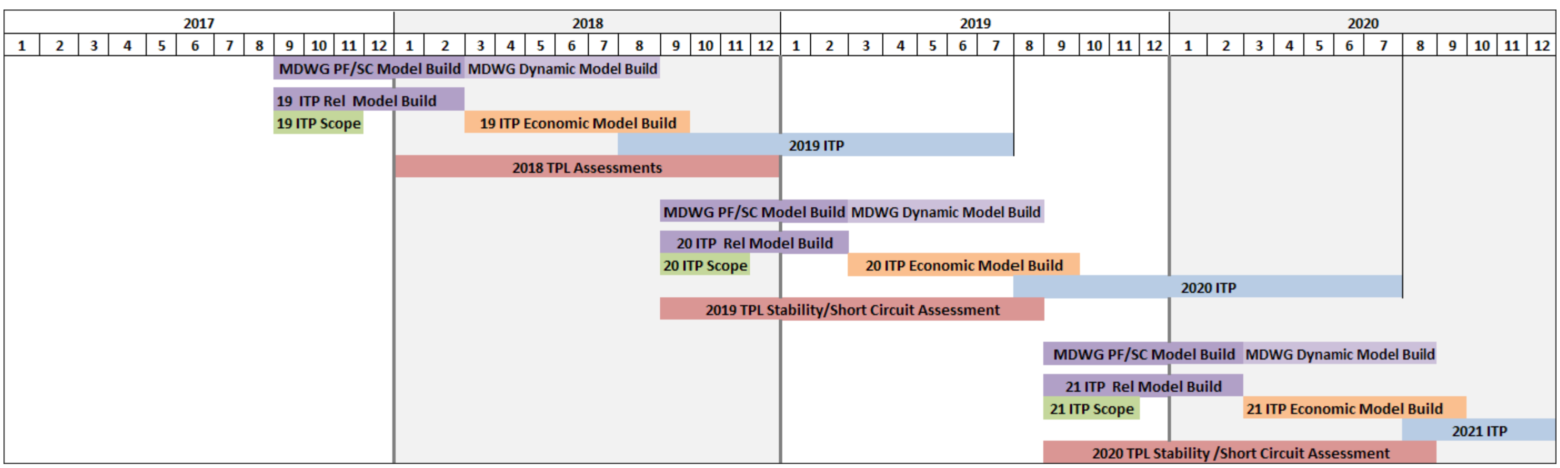
The TPITF identified a number of issues related to the current planning cycle that inhibit the flexibility, quality, and timeliness of the SPP planning process. While the complete issues list can be found in Appendix C, issues related to the planning study cycle are summarized as follows:

- The 3-year planning cycle is too long and is inflexible in addressing system needs.
- The frequency of the 10-year planning assessment (once every 3 years) is inadequate.
- The ITP20 is performed too frequently based on practical value compared with the time and cost to perform the assessment.
- Performing the planning assessments separately reduces the opportunities for synergy in addressing the reliability, public policy, compliance, and economic needs of the SPP system with NTCs.

Desired State

Proposed Planning Cycle

The TPITF proposes an ITP assessment process that produces an annual report and transmission expansion plan. The proposed planning cycle, as illustrated below, will consist of scope development and reliability and economic model builds prior to the planning assessment. Planning models for succeeding studies will be built concurrently with the in-process study to allow the annual performance of the 10-year assessment. The cycle will iterate in this fashion producing an annual report in perpetuity. Further details can be found in the Transition and Implementation section.



The annual assessment cycle addresses Stakeholder concerns that the current planning process takes too long by reducing the planning cycle from 36 months to 12. This is achieved primarily by three changes to the existing process. First, the TPITF proposes removing the ITP20 from the standard ITP planning cycle. While the TPITF recognizes the ITP20 provides significant strategic value, the deliverable of the study is informational and may not need to be refreshed with triennial frequency. Due to the intense resource usage and the desire to reduce the duration of the planning cycle, but yet maintain the value of the ITP20, the TPITF recommends removing the ITP20 from the planning cycle and performing it separately no less than once every five years unless directed by the SPP Board. Performance of the ITP20 more or less frequently would require specific direction from the Strategic Planning Committee (SPC) and approval by the SPP BOD. Second, the remaining 18-month cycle will become an annual 10-year assessment that combines the ITPNT, ITP10, TPL-001-4 Short Circuit and portions of the TPL-001-4

Steady State assessments into one assessment, which is discussed in further detail in the Holistic Planning Process section. This change is intended to increase synergy by performing the planning assessments in unison. Third, the planning cycles will overlap by 12 months producing three 10-year assessments over a three year period as opposed to just one 10-year assessment in that same timeframe with the current ITP process. This approach addresses the goal of increasing the frequency of the 10-year assessments for reliability, public policy, and economic needs.

Standardized ITP Assessment Scope

Purpose

A large concern for SPP Staff and TPITF members is the amount of SPP Stakeholder and Staff time spent during each study process reviewing and approving scope items that tend to remain the same from study to study. The TPITF recommends the review and standardization of study scope items that remain relatively unchanged throughout each study iteration. This standardization will provide specific details around each scope item and eliminate the need for repetitive reviews and approvals. Stakeholders will retain the ability to modify standardized scope items by using the SPP Revision Request process as discussed in more detail below.

An additional benefit of standardization will be an increase in the consistency of how the studies are performed year over year which will help facilitate more detailed project analysis.

Current State

Integrated Transmission Planning Manual[2]

The Integrated Transmission Planning Manual (ITP Manual) is a comprehensive document describing the model building and assessment processes of the ITPNT, ITP20, and ITP10 studies. It also includes language describing futures development, the Order 1000 process, and the deliverables for each of the assessments. While the ITP Manual goes to great length to describe the numerous aspects of the assessments, it is written in a fashion that leaves several scope items open for a range of interpretation. This results in the need for working group review and approval with each ITP cycle. As a result, specific detail is drafted in study scopes that are then circulated through the corresponding working groups, including MOPC, for approval.

Study Scope Development and Approval

The scope development processes between the ITPNT and ITP10 are similar in the way the scope documents are created but differ in how they are approved. For both processes, the scope documents are developed during the initial planning phases of the studies. These documents are developed by SPP Staff and reviewed and approved by the appropriate working groups before moving on to MOPC and the SPP BOD for final approvals. Where the processes differ is in the level of detail incorporated for each scope item. The scope for the ITPNT is constructed to include the final process details for each item so that the final approval of the scope solidifies the scope for the remainder of the study. The ITP10's approach differs in that the scope is constructed at a high-level with specific criteria surrounding each scope item formulated during the study process at a time before the corresponding actions occur. While a high-level scope is approved on the front-end of the ITP10 study process, specifics are not always reviewed and approved until after the study process has commenced and those scope-specific processes are ready to commence.

TPITF Issues Related to Study Scopes

The TPITF identified a number of issues related to study scopes that inhibit the flexibility, quality, and timeliness of the SPP planning process. While the complete issues list can be found in Appendix C, issues related to the planning study cycle are summarized as follows:

---

[2] Integrated Transmission Planning Manual can be found at the following location: http://www.spp.org/documents/28615/2015_itp_manual_append_1.pdf

- There is inconsistency from study to study in how some scope items are implemented. The scope can change mid-process due to a change in the expectations of members or conflicting expectations among members. This can cause difficulty with building consensus toward the approval of resultant transmission plans.
- Scope review and approval by working groups can take a long time and cause delays in the process. Scope approval, including individual scope items, can take several working group meetings before approval is granted creating a bottleneck in the study schedule.
- The lack of standardization in the study scope makes it difficult to estimate the amount of SPP and member resources needed to complete the study.

Desired State

Standardized Scope

The review and approval of methodologies and criteria that guide study processes will be included in the ITP Manual as standard study scope items. These are processes that will remain the same under typical/normal circumstances from study to study. Outside of minor modifications, these items will not require the same level of scrutiny and vetting other scope items like the definition of study futures may require. Standardizing these planning principles will simplify the scope development process, eliminate the need to review and approve these items annually, and help to provide the consistency members seek for the planning studies.

Assumptions Document

An assumptions document will be developed to fully outline and describe those study scope items that will require Stakeholder review and approval with each new study. These items will be approved by the appropriate working groups during the scope development phase of the planning cycle.

Scope items such as the definitions of futures or scenarios and sensitives may change with each study iteration in order to provide the appropriate context under which to assess the future performance of the existing transmission system and any needed improvements. For the 2017 ITP10 Assessment, the futures were modified to reflect the EPA's Clean Power Plan. Maintaining the ability to change these assumptions from study to study will provide the flexibility needed for the long-term transmission planning process.

The TWG and ESWG will review and approve the scope items that will be standardized and the scope items that will be a part of the assumptions document and update the ITP Manual accordingly. The TPITF recommends moving the revised ITP Manual under the SPP Planning Protocols.

Revision Request (RR) Process for Scope Changes

Modifications to the standardized scope document will be submitted through the SPP Revision Request (RR) process to govern how the submitted changes will be received, reviewed, and approved. The RR process is a key component of SPP's Stakeholder processes and allows Stakeholder input into decision making. It will place guidelines around the approval and implementation of study scope changes. The requests will be made via SPP's Request Management System (RMS) which will allow for the tracking and reporting of scope revision submissions.

This process will give Stakeholders the ability to submit scope revisions for review by other Stakeholders without interrupting the study process which will decrease the mid-process disruptions that have been experienced in past studies. Approved revisions will be incorporated into the scope of the subsequent study.

The TPITF believes the leveraging of the RR process will appropriately address member concerns while reducing the considerable amount of time it has taken in past studies to finalize the study scope due to numerous revisions submitted by Stakeholders.

The TPITF envisions the use of the RR process to address improvements to the foundational scope items standardized within the ITP Manual. The TPITF recognizes the importance of Stakeholder input into the scope development process; however, it is the Task Force's desire to see that substantive changes receive proper Stakeholder vetting and approval before implementation.

Standardized scope items will retain flexibility by granting the appropriate working group the ability to provide guidance on items as prescribed by the ITP Manual. An example of this flexibility may be with the standardizing of the scope item Fuel Prices. Standardized language may include the mechanism for setting fuel prices. Per the scope, the selected index would always be used for pricing information, however, the actual price of natural gas may change year-over-year. As the natural gas fuel prices change, the recommended prices would become a part of the assumptions while the standardized scope item would remain unchanged. If a Stakeholder recommends the use of another source for pricing information, that recommendation would be submitted through the RR process for proper Stakeholder vetting and approval.

Common Planning Model

Purpose

The SPP Modeling department in conjunction with the Model Development Working Group (MDWG) is responsible for developing the SPP Steady-State, Short Circuit, and Dynamics models. These model sets serve as the basis for further refinement into the base models for ITP and TPL Steady State assessments. The Economic Planning department is responsible for constructing the Economic model that is used during performance of the ITP10 study. The TPITF Scope document lists as one of its three objectives the "Utilization of data, including data collected by operations that will benchmark, to the best ability, the real-time and planning horizon assessments to ensure consistency in the planning process." To meet the goal of consistency in the planning process, the TPITF recommends the building of a common base reliability model that will be used for all SPP planning processes including Transmission Service and Generation Interconnection as well as the ITP. This base reliability model will also serve as the base model for the TPL Steady State assessment. The TPITF also recommends the TWG select the TPL sensitivity case from the CBA Reliability model set.

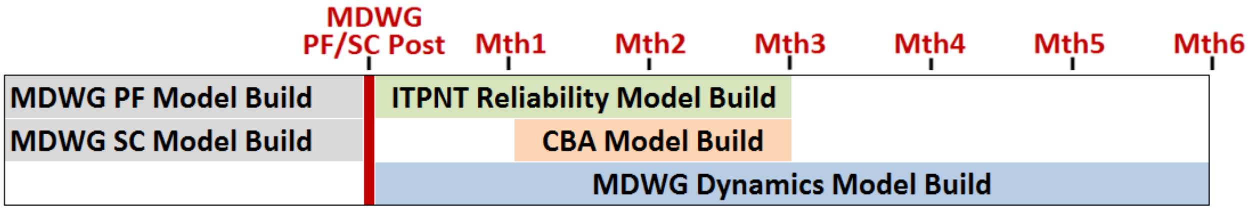
Current State

The set of models currently used in the SPP planning processes are listed below. The ITPNT Reliability and the TPL Steady State models use the MDWG Powerflow model as their base model.

Description[3]	Year 1	Year 2	Year 5	Year 10	Total
ITPNT Reliability	----	Scenario 0: ITPNT SP & WP Scenario 5: ITPNT SP & WP CBA: ITPNT SP & WP	Scenario 0: ITPNT SP & WP Scenario 5: ITPNT SP & WP CBA: ITPNT SP & WP Scenario 0, 5, & CBA (off-peak): ITPNT L	----	15
ITP10 Economic	----	----	Futures (1/2/3): 8760 hrs	Futures (1/2/3): 8760 hrs	6
ITP10 Reliability	----	----	DC/AC Future (1/2/3): S & L	DC/AC Future (1/2/3): S & L	12
TPL - Steady State Assessment	R2.1.1 Y-1 Peak: MDWG S (base) & ITPNT SP5 (sensitivity) R2.1.2 Y-1 Off-Peak: MDWG L (base) & ITPNT L5 (sensitivity)	----	R2.1.1 Y-5 Peak: MDWG (base) & ITPNT SP5 (sensitivity)	R2.2.1 Y-10 Peak: MDWG S (base)	4
TPL - Series Short Circuit	S Max Fault				1

[3] Cases are defined as: SP (summer peak), WP (winter peak), L (light load), and S (summer)

The current model build schedule can be summarized as shown below.



MDWG Models

The final MDWG Powerflow and Short Circuit models are typically scheduled to post simultaneously. This posting is usually scheduled for the 1st quarter of each new calendar year in the February timeframe.

Work on the MDWG Dynamics model is performed prior to the posting of the MDWG Powerflow model. The effort consists of building the DYRE files, incorporating topology updates submitted by members, and mitigating errors found in the model. Following the posting of the MDWG Powerflow model, the Dynamics model build continues, lasting approximately six months in duration.

ITP Models

The ITPNT Reliability models are built using the same database (MOD) as the MDWG Powerflow models. As with the Dynamics model build, work on the ITPNT Reliability model is performed prior to the posting of the final MDWG Powerflow models. This consists of modeling topology updates to reflect only existing and approved facilities, transactions, and updates to generation dispatch. Following the posting of the MDWG Powerflow models, the ITPNT Reliability model build will continue for approximately three months in duration.

The CBA Reliability model uses the initial pass of the ITPNT Scenario 0 Reliability model as its topology base. ITP10 economic data is utilized to provide seasonal generation economics, wind profiles, and hydro profiles. Each pass of the CBA Reliability model is dispatched based on a security constrained economic dispatch (SCED) and provided for member review.

The ITP10 models are based on the 10-year ITPNT Scenario 0, summer peak model. It incorporates the Scenario's topology for base load and generation. This topology is the base of the PROMOD economic model. The next steps in the economic model build process are the load and generation reviews where members can confirm or adjust their load, add economic data to the existing generation, and confirm or adjust the resource name plate values used to create the 10-year ITPNT model. In order to meet the renewable capacity and/or energy requirements, SPP Staff will evaluate if all the requirements are met and if they are not met, add additional renewable resources to the model. It is also necessary to meet the required capacity margin for each zone. To achieve that, it is necessary to develop a resource plan where conventional and renewable prototypes are considered to determine needed and more economically viable additions. Resources added to the economic model are then sited throughout the SPP system. The last step in the model build process is to perform a constraint assessment to verify how the models behave when the system is constrained and to identify any new flowgates that should be monitored. The number of models is dependent on the amount of Futures included in the ITP10 study scope. Members are responsible for the review and approval the model sets, and provide vital feedback during each of the model build steps mentioned above.

TPITF Issues Related to Current Modeling practices

The TPITF identified a number of issues related to the planning models and their corresponding builds that inhibit the efficiency, consistency, and accuracy of the currently constructed model sets. While the complete issues list can be found in Appendix C, issues related to the models are summarized as follows:

- Models are not constructed in a consistent manner across the planning processes. Models are fundamentally different between the processes.
- Separate model builds for the different planning processes place additional burdens on members to submit and review data several times throughout the year.
- The models are not indicative of what is happening in real-time under the new Integrated Marketplace. Market and Operations feedback should be reflected in the model development process.

Desired State

The table below lists the proposed model sets for the TPITF recommended ITP planning cycle. These models differ significantly from the planning model sets currently built and are described in further detail below. The base reliability model listed and described below will become the base model for all of SPP's planning processes including Transmission Service, Generation Interconnection, and the TPL Steady State compliance study. This will address concerns Stakeholders have expressed over model consistency between the planning processes.

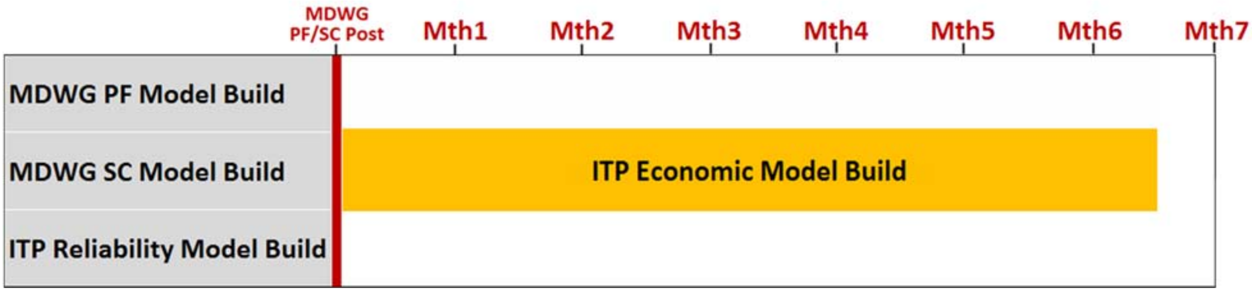
Description	Year 2	Year 5	Year 10	Total
Reliability: CBA (TPL Sensitivity Case)	One Future Coincident Peak [4]On/Off-Peak (2)	Up to Three Futures Coincident Peak On/Off-Peak (6)	Up to Three Futures Coincident Peak On/Off-Peak (6)	14
Reliability: Base Scenario TPL: Powerflow	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	9
Economic	One Future Coincident Peak 8760 (1)	Up to Three Futures Coincident Peak 8760 (3)	Up to Three Futures Coincident Peak 8760 (3)	7

The proposed model build schedule is listed below. In order to meet the model build timeline necessary to facilitate the 12-month ITP assessment window, the ITP Reliability model will be built in parallel with the MDWG Powerflow and Short Circuit models. With this change, the TPITF recognizes the need to collect the data required to build the ITP Reliability model earlier in the process than it is requested today. The current MDWG model build schedule will be leveraged to govern the collection of required data. Leveraging the MDWG model build schedule will address member concerns with multiple data review and submittal windows found across the separate model builds in the planning processes.

[4] NERC defines On-Peak as "...periods of higher electrical demand." and Off-Peak as "...periods of lower electrical demand."

Required data will be requested, submitted, and reviewed on the front-end of the model build process, thereby eliminating the multi-process burdens currently experienced by members.

Efficiencies implemented in the Economic model build process will also help facilitate the 12-month ITP assessment window by reducing the build time to a little over six months.



The TPITF recommends the structure of the ITP model sets to consist of the following:

- Base Reliability Model
- Economic Model
- CBA Reliability Model

Base Reliability Model

At least one scenario powerflow model will be required in order to meet the reliability planning requirements for the SPP region. This base reliability model will be developed as an indicative representation of how entities within SPP responsible for serving network load would serve network load utilizing network resources only. This model would consist of non-coincident peak load forecasts, assumed long-term firm transmission service usage levels, and expected conventional and renewable resource output levels. The TPITF recommends the modeling of renewable facilities' output at each facility's highest summer on-peak hour, hours 15:00-19:00, within the last three years per facility and off-peak and light load at 100% of firm service. For new renewable resources, the average of facility peaks within the new resources' areas will be used to model the resources' outputs.

The Year 2, 5, and 10 base reliability model set utilized for regional and sub-regional reliability planning will also be utilized as the base model(s) for long-term firm transmission service request studies. However, these base model(s) will be adjusted as necessary to appropriately analyze and integrate transmission service requests consistent with the SPP Tariff provisions and business practices that govern the process.

The base model set will not include the CBA model, but instead only the base scenario in which each entity's firm resources and transactions are dispatched to serve each entity's network load. As a result, upgrades resulting from the transmission service process should represent those necessary to support the firm transmission service requests that were added to the base model for study, also ensuring transmission facilities are not approved to support non-firm market transactions. This should also maintain consistency between the firm system capacity utilized to honor the transmission service and the firm system capacity that may be utilized as Auction Revenue Rights (ARRs) and ultimately Transmission Congestion Rights (TCRs) in the TCR market.

The Year 2, 5, and 10 base reliability model sets utilized for regional and sub-regional reliability planning will also be utilized as the base model sets for generator interconnection request studies. However, the base model set will be adjusted as necessary to execute the study of generator interconnection service requests consistent with the tariff provisions and business practices that govern the process.

Economic Model

Economic models will be developed to identify and assess solutions to the public policy and economic needs of the SPP system. Economic models will be developed for three study years (Years 2, 5, and 10). A single economic model will be developed for the one future in Year 2. It is assumed that multiple future cases are not necessary for Year 2 due to the limited uncertainty in policy or other factors impacting the system that could be implemented in such a short time frame. Up to three economic models will be developed for the reference case future in Years 5 and 10. As a result, up to seven total economic models may be developed to support economic assessments.

The current economic and policy study processes for the ITP10 call for needs assessments for Year 10 only. The proposal above will add additional economic and policy needs assessments for Years 2 and 5.

CBA Reliability Model

The CBA powerflow models will be developed as an indicative representation of how load would be served in the SPP Integrated Marketplace. This CBA model will be built from PROMOD output and will consist of coincident peak load forecasts for the SPP region and the security constrained commitment and dispatch of both firm and non-firm generating resources derived from economic planning models. Interchange between SPP and Tier 1 will be determined based on price differentials that may include hurdle rates as developed with the existing economic process. The TPITF recommends the TWG select the TPL sensitivity case from the CBA Reliability model set.

TPL Assessment Models

The Year 2, 5, and 10 base reliability model sets utilized for regional and sub-regional reliability planning will be utilized as the base model sets for the TPL Steady State assessment. As noted above, the CBA powerflow model set will be used for the selection of the sensitivity case required in addition to the base case model for TPL compliance. Not all of the reliability or CBA models will be used, only the models necessary to meet compliance with TPL-001-4.

The MDWG short circuit model with all planned generation and transmission facilities in service is represented with the following additional requirements:

- Place all available facilities in-service:
    - Generation
    - Transmission lines (Out for maintenance)
    - Transformers
    - Buses
- Flat – classical fault analysis conditions

This model set establishes category P0 as the normal System condition and defines the models that will be used for the short circuit analyses to comply with requirement TPL-001-4 R2.3 as the Maximum Fault Year 2 Summer.

Holistic Planning Process

Purpose

The TPITF envisions an efficient and effective planning process in which all SPP regional Planning assessments are coordinated to produce transmission expansion plans that will optimize the use of the SPP transmission system while maintaining reliability.

Creating efficiencies in the planning process by synchronizing processes and coordinating study findings will be the building blocks by which a planning process will be constructed that will address reliability, economics, public policy, and regulatory compliance needs over the 10-year planning cycle.

Aligning planning processes along with SPP Operations will facilitate the sharing of the most accurate information and data between studies and will allow the ITP process the opportunity to address issues that may have not been identified in the Generation Interconnection and Transmission Service Study processes but that are observed within the real-time environment.

Current State

TPITF Issues with parallel planning processes

The TPITF identified a number of issues related to the various aspects of the planning process. While the complete issues list can be found in Appendix C, issues related to the planning process are summarized as follows

- Chronic operational issues not being addressed in the long-term planning process.
- Project evaluation and selection does not consider all factors necessary for comprehensive engineering economic analysis. Planning horizon assessments do not appropriately account for the impacts of real-time markets.
- Planning process has no regional funding mechanism for projects necessary to mitigate higher depth contingency planning required for NERC compliance.
- Planning processes are disconnected and do not inform one another.

Desired State

The TPITF proposes a regional planning process built to leverage knowledge of the transmission system's reliability, public policy, compliance, and economic needs, as well as generation interconnection and transmission service request impacts in order to develop a more cost-effective transmission portfolio for a 10-year planning horizon. The TPITF believes this will be enabled by utilizing a common set of foundational modeling assumptions as the starting point for all planning studies within the planning cycle as discussed in the Common Planning Model section of this whitepaper. The staging of the model builds for all reliability, public policy, compliance, and economic studies will be determined to produce a single needs assessment for the 10-year planning horizon. System needs resulting from generation interconnection and transmission service requests will be identified within the currently established timelines for those processes. However, the evaluation of transmission service needs and associated projects will be coordinated with those identified in the 10-year horizon regional planning process to facilitate continuity in the overall transmission expansion plan.

Reliability and Compliance Assessments

Reliability and compliance needs will be determined based on NERC Standards, SPP Planning Criteria, and Sub-Regional Planning Criteria of individual SPP members. The reliability needs will be produced from the base reliability and CBA reliability models for Years 2, 5, and 10 as described in further detail in the Common Planning Model section of this whitepaper. The base reliability needs will represent potential criteria violations based on a model set that utilizes only firm resources and firm transactions to serve non-coincident network load on an individual Balancing Authority (BA) by individual BA basis. The CBA reliability needs will represent potential criteria violations based on a model set that utilizes both firm and non-firm resources with a market dispatch to serve SPP coincident network load.

Compliance needs will be produced from the TPL base reliability and Short Circuit models for Years 2, 5, and 10 as described in further detail in the Common Planning Model section. Compliance needs that may be considered for NTCs will represent TPL-001-4 contingencies that do not allow for non-consequential load loss or interruption of firm transmission service (P0-P3). Mitigations, at a minimum, will be developed by SPP Staff or the applicable TP for TPL-001-4 contingencies that do allow for non-consequential load loss or interruption of firm transmission service (P4-P7). Planning Event descriptions are listed in Appendix A.

After reviewing the TPL stability study process, the TPITF chose not to include the study in the ITP planning process. Factors considered were the historical lack of issues identified in the process that would require transmission projects, the use of the proposed ITP models, Order 1000 implications, and the general consensus within the TPITF that inclusion of the assessment does not provide any tangible benefit to the study that would justify the potential resource, cost, and schedule impacts its inclusion would have on the ITP planning process. The remaining TPL Steady State events will be handled along with the stability process outside of the ITP process.

Public Policy Assessments

Public policy needs are considered to be any system deficiency that prohibits attaining renewable energy mandates or goals in the economic model runs for each Future in Years 2, 5, and 10 due to renewable energy curtailments caused by transmission congestion.

Economic Assessments

Economic needs will be determined based on the adverse impact of congestion on the cost of energy production, energy purchases, and sales for the SPP region. Economic needs will be produced from the economic models for Years 2, 5, and 10 described in further detail in the Common Planning Model section. Economic needs will represent a list of the most congested flowgates in the economic model runs for each Future in Years 2, 5, and 10.

Generation Interconnection Request Assessments

Generation interconnection needs will be determined based on NERC Criteria, SPP Planning Criteria, and Sub-Regional Planning Criteria of individual SPP members. The reliability needs will be produced from the models that begin with the base reliability models for Years 2, 5, and 10 as described in further detail in the Common Planning Model section. All generation interconnection requests will be added to the models. The reliability needs identified will represent potential criteria violations due to the interconnection of the generation determined from the powerflow, dynamic stability, and short circuit assessments. For the powerflow assessment, transmission reinforcement is required for violations that meet the generator interconnection criteria for impacts to the constraints for the contingencies specified in the ITP process. For the stability analysis, unstable conditions will be addressed for transmission reinforcement for contingencies specified in the dynamic stability assessment for TPL-001-4 contingencies equivalent to P0, P1, P2.1-2.3, P4, and P5 as identified by SPP and the Transmission Owners. Higher depth contingencies (P6-P7) will be evaluated as necessary for the location of the generation for mitigations. For the short circuit assessment, transmission reinforcement will be required for a scenario with all generation and all transmission elements in service (P0).

Transmission Service Request Assessments

Transmission service needs will be determined based on NERC Criteria and SPP Planning Criteria and will be produced from the base reliability models for Years 2, 5, and 10 described in further detail in the Common Planning Model section. Transmission service needs will represent transmission system overloads caused or impacted by the requested transfer(s).

Network Integration Transmission Service (NITS) requests are modeled as generation to load transfers in addition to generation to generation transfers. This is done because NITS is a request to serve network load with the new designated network resource, and the impacts on the transmission system are determined accordingly. Point-To-Point transmission service requests are modeled as generation to generation transfers. Generation to generation transfers are accomplished by developing a post-transfer case for comparison by dispatching the requested source and redispatching the requested sink.

Operational Assessments

The determination of operational needs will be based on chronic operational issues with a significant financial or reliability impact identified in the operation of the integrated marketplace. SPP Operations observes a more diverse range of system operating scenarios that may not be feasible to effectively simulate in the planning environment. As a result, certain reliability and economic needs that are seen with relative frequency in the real time operations may not be identified in the long term planning process. Further, the long term planning process currently does not have a mechanism to address these issues with NTCs for new projects. The TPITF recommends the following process for incorporating operational issues into the planning process.

SPP Operations Staff will work with the appropriate Stakeholder groups to develop criteria around the definition and designation of chronic operational issues that should be evaluated in the planning process. Once the criteria for identifying operational issues has been established, SPP Operations will provide SPP Planning with a list of economic and reliability operational needs along with the historical context for each issue. For reliability operational needs, historical context may consist of data such as the frequency and duration of occurrences of the reliability events as well as related outage information along with other types of supporting information. For economic operational needs, historical context may consist of data such as congestion or uplifted costs associated with the issue.

Upon establishment of the ITP portfolio of proposed transmission projects, these projects will be tested as solutions to the reliability and economic operational needs using operational models that captured actual occurrences of the needs. These operational models will be approved by the applicable SPP stakeholder working groups to ensure consistency with the criteria established to designate the operational needs as chronic, rather than infrequent system needs. For those operational needs that are not mitigated by the proposed set of projects, SPP Staff will work with the affected incumbent transmission owners to develop candidate projects to address the needs. The candidate projects and associated justification will be presented to the TWG, ESWG, and ORWG for their review and endorsement. The list of endorsed projects will be submitted to MOPC and the SPP BOD for approval at the next meeting of each of the groups following the approval of the ITP project portfolio.

Seams

In order to ensure a robust and effective regional planning process, the evaluation of transmission system reliability, economic, and public policy needs must also account for the opportunity to jointly develop beneficial projects with SPP's neighbors. Interregional planning processes alone may not be sufficient to adequately address these needs along SPP's seams. SPP's regional planning processes should help to facilitate interregional planning where possible. SPP engages in interregional planning activities pursuant to FERC Order 1000 with MISO and the Southeastern Regional Transmission Planning (SERTP) group. Additionally, SPP has Joint Operating Agreements (JOAs) with various other utilities that govern periodic or ad-hoc joint planning processes.

Because many of the same Staff and Stakeholder resources are involved in both SPP regional and interregional planning activities, coordination between the various processes is vital to ensure consistency and efficiency. Each of the process changes envisioned in this recommendations whitepaper should be evaluated for opportunities to align or leverage similar activities occurring in interregional processes. Additional recommendations could also be made for SPP Staff to propose appropriate changes to applicable agreements with neighboring entities.

As described in the Common Planning Model section, SPP's regional model development attempts to model neighboring regions consistent with how those neighboring regions model themselves in their respective regional planning processes. During the construction of each regional planning model, efforts will be made to acquire the necessary modeling information from neighboring entities. This coordination process is best facilitated where SPP and neighboring modeling schedules are closely aligned. Where appropriate, information from recent interregional planning processes will be leveraged.

SPP's regional planning processes should also facilitate the identification and resolution of reliability, economic, and public policy needs along the seams. This consideration of needs along SPP's seams will include coordination with SPP markets and operations to evaluate issues impacting neighboring utilities. The development of a process to consider the impact of Market-to-Market transactions may provide valuable input into the identification of seams issues and potential mitigations

Solution Development

All reliability, compliance, public policy, and economic needs, as described above, that could result in NTCs will be aggregated and posted publicly to initiate a single Detailed Project Proposal (DPP) window. Compliance needs such as TPL-001-4 P4-P7 events as well as generation interconnection and transmission service request needs will be addressed outside of the DPP window in compliance with the timelines specified under the existing processes. SPP Staff will evaluate DPPs as well as Staff solutions to develop the most cost-effective solutions to all reliability, public policy, compliance, and economic needs. This will be accomplished by evaluating the patterns and drivers of system needs over the full 10-year planning horizon. Also, synergies of candidate solutions will be analyzed and leveraged as appropriate. For instance, the viability of deferring or displacing reliability, compliance, or public policy solutions with projects that preserve those attributes but also produce economic benefits will be evaluated for the full 10-year planning horizon.

Transmission system needs that are consistent across the full planning horizon will be addressed with cost-effective long-term solutions. When required, short-term mitigations will be sought, selected, and implemented while maintaining system reliability. Reliability, compliance, public policy, and economic needs that are identified in the early portion of the 10-year planning horizon, but not identified in the later portion will be evaluated in detail to determine the anticipated changes in system conditions or topology that are mitigating the need in the long-term. The system changes that mitigate transmission system needs in the long-term will be documented and the short-term need will be evaluated with the use of short-term mitigations or least-cost solutions until the need is permanently displaced with the longer-term solution. Reliability, compliance, public policy, and economic needs that are identified in the latter portion of the 10-year planning horizon, but are not identified in the early portion will be addressed with the use of cost-effective long-term transmission solutions.

Solutions that are evaluated in the 10-year regional planning process will also be evaluated as possible candidate solutions to needs identified in the generation interconnection and transmission service request evaluation processes. Identical needs occurring during identical time periods that are identified in both the 10-year regional planning process and the applicable service process will be evaluated using the 10-year regional planning process solution(s). Identical needs that occur in an earlier time period in the 10-year regional planning process than in the applicable service process will be evaluated using the 10-year regional planning process solution. Identical needs that occur in the 10-year regional planning process after they occur in the applicable service process will be evaluated using acceleration of the 10-year regional planning process solution, and costs will be allocated consistent with existing cost allocation methodologies under the SPP Tariff. For all other needs that are identified in the generation interconnection and transmission service request processes, the least-cost solution necessary to accommodate the service request will be selected.

Solutions for compliance needs such as TPL-001-4 P4-P7 events will be developed through coordination between SPP Staff and SPP Transmission Owners. These solutions will be considered corrective action plans that may or may not include transmission expansion.

Staff/Stakeholder Accountability

Current State

The ITP process requires a significant amount of collaboration between SPP Staff and SPP Stakeholders in order to produce the required deliverables of the study. SPP Stakeholders are responsible for establishing the scope of the studies and also providing guidance for the methodologies to be used in the studies. Further, SPP Stakeholders are responsible for providing the data necessary to implement the scope and methodologies and to also review study data and results to certify quality.

SPP Staff is responsible for the facilitation of the Stakeholder process and implementation of the study scope. These efforts include notifying SPP Stakeholders of tariff and other governing document requirements to support study scope development, identification and solicitation of data necessary to implement the scope, recommendations for methodologies to efficiently execute the scope, and any other general support necessary to implement the study scope. Staff is also responsible for developing project schedules that determine the time allotted to accomplish each aspect of the study scope and also the responsible party for those aspects of the scope.

The data exchange and data review deadlines in these schedules are often breached in the current ITP process. This has led to project schedule mitigations actions that have proven to be inefficient and costly. These project schedule mitigations may reduce time for Staff to perform study work and also reduce Stakeholder review time and threatens Stakeholder satisfaction and the overall quality of the study.

Desired State

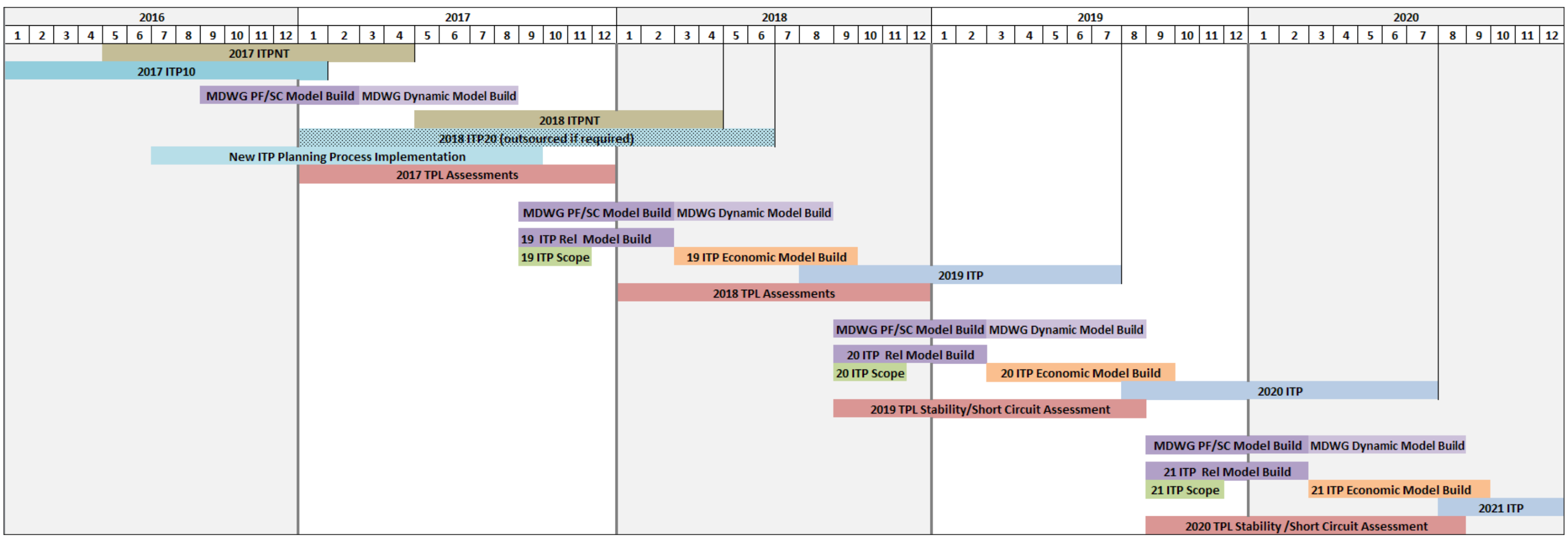
The TPITF recommendations for reforms to the planning process, specifically the inclusion of TPL analysis in the study and the annual planning cycle, will increase the criticality of coordination between SPP Stakeholders and Staff. SPP Stakeholders are responsible for establishing the scope of the studies and also providing guidance for the methodologies to be used in the studies. Further, Stakeholders are responsible for providing the data necessary to implement the scope and methodologies and to also review study data and results to certify quality. SPP Stakeholders and Staff will implement an accountability assurance program that consists of mechanisms designed to promote timely data exchanges, reviews, and approvals within the transmission planning process. The program will identify all entities responsible for providing data to the process and also include the identification of actions that will be taken in the absence of timely data exchanges, reviews, and approvals. The program will also describe options available to any entities that would like to submit study data after the data exchange deadlines or request changes to data after the data review deadlines.

SPP Staff will develop a project schedule in parallel with the development of the scope of each study. This schedule will identify the timing, duration, and responsible parties for all data exchanges, data reviews, and approvals required to complete the ITP study. SPP Staff will coordinate with Stakeholders in the development of this schedule and formally vet the final schedule with Stakeholders within one month of the completion of the study scope and assumptions document. Each member company will identify a single point of contact for their company that will be responsible for addressing all data required to support the modeling process. For each data exchange identified in the study schedule, applicable SPP working groups and Staff will agree upon the data that will be used as a proxy for Stakeholder supplied data to keep the process moving forward in the event the data is not supplied by the data exchange deadline. If data reviews are not conducted by the associated schedule deadlines, the data will be assumed to be appropriate and the study will move forward as scheduled. At the conclusion of each data exchange window, but no less than each quarter, SPP Staff will provide a report card to the MOPC listing any deadlines breached by SPP Stakeholders or Staff.

Any entity that does not meet prescribed data exchange, review, or approval deadlines and wants to add or change data used in the study may make a request for a waiver of the deadline to the MOPC. SPP Staff will provide the MOPC with the project schedule impacts, schedule mitigation plans, and an estimate of any costs associated with accommodating the waiver to support the MOPC decision making process. Upon approval of the waiver and associated schedule mitigations and costs, SPP Staff will incorporate the Stakeholder data into the planning process. In the event the waiver is not approved, SPP Staff will make no changes to the study process and will continue moving forward with the current study schedule.

Transition and Implementation

The TPITF recommends a transition to the new 2019 ITP planning process starting in September 2017 with the ITP model builds and scope development leading to the initial ITP planning assessment that will be completed in July of 2019. The transition to the new planning process will require two preliminary steps. First, the current planning cycle will need to be completed. Second, SPP Stakeholders and Staff will need to implement all changes necessary to allow the new process to move forward. These changes will include, but are not limited to modifications to the SPP tariff and other appropriate governing documents, establishment of the details of the new processes and procedures for the new planning study by the applicable SPP working groups, and the procurement of resources and tools necessary to implement the process. The chart below illustrates the transition activities, projected durations, and the timing of the first two planning processes under the new ITP process and is discussed in further detail below.



Current Planning Cycle Completion

The current ITP planning cycle has two remaining studies, the 2017 ITP10 and the 2017 ITPNT. The 2017 ITP10 is scheduled to be completed in January 2017. The 2017 ITPNT is scheduled to begin in April 2016 and be completed in April 2017. The next ITP planning cycle under the current process would begin with an ITP20 assessment that commences in 2017, as well as the 2018 ITPNT that would begin in April 2017 and end in April of 2018.

While the TPITF believes the 2018 ITPNT assessment is necessary to for continued reliability planning during the transition, the TPITF does not believe an ITP20 study should begin in 2017. Instead, the TPITF believes SPP Stakeholder and Staff resources would be better utilized by focusing their efforts on initiatives necessary to facilitate the successful implementation of the new ITP Planning process. The TPITF recommends the suspension of the ITP20 for 2017. SPP will need to make a FERC filing to accomplish this recommended suspension. If the study is required by the SPP BOD, the TPITF recommends outsourcing the performance of the study to free up the resources necessary for implementation of the new planning process.

There will be three more TPL assessments performed under the current processes, prior to the inclusion of TPL power flow and short circuit assessments into the new ITP planning process. These assessments are the 2016, 2017, and 2018 TPL assessments and will be completed in December 2016, December

2017, and December 2018 respectively. The 2019 TPL stability assessment will commence in the latter half of 2018 rather than January of 2019 to align with the 2019 ITP assessment timeframe. In essence, the TPL assessments will be performed twice in 2018 in order to facilitate alignment with and inclusion in the 2019 ITP assessment and meet annual NERC posting requirements.

Implementation Preparation

The TPITF will provide a final set of recommendations to the MOPC, SPC, and SPP BOD in July 2016 for approval. At that point, it is the Task Force's intent to forward the approved recommendations to the appropriate Stakeholder groups for process development and implementation. During the timeframe between the 2016 April and July MOPC/SPP Board cycle, the TPITF will work with impacted Stakeholder groups to develop timelines for the development, review, and implementation of the changes to the planning process. This information will be used to develop more detailed schedules for the transition to the new process. The TPITF will also work with SPP Staff and Stakeholders to determine potential resource and other budgetary impacts of the recommended process improvements. Workshops will be held to inform and educate Stakeholders on the proposed improvements in order to present a clear and vetted set of final recommendations in July 2016.

The TPITF will also present an implementation plan that will outline the deliverables and timelines required by Stakeholder groups to meet the start date of the new ITP planning process. The plan will also describe the changes to governing documents needed to facilitate the move to a holistic planning process. The TPITF foresees major involvement from SPP Staff, TWG, ESWG, ORWG, RCWG, and RTWG with the coordination of the transition to the new planning process along with the work necessary to update the ITP Manual, SPP Tariff, SPP business practices, and SPP Criteria.

Recommendations

Annual Planning Cycle

The TPITF recommends the reduction of the three-year Integrated Transmission Plan assessment cycle to an annual planning cycle that will produce a 10-year transmission expansion plan each year.

- Remove the ITP20 Assessment from the three-year ITP cycle. Place the performance of the 20-year study under the guidance of the SPC to be performed no less than once every five years unless directed by the SPP Board.
- Combine the Near Term and 10-year Assessments into a single planning study.

Standardized ITP Study Scope

The TPITF recommends standardizing ITP study scope items and the development of a streamlined assumptions document.

- Standardize scope items and incorporate into the ITP Manual.
- Place the ITP Manual under SPP Planning Protocols.
- Assumptions document for approval items. Identify items that will require up-front approval (futures, fuel prices, etc.).
- Utilize SPP's RR process for changes to standard scope items.

Common Planning Model

The TPITF recommends the development of a single, base reliability powerflow model that will be used for all SPP planning processes including Transmission Service and Generation Interconnection as well as the TPL Steady State assessment.

- One base reliability model for all planning processes including TPL Steady State assessment replacing the Scenario 0 and 5 models with an as-expected model.
- Model renewable facilities' output at each facility's highest summer on-peak hour, hours 15:00-19:00, within the last three years per facility and off-peak and light load at 100% of firm service. For new renewable resources, the average of facility peaks within the new resources' areas will be used to model the resources' outputs.

Holistic Planning Process

The TPITF recommends combining the ITPNT, ITP10, and the TPL Steady State and Short Circuit assessments into a single, 10-year ITP study that will produce an integrated transmission expansion plan addressing reliability, economic, policy, and compliance needs in Years 2, 5, and 10.

- Issue NTCs for all needs in Years 2, 5, and 10.
- Develop a process for identifying and incorporating chronic operational issues into the ITP process.

SPP Staff/Stakeholder Accountability

The TPITF recommends development of an accountability assurance program that consists of mechanisms designed to promote timely data exchanges, reviews, and approvals within the transmission planning process.

- Formal MOPC/SPP BOD reporting structure for communicating staff/stakeholder non-compliance with deadlines.

Transition and Implementation

The TPITF recommends a transition to the new 2019 ITP planning process starting in September 2017 with the ITP model builds and scope development leading to the initial ITP planning assessment that will be completed in July of 2019.

- Suspension of the ITP20 for 2017. If the study is required by the SPP BOD, the TPITF recommends outsourcing the performance of the study to free up the resources necessary for implementation.

Appendix A: Planning Events

P0

- N-0, No Contingencies

P1

- N-1, Single Contingency
- Must use footnote 12 to have Non-consequential load loss or curtailment of Firm Transmission service
- Steady State
    - Use auto N-1 to capture all possible combinations
- Stability
    - Use Fast Fault Scan to determine events for study

P2

- N-1, Single Contingency
- Steady State
    - TP submitted 230 kV and above
    - Captured in auto N-1
    - Script written to capture opening line section without fault
- Stability
    - Use Fast Fault Scan to determine events for study
    - TP submitted 230 kV and above

P3

- G-1, N-1, Multiple Contingency
- Must use footnote 12 to have Non-consequential load loss or curtailment of Firm Transmission service
- Steady State
    - First contingent element will be a generator
    - System Adjustments are made
    - Second contingent element will be in same area as first
- Stability
    - Use Fast Fault Scan to determine events for study
    - TP submitted 230 kV and above

P4

- N-k + stuck breaker, Multiple Contingency
- Can use Non-consequential load loss and curtailment of Firm Transmission service for HV (<300kV)
- Steady State
    - TP submitted 230 kV and above
- Stability
    - TP submitted 230 kV and above

P5

- N-k + non-redundant relay failure, Multiple Contingency
- Can use Non-consequential load loss and curtailment of Firm Transmission service for HV (<300kV)
- Steady State
    - TP submitted 230 kV and above
- Stability

    - TP submitted 230 kV and above

P6

- N-1-1, Multiple Contingency
    - No Generator contingencies
- Can use Non-consequential load loss and curtailment of Firm Transmission service
- Steady State
    - First contingent element will not be a generator
    - System Adjustments are made
    - Second contingent element will be in same area as first
- Stability
    - Use Fast Fault Scan to determine events for study
    - TP submitted 230 kV and above

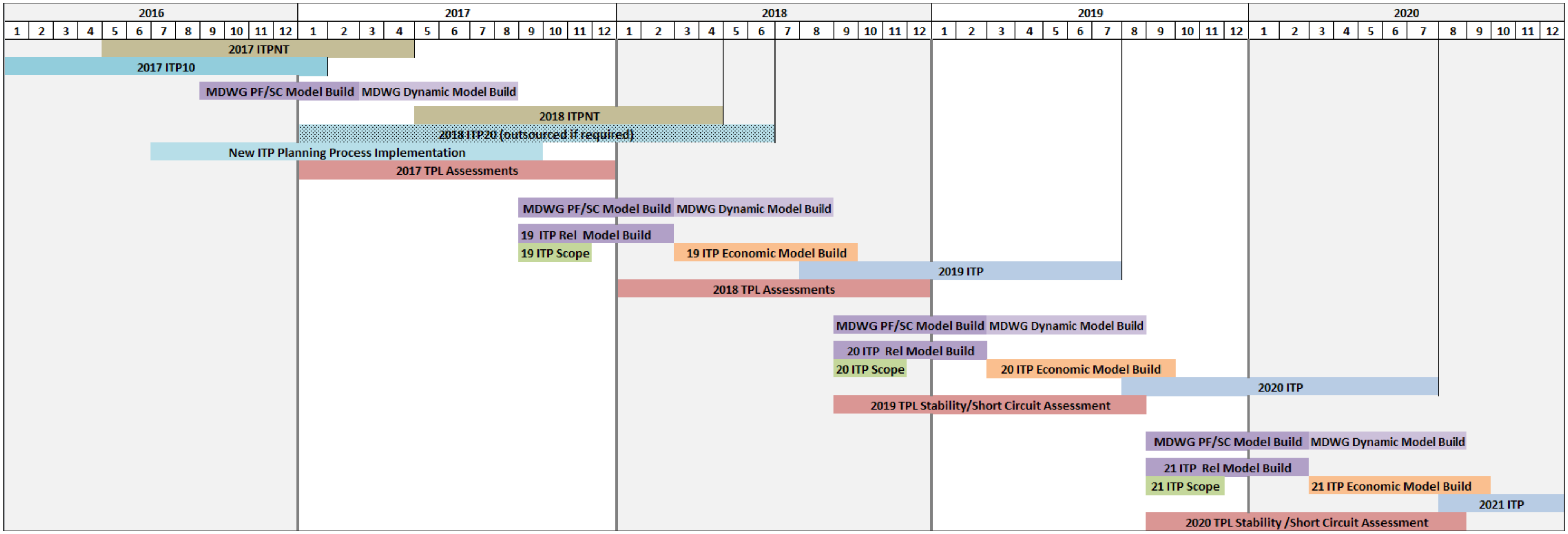
P7

- N-2, Multiple Contingency
    - Common Structure or loss of a bipolar DC line
- Can use Non-consequential load loss and curtailment of Firm Transmission service
- Steady State
    - TP will provide to PC
- Stability
    - TP will provide to PC

Extreme Events

- N-k +, Multiple Contingency
- Steady State
    - TP will provide to PC
- Stability
    - TP will provide to PC

Appendix B: Proposed ITP Planning Process Timeline



Appendix C: TPITF Issues List

TPITF Issue	Classification
Build time - A year to develop model is too long, and leaves only 30 days to use it	Common Planning Model
Build time - Need some models to last longer than a year to reduce burden on member staffs	Common Planning Model
Build time - Issues show up with little time to address (load/gen input issues, inconsistent assumptions between processes, etc.)	Common Planning Model
Data review - Schedule and process, especially for economic models, could use better documentation and structure	Standardized Scope
Bridge model - Need a 7-year-out model to bridge gaps between ITP-NT and ITP-10 (NT & 10 are fundamentally different models)	Holistic Planning Process
Seams - Study process and/or inputs hampered by lack of relationship between interregional and intraregional models	Seams Discussion
Seams - Planning models don't reflect needs on the seams	Seams Discussion
Load forecasting - Inconsistency across entities, combined with no verification mechanisms, leads to distrust	TWG Consideration
Load forecasting - Need a consistent methodology for including load forecasting in the SPP model	TWG Consideration
Load/generation - Minimize potential for gaming by having unit dispatch for models come from SPP under CBA model	Review Completed
Market realities - Market feedback should be reflected within model development (including generation dispatch, SCED)	Common Planning Model/Holistic Planning Process
Market realities - Inconsistency with how markets work, e.g., models rely on block dispatch vs. market dispatch	Common Planning Model/Holistic Planning Process
Market realities - Reflection of CBA dispatch needs to become more prevalent	Common Planning Model/Holistic Planning Process
Market realities - Inconsistencies in modeling delivery between evaluations, e.g., between studies like ITP-NT and GI	Common Planning Model

TPITF Issue	Classification
Is MOD the right tool? Other alternatives?	Review Completed
Data Submittal - SPP does not get enough accurate data on the first pass; should be close by second pass	Staff/Stakeholder Accountability
Data Submittal - Need more enforceable deadlines for meeting set submission timelines	Staff/Stakeholder Accountability
Data Submittal - Data is coming from planners; not operations or markets	Holistic Planning Process
Corrections - Sometimes make the same corrections over and over (lost productivity); affects confidence in models	Common Planning Model
Corrections - Known problems such as flowgate issues don't get fixed in between models	Holistic Planning Process
Corrections - Are we address flowgate and other issues identified in the state-of-the-market report?	Holistic Planning Process
Gaps - Disconnect between SPP planning and operations results in issues making it into model (MOD-33 may fix?)	Holistic Planning Process
Gaps - Models inconsistent among various processes (ITP, GI, Agg, TS) and between RTOs	Common Planning Model
Gaps - Experiencing operational issues that didn't show up in planning models	Holistic Planning Process
Gaps - No feedback loop from member IRPs to the transmission planning model	Standardized Scope/Accountability
Gaps - Reliability models in ITP-10 may not be sufficient; may need to be more similar to ITP-NT model	Common Planning Model
Gaps - Stakeholders not consistently informed of material changes in models when request window is still open	Staff/Stakeholder Accountability
Gaps - Validation issues result from ProMod tool automatically doing 6-month public data updates; can address by notifying vendor	ESWG Consideration
Automation - Members need more automation to help with their data reviews	Staff Consideration
Automation - Improve MOD tool for consistency and reduced build time	Review Completed
Uncertainty of and lack of validation of data in the models	Staff/Stakeholder Accountability

TPITF Issue	Classification
Experience delays in receiving model from members	Staff/Stakeholder Accountability
Duplication of effort due to lack of standardization of data	Common Planning Model
People don't trust the data	Staff/Stakeholder Accountability
Disconnect between submitters and users	Single Point of Contact
Notices to Construct - Lack clarity around what qualifies for NTCs	Standardized Scope
Wind - Need to improve modeling of wind farms that have interconnection but no transmission service	Standardized Scope
RCAR - Which group should address RCAR model issues?	ESWG Consideration
Cycle: 18-month cycle not long enough (Board wants shorter timeframe); find efficiencies in model build to enable shorter process	18-mth Planning Cycle/ Common Planning Model
Planning Horizon: ITP-NT only looks out 5 years, creating gap with ITP-10 for years 6-9	18-mth Planning Cycle/Holistic Planning Process/Common Planning Model
Planning Horizon: Disconnect between ITP-NT and multi-year view of flowgates depending on viewpoint of the party looking at them	18-mth Planning Cycle/Holistic Planning Process
Planning Horizon: No long-term planning for real-time markets; may need policy change	Holistic Planning Process
Quantity: Don't do enough futures and the amount is limited by rate impact concerns	Standardized Scope
Type: No sensitivities around gas/wind prices (gen build); consider doing sensitivities when doing generation build	ESWG Consideration
Type: No economic assessment in the ITP-NT; add economics to ITP-NT	18-mth Planning Cycle/Holistic Planning Process
Type: Supply and demand build (beyond # of futures) not robust; not enough time evaluating gen and supply issues (gas prices, etc.)	18-mth Planning Cycle/Holistic Planning Process
Approach: SPP methodology is inconsistent in how futures are treated; impacts final design	Standardized Scope
Quality: Lack of planning beyond N-1 (less robust system); consider new TPL requirements and regional funding mechanism for compliance	Holistic Planning Process

TPITF Issue	Classification
Quality: Don't consider infrastructure age and condition in planning studies	Review Completed
Quality: Inconsistency on how non-transmission alternatives are handled can lead to sub-optimal outcomes; more options needed; policy consideration	Review Completed
Methodology: Unclear whether TCRs are accounted for in ITP process. Resource cost (no congestion) verses LMPs. Resource cost captures the TCR.	ESWG Consideration
Methodology: 1-year benefits-to-cost ratio may not be adequate; is 0.9 the right cutoff level?	ESWG Consideration
Methodology: Generation location modeling in ITP-10 is off-base; do we need to model generation where it's going in? Incorporate the GI queue.	Standardized Scope
Methodology: No transfer analysis for in-process construction, if not specifically called for in study scope (ties back to need for more information)	ESWG Consideration
Methodology Could a deliverability study count toward the 12% capacity margin requirement for CDR (capacity and demand reserve) purposes? CMTF looking into this.	CMTF Consideration
Methodology: More consistent use of benefit metrics through the process, both year-to-year and process to process	Standardized Scope
Equitability: Scenario 5 near-term models may not be sufficient to preserve rights of long-term firm transmission. Reflective of how the system is used to preserve the LT rights? Assumes wind at 100% on-peak (not accurate). Could cause over-build of the system due to unrealistic dispatch. High-wind better in a shoulder or off-peak case. Service: Financial vs physical firm. Developed pre-market.	Common Planning Model
Value Creation: May be missing opportunities to develop solutions that could be leveraged through off-takers outside the SPP footprint	Holistic Planning Process/18-month Planning Cycle
ITPNT and ITP10 built to address different needs.	18-mth Planning Cycle/Holistic Planning Process
ProMod: Tool uses generic data vs. replicating what's happening in the new market	ESWG Consideration
ProMod: Tool has memory limitations; need to explore better use of hardware and software supporting our planning processes	Staff/ESWG Consideration
Policy: Do we need ITP-20 given we already have option of special high-priority study if we end up needing that data set?	18-mth Planning Cycle

TPITF Issue	Classification
Policy: No long-term planning for real-time markets; seeing flowgates that aren't getting fixed. Economic and Reliability screens. may need policy change	Holistic Planning Process
Timelines: Timelines don't align across SPP ITP, MISO MTEP, and IPSAC processes	18-mth Planning Cycle
Timelines: Study duration timelines (predetermined) often do not reflect scope of work required	18-mth Planning Cycle/Standardized Scope
Timelines: Timing of ITP-10 minimizes any positive impact that may result (no flexibility)	18-mth Planning Cycle
FERC: Unclear whether NTC re-evaluation process is still appropriate given Order 1000	Holistic Planning Process
FERC: Order 1000 had a large impact on the amount and scope of work for the planning processes	CTPTF Consideration
Cycle Impact: High regulatory bar conflicts with desire to go faster	18-mth Planning Cycle
Market-to-market: Unclear how market-to-market impacts should be addressed in the planning process	Standardized Scope
Too much transmission service protection; duplication leads to overbuilding	Common Planning Model
NTCs: No mechanism to administer NTCs from TPL studies; should we fold into ITP-NT process or revise tariff to give TPL authority to administer NTCs?	18-mth Planning Cycle/Holistic Planning Process
Efficiency: Redundancy of model/contingency sets suggest need to combine all or parts of ITP-NT, TPL and/or ITP10	Common Planning Model/Holistic Planning Process
Efficiency: Having to run separate AQ process creates inefficiency vs. including in ITP-NT where possible or not having TOs perform the studies	AQITF will address
Bifurcation of planning process and NERC planning standards	Holistic Planning Process
Accuracy: Difficult to accurately reflect external systems with each planning process (impacts accuracy of regional results)	Holistic Planning Process
Completeness: No mechanism to capture/fix all seams needs to ensure comprehensive planning (East not getting appropriate benefits?)	Holistic Planning Process
Timeliness: Interregional planning is a two-party process, which can cause timeline issues	18-mth Planning Cycle/Holistic Planning Process

TPITF Issue	Classification
Timeliness: Planning processes don't align with inter-regional processes	18-mth Planning Cycle/Holistic Planning Process
Resource: Not enough SPP resource to expand value of long-range planning; need honest cost assessment to align budget with study expectations	Staff/Stakeholder Accountability
Responsiveness: Projects showing up at the last minute due to a lack of foresight	Holistic Planning Process/TWG Consideration
Collaboration: Need fundamental principles balanced with back-end direction	Standardized Scope
Time spent on studies not used/leveraged in other processes. What's the value of the studies? Are we utilizing the results? - ERAG, EIPC, JOA, ITP20	Review Completed
Lack of Engineering Economic Analysis. Consider costs, etc. when evaluating and selecting a project(s) as a fix. Bridge to operational planning.	Holistic Planning Process
Misalignment of stakeholder incentives; RCAR. Plan system regionally and look at cost allocation etc. via zone.	Review Completed
Inefficient staff resource usage. Time not spent on the development of regional plan due to work from WGs outside of planning studies scopes.	Standardized Scope/Staff/Stakeholder Accountability
Lack of higher-level vision for studies; reactive planning vs pro-active planning. Tactical and short-term vs long-term strategic plan.	18-mth Planning Cycle/Holistic Planning Process
Lack of detailed project analysis. Higher-level vs detailed project analysis. Issues: study scope, delays in the schedule (time crunch)	Standardized Scope/Staff/Stakeholder Accountability
Projects screened out or selected based on cost estimates that may not be accurate.	Staff Consideration
Too slow to accept new realities; CBA, TPL, CPP	Holistic Planning Process
Assignment of costs associated with siting generation due to the location of a flowgate (mkt). Have to work around the issue.	Staff Consideration
Direction: SPP staff feels we do not have enough guidance upfront; prefer fundamental principles with back-end discretion	Standardized Scope
Milestone Reviews: Requirement that working groups review each ITP-10 milestone creates elongated process; policy changes could speed updates	Standardized Scope
Consensus: Growing difficulty to build consensus toward approval of transmission plans	Standardized Scope

TPITF Issue	Classification
Changing of expectations; mid-process	Standardized Scope/Staff/Stakeholder Accountability
Conflicting member expectations	Standardized Scope/Staff/Stakeholder Accountability
Responsiveness: Too many planning processes at SPP - sheer number limits speed of member inputs	Common Planning Model/Standardized Scope
Organization: Planning processes at SPP too siloed (e.g., Aggregate Studies, Generator Interconnection) - should eliminate or consolidate	Common Planning Model/Holistic Planning Process
Resources: Limited member staff to participate in the process (results, models, etc.)	Staff/Stakeholder Accountability
Resources: SPP introducing software that entities don't have; as a result, they lose the ability to validate the data	Staff/Stakeholder Accountability
Lack of feedback loop due to Order 1000. All projects considered competitive until deemed otherwise. Limits discussion regarding the projects until they are determined to be non-competitive.	CTPTF Consideration
Incentive points awarded for DPP submission creates issues. DPPs submitted just to get bonus points. 1-step vs 2-step	CTPTF Consideration
Flowgates: Operations and Planning coordinate on annual flowgate assessment but don't create actual solutions; consider merging with ITP-NT process and adding solutions (at least enable quarterly removal of flowgates)	Standardized Scope/Holistic Planning Process
Generation: Expectations for generation at odds with reality, as evidenced in gaps between GI/Agg Studies and ITP (are assumptions on delivery different; should they be?)	Common Planning Model
Integration: Processes don't tend to "talk" to each other – can GI and Aggregate study results be better integrated into other studies?	Common Planning Model/Holistic Planning Process
Process Clarity: No distinction on what you get between ERIS and NRIS	Staff Consideration
Regulatory: Unclear of impact to LTCR outcomes based on upcoming Boston Energy FERC compliance ruling (is it an issue?)	MWG\CAWG Consideration
Methodology: TSS assumes all firm service is rolled over; no mechanism to verify roll-over of service in planning processes. How addressed since all service is modeled in perpetuity. How to consider service in the out-years. No transactions in the ITP10 but captured in the ITPNT.	Common Planning Model/Holistic Planning Process

Appendix D: Glossary

ARR	Auction Revenue Rights
BPWG	Business Practice Working Group
CAWG	Cost Allocation Working Group
CBA	Consolidated Balancing Authority
DPP	Detailed Project Proposal
ESWG	Economic Studies Working Group
IROL	Interconnection Reliability Operating Limits
ITP	Integrated Transmission Planning
ITP10	ITP 10-Year Assessment
ITP20	ITP 20-Year Assessment
ITPNT	ITP Near-term Assessment
MDWG	Model Development Working Group
MOPC	SPP Market and Operations Policy Committee
NERC	North American Electric Reliability Corporation
NITS	Network Integration Transmission Service
NTC	Notifications to Construct
OATT	Open Access Transmission Tariff
RCWG	Regional Compliance Working Group
RMS	SPP Request Management System
RR	Request Revision process
RSC	Regional State Committee
RTWG	Regional Tariff Working Group
SPC	SPP Strategic Planning Committee
SSC	Seams Steering Committee
TCR	Transmission Congestion Rights
TWG	Transmission Working Group


SPP
75th Anniversary
75
SEVENTY-FIVE YEARS OF
RELIABILITY THROUGH RELATIONSHIPS

Economic Needs Assessment

ESWG

April 21st, 2016

What is an Economic Need?

- Congested flowgates are created when powerflows on the system require the SCUC/SCED simulation to redispatch generation in order to not violate the thermal rating of a transmission branch (line/transformer) that is defined as a constraint
- An economic need is a congested flowgate that meets certain criteria
  - In the top 25 of congested flowgates
  - Annual flowgate congestion score > $50k
  - Provides benefit to SPP
- All economic needs are congested flowgates, not all congested flowgates are defined as economic needs

Defining Economic Needs

1. Rank the congested flowgates by congestion score
2. Determine which congested flowgates have greater than $50k in annual flowgate congestion score
3. Determine whether the remaining flowgates provide benefit to SPP by alleviating each constraint (run simulations removing them from the event file one by one)
4. Remove any flowgates that provide none or negative benefit to SPP
5. Remaining top 25 congested flowgates from each future considered economic need
6. Identify economic needs as seams needs by:
   - Evaluating the benefit of each remaining constraint to external areas (MISO/AECI)
   - Current market to market flowgates

Economic Need Drivers

- Staff to research drivers of each need for economic project development and selection
- Reports and data points to check in PROMOD and PAT:
  - Generation dispatch
  - Transmission flows
  - Generation and load shift factors
  - LMP

RCAR II Metrics Update

ESWG

April 21st, 2016

Purpose & Background

- Regional Cost Allocation Review is an analysis of the zonal impacts of the Highway/Byway cost allocation methodology
  - Concludes July 2016
- Today: Metrics Update
- 5/18: Review of metric <u>results</u>
  - <u>Not</u> seeking official ESWG approval
- Began working on the current RCAR II in September 2015
  - PROMOD Modeling Issues approaches – approved by ESWG Oct 2015
  - Powerflow Models – approved by TWG January 2016
  - Economic Models – approved by ESWG March 2016
  - Constraints – approved by TWG March 2016

RCAR Modeling Assumptions

- RCAR II modeling assumptions are consistent with 2017 ITP10 modeling assumptions
- Brightline date of October 1, 2015 was used for topology updates in the models
- Base case models created by removing all Highway/Byway (HWBW) upgrades from the models

	Includes HWBW upgrades	Powerflow models	PROMOD models
2020 Base		1	2
2020 Change	x	1	1
2025 Base		1	2
2025 Change	x	1	1
2035 Base		0	2
2035 Change	x	0	1

Discussion Items

- Load Pockets
- Trapped Generation
- Reduced Capacity Costs Due to Reduced Losses On-Peak
  - Net CONE Analysis
- Avoided or Delayed Reliability Projects
  - Loading Threshold

Load Pockets

- Significant load pockets in the base case models can cause excessive emergency generation and breaching constraints, leading to unreasonable APC benefit
- Approved approach is to add CTs to load pocket area to achieve more reasonable model behavior
  - CT added at or near buses with emergency generation
- CTs were added in base cases to SPS area to address load pocket issues
  - 2020: 1.3 GW/ 6 CTs
  - 2025: 1.9 GW/ 9 CTs cumulative
  - 2035: 3.2 GW/ 15 CTs cumulative

	SPS Emergency	
(GWh)	Before CT Additions	After CT Additions
2020	1,574	0
2025	2,272	6
2035	4,423	21

Rest of EI: under 300 GWh emergency

Trapped Generation

- Areas with significant trapped generation can produce unreasonable APC benefit results
- A hybrid approach was approved to derive APC benefit based on combination of:
  - Standard modeling
  - Alternate base case model in which renewables are removed if they were made possible by the HWBW upgrades
- An alternate base case model was created for each study year in which renewables were removed if they were made possible by the HWBW upgrades
  - Determined from GI Agreements

(GW)	2020	2025	2035
KS	2.0	2.0	2.3
NM	0.3	0.3	0.3
OK	2.4	2.6	2.9
TX	0.5	0.5	0.5
Total	**5.2**	**5.4**	**5.9**

SPP 75

Reduced Capacity Costs due to Reduced Losses On Peak

- Captures the value for generation capacity that may no longer be required due to a reduction in peak losses
  - Peak MW Losses computed by zone in powerflow models
- This reduction to the installed capacity requirement can be monetized using a Net CONE for new generation
  - Net CONE of $66.30/kW-year (2015 $) obtained through 5 year average
- Metric calculated on a zonal basis
- Developed and monetized early in the ITP process, identified in the 2012 MTF Report

$$\text{MW Loss Reduction} \times 1.12 \times \text{Net CONE for CT (\$/MW-yr)} = \text{Reduced Capacity Savings (\$/yr)}$$

75

Net CONE Analysis ($/kW-Yr)

	2011	2012	2013	2014	2015	5-yr Avg (2015$)
Levelized Capital Cost	$69.54	$71.28	$73.06	$74.88	$76.76	
Fixed O&M	$6.75	$6.92	$7.10	$7.27	$7.45	
EIA Gross CONE	$76.29	$78.20	$80.15	$82.16	$84.21	
Energy Margin	$4.59	$3.68	$3.17	$29.89	$16.24	
Non-spinning Reserve Revenue	$5.49	$5.62	$5.77	$5.91	$6.06	
Net CONE	$66.21	$68.90	$71.22	$46.36	$61.92	
Net CONE (2015$/kW-Yr)	$73.08	$74.20	$74.82	$47.52	$61.92	**$66.30**

***Levelized Cost of Capital, Fixed O&M derived from EIA 2013 AEO**
****Energy Margin and Non-spinning reserve derived from historical data**

<u>Net CONE from previous analyses:</u>

- RCAR I: **$99.90**/kW-yr (2015$)
- 2015 ITP10: **$81.94**/kW-yr (2015$)

SPP 75

Avoided or Delayed Reliability Projects

- Captures the benefit provided by an economic or policy project by helping to avoid (or delay) a reliability project that would otherwise be needed
- This metric is calculated as follows:
  - Analyze thermal reliability needs in a powerflow model **with and without** the economic and policy projects
  - Identify any thermal reliability needs that are present only in the model without the economic and policy projects
  - Identify projects that would mitigate each of these thermal reliability needs
- This benefit metric monetizes the reliability benefit as the avoided cost of not having to build a separate reliability project
  - Benefit allocated based on each zone's share of costs for the avoided or delayed project

Avoided or Delayed Reliability Projects

- Identified 7 projects that would mitigate these thermal reliability needs
- Re-evaluated due to project in the IS
- Determined a 98% maximum loading threshold
- 3 remaining projects make up $38.3M in benefit
- Total benefit with all 7 projects would have been $56.1M

*Dollar amounts are 40-yr NPV (2015$)

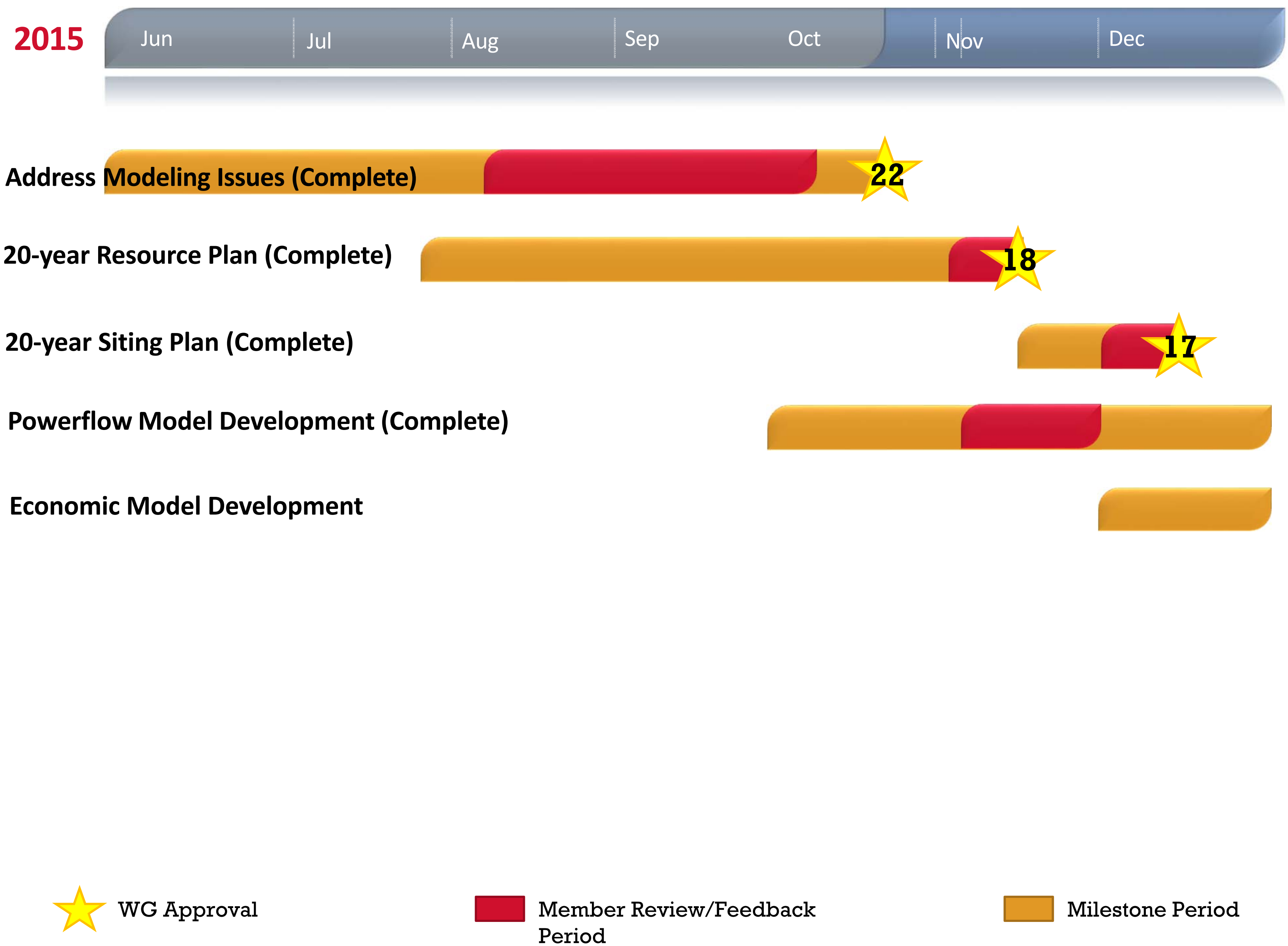
Next Steps

- Continue metric analysis and bring results to stakeholders in May
- Remedy Analysis
- Report
- Completion of analysis in July 2016

RCAR II Schedule

ESWG

April 21st, 2016


2015
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2015
Address Modeling Issues (Complete)
22
20-year Resource Plan (Complete)
18
20-year Siting Plan (Complete)
17
Powerflow Model Development (Complete)
Economic Model Development
WG Approval
Member Review/Feedback Period
Milestone Period


2016
Jan
Feb
Mar
Apr
May
Jun
Jul
Today
27
24
Powerflow Model Development (Complete)
28
Economic Model Development
28
Constraint Assessment
20
Benefit Metrics
12
Remedy Analysis
30
Report Development
MOPC/BOD Approval
WG Approval
Member Review/Feedback Period
Milestone Period

RCAR II Milestone Schedule Summary

Task Name	Start	Finish	Review Period	Feedback Cutoff	End of Milestone
Address Modeling Issues	**April '15**	**October '15**	Multiple Reviews	10/15/15	10/22/15
20-year Resource Plan	**July '15**	**November '15**	11/02/15 – 11/09/15	11/09/15	11/18/15
20-year Siting Plan	**October '15**	**December '15**	11/12/15 - 12/10/15	12/10/15	12/17/15
Powerflow Model Development	**October '15**	**February '16**	Multiple Reviews	1/20/16	2/16/16
Economic Model Development	**November '15**	**March '16**	02/16/16 – 03/01/16, 03/11/16 – 03/15/16	03/01/16, 03/15/16	03/15/16
Constraint Assessment	**February '16**	**March '16**	03/11/16 – 03/18/16	03/18/16	03/28/16
Benefit Metrics	**January '16**	**May '16**	May '16		05/20/16
Remedy Analysis	**May '16**	**June '16**	May, June '16		06/12/16
Report Development	**March '16**	**June '16**	May, June '16		06/30/16
Study Concludes		**July '16**			Late July, 2016

Note: Most review period dates are subject to change based on future WG meeting schedules.

RCAR II Summary

- Current work
  - Powerflow-based Metrics
  - Economic-based Metrics
- Upcoming work
  - Verification of metric results
  - Presentation of metric results
- Staff will be presenting metric results at the May ESWG meeting