SOUTHWEST POWER POOL

ECONOMIC STUDIES WORKING GROUP MEETING

March 3-4, 2021
Net Conference

SUMMARY OF MOTIONS AND ACTION ITEMS

- Approved February ESWG meeting **minutes**.
- Approved **2022 ITP Scope modification for MTEP models**
- Approved **2022 ITP Scope modification for renewable mix for policy additions**
- Approved **RR 448** – move RPS table from ITP Manual to scope document
- Approved the **2021 ITP mitigation plan**
- Approved **2022 ITP and 20-YA age-based retirement exceptions and must-run exceptions**

SOUTHWEST POWER POOL
ECONOMIC STUDIES WORKING GROUP MEETING
March 3-4, 2021
Net Conference

MINUTES

AGENDA ITEM 1 – ADMINISTRATIVE ITEMS

Economic Studies Working Group (ESWG) Chair Alan Myers called the meeting to order at 8:00 a.m. The following members were in attendance or represented by proxy:

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

Proxies:
Bob Tallman for Zac Hager
JP Meitner for Derek Brown
John Turner for Calvin Daniels (Day 2; 10-12)

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

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

Calvin Daniels made a motion, seconded by Bob Tallman to approve the agenda. The motion was approved unanimously.

AGENDA ITEM 2 – CONSENT AGENDA

The consent agenda included the following items:

Meeting Minutes – February 3-4, 2021 (Attachment 4 – February 3-4 2020 ESWG Minutes)

2022 ITP Scope Modification – MTEP models (Attachment 5 – Scope Modification slides) (Attachment 6 – Scope Modification)

2022 ITP Scope Modification #2 – Renewable Mix for Policy Additions (Attachment 6 – Scope Modification #2 slides) (Attachment 7 – Scope Modification #2)

The consent agenda was approved unanimously.

AGENDA ITEM 3 – REVIEW OF PAST ACTION ITEMS

Joshua Norton reviewed past action items. (Attachment 8 – Past Action Items)

AGENDA ITEM 4 – RR 448 – MOVE RPS TABLE TO SCOPE

Joshua Norton presented RR 448, detailed the changes that would come from it, and recommended the ESWG approve RR 448. (Attachment 9 – RR 448 slides) (Attachment 10 – RR 448 recommendation report)

Tim Owens made the motion, seconded by Steve Gaw, to approve RR 448. The motion was approved unanimously.

AGENDA ITEM 5 – 2020 ITP ADDENDUM FOR HURDLE RATE SENSITIVITY

Chris Jamieson (SPP) continued discussions of the hurdle rate sensitivities performed on the 2020 ITP Assessment. (Attachment 11 – 2020 ITP supplemental information)

AGENDA ITEM 6A – 2021 ITP MITIGATION PLAN

Chris Davis (SPP) reviewed an updated mitigation plan and made a recommendation for ESWG approval. Anita Sharma and others raised concerns for removing economic assessment from the 2023 ITP. (Attachment 12 – 2021 ITP Mitigation Status)

Al Tamimi made the motion, seconded by Calvin Daniels, to approve the proposed 2021 ITP mitigation plan.

Steve Gaw made a motion, seconded by Anita Sharma, to amend the motion on the floor by removing the elimination of the 2023 ITP economic analysis from the mitigation plan.

The amendment failed with six votes to approve, seven to oppose, and three abstentions.

The motion to approve the proposed 2021 ITP mitigation plan was approved with ten votes to approve, three votes to oppose, and one abstention.

Voting Rationale:

I voted against the motion to approve the proposed 2021 ITP mitigation plan as the reduction in the scope of the 2023 ITP to NERC-required processes will eliminate the economic assessment which is an integral function of the ITP. I am not opposed to the various other mitigations proposed by Staff. In addition to the listed mitigations, the ESWG has also simplified and limited the 20-year assessments to evaluating four futures instead of the five futures that could be evaluated in order to reduce the impacts of delays on future work schedules. Fundamentally, the ITP was designed to analyze synergies that may exist between reliability and economic solutions and by not performing an economic assessment we will be deprived of the ability to determine if a reliability project can be deferred or replaced by an economic project. For these reasons, we believe that SPP should perform an economic evaluation in every ITP and utilize the holistic approach to planning that was originally envisioned by the TPITF.

-Anita Sharma

LES voted "No" on the amendment offered up to "remove elimination of the 2023 ITP economic analysis" from the 2021 ITP Mitigation Plan. While we agree with the concerns of many of our fellow ESWG members about removing most of the economic modeling from the 2023 ITP is not the correct thing to be doing, it is also important to bring the

scheduled completion date of the 2021 ITP back to a 2021 ending date instead of early 2022. The mitigation plan brought forward by SPP staff seemed to be well thought out and hopefully will allow SPP staff relieve of some of their time and resource constraints while also helping to alleviate potential schedule delays in the 20-year assessment and future 2022 and 2023 ITPs. We did vote "Yes" on accepting the 2021 ITP Mitigation Plan, even though we feel this may just be a band-aid approach. We feel that this is not a sustainable process as future delays will continue to pop up due to staff's and ESWG member's workload and the continual addition of even more projects to their/our schedule. At some time study results will suffer unless SPP is better able to manage their priorities properly.

–Kurt Stradley

I can understand the desire and perspectives that want to keep the 2023 ITP economic analysis, but I believe Tariff compliance of the 2021 ITP is in jeopardy if the 2023 ITP economic analysis is not cut. The reason for my abstention in both votes is because I don't support the need to bandage each ITP study by compressing schedules even more and weakening future studies. I believe this sacrifices accuracy and potentially calls into question the validity of results. I believe this mitigation situation and proposal continues to highlight that this current ITP process is not sustainable. Until a sustainable process is identified sacrifices will continue to be needed. The increases in SPP Staff workload and member's workload due to other significant initiatives further jeopardizes ITP schedules in the future. I understand the need to mitigate the current delays in order to complete the current study, but this shouldn't come at the cost of future study validity. I appreciate the tremendous lift that the ITP studies represent to SPP Staff and member's, but I am fairly confident that both the 2022 and 2023 ITP's will suffer from some sort of delays even though some of the scope of work is being removed due to the 2021 ITP mitigation plan. For these reasons I chose to abstain rather than vote yes or no.

-Steve Hohman

I voted "no" on the motion to amend the original motion before the ESWG to approve the 2021 ITP Mitigation Plan, by removing the reduction in scope for the 2023 ITP Assessment from the mitigation plan. I share the concerns expressed by other ESWG members about removing the bulk of the economic modeling from the 2023 ITP. However, I believe Staff's proposed mitigation plan, as presented during the meeting, was well considered and necessary to try and bring the 2021 ITP scheduled completion date back before the end of the year, relieve future staff resource constraints, and hopefully mitigate the potential for additional schedule delays with the 2022 & 2023 ITP and 20-year assessments. I reluctantly voted "yes" on the original motion to approve the 2021 ITP Mitigation Plan, as presented during the meeting. It is unfortunate the ESWG, TWG, and SPP staff need to consider such drastic mitigation efforts. Additional effort by SPP to effectively prioritize the myriad competing priorities it is trying to simultaneous address is urgently needed to avoid the need for similar mitigation efforts in the future.

-Tim Owens

AGENDA ITEM 6B – 2021 ITP CONSTRAINT ASSESSMENT

Ahmed Alazzawi (SPP) presented an update on the constraint assessment milestone. (Attachment 13 – Constraint Assessment Update)

AGENDA ITEM 6C – TARGET AREA ANALYSIS

Chris Jamieson gave an update for issues and resolutions for the Bakken Target Area and stated that recommendations will be brought to the ESWG and TWG in April. (Attachment 14 – 2021 Target Areas Update)

AGENDA ITEM 7A – LOAD AND GENERATION REVIEW UPDATES

Brooke Keene (SPP) reviewed slides detailing the future 2 age-based retirement exceptions and must run exceptions then recommended the group act on groups of exceptions at a time. (Attachment 15 – 2022 ITP and 20-Year Assessment Load and Generation Review)

Al Tamimi made the motion, seconded by Kurt Stradley, to approve the slide 4 age-based retirement exceptions for units that continue to be maintained and tested

according to the SPP tariff, with no plans for retirement, and that are needed to meet SPP resource adequacy requirements. The motion was approved with two votes opposed (Anita Sharma and Steve Hohman) and one abstention: Steve Gaw.

Bob Tallman made the motion, seconded by Jeremy Severson, to approve the slide 5 age-based retirement exceptions for units purchased in 2019 with an expected remaining life of 30 years. The motion was approved unanimously.

Bob Tallman made the motion, seconded by Kurt Stradley, to approve the slide 6 age-based retirement exceptions where the retirement date has been set to match public opinion. The motion was approved with two votes opposed: Anita Sharma and Steve Hohman.

Kurt Stradley made the motion, seconded by Tim Owens, to approve the slide 7 age-based retirement exceptions for units that have no planned retirement date within the study years. The motion was approved unanimously.

Bob Tallman made the motion, seconded by Jeremy Severson, to approve the slide 8 age-based retirement exceptions for units that have planned upgrades. The motion was approved unanimously.

Tim Owens made the motion, seconded by Kurt Stradley, to approve the must-run exception for Holcomb East:1 in 2022 ITP and 20-year through 2034. The motion was approved with two abstentions: Bob Tallman and Bennie Weeks.

All 7A voting rationale:

I voted against the motion to approve the age-based retirement exceptions in Future 2 for several units that had no upgrades performed to extend the life of units. Future 1, which reflects the continuation of current industry trends, is particularly intended to

allow stakeholder exceptions based on utility-specific integrated resource plans. Future 2 is an emerging technology future and assumes that the adoption of new technologies will drive retirements of coal and gas units earlier than originally planned by utilities. We believe that allowing these retirements in Future 2 contradicts the objective and diminishes the value of developing a scenario specifically designed to evaluate impacts of these retirements on the transmission system.

-Anita Sharma

The reason I voted no on the F2 age-based retirement exceptions listed on Slide 4 and Slide 6 of the presentation posted for agenda item 7A is because there was no indication of an active effort, ie, dollars spent or other commitments that would extend their life beyond what is the intention of the Fossil Fuel Retirements driver of F2. F2 is supposed to be more aggressive and plot a trajectory for if a reasonable set of changes from business as usual take place. I think there needs to be good reason to circumvent those F2 assumptions, especially since there is a resource planning study phase that would replace that capacity anyway. I do not interpret retirements in F2 as being recommendations by SPP Staff to retire units and believe that F2 offers an opportunity to, in part, test some reasonable "what ifs" that may stray from the announced or known plans that a GO may have today. I was generally supportive of those exceptions that had provided some description of intentional efforts at life extension. That is not meant to belittle any maintenance or upkeep of the units listed on Slide 4 and Slide 6, but I thought a reason like "we have no plans to retire these" was not strong enough to overcome the F2 drivers.

-Steve Hohman

I voted for the Future 2 Age-Based retirement exceptions and Must-run exception, as presented during the meeting. I believe the generator owners have a better understanding than I do of their plans for their resources. Therefore I am not comfortable in second guessing their requests for exceptions.

-Tim Owens

AGENDA ITEM 7B – WIND HUB HEIGHTS METHODOLOGY

Brooke Keene reviewed the background of hub heights methodology and and detailed an option to use 80m profiles. (Attachment 16 – Wind Hub Heights Methodology)

AGENDA ITEM 8AI – 20YA SCOPE EXECUTION ITEMS UPDATED LIST

Sherri Maxey (SPP) reviewed the updated list and reminded the group to review for any additional items. (Attachment 17 – 20-Year Assessment Scope Execution Items)

AGENDA ITEM 8AII – 20YA SCOPE EXECUTION ITEMS – LOAD REVIEW METHODOLOGY (F3 & F4)

Brooke Keene lead the group in discussing the scope implementation of demand response, distributed generation, electrification through various opportunities, energy efficiency, and emissions reduction target. (Attachment 18 – 20-Year Load Review Methodology)

ECONOMIC STUDIES WORKING GROUP MINUTES

March 3-4, 2021

AGENDA ITEM 9 – CLOSING ITEMS

There were no action items taken.

Respectfully Submitted,

Joshua Norton

Secretary

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Proxy Statements

Member	Proxy	Note
Derek Brown	JP Meitner	
Zac Hager	Bob Tallman	
Calvin Daniels	John Turner	Day 2 10:00-12:00

Alan and Josh,

JP Meitner will have my proxy for the 3/3-4 ESWG meetings

Thanks,

Derek Brown, MSEE, PE
Manager, Short-Term Planning
Evergy

Hi guys, I'm double booked this week so I won't be making it to the ESWG call.

Bob Tallman will have my proxy

Thanks,

Zac Hager
OG&E Resource Planning
(405) 553-3635

Hi Alan,

I'm sorry but I have to miss the last two hours of the ESWG meeting next week on Thursday. Please accept John Turner as my Proxy from 10 to the end of the ESWG meeting on March 4, 2021.

Calvin Daniels
Transmission System Reliability Engineer
Western Farmers Electric Cooperative
701 NE 7th Street
Anadarko, OK 73005
Office: 405.247.4221

wfec western farmers electric cooperative

SOUTHWEST POWER POOL, INC.
ECONOMIC STUDIES WORKING GROUP MEETING
March 3-4, 2021
Net Conference

AGENDA

Wednesday, 8:00a.m – 12:00p.m.
Thursday, 8:00a.m – 12:00p.m.

1. Administrative Items.....Alan Myers (15 min)
   A. Call to Order, Introductions.....Alan Myers
   B. Receipt of Proxies.....Joshua Norton
   C. Review of Agenda[1].....Alan Myers
   D. Antitrust Reminder.....Joshua Norton
2. Consent Agenda[1]
   A. February 3-4, 2021 minutes
   B. 2022 ITP Scope Modification – MTEP models
   C. 2022 ITP Scope Modification #2 – Renewable Mix for Policy Additions
3. Review of Past Action Items[1].....Joshua Norton (10 min)
4. RR 448 – Move RPS Table to Scope (Approval)[1].....Joshua Norton (20 min)
5. 2020 ITP Addendum For Hurdle Rate Sensitivity (Approval)[1].....Chris Jamieson (30 min)
6. 2021 ITP
   A. Mitigation Plan (Approval)[1].....Chris Davis (60 min)
   B. Constraint Assessment Update[1].....Ahmed Alazzawi (10 min)

[1] Background Material Included

C. Target Area Analysis[1] ..... Chris Jamieson (30 min)

7. 2022 ITP

A. Load and Generation Review Updates (Approval)[1] ..... Brooke Keene (30 min)

B. Wind Hub Heights Methodology ..... Brooke Keene (15 min)

8. 20-Year Assessment

A. Scope Execution Items

i) Updated List[1] ..... Sherri Maxey (10 min)

ii) Load Review Methodology (F3 & F4)[1] ..... Brooke Keene (30 min)

9. Closing Items ..... All (10 min)

A. Summary of Action Items

B. Upcoming Meeting Agenda Items

C. Future Meetings

i) March 31-April 1, 2021: Net Conference
ii) May 5-6, 2021: TBD
iii) June 2-3, 2021: TBD

SOUTHWEST POWER POOL

ECONOMIC STUDIES WORKING GROUP MEETING

February 2-3, 2021
Net Conference

SUMMARY OF MOTIONS AND ACTION ITEMS

- Approved meeting **minutes**
  - December 3-4
  - January 7
- Approved **E1 whitepaper**
- Endorsed the development of a revision request for a **DPP fee schedule**

SOUTHWEST POWER POOL
ECONOMIC STUDIES WORKING GROUP MEETING
February 2-3, 2021
Net Conference

MINUTES

AGENDA ITEM 1 – ADMINISTRATIVE ITEMS

Economic Studies Working Group (ESWG) Chair Alan Myers called the meeting to order at 8:00 a.m. The following members were in attendance or represented by proxy:

Al Tamimi, SUNC
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Anita Sharma, AEP
Bennie Weeks, Xcel
Calvin Daniels, WFEC
Derek Brown, Evergy
Gayle Nansel, WAPA
Jeremy Severson, BEPC
Jody Holland, SCMCN
Kurt Stradley, LES
Kyle McKinney, GSEC
Michael Watt, OMPA
Randy Collier, CUS
Steve Gaw, APA
Steve Hohman, OPPD
Tim Owens, NPPD
Zac Hager, OGE

Proxies:
JP Meitner for Derek Brown

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

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

Tim Owens made a motion, seconded by Kurt Stradley to approve the agenda. The motion was approved unanimously.

AGENDA ITEM 2 – CONSENT AGENDA

The consent agenda included the following items:

Meeting Minutes – December 3-4, 2020 (Attachment 4 – December 3-4 2020 ESWG Minutes)

Meeting Minutes – January 4, 2021 (Attachment 5 – January 4 2021 ESWG Minutes)

Meeting Minutes – January 7, 2021 (Attachment 6 – January 7 2021 ESWG Minutes)

The January 4, 2021 meeting minutes were pulled from the consent agenda for cleanup and will be on the next meeting consent agenda.
The amended consent agenda was approved unanimously.

AGENDA ITEM 3A – ESR TASK TEAM REPORTS: E1 WHITEPAPER

Al Tamimi presented the draft E1 whitepaper and answered questions. Steve Gaw asked if this document would go to the ESR Steering Committee and Alan indicated it should. Steve Gaw also posed a question about the study process for batteries. Al stated that as an ITP solution, a battery can only be used for the condition that it solves and any other use would require the appropriate study through GI or AQ. Anita Sharma asked if ABB has the capability to support ESR transmission solutions. Kelsey Allen (SPP) indicated that ABB has included this in PROMOD 11.4. (Attachment 7 – E1 Draft Whitepaper)

Al Tamimi made the motion, seconded by Jeremy Severson, to approve the E1 whitepaper. The motion was approved with one abstention: JP Meitner (proxy for Derek Brown).

Voting Rationale:
"Evergy would recommend further cleanup of the document and then bringing it back to TWG/ESWG for further comments and edits. We would then recommend sending this whitepaper to the ESR Steering Committee to see if they have any comments, contradictions, or concerns (e. g., definition and use of storage as a transmission asset) ahead of voting for approval."
-JP Meitner

AGENDA ITEM 4 – REVIEW OF PAST ACTION ITEMS

Joshua Norton reviewed February updates for past action items. (Attachment 8 – Past Action Items)

AGENDA ITEM 5A – 2021 ITP: MITIGATION PLAN

Chris Davis (SPP) informed stakeholders the 2021 ITP assessment is now in 'red' status, meaning a mitigation plan is necessary to meet the study deadline. Chris reviewed the proposed mitigation plan with the members and asked for feedback. Tim Owens stated he does not recommend reducing working group approvals as a way to mitigate the schedule. Brian Johnson (AEP) brought up concerns of downstream impacts when conceptual cost estimates are used. Pay Hayes (LS Power) and Steve Gaw had concern with a reduced scope for the 2023 ITP. Steve Hohman expressed openness to increasing time between economic assessments. Jody Holland emphasized the need to consider economics and reliability as inseparable. Anita Sharma asked if reducing other needs (e.g., limiting to top 10 economic) could be considered along with or instead of carving out the Market Powerflow Model needs. Chris Davis stated this will be discussed again in upcoming meetings. (Attachment 9 – 2021 ITP Mitigation Status)

AGENDA ITEM 5B – 2021 ITP: MARKET ECONOMIC MODEL UPDATE

Charlton Hill reviewed changes to the Market Economic Model (MEM) since the January 13 posting, presented outcomes of ancillary co-optimization research, and results of interchange methodology review. (Attachment 10 – MEM Update)

AGENDA ITEM 5C – 2021 ITP: TARGET AREA ANALYSIS

Chris Jamieson provided updates on items related to target area analysis including the following: Base Reliability (BR) SVC Removal, SPS South and Bakken interfaces, and preliminary (Book of Flowgates) BR and congestion results. He reviewed some ideas for additional analysis and a checklist for the target area analysis. (Attachment 11 – Target Areas Update)

AGENDA ITEM 6A – 20-YEAR ASSESSMENT: DISCUSSION ITEMS

Sherri Maxey reviewed the list of discussion items for the 20-year assessment and discussed staff's chronological approach to addressing them. The list will be updated with some suggestions mentioned during the meeting and will be brought back to the group. (Attachment 12 – 20-Year Assessment Scope and Study Execution Items)

AGENDA ITEM 7 – DPP FEE SCHEDULE PROPOSAL

Kirk Hall reviewed the proposal for a DPP fee schedule and presented the revised recommended motion from TWG. (Attachment 13 – DPP Fee Schedule)

> **Anita Sharma made the motion, seconded by Calvin Daniels, to endorse the development of a revision request for a DPP fee schedule. The motion was**

approved with one vote against (Jody Holland) and three abstentions: Alan Myers, Steve Gaw, and Bennie Weeks.

Voting Rationale:
"ITC is not opposed to the concept or the specifics regarding imposing a fee on DPP submittals as presented at the 2/4/21 meeting. We do however believe that the question would more appropriately be considered in the TOSP Task Force recently formed by MOPC. This will allow signals regarding planning inputs to be considered in the full scope of potential process and policy changes rather than in isolation."
-Alan Myers

AGENDA ITEM 8 – 2021 & 2022 INTEGRATED TRANSMISSION PLANNING (ITP) OPERATIONAL SOLUTION EVALUATION

Chris Jamieson provided a quarterly comparison of 2021 ITP Market Economic Model and Ops congestion and gave an update on the efforts for the 2021 ITP persistent operational economic solution evaluation. The comparison revealed that the Midwest-Franklin 138 kV FLO Cedar Lane-Canadian 138 kV had real-time congestion cost of 70 million for two years while the 2021 ITP models showed none. Anita Sharma asked if the planning model would show more congestion after constraint assessment and Chris responded that the gap is likely due to operational volatility not being represented in the planning model. Jody Holland commented that this seems like something the transmission owner could fix right now. Steve Hohman suggested there could be a process where operations staff evaluates small improvements to alleviate these issues not seen in planning models. Chris Jamieson discussed next steps to address this topic. (Attachment 14 – Operational Solution Evaluation)

AGENDA ITEM 9 – ACTION ITEM 199: SITING PLAN

Joshua Norton reviewed the current process of siting batteries in the ITP assessments and discussed the next steps for the action item, including a survey to help identify process changes. The survey will be sent out to exploders, including the Generation Interconnection User Forum. (Attachment 15 – AI 199 – Battery Siting)

AGENDA ITEM 10A – FORMALIZATION OF 2020 ITP HURDLE RATE SENSITIVITY

Chris Jamieson reviewed results of hurdle rate sensitivities performed on the 2020 ITP Assessment portfolio. (Attachment 16 – 2020 ITP Supplemental Information)

AGENDA ITEM 10B – REVIEW 2021 ITP MARKET ECONOMIC MODEL (MEM) INTERCHANGE

Chris Jamieson reviewed net interchange results from the 2021 ITP MEM with comparisons to 2019 Operations and the 2020 ITP MEM. (Attachment 17 – Review 2021 ITP MEM Interchange)

AGENDA ITEM 11 – ACTION ITEM 206: DRAFT REVISION REQUEST

Joshua Norton reviewed the draft revision request to be submitted to remove the Renewable Portfolio Standards table from the ITP Manual. (Attachment 18 – RPS RR Submission Form)

AGENDA ITEM 12 – 2020 ESWG ORGANIZATIONAL GROUP EFFECTIVENESS SURVEY RESULTS

Joshua Norton reviewed results of the Organization Group Effectiveness Survey, highlighted high and low scores and a summary of submitted comments and recommendations for improvement. (Attachment 19 – Organizational Group Effectiveness Survey)

AGENDA ITEM 13 – 2021 ESWG GOALS & INITIATIVES

Joshua Norton presented a process to review all ESWG-related initiatives and have the ESWG members prioritize. (Attachment 20 – 2021 ESWG initiatives)

AGENDA ITEM 14 – 2025 WATT COALITION STUDY OF GETS IN OK & KS

Jay Caspary (Grid Strategies) and Bruce Tsuchida (Brattle) presented an overview on the study Unlocking the Queue with Grid Enhancing Technologies which analyzes use of Advanced Power Flow Control, Dynamic Line Ratings, and Topology Optimization. Jay Caspary indicated that the results would be released soon. (Attachment 21 – WATT Technologies Presentation)

AGENDA ITEM 15 – MODELS REDUCTION (TWG AI 186)

Sunny Raheem reviewed the base planning model reduction recommendation and indicated it would be back in front of the group for approval in an upcoming meeting. (Attachment 22 – Planning Model Reduction)

ECONOMIC STUDIES WORKING GROUP MINUTES

February 2-3, 2021

AGENDA ITEM 16 – CLOSING ITEMS

There were no action items taken.

Respectfully Submitted,

Joshua Norton

Secretary

SPP Southwest Power Pool

2022 ITP

2022 ITP SCOPE MODIFICATION

BROOKE KEENE

MARCH 2021

OVERVIEW OF MODIFICATION

- Issue
  - MTEP21 economic models utilized for external generation and load review have been delayed several months
- 2022 ITP Scope specifies that we will utilize the MTEP21 models

MODIFICATION

- Remove External Load Forecasts language from 2022 ITP Scope

~~**EXTERNAL LOAD FORECASTS**~~

~~Table 2 details the data sources of load forecasts external to SPP for the Market Economic Models (MEM) and Market Powerflow Models (MPM) for the simulated regions.~~

~~External Entity~~	~~Load Data Source~~
~~AECI~~	~~2021 Base Reliability Model[2]~~
~~MISO~~	~~MTEP21~~
~~Manitoba Hydro~~	~~MTEP21~~
~~TVA~~	~~MTEP21~~

~~*Table 2: External Load Data Sources*~~

ITP MANUAL LANGUAGE

Section 2.2.1.2 Load and Energy Forecasts

…External region load forecasts will be taken from the base reliability model set and each region will be allowed to review load forecast data prior to use in the ITP assessment. ***If readily available and appropriate, load forecasts from the most current neighboring entity's study will be used for their region in the ITP assessment in place of the base reliability model data.*** The use of their load forecast will be future specific. If there is not a future comparable to the ITP future, as determined by SPP and the ESWG, the load forecast would be determined utilizing base reliability model data. The data sources approved by the ESWG to be used will be documented in the study report.

STAFF RECOMMENDATION

- We are proposing to remove the language from the 2022 ITP Scope such that we have the flexibility to choose between the MTEP20 and MTEP21 models, as appropriate
- We will evaluate MTEP21 Futures as they become available to ensure compatible futures are utilized for the 20-Year Assessment
- ESWG will approve which MTEP models are being utilized for both the 2022 ITP and 20-Year Assessment once analysis on compatibility has been determined
- Note: The models chosen will also be utilized in all subsequent milestones

2022 INTEGRATED TRANSMISSION PLANNING ASSESSMENT SCOPE

By SPP Engineering

Published on February 2, 2021

Version 1.0

REVISION HISTORY

Date or version number	Author	Change Description	Comments
11/25/2020 v0.1	SPP Staff	Initial Draft Scope	Posted for stakeholder review
01/04/2021 v0.2	SPP Staff	Final Draft Scope	ESWG/TWG approval received; posted for MOPC approval
01/11/2021 v0.2	SPP Staff	Final Scope	MOPC approval received
02/02/2021 v1.0	SPP Staff	Final Approved Scope	Posted to SPP.org
03/02/2021 v1.1	SPP Staff	Scope Revision	Updates to remove reference to specific MTEP model to be utilized; for TWG approval on 03/02/2021 and ESWG approval on 03/03/2021

CONTENTS

SECTION 1: OVERVIEW

This document presents the scope and schedule of work for the 2022 Integrated Transmission Planning (ITP) Assessment. The Economic Studies Working Group (ESWG) and Transmission Working Group (TWG) are responsible for the creation and review of this document with approvals from the Market Operations and Policy Committee (MOPC) and the board of directors (Board).

OBJECTIVE

The objective of the 2022 ITP Assessment is to develop a regional transmission plan that provides reliable and economic delivery of energy and facilitates achievement of public policy objectives, while maximizing benefits to the end-use customer. This 2022 ITP Assessment Scope contains assumptions to be utilized in the 2022 ITP Assessment that are not standardized in the ITP Manual. These documents should be reviewed together for a comprehensive view of the 2022 ITP process and assumptions.

SECTION 2: MODELING DETAILS AND ASSUMPTIONS

MARKET ECONOMIC MODEL OVERVIEW

FUTURES

The ESWG developed two futures with input from the Strategic Planning Committee (SPC) and TWG. The MOPC reviewed both futures in October 2020.

Reference Case Future (Future 1)

The reference case future will reflect the continuation of current industry trends and environmental regulations. For years 5 and 10, subject to review from generator owners, coal generators over the age of 56 will be retired, while gas fired and oil generators over the age of 50 years will be retired. Exceptions will be allowed based on stakeholder-submitted, utility-specific integrated resource plans (IRP). Long-term industry forecasts will be used to determine coal prices. Natural gas prices will be determined per the ITP Manual. Solar and wind additions will exceed current renewable portfolio standards (RPS) due to economics, public appeal, and current trends as reflected in historical renewable installations and Generator Interconnection (GI) requests. Battery energy storage resources will also be included relative to the approved solar amounts.

Emerging Technologies Future (Future 2)

The emerging technologies future will be driven primarily by the assumption that electrical vehicles and distributed generation will impact energy growth rates. Coal generators over the age of 52 will be retired, while gas-fired and oil generators over the age of 48 will be retired. Exceptions will be allowed as requested by generator owners and approved by the ESWG. As in the reference case future, current environmental regulations will be assumed and coal prices will use long-term industry forecasts. Natural gas prices will be determined per the ITP Manual. This future also assumes higher solar, wind, and energy storage resource additions than the reference case due to advances in technology that decrease capital costs and increase energy conversion efficiency. This future also accounts for the potential that state and/or federal policies will promote the utilization of these technologies in an effort to modernize the grid. This future will align the renewable resource potential with company IRP goals to the extent possible.

	DRIVERS				
KEY ASSUMPTIONS	Year 2	Future 1 – Reference Case		Future 2 – Emerging Technologies	
	2	5	10	5	10
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	

KEY ASSUMPTIONS	DRIVERS				
	Year 2	Future 1 – Reference Case		Future 2 – Emerging Technologies	
	2	5	10	5	10
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		Increase due to electric vehicle growth	
Natural Gas Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Coal Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Current forecast	Coal age-based 56+, Gas/Oil age-based 50+, subject to generator owner (GO) review		Coal age-based 52+, Gas/Oil age-based 48+, subject to GO review and ESWG approval	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[1]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		+300 MW	+500 MW
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Storage	Existing + RARs	20% of projected solar (1.4 GW / 2.2 GW)		35% of projected solar (3.7 GW / 5.2 GW)	
Total Renewable Capacity					
Solar (GW)	Existing + RARs	7	11	9	15
Wind (GW)	Existing + RARs	33	36	38	42

Table 1: Future Drivers

[1] As defined in the MDWG Model Development Procedure Manual: MDWG Manual

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~~*Table 2: External Load Data Sources*~~

MUST-RUN UNITS

Must-run designations for SPP areas will be assigned to co-generation, nuclear, landfill gas, and hydroelectric units, unless an exception is requested during the generation review and approved by the ESWG. Co-generation units will be identified based on EIA 860 data, as well as ABB simulation-ready data. If a unit was originally identified as a must-run in a previous study, but was removed as an exception, it will not be identified as a must-run in the 2022 ITP. External areas will have the same criteria, with the deviation that external co-generation units will be assigned a must-run status subject to SPP review.

HURDLE RATES AND INTERCHANGE

Hurdle rates for all futures will be based upon the latest vendor data set. However, prior to and during the MEM benchmarking and initial year 5 and year 10 MEM builds, SPP and ESWG will be reviewing the reasonableness of the latest vendor data set hurdle rates and respective interchange. SPP and ESWG may utilize, as appropriate, previous ITP MEMs in this review. This review may result in adjustments to the MEM hurdle rates and/or other economic model parameters that impact MEM interregional "economy-energy" transactions. Any ESWG-approved adjustments and MEM interchange results will be documented in the ITP assessment report.

~~[2] AECI actively participates in the SPP model development process that produces the base reliability model set.~~

RESOURCE PLAN

CONVENTIONAL GENERATOR PROTOTYPES

Generator prototype parameters will be set using the Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2020 – EIA (EIA-AEO).[3] Multi-shaft combined cycle (CC) and industrial combustion turbine (CT) prototypes will be used as the available alternatives. While both the multi-shaft CC and industrial CT prototypes were approved, the resource plan will initially consist of the industrial CT prototypes based upon a waiver of the ITP Manual requirement to use resource planning software. The waived requirement to utilize resource planning software was based upon historical performance of the resource planning software and the cost curves associated with the conventional prototypes considered for the 2022 ITP. If any exceptions for the resource plan are requested, the multi-shaft CC prototype data will be used. Table 3 details the characteristics of the approved prototypes, in 2019 dollars for currency values.

Generation Type	Data Source	Technology Type	Size (MW)	Total Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Combined Cycle (CC)	EIA-AEO 2020	Multi-Shaft	1,083	$954	$1.86	$12.15	6,370
Combustion Turbine (CT)	EIA-AEO 2020	Industrial	237	$710	$4.48	$6.97	9,905

Table 2: Generator Prototype Parameters

RENEWABLE ACCREDITATION

Accreditation of existing renewable units will be determined by member data based on SPP Planning Criteria 7.1.6 (7)(8)[4] submitted through the Generation Review. If no accreditation data is submitted for a resource then it will default first to previous ITP study data and secondly to the average of the submitted data for the existing resources in the 2022 ITP, capped at the accreditation values for projected resources. A projected resource that is assigned ownership to a load serving entity within the modeled SPP footprint is eligible for capacity credit. Projected wind, utility scale solar, and battery storage resources will have a stand-alone capacity accredited at 20, 70, and 100 percent, respectively. Total projected utility scale solar, wind, and storage will be accredited based on the approximate average effective load-carrying capability (ELCC) value for the respective resource. Projected wind and

[3] https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf
[4] SPP Planning Criteria

battery storage accredited capacity used to meet load and reserve requirements will be capped at 12 percent of a load serving entity's total load to reflect the assumption that the resources will not have transmission service and thus can only be used to meet the 12 percent reserve margin.

NEW RESOURCE ALLOCATION AND ASSIGNMENT

	SOLAR	WIND	BATTERY STORAGE
ASSIGNED	Yes	No	No
ALLOCATED	Load-Ratio Share	Based on Zonal Reserve Margin	Load-Ratio Share

Table 3: Resource assignment and allocation

Projected utility scale solar will be assigned and allocated by load-ratio share. Projected wind will be unassigned and allocated to maximize accreditation to deficient zones. Projected battery storage will be unassigned and allocated by load ratio share. Policy additions will be met with 70 percent wind and 30 percent solar, based on the active, non-suspended GI queue requests. The accreditation process is as shown:

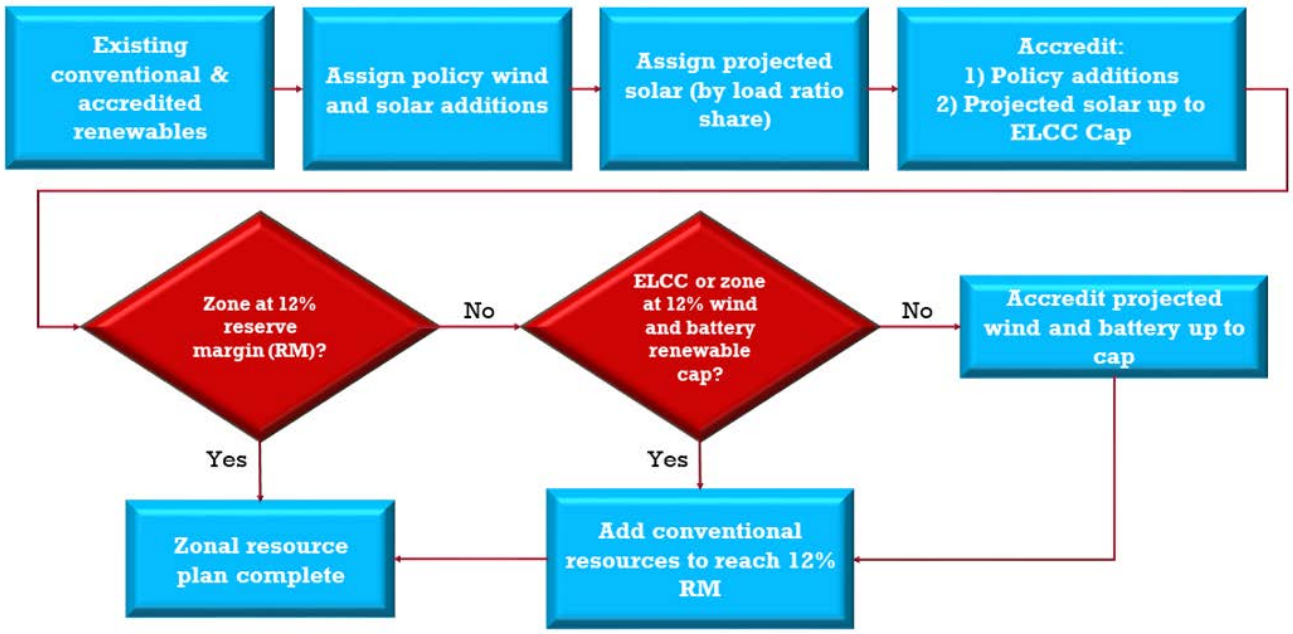


Figure 1: Accreditation process flowchart

RESOURCE PLAN MODELING

As noted in the ITP Manual, the MPM will contain system topology consistent with their respective MEM. This topology consistency does not include the reactive power settings of the resource plans because they are not considered in the MEM. The following parameters will guide how the resource plans, both internal and external, are modeled with regards to reactive settings, such as maximum and minimum VAR support and voltage schedule. Stakeholders are given the opportunity to review certain reactive device settings during the MPM review period described in Section 2.3.2 of the ITP Manual.

All resources included in the internal or external resource plans (excluding distributed generation, such as rooftop solar) will be modeled as directly injecting power at the point of interconnection (*i.e.,* ESWG-approved site). Maximum and minimum reactive capability of generators will be determined by utilizing a .95 power factor and the maximum real power capability of the resource. Resources sited where existing generation is already interconnected will follow the voltage schedule and remote bus determination of the existing resource. The following information is resource fuel type specific and references settings observed in the powerflow modeling software utilized in the ITP process. The following settings apply to both the internal and external resource plans.

Conventional Generation

The control mode for conventional generation will be set to "Not a wind machine." The voltage schedule (*i.e.,* vsched) will be set at 1.015 per unit for system peak models and 1.00 per unit for off-peak models, unless a voltage set point warning is observed. For sites with no existing generation, the remote bus will be the point of interconnection of the new resource.

Solar, Wind, or Energy Storage Resources

The control mode for renewable and energy storage resources will be "+ or – Q limits based on WPF[5]". WPF will be set at .95. The voltage schedule will be set at 1.015 per unit for system peak models and 1.00 per unit for off peak models, unless a voltage set point warning is observed. For sites with no existing generation, the remote bus will be the point of interconnection of the new resource.

[5] Wind power factor

SECTION 3: SOLUTION EVALUATION & PORTFOLIO DEVELOPMENT

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

Leading up to the 2022 ITP needs assessment, SPP will leverage the 2021 ITP economic operational needs assessment and solution evaluation outcome and continue to track on a quarterly basis operations and planning congestion throughout the 2021 ITP. SPP will make a recommendation to working groups on whether or not to address on as needed basis new and unresolved persistent operation economic congestion remaining after 2021 ITP persistent operation needs assessment and solution evaluation.

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

CONSOLIDATION

SPP must consolidate the future-specific portfolios into a single set of projects to determine a recommended plan. The methodology by which this consolidation will occur is based on individual project performance. A systematic approach to evaluate each project's merits and an SPP-developed narrative of each project's drivers will guide the decision for inclusion in the recommended plan. Three different scenarios could occur during the consolidation of the future-specific portfolios into a recommended plan:

1. The same project is addressing the same or similar needs in both futures
2. Different projects are addressing the same or similar needs in both futures
3. A project addresses certain needs only in one future

Projects applicable to scenario one will be considered for the recommended plan. Projects applicable to scenarios two and three will be given a score based on the point system detailed in Table 5. Each project will be awarded points based on its performance or ability to meet six different considerations, up to 100 total possible.

No.	Considerations	Points Possible	Threshold
1	40-year (1-year) APC B/C in Selected Future	50	1.0 (0.9)
	40-year (1-year) APC B/C in Opposite Future		0.8 (0.7)
	40-year (1-year) APC Net Benefit in Selected Future ($M)		N/A
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		N/A
2	Congestion Relieved in Selected Future (by need(s), all years)	10	N/A
	Congestion Relieved in Opposite Future (by need(s), all years)	10	N/A
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	>0
4	New EHV	7.5	Y/N
5	Mitigate Non-Thermal Issues	7.5	Y/N
6	Long Term Viability (e.g. 2013 ITP20) or Improved Auction Revenue Right (ARR) Feasibility	5	Y/N
	Total Points Possible	**100**	

Table 4: Consolidation Considerations Scoring Table

For two projects (P1 and P2) applicable to scenario two, points for consideration one will be calculated as follows:

1. Test B/C thresholds in opposite future
    - If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
    - If project meets 0.8 40-year B/C threshold in opposite future, continue calculations
2. Calculate 40-year net adjusted production cost (APC) benefits
    - Net APC $\text{benefit}_{P1,AVE}$
    - Net APC $\text{benefit}_{P2,AVE}$
    - Net APC benefit_{Max} = Maximum(Net APC $\text{benefit}_{P1,AVE}$, Net APC $\text{benefit}_{P2,AVE}$)
3. Calculate points awarded
    - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVE}}{Net\ APC\ benefit_{Max}}$
    - $Points\ awarded_{P2,\%} = 50 \times \frac{Net\ APC\ benefit_{P2,AVE}}{Net\ APC\ benefit_{Max}}$

For individual projects (P1) applicable to scenario three, points for consideration one will be calculated as follows:

1. Test B/C threshold in opposite future
    - If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
    - If project has at least 1.0 40-year B/C in opposite future, 50 points will be awarded
    - If project meets 0.8 40-year B/C threshold in opposite future, but is less than 1.0, continue calculations

2. Calculate net APC benefits
    - Net APC benefit$_{P1,AVE}$
    - Net APC benefit$_{P1',AVE}$ = Net APC benefit$_{P1,AVE}$ with 1.0 40-year B/C in opposite future
3. Calculate points awarded
    - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVE}}{Net\ APC\ benefit_{P1',AVE}}$

Points for consideration two will be calculated as the percentage of total congestion relieved on the needs addressed by the project, multiplied by the points possible.

$$Points\ awarded = 10 \times \%\ Congestion\ relieved_{F1,addressed\ needs} + 10 \times \%\ Congestion\ relieved_{F2,addressed\ needs}$$

Points for consideration three will be calculated based on the severity of an operational issue that the project is expected to address, as a percentage of the operational needs criteria[6] multiplied by the points possible, up to 10.

$$Points\ awarded = \left(\frac{\$\ of\ congestion\ cost_{24\ months}}{\$10M}\right) \times 10$$

OR

$$Points\ awarded = \left(\frac{Hours\ of\ system\ reconfiguration_{12\ months}}{X\%^{7} \times 8{,}760}\right) \times 10$$

All points possible for considerations four, five, and six will be awarded if the project meets the description of the consideration.

For projects applicable to scenario two, the project with the highest score will be considered the favorable project based on the systematic approach. Projects applicable to scenario three with a total score of 70 or greater will be considered for the final recommended plan.

SPP may use engineering judgement or other analysis to support or oppose results of the systematic approach described above. SPP will bring consolidation results and a recommendation for all projects selected for a future-specific portfolio to the ESWG and TWG for review and feedback.

[6] Flowgate congestion cost totaling more than $10M over the last 24 months or system reconfiguration through an agreed-upon operating guide implemented 25 percent of year.

[7] X equals 25 percent for operational thermal issues. X equals 10 percent for operational voltage issues.

SECTION 4: FINAL ASSESSMENTS

SENSITIVITIES

Sensitivities will be conducted on the final consolidated portfolio in both futures to measure the flexibility of the portfolio with respect to the uncertainties of certain assumptions. Economic analysis will be performed for the sensitivities below:

- High and low natural gas prices
- High and low demand levels

These sensitivities will be applied to years 5 and 10 and will not be used to develop the transmission projects nor filter out projects.

Additional futures relevant sensitivity analyses will be determined via stakeholder survey leading up to this analysis, and will be documented in the ITP assessment report.

VOLTAGE STABILITY ASSESSMENT

A voltage stability assessment will be conducted in both futures using the final consolidated portfolio to assess the megawatt transfer limit under two scenarios:

- Increasing renewable generation in SPP and decreasing conventional thermal generation in SPP.
- Increasing renewable generation in SPP and decreasing conventional thermal generation in external areas.

The transfer limit will be determined by examining voltage performance during power transfers across SPP. The stability assessment consists of a dispatch analysis to determine if the dispatched generation in the year 10 summer and light-load models can be dispatched without the occurrence of voltage collapse or thermal violations.

SECTION 5: SCHEDULE

The 2022 ITP assessment began in July 2020 and will be completed by October 2022. *Figure 2* and Table 6 detail the study timeline.

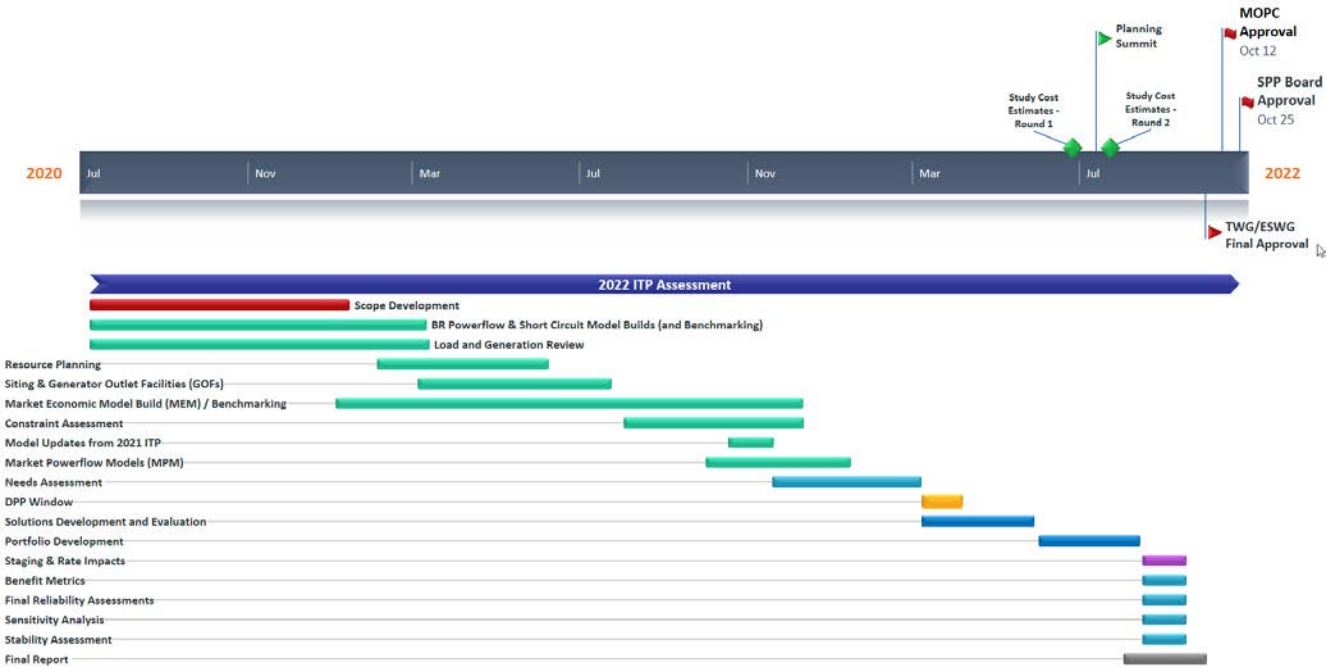


Figure 2: 2022 ITP Timeline

Milestone Name	Group(s) to Review/Endorse	Start Date	Completion Date
Scope Development	ESWG, TWG, MOPC, SPC	Jul 2020	Jan 2021
Load and Generation Review	ESWG, TWG, MDWG	Jul 2020	Mar 2021
Renewable Resource Plan	ESWG	Jan 2021	Mar 2021
Conventional Resource Plan	ESWG	Jan 2021	Jun 2021
Siting Plan & Generator Outlet Facilities (GOFs)	ESWG	Mar 2021	Jul 2020
Powerflow Model Development	TWG	Jul 2020	Mar 2021
Short Circuit Model Development	TWG	Jul 2020	Mar 2021
Economic Model Development	ESWG	Jan 2021	Dec 2021
Model Benchmarking	ESWG, TWG	Dec 2020	May 2021
Model Updates after October 2021 MOPC/Board (NTC/Re-evaluations)	TWG	Oct 2021	Nov 2021
Constraint Assessment	TWG	Aug 2021	Dec 2021
Needs Assessments	ESWG, TWG	Nov 2020	Mar 2022
Detailed Project Proposal (DPP) Window	ESWG, TWG	Mar 2022	Apr 2022
Solutions Development	ESWG, TWG	Apr 2022	May 2022
Project Grouping	ESWG, TWG	Jun 2022	Jul 2022
Study Cost Estimates (Round 1)		Jun 2022	Jun 2022
Summit		Jul 2022	Jul 2022
Study Cost Estimates (Round 2)		Jul 2022	Jul 2022
Final Reliability Portfolios	TWG	Jul 2022	Jul 2022
Portfolio Optimization / Consolidation	ESWG, TWG	Jul 2022	Aug 2022
Project Staging	ESWG, TWG	Aug 2022	Sep 2022
Benefit Metrics Calculations	ESWG	Aug 2022	Sep 2022
Stability Analysis	TWG	Aug 2022	Sep 2022
Sensitivity Analysis	ESWG	Aug 2022	Sep 2022
Final Reliability Assessment	TWG	Aug 2022	Sep 2022
Review Draft Report with Recommended Solutions	ESWG, TWG	Aug 2022	Sep 2022
Final Report with Recommended Solutions	ESWG, TWG	Sep 2022	Sep 2022
	RSC, SPC, SSC	October 2022	
	MOPC, SPP Board		
	MOPC, SPP Board		

Table 5: 2022 ITP Schedule

SECTION 6: CHANGES IN PROCESS AND ASSUMPTIONS

To protect against changes in process and assumptions that could present a significant risk to the completion of the 2022 ITP Assessment, any changes to this scope or assessment schedule must be appropriately vetted and follow the process outlined in the stakeholder accountability section of the ITP Manual.

SPP Southwest Power Pool

2022 ITP

2022 ITP SCOPE MODIFICATION #2

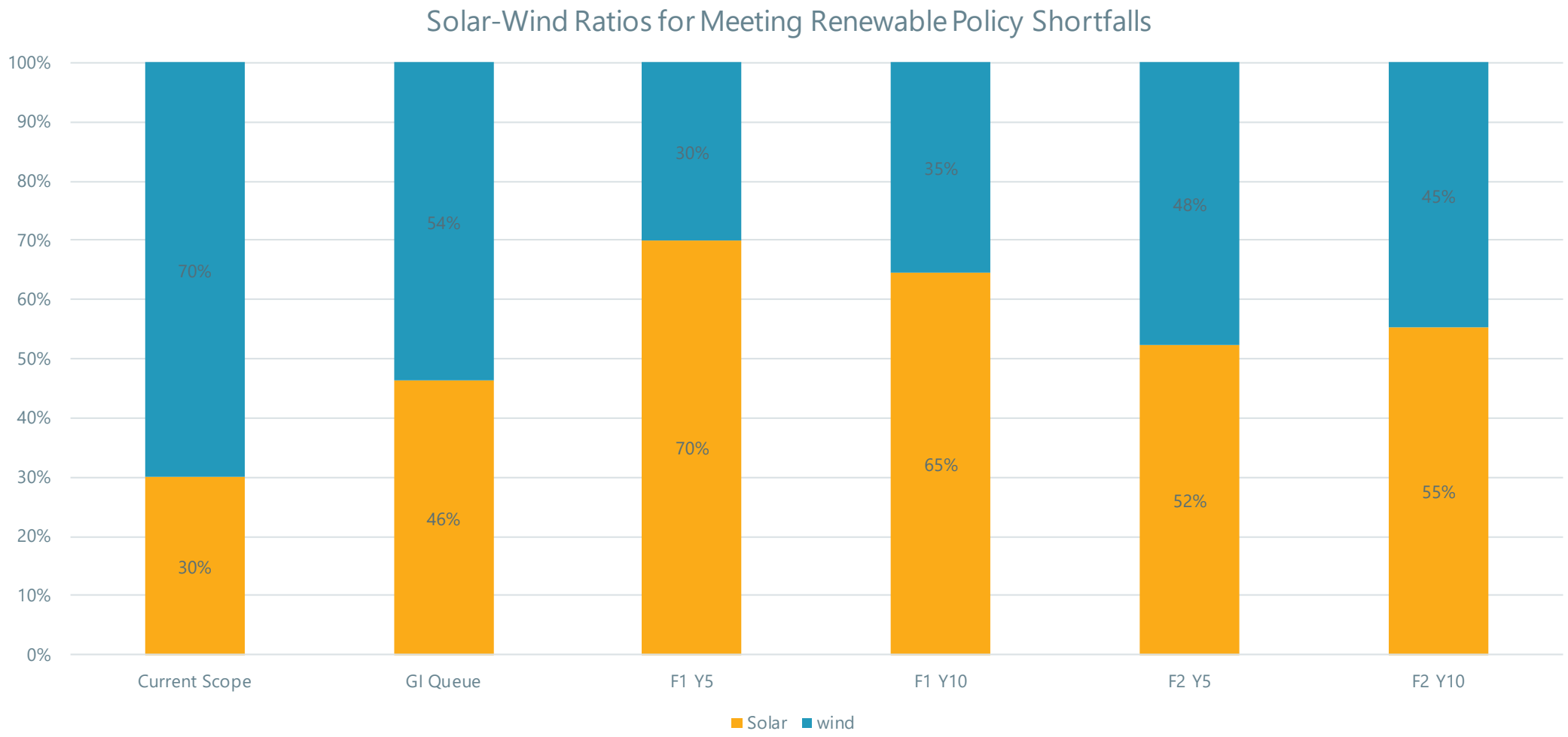
JOSHUA NORTON

MARCH 2021

OVERVIEW OF MODIFICATION

- Issue
  - Changes in GI queue since evaluation in scope milestone have significantly changed basis for the renewable mix used in policy additions
  - Additionally, latest GI queue is more in line with Scope projections for wind and solar

50/50 MIX IS MORE IN LINE WITH GI QUEUE AS WELL AS SCOPE PROJECTIONS



MODIFICATION

Policy additions will be met with 50~~70~~ percent wind and 50~~30~~ percent solar, based on the active, non-suspended GI queue requests

STAFF RECOMMENDATION

- ESWG approve the scope modification to use 50% solar and 50% wind mix for policy additions

2022 INTEGRATED TRANSMISSION PLANNING ASSESSMENT SCOPE

By SPP Engineering

Published on February 2, 2021

Version 1.0

REVISION HISTORY

Date or version number	Author	Change Description	Comments
11/25/2020 v0.1	SPP Staff	Initial Draft Scope	Posted for stakeholder review
01/04/2021 v0.2	SPP Staff	Final Draft Scope	ESWG/TWG approval received; posted for MOPC approval
01/11/2021 v0.2	SPP Staff	Final Scope	MOPC approval received
02/02/2021 v1.0	SPP Staff	Final Approved Scope	Posted to SPP.org
03/03/2021 v1.1	SPP Staff	Scope Modification #2	Update to the renewable mix used for meeting policy shortfalls

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Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	

KEY ASSUMPTIONS	DRIVERS				
	Year 2	Future 1 – Reference Case		Future 2 – Emerging Technologies	
	2	5	10	5	10
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		Increase due to electric vehicle growth	
Natural Gas Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Coal Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Current forecast	Coal age-based 56+, Gas/Oil age-based 50+, subject to generator owner (GO) review		Coal age-based 52+, Gas/Oil age-based 48+, subject to GO review and ESWG approval	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[1]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		+300 MW	+500 MW
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Storage	Existing + RARs	20% of projected solar (1.4 GW / 2.2 GW)		35% of projected solar (3.7 GW / 5.2 GW)	
Total Renewable Capacity					
Solar (GW)	Existing + RARs	7	11	9	15
Wind (GW)	Existing + RARs	33	36	38	42

Table 1: Future Drivers

[1] As defined in the MDWG Model Development Procedure Manual: MDWG Manual

EXTERNAL LOAD FORECASTS

Table 2 details the data sources of load forecasts external to SPP for the Market Economic Models (MEM) and Market Powerflow Models (MPM) for the simulated regions.

External Entity	Load Data Source
AECI	2021 Base Reliability Model[2]
MISO	MTEP21
Manitoba Hydro	MTEP21
TVA	MTEP21

Table 2: External Load Data Sources

MUST-RUN UNITS

Must-run designations for SPP areas will be assigned to co-generation, nuclear, landfill gas, and hydroelectric units, unless an exception is requested during the generation review and approved by the ESWG. Co-generation units will be identified based on EIA 860 data, as well as ABB simulation-ready data. If a unit was originally identified as a must-run in a previous study, but was removed as an exception, it will not be identified as a must-run in the 2022 ITP. External areas will have the same criteria, with the deviation that external co-generation units will be assigned a must-run status subject to SPP review.

HURDLE RATES AND INTERCHANGE

Hurdle rates for all futures will be based upon the latest vendor data set. However, prior to and during the MEM benchmarking and initial year 5 and year 10 MEM builds, SPP and ESWG will be reviewing the reasonableness of the latest vendor data set hurdle rates and respective interchange. SPP and ESWG may utilize, as appropriate, previous ITP MEMs in this review. This review may result in adjustments to the MEM hurdle rates and/or other economic model parameters that impact MEM interregional "economy-energy" transactions. Any ESWG-approved adjustments and MEM interchange results will be documented in the ITP assessment report.

[2] AECI actively participates in the SPP model development process that produces the base reliability model set.

RESOURCE PLAN

CONVENTIONAL GENERATOR PROTOTYPES

Generator prototype parameters will be set using the Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2020 – EIA (EIA-AEO).[3] Multi-shaft combined cycle (CC) and industrial combustion turbine (CT) prototypes will be used as the available alternatives. While both the multi-shaft CC and industrial CT prototypes were approved, the resource plan will initially consist of the industrial CT prototypes based upon a waiver of the ITP Manual requirement to use resource planning software. The waived requirement to utilize resource planning software was based upon historical performance of the resource planning software and the cost curves associated with the conventional prototypes considered for the 2022 ITP. If any exceptions for the resource plan are requested, the multi-shaft CC prototype data will be used. Table 3 details the characteristics of the approved prototypes, in 2019 dollars for currency values.

Generation Type	Data Source	Technology Type	Size (MW)	Total Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Combined Cycle (CC)	EIA-AEO 2020	Multi-Shaft	1,083	$954	$1.86	$12.15	6,370
Combustion Turbine (CT)	EIA-AEO 2020	Industrial	237	$710	$4.48	$6.97	9,905

Table 3: Generator Prototype Parameters

RENEWABLE ACCREDITATION

Accreditation of existing renewable units will be determined by member data based on SPP Planning Criteria 7.1.6 (7)(8)[4] submitted through the Generation Review. If no accreditation data is submitted for a resource then it will default first to previous ITP study data and secondly to the average of the submitted data for the existing resources in the 2022 ITP, capped at the accreditation values for projected resources. A projected resource that is assigned ownership to a load serving entity within the modeled SPP footprint is eligible for capacity credit. Projected wind, utility scale solar, and battery storage resources will have a stand-alone capacity accredited at 20, 70, and 100 percent, respectively. Total projected utility scale solar, wind, and storage will be accredited based on the approximate average effective load-carrying capability (ELCC) value for the respective resource. Projected wind and

[3] https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf
[4] SPP Planning Criteria

battery storage accredited capacity used to meet load and reserve requirements will be capped at 12 percent of a load serving entity's total load to reflect the assumption that the resources will not have transmission service and thus can only be used to meet the 12 percent reserve margin.

NEW RESOURCE ALLOCATION AND ASSIGNMENT

	SOLAR	WIND	BATTERY STORAGE
ASSIGNED	Yes	No	No
ALLOCATED	Load-Ratio Share	Based on Zonal Reserve Margin	Load-Ratio Share

Table 4: Resource assignment and allocation

Projected utility scale solar will be assigned and allocated by load-ratio share. Projected wind will be unassigned and allocated to maximize accreditation to deficient zones. Projected battery storage will be unassigned and allocated by load ratio share. Policy additions will be met with 50~~70~~ percent wind and 50~~30~~ percent solar, based on the active, non-suspended GI queue requests. The accreditation process is as shown:

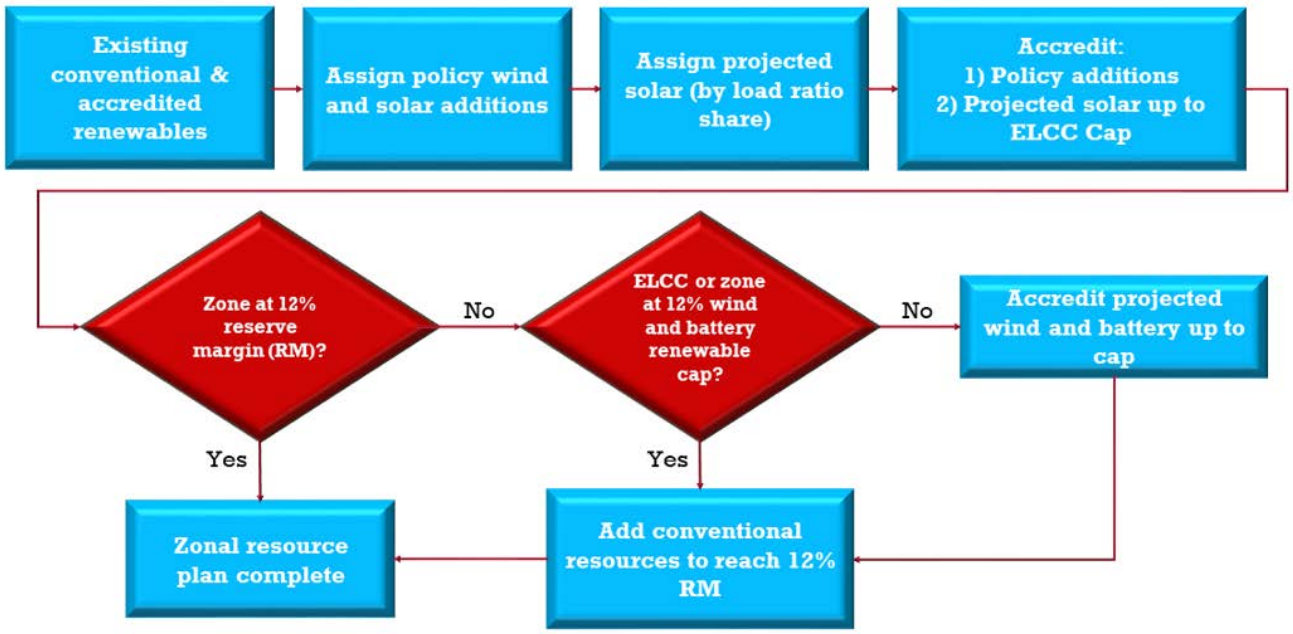


Figure 1: Accreditation process flowchart

RESOURCE PLAN MODELING

As noted in the ITP Manual, the MPM will contain system topology consistent with their respective MEM. This topology consistency does not include the reactive power settings of the resource plans because they are not considered in the MEM. The following parameters will guide how the resource plans, both internal and external, are modeled with regards to reactive settings, such as maximum and minimum VAR support and voltage schedule. Stakeholders are given the opportunity to review certain reactive device settings during the MPM review period described in Section 2.3.2 of the ITP Manual.

All resources included in the internal or external resource plans (excluding distributed generation, such as rooftop solar) will be modeled as directly injecting power at the point of interconnection (*i.e.,* ESWG-approved site). Maximum and minimum reactive capability of generators will be determined by utilizing a .95 power factor and the maximum real power capability of the resource. Resources sited where existing generation is already interconnected will follow the voltage schedule and remote bus determination of the existing resource. The following information is resource fuel type specific and references settings observed in the powerflow modeling software utilized in the ITP process. The following settings apply to both the internal and external resource plans.

Conventional Generation

The control mode for conventional generation will be set to "Not a wind machine." The voltage schedule (*i.e.,* vsched) will be set at 1.015 per unit for system peak models and 1.00 per unit for off-peak models, unless a voltage set point warning is observed. For sites with no existing generation, the remote bus will be the point of interconnection of the new resource.

Solar, Wind, or Energy Storage Resources

The control mode for renewable and energy storage resources will be "+ or – Q limits based on WPF[5]". WPF will be set at .95. The voltage schedule will be set at 1.015 per unit for system peak models and 1.00 per unit for off peak models, unless a voltage set point warning is observed. For sites with no existing generation, the remote bus will be the point of interconnection of the new resource.

[5] Wind power factor

SECTION 3: SOLUTION EVALUATION & PORTFOLIO DEVELOPMENT

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

Leading up to the 2022 ITP needs assessment, SPP will leverage the 2021 ITP economic operational needs assessment and solution evaluation outcome and continue to track on a quarterly basis operations and planning congestion throughout the 2021 ITP. SPP will make a recommendation to working groups on whether or not to address on as needed basis new and unresolved persistent operation economic congestion remaining after 2021 ITP persistent operation needs assessment and solution evaluation.

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation by SPP in the Integrated Marketplace to provide relief on the system. The make-whole payments avoided when a proposed solution is included in the model will be considered in the solution's benefit. Each solution's one-year benefit-to-cost (B/C) ratio and its ability to reduce or eliminate the need for manual commitments will be considered during project selection.

CONSOLIDATION

SPP must consolidate the future-specific portfolios into a single set of projects to determine a recommended plan. The methodology by which this consolidation will occur is based on individual project performance. A systematic approach to evaluate each project's merits and an SPP-developed narrative of each project's drivers will guide the decision for inclusion in the recommended plan. Three different scenarios could occur during the consolidation of the future-specific portfolios into a recommended plan:

1. The same project is addressing the same or similar needs in both futures
2. Different projects are addressing the same or similar needs in both futures
3. A project addresses certain needs only in one future

Projects applicable to scenario one will be considered for the recommended plan. Projects applicable to scenarios two and three will be given a score based on the point system detailed in Table 5. Each project will be awarded points based on its performance or ability to meet six different considerations, up to 100 total possible.

No.	Considerations	Points Possible	Threshold
1	40-year (1-year) APC B/C in Selected Future	50	1.0 (0.9)
	40-year (1-year) APC B/C in Opposite Future		0.8 (0.7)
	40-year (1-year) APC Net Benefit in Selected Future ($M)		N/A
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		N/A
2	Congestion Relieved in Selected Future (by need(s), all years)	10	N/A
	Congestion Relieved in Opposite Future (by need(s), all years)	10	N/A
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	>0
4	New EHV	7.5	Y/N
5	Mitigate Non-Thermal Issues	7.5	Y/N
6	Long Term Viability (e.g. 2013 ITP20) or Improved Auction Revenue Right (ARR) Feasibility	5	Y/N
	Total Points Possible	**100**	

Table 5: Consolidation Considerations Scoring Table

For two projects (P1 and P2) applicable to scenario two, points for consideration one will be calculated as follows:

1. Test B/C thresholds in opposite future
    - If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
    - If project meets 0.8 40-year B/C threshold in opposite future, continue calculations
2. Calculate 40-year net adjusted production cost (APC) benefits
    - Net APC $\text{benefit}_{P1,AVE}$
    - Net APC $\text{benefit}_{P2,AVE}$
    - Net APC benefit_{Max} = Maximum(Net APC $\text{benefit}_{P1,AVE}$, Net APC $\text{benefit}_{P2,AVE}$)
3. Calculate points awarded
    - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVE}}{Net\ APC\ benefit_{Max}}$
    - $Points\ awarded_{P2,\%} = 50 \times \frac{Net\ APC\ benefit_{P2,AVE}}{Net\ APC\ benefit_{Max}}$

For individual projects (P1) applicable to scenario three, points for consideration one will be calculated as follows:

1. Test B/C threshold in opposite future
    - If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
    - If project has at least 1.0 40-year B/C in opposite future, 50 points will be awarded
    - If project meets 0.8 40-year B/C threshold in opposite future, but is less than 1.0, continue calculations

2. Calculate net APC benefits
    - Net APC benefit$_{P1,AVE}$
    - Net APC benefit$_{P1',AVE}$ = Net APC benefit$_{P1,AVE}$ with 1.0 40-year B/C in opposite future
3. Calculate points awarded
    - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVE}}{Net\ APC\ benefit_{P1',AVE}}$

Points for consideration two will be calculated as the percentage of total congestion relieved on the needs addressed by the project, multiplied by the points possible.

$$Points\ awarded = 10 \times \%\ Congestion\ relieved_{F1,addressed\ needs} + 10 \times \%\ Congestion\ relieved_{F2,addressed\ needs}$$

Points for consideration three will be calculated based on the severity of an operational issue that the project is expected to address, as a percentage of the operational needs criteria[6] multiplied by the points possible, up to 10.

$$Points\ awarded = \left(\frac{\$\ of\ congestion\ cost_{24\ months}}{\$10M}\right) \times 10$$

OR

$$Points\ awarded = \left(\frac{Hours\ of\ system\ reconfiguration_{12\ months}}{X\%^{7} \times 8{,}760}\right) \times 10$$

All points possible for considerations four, five, and six will be awarded if the project meets the description of the consideration.

For projects applicable to scenario two, the project with the highest score will be considered the favorable project based on the systematic approach. Projects applicable to scenario three with a total score of 70 or greater will be considered for the final recommended plan.

SPP may use engineering judgement or other analysis to support or oppose results of the systematic approach described above. SPP will bring consolidation results and a recommendation for all projects selected for a future-specific portfolio to the ESWG and TWG for review and feedback.

[6] Flowgate congestion cost totaling more than $10M over the last 24 months or system reconfiguration through an agreed-upon operating guide implemented 25 percent of year.

[7] X equals 25 percent for operational thermal issues. X equals 10 percent for operational voltage issues.

SECTION 4: FINAL ASSESSMENTS

SENSITIVITIES

Sensitivities will be conducted on the final consolidated portfolio in both futures to measure the flexibility of the portfolio with respect to the uncertainties of certain assumptions. Economic analysis will be performed for the sensitivities below:

- High and low natural gas prices
- High and low demand levels

These sensitivities will be applied to years 5 and 10 and will not be used to develop the transmission projects nor filter out projects.

Additional futures relevant sensitivity analyses will be determined via stakeholder survey leading up to this analysis, and will be documented in the ITP assessment report.

VOLTAGE STABILITY ASSESSMENT

A voltage stability assessment will be conducted in both futures using the final consolidated portfolio to assess the megawatt transfer limit under two scenarios:

- Increasing renewable generation in SPP and decreasing conventional thermal generation in SPP.
- Increasing renewable generation in SPP and decreasing conventional thermal generation in external areas.

The transfer limit will be determined by examining voltage performance during power transfers across SPP. The stability assessment consists of a dispatch analysis to determine if the dispatched generation in the year 10 summer and light-load models can be dispatched without the occurrence of voltage collapse or thermal violations.

SECTION 5: SCHEDULE

The 2022 ITP assessment began in July 2020 and will be completed by October 2022. *Figure 2* and Table 6 detail the study timeline.

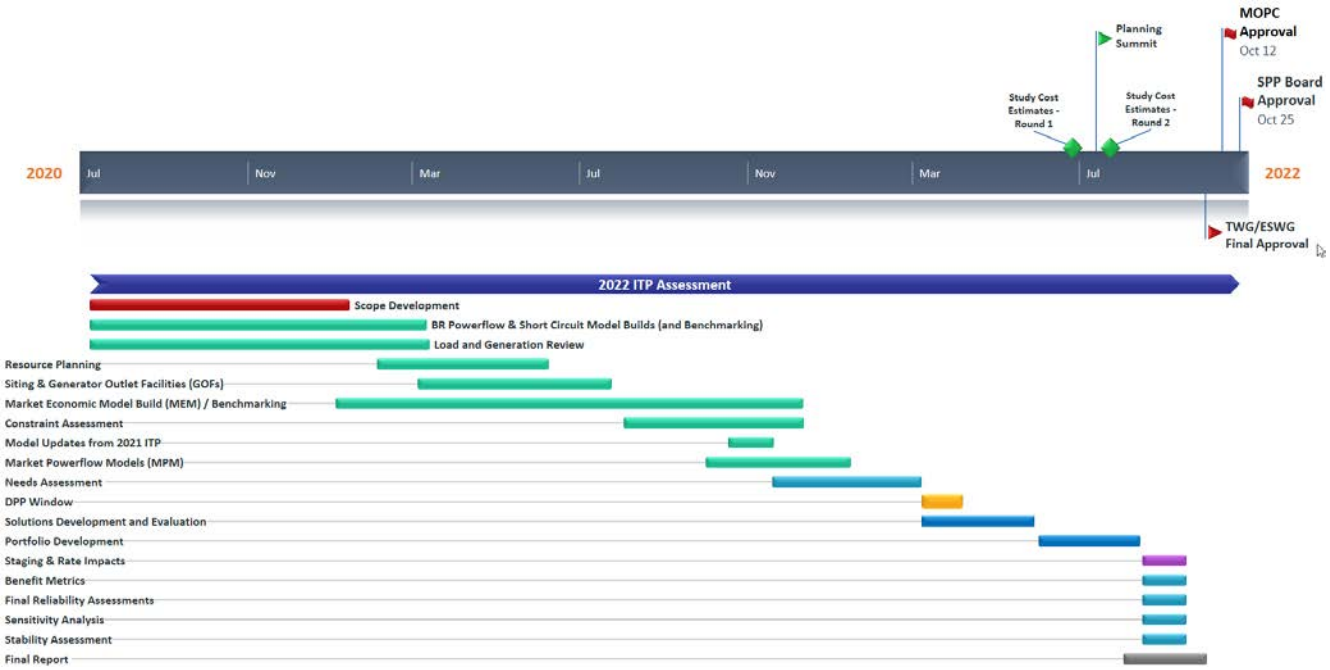


Figure 2: 2022 ITP Timeline

Milestone Name	Group(s) to Review/Endorse	Start Date	Completion Date
Scope Development	ESWG, TWG, MOPC, SPC	Jul 2020	Jan 2021
Load and Generation Review	ESWG, TWG, MDWG	Jul 2020	Mar 2021
Renewable Resource Plan	ESWG	Jan 2021	Mar 2021
Conventional Resource Plan	ESWG	Jan 2021	Jun 2021
Siting Plan & Generator Outlet Facilities (GOFs)	ESWG	Mar 2021	Jul 2020
Powerflow Model Development	TWG	Jul 2020	Mar 2021
Short Circuit Model Development	TWG	Jul 2020	Mar 2021
Economic Model Development	ESWG	Jan 2021	Dec 2021
Model Benchmarking	ESWG, TWG	Dec 2020	May 2021
Model Updates after October 2021 MOPC/Board (NTC/Re-evaluations)	TWG	Oct 2021	Nov 2021
Constraint Assessment	TWG	Aug 2021	Dec 2021
Needs Assessments	ESWG, TWG	Nov 2020	Mar 2022
Detailed Project Proposal (DPP) Window	ESWG, TWG	Mar 2022	Apr 2022
Solutions Development	ESWG, TWG	Apr 2022	May 2022
Project Grouping	ESWG, TWG	Jun 2022	Jul 2022
Study Cost Estimates (Round 1)		Jun 2022	Jun 2022
Summit		Jul 2022	Jul 2022
Study Cost Estimates (Round 2)		Jul 2022	Jul 2022
Final Reliability Portfolios	TWG	Jul 2022	Jul 2022
Portfolio Optimization / Consolidation	ESWG, TWG	Jul 2022	Aug 2022
Project Staging	ESWG, TWG	Aug 2022	Sep 2022
Benefit Metrics Calculations	ESWG	Aug 2022	Sep 2022
Stability Analysis	TWG	Aug 2022	Sep 2022
Sensitivity Analysis	ESWG	Aug 2022	Sep 2022
Final Reliability Assessment	TWG	Aug 2022	Sep 2022
Review Draft Report with Recommended Solutions	ESWG, TWG	Aug 2022	Sep 2022
Final Report with Recommended Solutions	ESWG, TWG	Sep 2022	Sep 2022
	RSC, SPC, SSC	October 2022	
	MOPC, SPP Board		
	MOPC, SPP Board		

Table 6: 2022 ITP Schedule

SECTION 6: CHANGES IN PROCESS AND ASSUMPTIONS

To protect against changes in process and assumptions that could present a significant risk to the completion of the 2022 ITP Assessment, any changes to this scope or assessment schedule must be appropriately vetted and follow the process outlined in the stakeholder accountability section of the ITP Manual.

Southwest Power Pool, Inc.

ECONOMIC STUDIES WORKING GROUP

Pending Action Items Status Report

February 3-4, 2021

#	Action Item	Date Originated	Status	Comments
190	Utilize the results from RCAR III to determine the ratio of APC benefit to Transmission Outages benefit to be applied in the ITP assessments.	October 12th, 2017	On Hold	Working with SPP operations on additional APC benefit with outages included. **Mar:** Ops is planning to perform after RCAR III and Value of Transmission study.
199	How we inform our Siting Plan: Research the appropriateness of relying on the GI Queue for Siting of renewables and Battery Storage and looking into other available information	April 2019	In Progress	Goal: to complete and implement for the 2021 ITP Assessment Continue discussing the battery storage piece **Mar:** Battery Survey to be sent out soon
201	Review the interchange methodology	July 2019	In Progress	Goal: To complete for the 2021 ITP Assessment **Mar:** 2021 portion considered complete. Outstanding long-term items: • Transactions between simulated and non-simulated regions • Benchmarking of pseudo-ties
203	Conduct a Lessons Learned Session with the ESWG on the 2019 ITP Assessment	August 2019	In Progress	Presented in June 2020; more to cover soon in addition to 2020 ITP **Feb:** Adding to schedule slides soon to report

				completion and facilitate ESWG discussion
209	Create Revision Request to remove RPS table from the ITP Manual	December 2020	In Progress	**Mar:** review and approve RR on agenda
210	Create list of 20YA items to review	January 2021	In Progress	**Mar:** Review updated list on agenda. Some items on agenda for discussion

RR 448

REMOVING RPS TABLE FROM ITP MANUAL AND PLACING IN SCOPE

JOSHUA NORTON

MARCH 2021

WHY WE NEED THIS REVISION REQUEST

- Eliminate mismatch between ITP Manual, study process and report
- Line up processes
- Specify study years being assessed for shortfalls
- Enhances and clarifies working group process for review and approval

ELIMINATE MISMATCH

RPS in ITP Manual

State	RPS Type	Generation Type	Capacity- or Energy- Based	Year 5 %	Year 10 %
Kansas	Goal	Both	Capacity	20	20
Minnesota	Mandate	Both	Energy	20	25
Missouri	Mandate	Both	Energy	15	15
Montana	Mandate	Both	Energy	15	15
North Dakota	Goal	Both	Energy	10	10
New Mexico	Mandate	Wind	Energy	15	15
New Mexico	Mandate	Solar	Energy	4	4
South Dakota	Goal	Both	Energy	10	10
Texas	Mandate	Both	Capacity	5	5

RPS Updates for 2021 ITP

State	RPS Type	Generation Type	Capacity- or Energy- Based	Year 5 %	Year 10 %
Kansas	Goal	Both	Capacity	20	20
Minnesota	Mandate	Both	Energy	**25**	25
Missouri	Mandate	Both	Energy	15	15
Montana	Mandate	Both	Energy	15	15
North Dakota	Goal	Both	Energy	10	10
New Mexico	Mandate	**Both**	Energy	**40**	**50**
South Dakota	Goal	Both	Energy	10	10
Texas	Mandate	Both	Capacity	5	5

LINE UP PROCESS

- Legislation review completed in August each year
  - Already lines up with ITP Scope timeline

SPECIFY STUDY YEARS BEING ASSESSED FOR SHORTFALLS

- Year 2 is not assessed for shortfall

ENHANCE AND CLARIFY WORKING GROUP PROCESS

1. The previous ITP study's mandate and goal values will be used as a starting point for the current study's calculations
2. Any changes to these values will be reviewed by the CAWG and approved by the ESWG
3. Ultimately, the renewable policy review results will be reviewed by the CAWG and approved by the ESWG.

RECOMMENDATION

- Staff recommends ESWG approve RR 448

Revision Request Form

SPP STAFF TO COMPLETE THIS SECTION	
RR #: 448	**Date: 2/12/2020**
RR Title: Removing RPS Table from ITP Manual and placing in Scope	

System Changes ☒ No ☐ Yes

Process Changes? ☒ No ☐ Yes

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

SUBMITTER INFORMATION

Name: Joshua Norton	**Company:** SPP
Email: jnorton@spp.org	**Phone:** 501-482-2465

Only Qualified Entities may submit Revision Requests.
Please select at least one applicable option below, as it applies to the named submitter(s).

☒ **SPP Staff** ☐ **SPP Market Participant** ☐ **SPP Member** ☐ **An entity designated by a Qualified Entity to submit a Revision Request "on their behalf"**	☐ **SPP Market Monitor** ☐ **Staff of government authority with jurisdiction over SPP/SPP member** ☐ **Rostered individual of SPP Committee, Task Force or Working Group** ☐ **Transmission Customers or other entities that are parties to transactions under the Tariff**

REVISION REQUEST DETAILS

Requested Resolution Timing: ☒ **Normal** ☐ **Expedited** ☐ **Urgent Action**

Reason for Expedited/Urgent Resolution:

Type of Revision (select all that apply):

☐ Correction *(i.e., revising erroneous language or language that needs clean-up for grammatical errors or inconsistency across governing documents - no changes to intent or policy)*

☒ Clarification *(i.e., revising language to better represent existing intent, no changes to functionality or policy)*

☐ Enhancement *(i.e., revising language to expand upon existing intent or functionality)*

☐ New Protocol, Business Practice, Criteria, Tariff *(i.e, new language to accommodate new functionality or policy not existing today)*

☐ NERC Standard Impact *(Specifically state if revision relates to/or impacts NERC Standards, list standard(s))*

☐ FERC Mandate *(List order number(s))*

REVISION REQUEST RISK DRIVERS

Are there existing risks to one or more SPP Members or the BES driving the need for this RR? ☐ Yes ☒ No

If yes, provided details to explain the risk and timelines associated:

☐ Compliance (Tariff, NERC, Other)

☐ Reliability/Operations

☐ Financial

SPP Documents Requiring Revision: *Please select your primary intended document(s) as well as all others known that could be impacted by the requested revision (e.g. a change to a protocol that would necessitate a criteria or business practice revision).*		
☐ **Market Protocols**	**Section(s):**	**Protocol Version:**
☐ **Operating Criteria**	**Section(s):**	**Criteria Date:**
☐ **Planning Criteria**	**Section(s):**	**Criteria Date:**
☐ **Tariff (OATT)**	**Section(s):**	
☐ **Business Practice**	**Business Practice Number:**	
☒ **Integrated Transmission Planning (ITP) Manual**	**Section(s): 2.2.1.3**	
☐ **Revision Request Process**	**Section(s):**	
☐ **Minimum Transmission Design Standards for Competitive Upgrades (MTDS)**	**Section(s):**	
☐ **Reliability Coordinator and Balancing Authority Data Specifications (RDS)**	**Section(s):**	
☐ **SPP Communications Protocols**	**Section(s):**	

OBJECTIVE OF REVISION

Objectives of Revision Request:

When the ITP Manual was first developed it was expected that it would be rare for changes to be made to the renewable portfolio standards (RPS) table and allowed for changes to be approved and included in the study report. After the first few study cycles, the table was found to be out-of-date each time and the ITP Manual and study reports would have a mismatch often.

These proposed revisions will allow for review of the data each cycle with the ITP study scope, which will remove the possibility of conflicts between governing documents of a given ITP assessment.

REVISIONS TO SPP DOCUMENTS

In the appropriate sections below, please provide the language from the current document(s) for which you are requesting revision(s), with all edits redlined.

Integrated Transmission Planning (ITP) Manual

2.2.1.3 Renewable Policy Review

After the forecasted load is finalized, renewable policy standards (RPS) will be assessed for utilities within the SPP footprint. The ITP study scope will ~~The percentages in Table 3 will be used to calculate the~~ detail mandate and ~~or~~ goal values for each utility ~~residing in the listed states~~ with respect to the load submitted as part of the SPP annual data request. For those utilities that span multiple states, the approved powerflow models and geographical information system (GIS) data will be used to calculate each utility's load obligation in the corresponding state for purposes of calculating mandates and goals.

The previous ITP study's mandate and goal values will be used as a starting point for the current study's calculations. Any changes to these values will be reviewed by the CAWG and approved by the ESWG. Ultimately, the renewable policy review results will be reviewed by the CAWG and approved by the ESWG. The values for mandates and goals will ~~in Table 3~~ consider forward-looking legislation set by the states that either should be or must be met, depending on the state, in ~~each of the study~~ years 5 and 10. ~~A generation type of "both" indicates the mandate or goal can be met by either wind or solar generation in the study.~~ Both capacity- and energy-based mandates and goals will be assessed for fulfillment during development of the resource plan. Those that are energy-based also will be assessed during the policy needs assessment. ~~States within the SPP footprint that are not included in Table 3 do not have RPS requirement for the purposes of this renewable policy review.~~

State	RPS Type	Generation Type	Capacity or Energy Based	Year 5 %	Year 10 %
Kansas	Goal	Both	Capacity	20	20
Minnesota	Mandate	Both	Energy	20	25
Missouri	Mandate	Both	Energy	15	15
Montana	Mandate	Both	Energy	15	15
North Dakota	Goal	Both	Energy	10	10
New Mexico	Mandate	Wind	Energy	15	15
New Mexico	Mandate	Solar	Energy	4	4
South Dakota	Goal	Both	Energy	10	10
Texas	Mandate	Both	Capacity	5	5

Table 3: ITP RPS by State

Renewable energy credits will be accommodated appropriately as provided to SPP.
If any significant changes to renewable mandates or goals occur during an ITP assessment, SPP stakeholders can bring them to the ESWG for review and potential approval for use in the ITP assessment. If exemptions to the mandates or goals are allowed (e.g. the applicable technology is cost prohibitive or municipals are exempt), those exemptions will be considered as SPP is notified during the renewable policy review.
Any resulting deviations from the standard values in Table 3 will be noted in the study report.

2020 INTEGRATED TRANSMISSION PLANNING ASSESSMENT SUPPLEMENTAL INFORMATION

By SPP Engineering

Approved on TBD

Version 0.1

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
1/29/2021 v0.1	SPP Staff	Initial Draft	Supplemental Hurdle Rate Sensitivity posted for ESWG review
TBD v0.2	SPP Staff	Initial Draft Report Addendum	Updated with stakeholder feedback and approved by ESWG
TBD v0.3	SPP Staff	Initial Draft Report Addendum	Posted for MOPC

CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY

The final 2020 Integrated Transmission Planning (ITP) project portfolio was tested against a wide range of sensitivities, including natural gas prices, generator retirements, renewables development, battery storage and demand. Hurdle rate [1] sensitivities have been added to the 2020 ITP report sensitivities as this supplemental information. The supplemental sensitivity analysis determined that APC savings across the hurdle rate sensitivities had a benefit-to-cost ratio greater than 1.0. See Section 8.3 for more information.

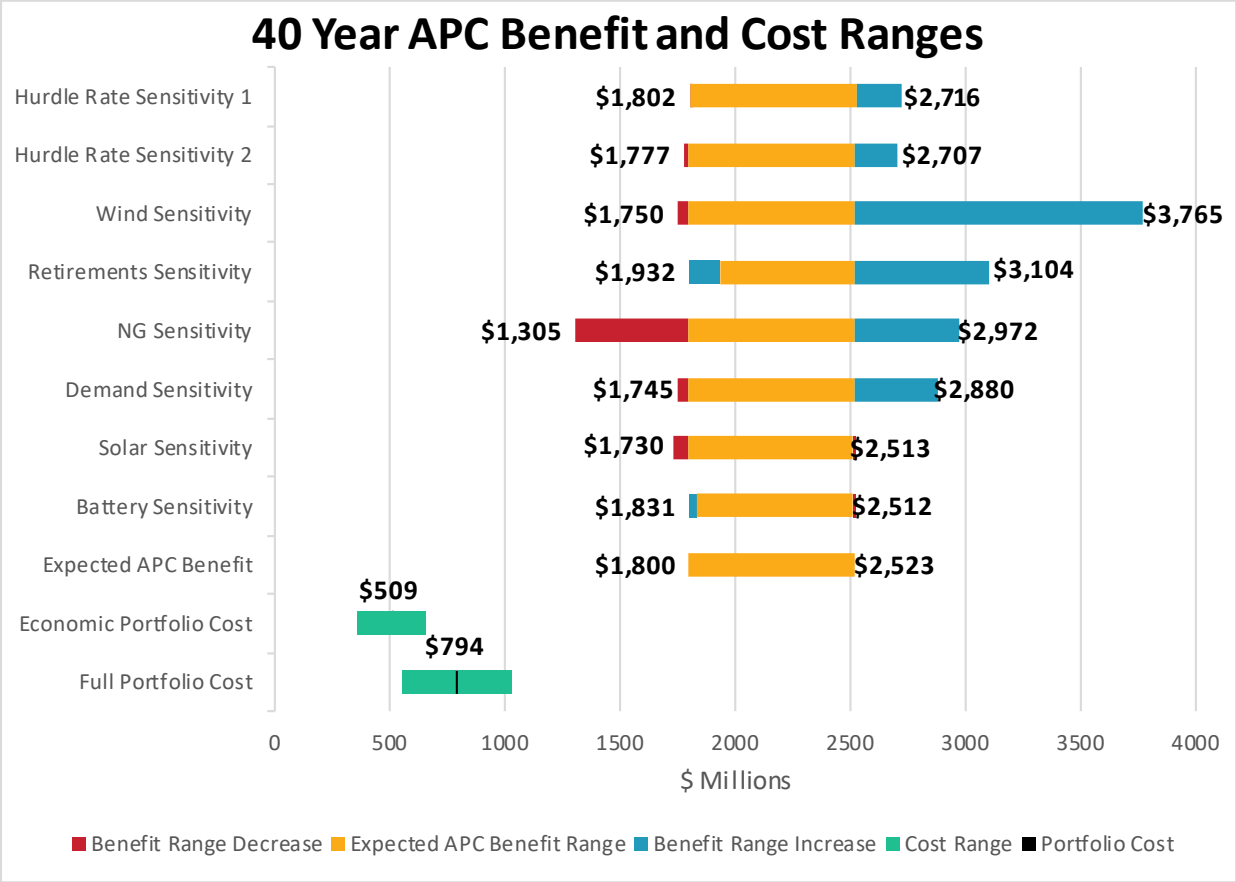


Figure 0.1: 40-Year APC Benefit and Cost Ranges

[1] Hurdle Rates in the 2020 ITP market economic models are used to set a minimum savings criteria to allow for exchange of economy interchange between SPP and neighboring AECI and MISO regions, and between AECI, MISO and TVA regions.

1 INTRODUCTION

1.1 2020 ITP REPORT SUPPLEMENTAL INFORMATION

SPP staff and its stakeholders on occasion identify the need to provide supplemental information pertaining to an approved ITP report. This report addendum includes supplemental information to provide further relevant information to meet the overall objectives of the 2020 ITP.

1.2 REPORT SUPPLEMENTAL INFORMATION STRUCTURE

This report supplemental information uses a style and format consistent with the original 2020 ITP Report. [2] The background and how each addendum relates to the original report revision are provided in this introduction section.

1.3 SENSITIVITY ANALYSIS SUPPLEMENTAL INFORMATION

A Hurdle Rate Sensitivity section has been added to 2020 ITP Report v1.0, Section 8.3 Sensitivity Analysis, as well as Figure 8.3, Figure 8.10, Figure 8.11, and Table 8.29. Section 8.3.7 Hurdle Rate Sensitivity includes information regarding the sensitivity analysis inputs and results. The final project portfolio was tested against two sets of hurdle rate sensitivities. The analysis determined the adjusted production cost (APC) savings across hurdle rate sensitivities had a minimum impact on portfolio benefits.

[2] https://www.spp.org/Documents/63434/2020%20Integrated%20Transmission%20Plan%20Report%20v1.0.pdf

8 INFORMATIONAL PORTFOLIO ANALYSIS

8.3 SENSITIVITY ANALYSIS

Hurdle rate sensitivities were performed to further explore the performance of the portfolio under varying conditions[3]. The consolidated portfolio was tested in both futures. The APC savings impacts of variations in the model inputs were calculated for the simulations. The Hurdle Rate Sensitivity 1 and 2 were added to 2020 ITP Report, Figure 8.3.[4]

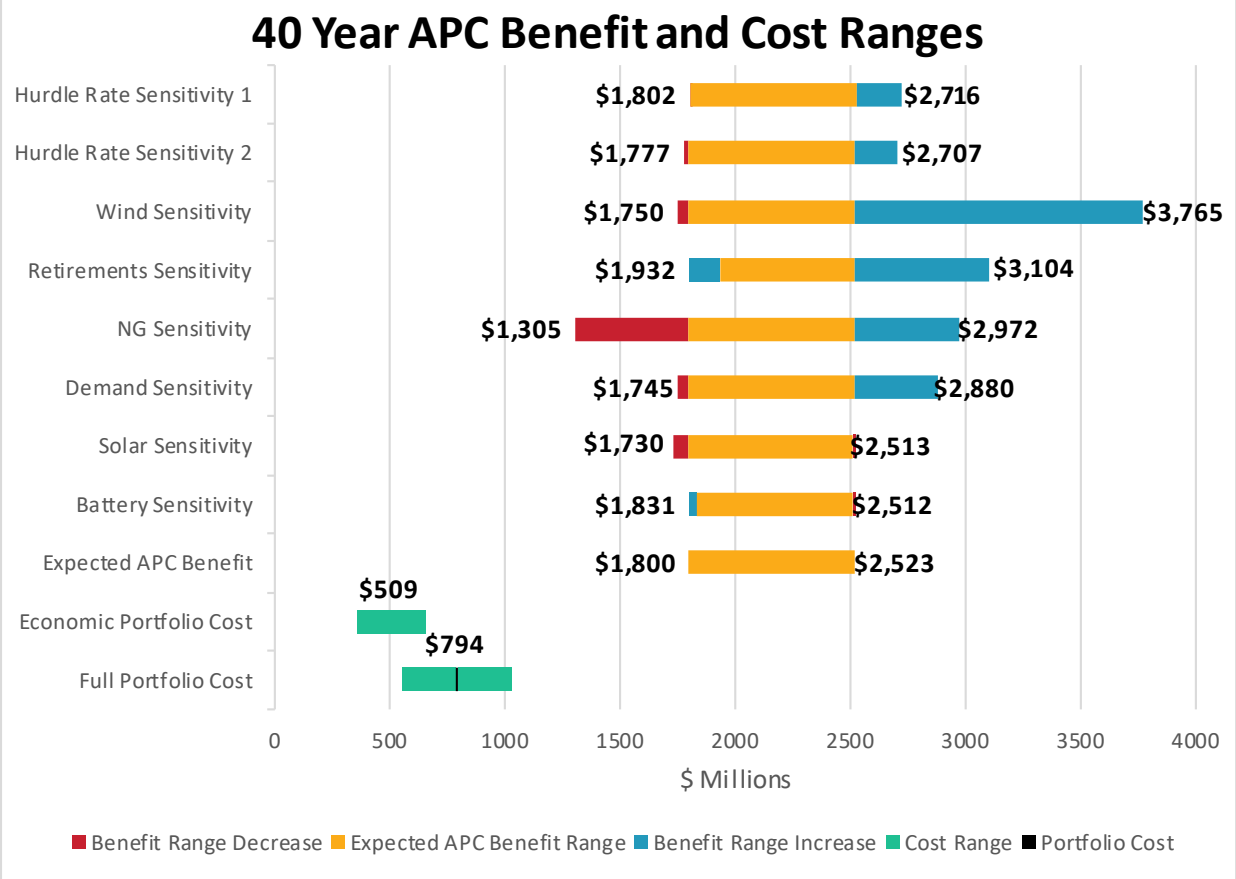


Figure 8.1: 40-Year APC Benefit and Cost Ranges

[3] The recommended portfolio was tested under select sensitivities to understand the economic impacts associated with variations in certain model assumptions. These sensitivities were not used to develop transmission projects nor filter out projects, but rather to measure the flexibility of the final consolidated portfolio in both futures under different uncertainties.

[4] Figure 8.3 illustrates the expected range of APC savings benefit in comparison to the range of portfolio cost and the impacts of varying sensitivity assumptions on that range of benefits. The cost ranges represent the ±30 percent Study Estimate requirement. The dashed bar in subsequent figures represents the expected case B/C ratio for comparison to the sensitivity case B/C ratios

8.3.7 HURDLE RATE SENSITIVITY

Two sets of hurdle rate sensitivities were conducted to test the portfolio's performance. The first set of hurdle rate sensitivities identified as Hurdle Rate Sensitivity 1 involved only changing hurdle rates between SPP and neighboring AECI and MISO regions in the market economic model to the amounts shown in Table 8.29. The second set of hurdle rate sensitivities identified as Hurdle Rate Sensitivity 2 involved changing all hurdle rates between respective neighboring regions in the market economic model to the amounts shown in Table 8.29.[5]

Variable	Sensitivity	Future 1 Year 5	Future 1 Year 10	Future 2 Year 5	Future 2 Year 10
Hurdle Rate	**$0 Hurdle Rate**	$0	$0	$0	$0
	$4 Hurdle Rate	$4	$4	$4	$4
	Expected Hurdle Rate	$8	$8	$8	$8
	$16 Hurdle Rate	$16	$16	$16	$16
	$32 Hurdle Rate	$32	$32	$32	$32
	$64 Hurdle Rate	$64	$64	$64	$64
	$128 Hurdle Rate	$128	$128	$128	$128

Table 8.1: Hurdle Rate Sensitivity

These high and low values were included as inputs to the base models of each future with and without the recommended portfolio. The results of the 40-year APC benefits for the two sets of sensitivities are reflected in Figure 8.10 and Figure 8.11. *Insert additional commentary once available.*

[5] Hurdle rate assumptions for the 2020 ITP are based upon the latest vendor data set consistent with the ITP Manual. The market economic hurdle rates influence economic interchange between simulated regions by setting a minimum dispatch savings for non-firm purchases and sales to occur between simulated regions and are intended to reflect the interregional non-firm transmission wheeling rates and account for market-to-market friction.

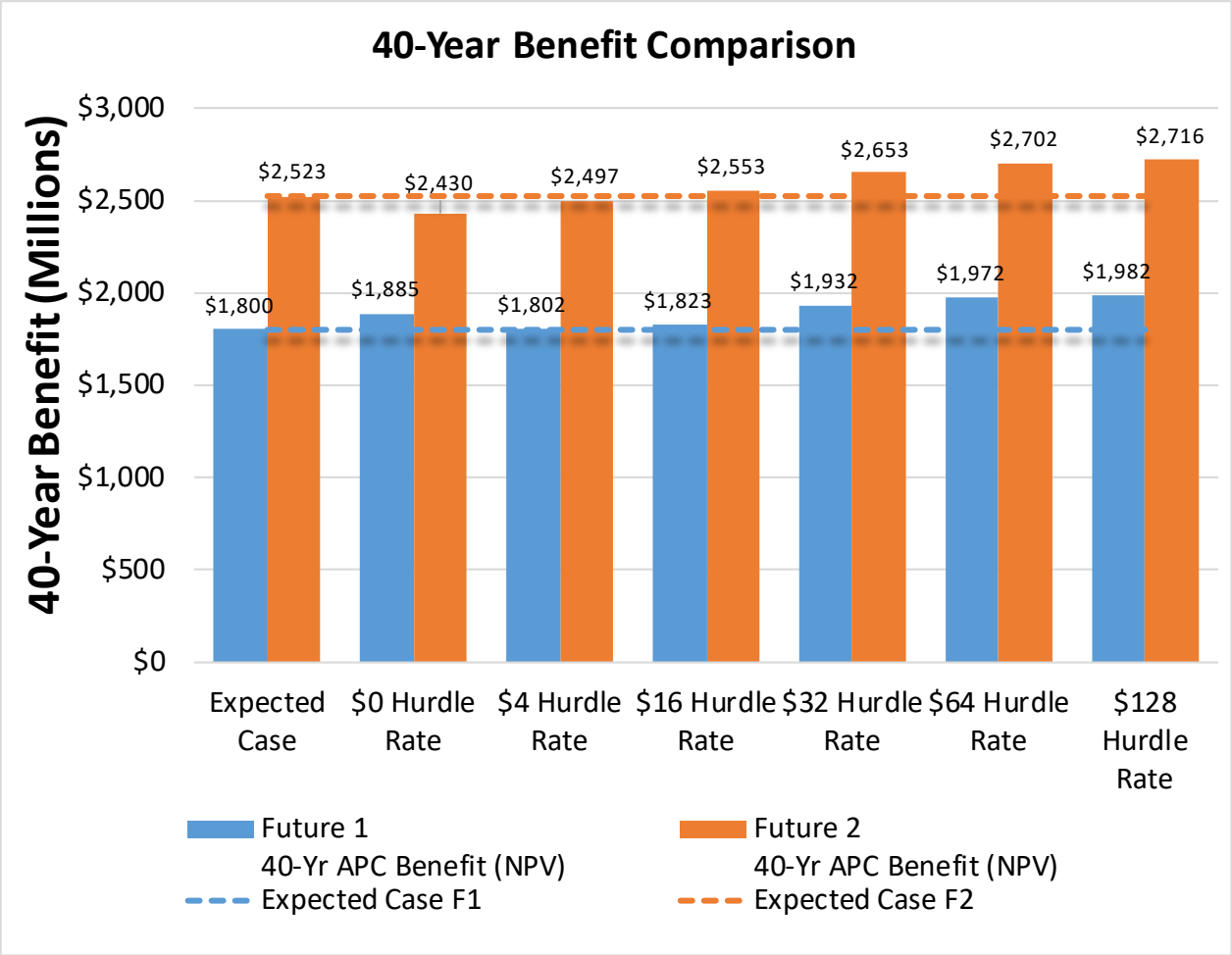


Figure 8. 2: 40-Year Benefit Comparison (Hurdle Rate Sensitivity 1)

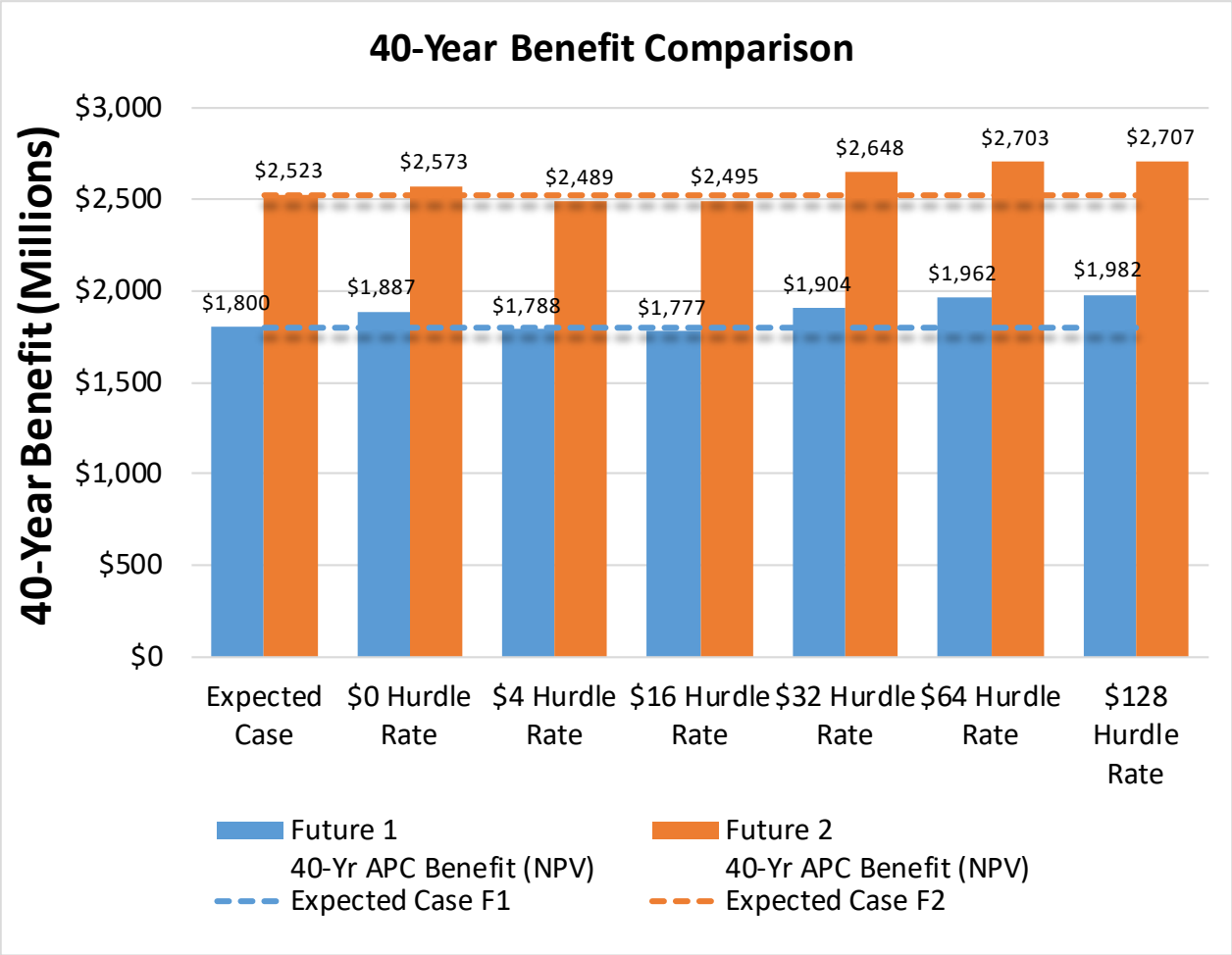
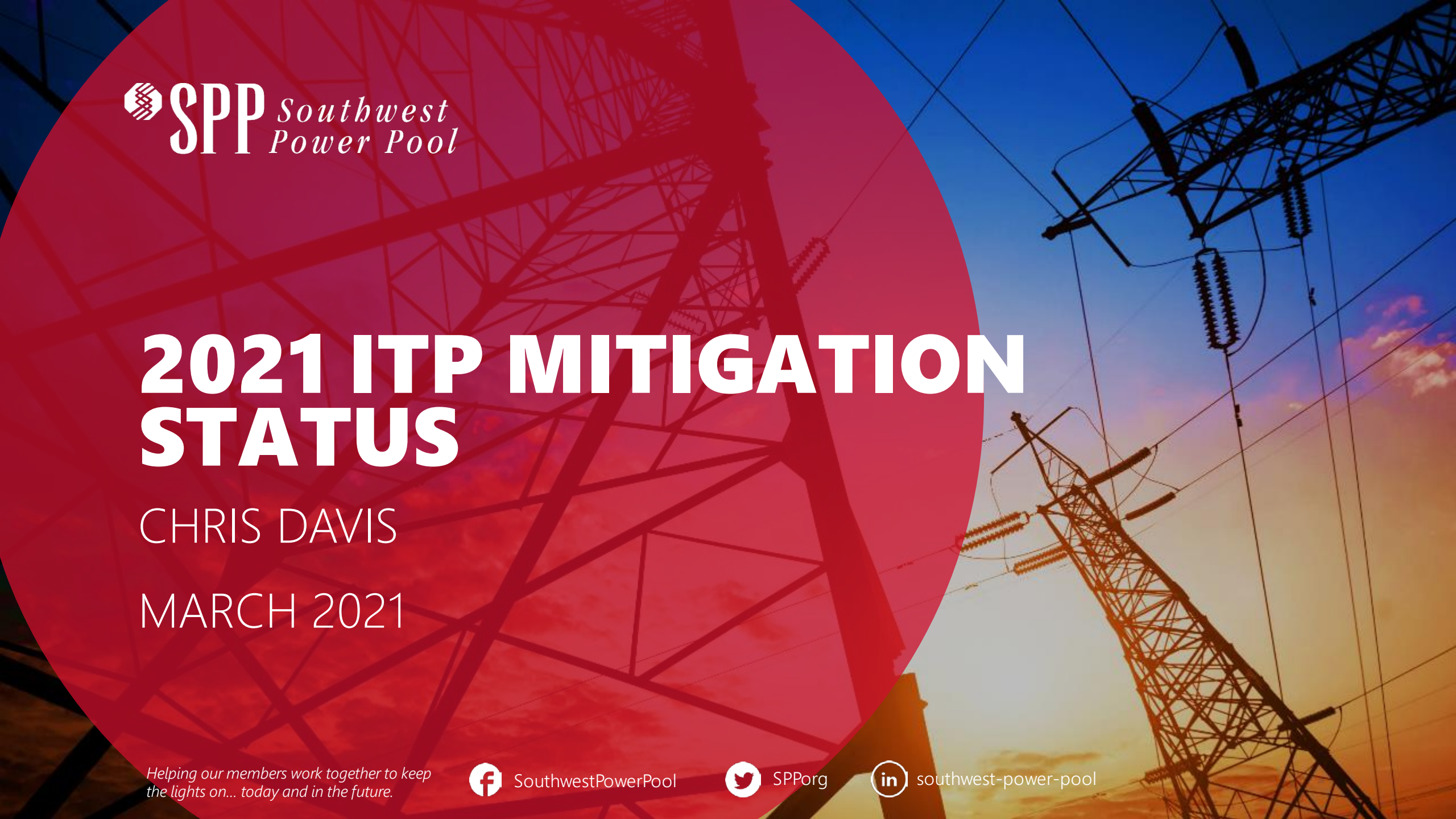


Figure 8. 3: 40-Year Benefit Comparison (Hurdle Rate Sensitivity 2)



SPP Southwest Power Pool

2021 ITP MITIGATION STATUS

CHRIS DAVIS

MARCH 2021

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

SouthwestPowerPool SPPorg southwest-power-pool

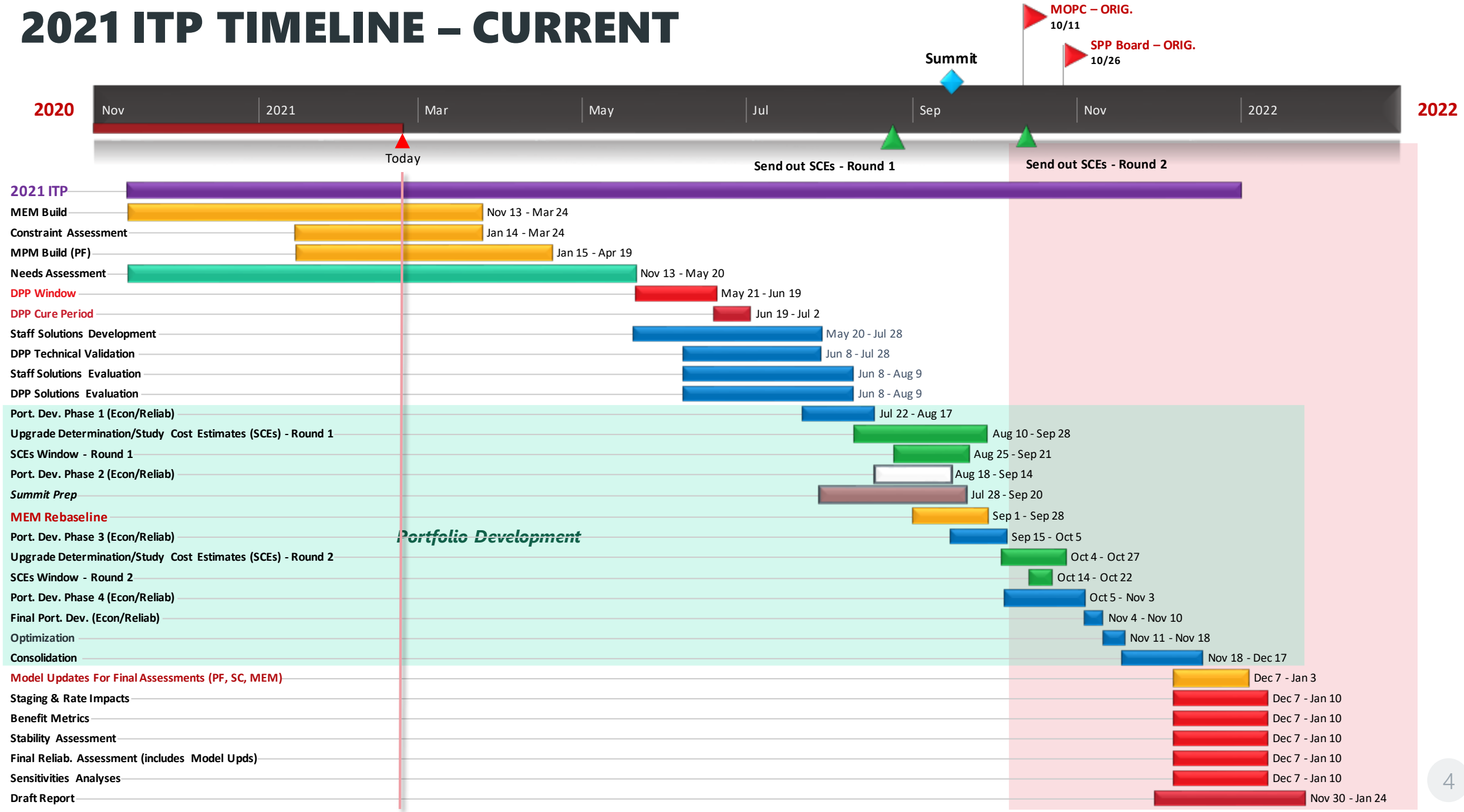
PURPOSE

- Recap stakeholder feedback from February TWG/ESWG
- Provide update on 2021 ITP mitigation items
- Overview waivers needed
- Recommend approval of 2021 ITP mitigation plan

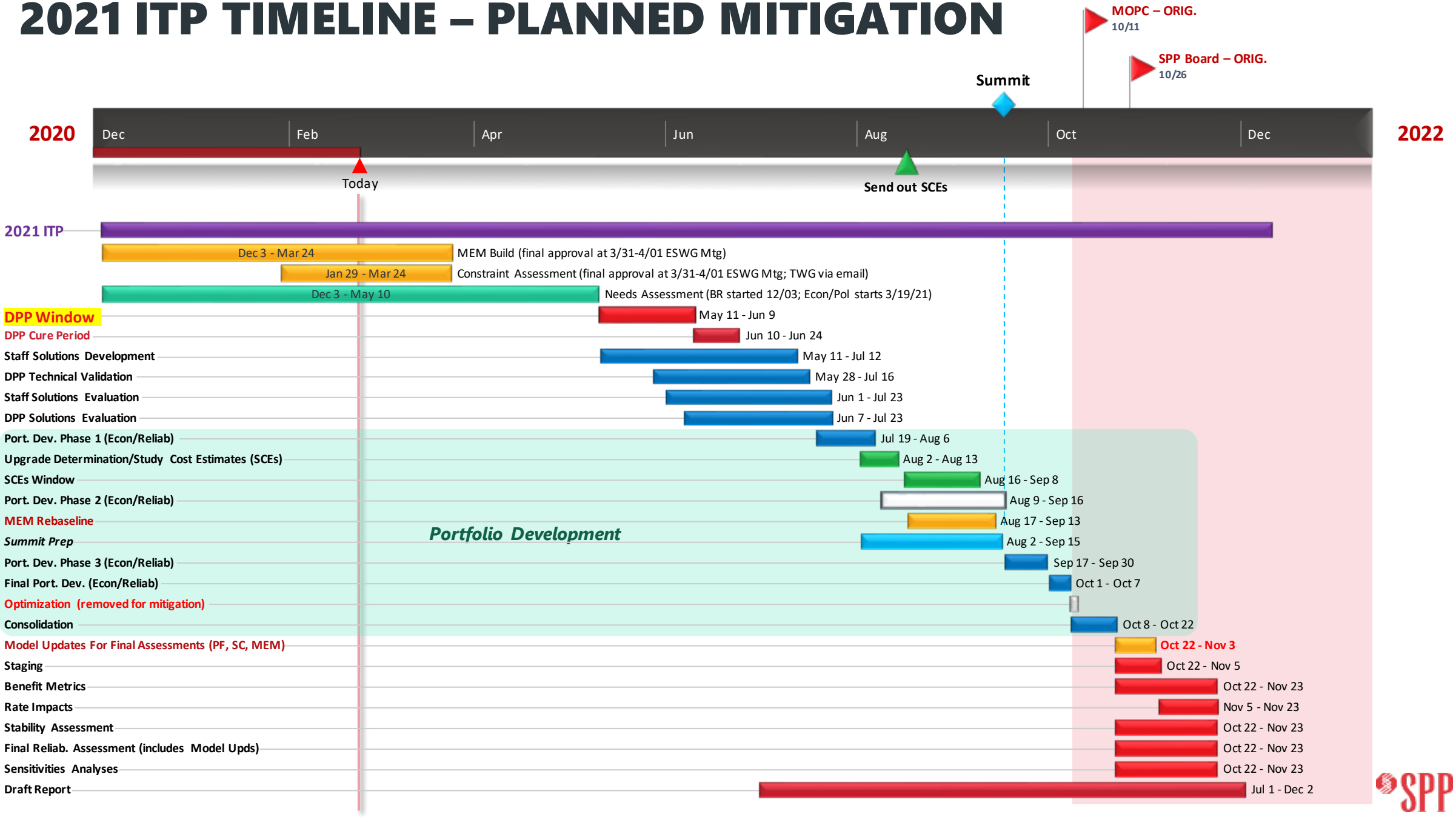
FEEDBACK FROM FEBRUARY 2021 TWG/ESWG

- Concerns of reducing the amount of milestone approvals
- Concerns of reducing amount of study cost estimates used
- Concerns of reducing scope of 2023 ITP
- Support for reducing number of economic constraints in 2021 ITP
- Support for re-using 2021 Market Economic Model (MEM) in 2022 ITP
- Support for increasing consulting to complete the 2021 ITP

2021 ITP TIMELINE – CURRENT



2021 ITP TIMELINE – PLANNED MITIGATION



UPDATED MITIGATION PLAN

MITIGATION PLAN UPDATE

- Take steps to reduce quantity of Detailed Project Proposals (DPPs) submitted while maintaining quality submissions
- ~~Reduce amount of milestone approvals needed in working groups~~
- Utilize additional staff as available
- Reduce scope of 2023 ITP to NERC-required processes
- Carve out Market Powerflow Model (MPM) needs from 2021 ITP process
- Reduce number of economic needs to post
- Revisions to study cost estimate request process
- Re-use 2021 ITP MEM as base for 2022 ITP
- Slide end date to early December 2021
- Utilize contractors if staff augmentation needs are forecasted

NEEDS POSTING AND DPP WINDOW PREP

- SPP will take steps to help DPP submitters maintain same quality of DPP submissions while reducing quantity
  - Repeat education sessions that were given in 2020 to help submitters understand SPP validation and evaluation processes
  - SPP is working to gather available data about conductor ratings to post a "conductor-limited" flag along with needs posting to help DPP submitters determine which needs to submit solutions for

REDUCE NUMBER OF MILESTONE APPROVALS

- Original approach was to eliminate working group approvals of certain milestones in order to be able to keep ITP moving without waiting for approval of the previous milestones
- After discussions with staff, this is already reflected in the schedule, so not much to be gained by doing this
- If necessary, SPP staff may ask for expedited approval or email approval to continue making progress on ITP work

REDUCE SCOPE OF 2023 ITP

- Reduce 2023 ITP to processes required by NERC for compliance
  - Will include base reliability (BR) needs assessment and TPL processes, no economic or policy assessment
  - Years 2, 5 and 10 (Summer/Winter/Light Load)
- Potential 10-11 model reduction
  - May still need some form of MEM for Deliverability Study and to produce TPL sensitivity models
- Still an improvement from pre-TPITF modifications, where economic assessments were once every three years
- Will have time savings for 2021, 2022 and 2023 ITP
- No adverse impact to TWG AI 186 model reduction effort

MPM CARVE-OUT

- Original proposal was to exclude MPM violations from the ITP Needs Assessment posting
- New approach is to carve out MPM violations from ITP altogether
- Excluding MPM violations from the 2021 ITP draws a cleaner line from a compliance standpoint
- Support TPL compliance with F1 Y2 peak, Y2 off-peak, and Y5 peak MPM only

REDUCE NUMBER OF ECONOMIC NEEDS

- Including this item based on feedback from February 2021 working groups
- ITP Manual already supports doing this
  - A more qualitative assessment may be used to limit the number of needs to meet the study schedule and objectives. This assessment will consider the number of binding constraints with similar attributes, recommended constraints, and/or target areas for additional analysis, mitigation need dates, general transmission solution lead times, and other project staging considerations.
- SPP will consider schedule in order to determine appropriate constraints while meeting ITP deadlines

COST ESTIMATES

- Cost estimate requests will be sent out as-needed beginning at closing of DPP window through approximately end of summer
  - Note: Submitters may review needs list and anticipate which requests may be received
- More frequent posting of project list – email notification when project list is refreshed
- Conceptual costs will be used until more refined estimate is received
- Submitters have four weeks to respond after receipt of request
  - One week to acknowledge that a response will be prepared

RE-USE 2021 ITP MEM AS BASE FOR 2022 ITP

- No changes to this approach from February 2021
- No concerns have been voiced over this approach
- Re-using static portions of MEM will allow staff to focus more on 2021 ITP while not allowing other efforts to slip
- SPP will refresh MEM vendor data that is appropriate for 2022 ITP
  - Fuel prices
  - Emissions prices
  - Hurdle rates

SLIDE 2021 ITP END DATE TO DECEMBER 2021

- No changes to new end date of December 2, 2021 from last month
- Earliest feasible end date while still getting ITP approvals before holidays

UTILIZE CONTRACTORS AS NEEDED

- Feedback received from February 2021 that contractors should be used to help complete the 2021 ITP
- SPP staff made necessary schedule adjustments to ensure successful completion of 2021 ITP within 2021 calendar year
- 2021 consulting budget to support ITP has been allocated
  - SPP management will be prepared to make a case for out-of-budget request for contractors should the need arise

SUMMARY OF WAIVERS NEEDED

Item	Tariff Waiver	ITP Manual Waiver
~~Reduce milestone approvals~~		~~TBD~~
Reduce 2023 ITP Scope	April TWG/ESWG April MOPC	April TWG/ESWG April MOPC
Carve out 2021 MPM Needs		April TWG/ESWG April MOPC
Revise 2021 Study Cost Process		April TWG/ESWG April MOPC

IMPACTS TO 2022 ITP AND 2023 ITP

- With approval of 2021 ITP being delayed to December, this will delay approval of all 2022 ITP models, BR needs assessment, and constraint assessment
- Typically, BR needs assessment is not a critical path schedule item; however, delays will increase overlaps with other ITP processes
- Reducing scope of 2023 ITP will help relieve resource collisions and should mitigate delays in subsequent milestones

RECOMMENDATION

SPP staff recommends ESWG approve the proposed 2021 ITP mitigation plan

Vote to add amendment:

Steve proposed ammendment: Remove elimination of 2023 ITP economic analysis from mitigation plan

RECOMMENDATION

SPP staff recommends ESWG approve the proposed 2021 ITP mitigation plan

Original motion to approve staff's recommendation

SPP Southwest Power Pool

2021 ITP

2021 ITP ECONOMIC CONSTRAINT ASSESSMENT UPDATE

AHMED ALAZZAWI

MARCH 2-3, 2021

OBJECTIVE

- Update on the current status of the constraint assessment process
- Reminder for constraint assessment feedback

MILESTONE UPDATE

- Processed PROMOD runs and determined SPP Peak and Off Peak hours
- Validated PAT identified constraints
- Solicited Stakeholders for 69kV constraints
- Filtering constraints

	OFF-PEAK			PEAK		
Scenario	DATE	HOUR (AM)	WIND PENETRATION	DATE	HOUR (PM)	LOAD (MW)
Future 1 year 2	Wednesday, April 5, 2023	3	90.20%	Thursday, Jun 22, 2023	5	50,691
Future 1 year 5	Wednesday, May 20, 2026	2	99.40%	Wednesday, July 22, 2026	7	52,108
Future 2 year 5	Wednesday, May 20, 2026	2	113.20%	Wednesday, July 22, 2026	7	52,225
Future 1 year 10	Tuesday, April 1, 2031	3	110.10%	Thursday, July 24, 2031	7	54,008
Future 1 year 10	Tuesday, April 1, 2031	3	124.90%	Thursday, July 24, 2031	7	54,630

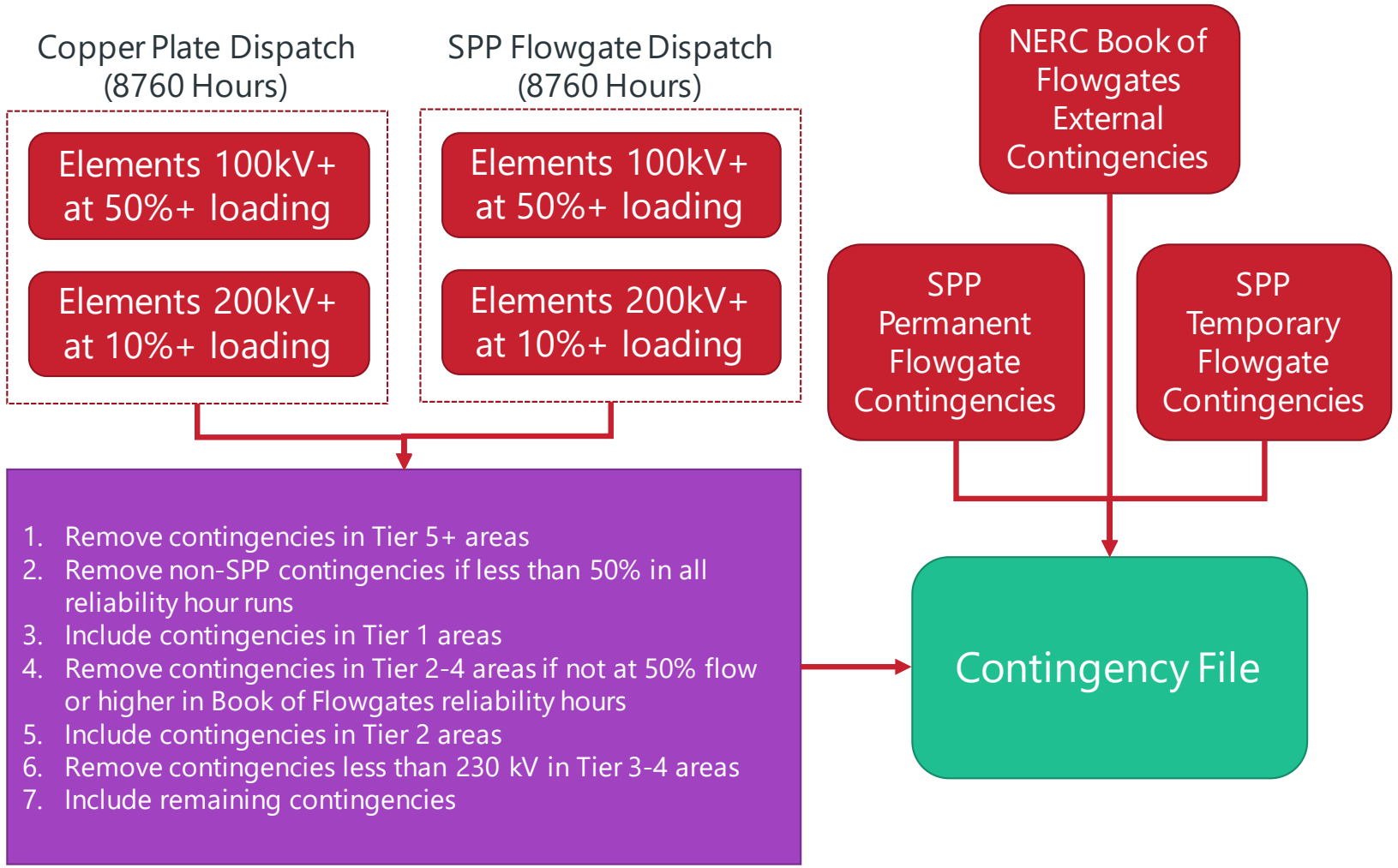
STAKE HOLDER REVIEW PERIOD

- Event Evaluation and Filtering: 2/10 - 03/01
- Stakeholder Constraints Review Period: 03/02 - 03/08
- SPP Staff incorporate feedback: 03/09 - 03/15
- TWG Expedited Email vote: 03/27 - 03/29
- *Dates are tentative and SPP staff is working to bring them in as part of schedule mitigation

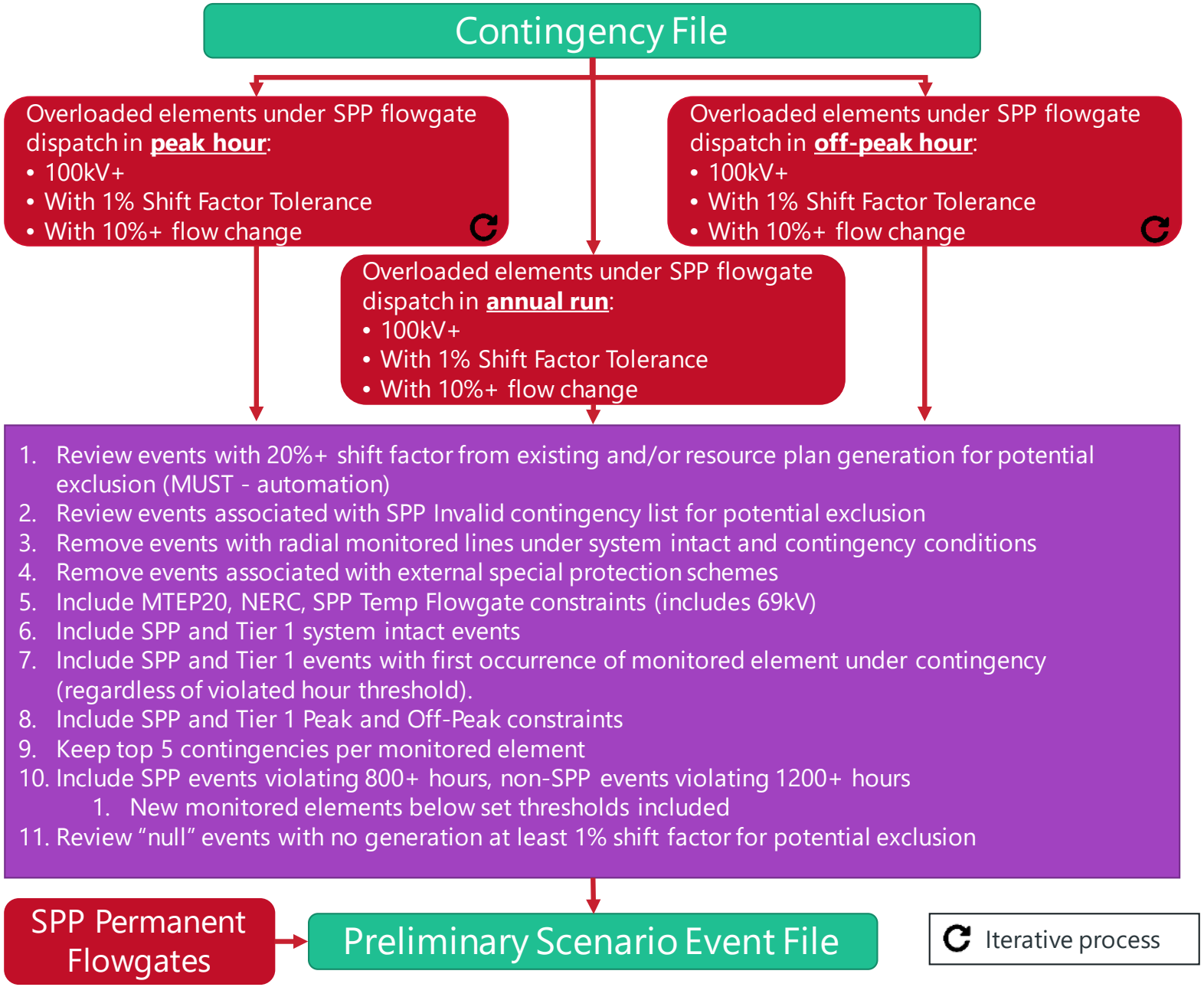
2021 **ITP**

APPENDIX

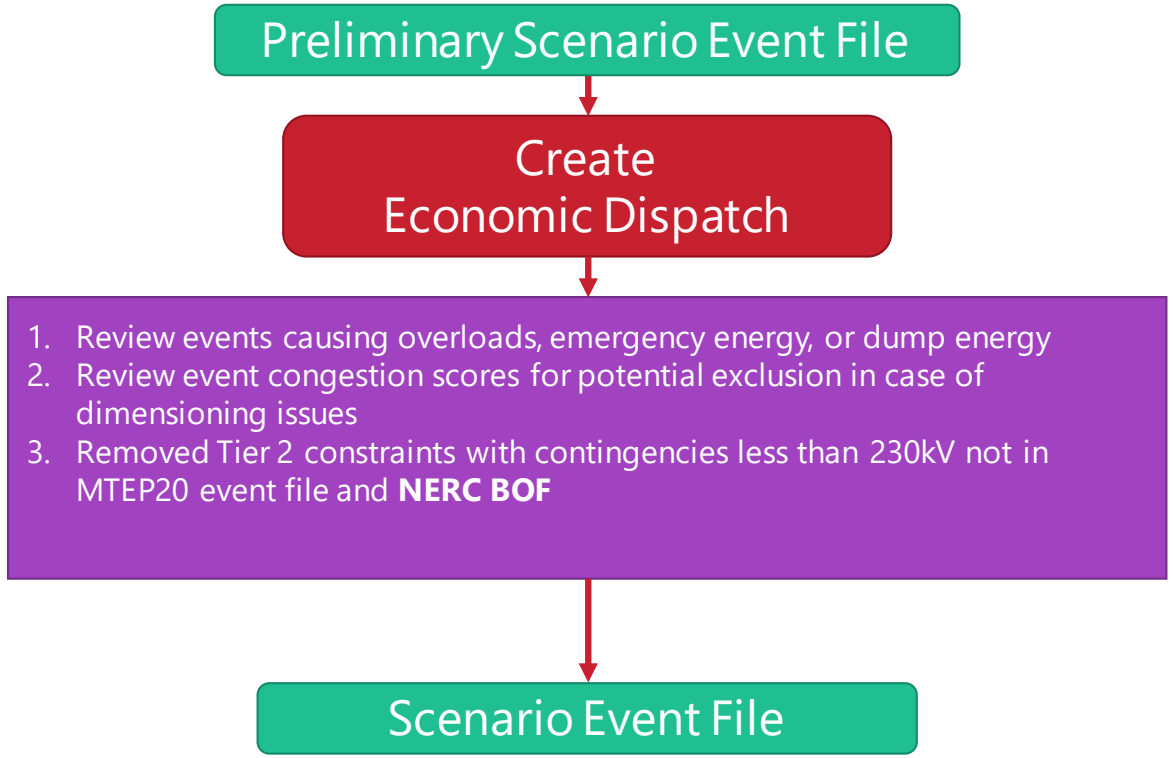
CONTINGENCY CREATION BY SCENARIO



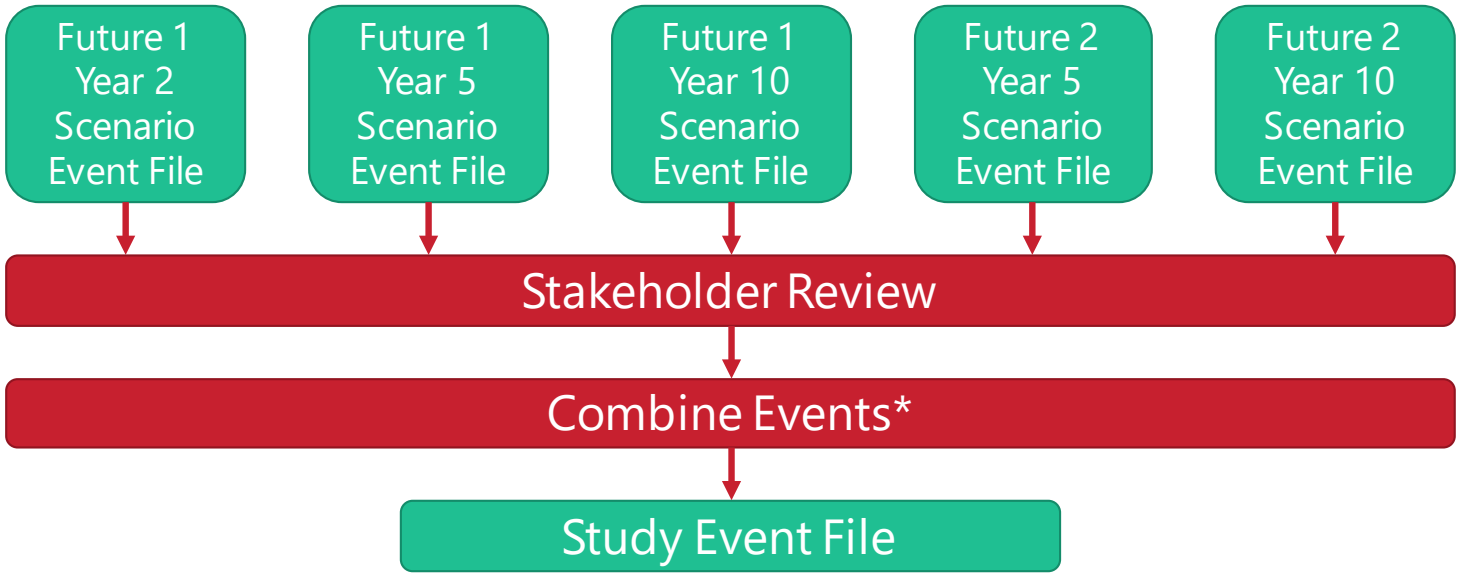
EVENT CREATION (BY SCENARIO)



EVENT CREATION II BY SCENARIO



METHODOLOGY OVERVIEW
EVENT CREATION – STUDY-SPECIFIC



- *To the extent possible with topology changes amongst scenarios

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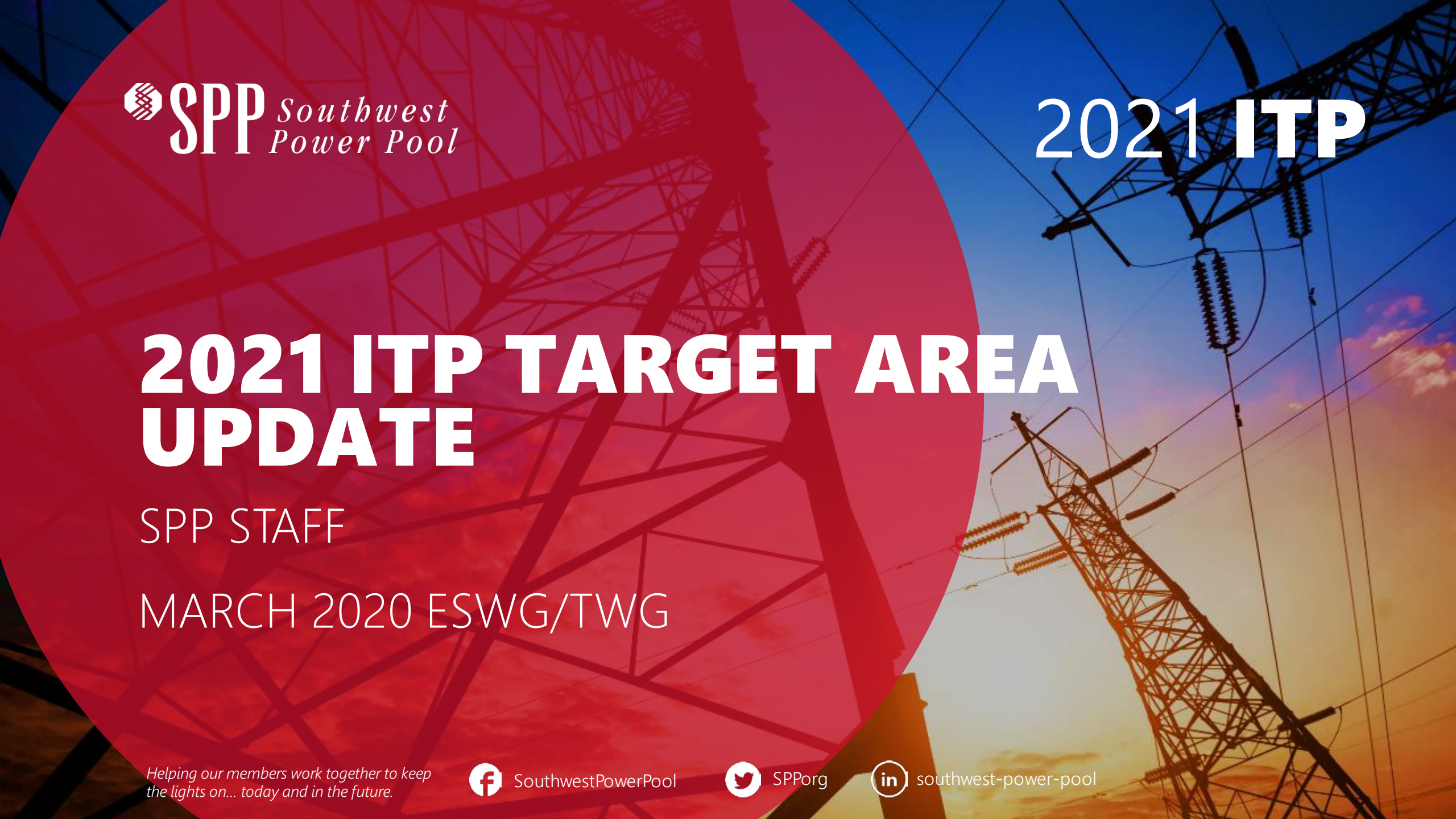
2021 ITP

2021 ITP TARGET AREA UPDATE

SPP STAFF

MARCH 2020 ESWG/TWG



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OVERVIEW

- Bakken Target Area Update

2021 **ITP**

BAKKEN TARGET AREA UPDATE

BAKKEN TARGET AREA UPDATE

- Issues:
  - Bakken Load forecast higher than currently expected
  - Market Economic Model has excessive emergency generation in Bakken
- Resolutions:
  - SPP Staff is investigating mitigation options with impacted stakeholders on how best to address load forecast concerns for the 2021 ITP, TPL-001, and other SPP planning processes that use common planning model to minimize planning process impacts
  - SPP Staff is investigating resource and siting adjustment options with impacted stakeholders to be executed congruent with the constraint assessment milestone completion to minimize 2021 ITP schedule impacts

NEXT STEPS

NEXT STEPS

- Provide issue resolution recommendations and rationale to ESWG and TWG in April or earlier
- Finalize Target Area Scoping in April and May prior to DPP window

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2022 **ITP**

2022 ITP AND 20-YEAR ASSESSMENT LOAD AND GENERATION REVIEW

BROOKE KEENE

MARCH 2021

OBJECTIVES

- Scope Review
- Future 2 Retirement Age-Based Exceptions Review (Approval Item)
- Must Run Language Review
- Must Run Exception Review (Approval Item)
- 20-Year Assessment methodology

2022 ITP AND 20-YEAR ASSESSMENT SCOPE

KEY ASSUMPTIONS	DRIVERS				
	Year 2	Future 1 – Reference Case		Future 2 – Emerging Technologies	
	2	5	10	5	10
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		Increase due to electric vehicle growth	
Natural Gas Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Coal Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Emissions Prices	Current industry forecast	Current industry forecast		Current industry forecast	
Fossil Fuel Retirements	Current forecast	Coal age-based 56+, Gas/Oil age-based 50+, subject to generator owner (GO) review		Coal age-based 52+, Gas/Oil age-based 48+, subject to GO review and ESWG approval	

F2 AGE-BASED RETIREMENT EXCEPTIONS

- Unit continues to be maintained and tested according to the SPP tariff
- No plans of retirement
- Requires the full MW capacity to meet SPP resource adequacy requirements

Unit Name	Category	Max Capacity (MW)	F2 Exception Retirement Date	F2 Retirement Date w/o Exception
Beloit (KS):1	IC Oil	12.35	12/31/2099	7/1/1999
Cimarron River:1	ST Gas	61.3	1/1/2038	12/1/2011
Fort Dodge (KS):4	ST Gas	146.7	1/1/2044	6/1/2017
Garden City:S2	ST Gas	92.7	1/1/2048	3/1/2021
Garden City:S4	CT Gas	49.4	1/1/2035	5/1/2024
Garden City:S5	CT Gas	48.4	1/1/2037	6/1/2027
Great Bend 3:3	ST Gas	92.7	1/1/2038	6/1/2011
Holcomb East:1	ST Coal	358.8	1/1/2058	8/1/2035
Kingman:2	IC Gas	18.2	12/31/2099	4/1/2010

F2 AGE-BASED RETIREMENT EXCEPTIONS

- Purchased in 2019 with expected remaining life of 30 years

Unit Name	Category	Max Capacity (MW)	F2 Exception Retirement Date	F2 Retirement Date w/o Exception
Frontier	Combined Cycle (Existing)	120	12/31/2048	9/1/2037
River Valley 1	ST Coal	160	12/31/2057	9/1/2042
River Valley 2	ST Coal	160	12/31/2057	11/1/2042

F2 AGE-BASED RETIREMENT EXCEPTIONS

- Set to match public position

Unit Name	Category	Max Capacity (MW)	F2 Retirement Date Exception	F2 Retirement Date w/o Exception
Horseshoe Lake:6	ST Gas	163	12/31/2023	4/1/2006
Horseshoe Lake:8	ST Gas	403	12/31/2029	6/1/2017
Horseshoe Lake:ST7	ST Gas	211	12/31/2028	6/1/2011
Muskogee:6	ST Coal	503	12/31/2049	6/1/2036
Mustang:5A	CT Gas	33	12/31/2025	6/1/2019
Mustang:5B	CT Gas	31	12/31/2025	6/1/2019
Seminole (OK):1	ST Gas	485	12/31/2030	3/1/2019
Seminole (OK):2	ST Gas	500	12/31/2030	2/1/2021
Seminole (OK):3	ST Gas	475	12/31/2030	6/1/2023

F2 AGE-BASED RETIREMENT EXCEPTIONS

- No plans of retirement

Unit Name	Category	Max Capacity (MW)	F2 Exception Retirement Date	F2 Retirement Date w/o Exception
J Street:1	CT Gas	31.7	2/1/2032	2/1/2020
Rokeby:GT1	CT Gas	72	2/1/2040	7/1/2023

F2 AGE-BASED RETIREMENT EXCEPTIONS

- Upgrades performed to the unit

Unit Name	Category	Max Capacity (MW)	F2 Retirement Date Exception	F2 Retirement Date w/o Exception
Hawthorne (MO):5	ST Coal	564	5/1/2047	5/1/2021
Sooner:1	ST Coal	516	12/31/2044	11/1/2031
Sooner:2	ST Coal	515	12/31/2045	12/1/2032

ITP MANUAL LANGUAGE (SECTION 2.2.1.11)

"Must-run units in the ITP assessment are dispatched during all available hours to their minimum capacity states, regardless of economics. Must-run statuses will be removed from all units at the start of each study. In the development of the ITP study scope, the ESWG will determine if must-run units will be allowed and the criteria needed for such designation. Individual generating units meeting must-run criteria will be identified by SPP or stakeholders during the generation review and subject to approval by the ESWG."

MUST RUN EXCEPTION

- Holcomb East:1
  - Sunflower has unaffiliated confidential supply-chain contracts that require Holcomb to operate at an approximate 50% capacity factor through the term of the 2021 ITP study period (term extends thru 2034). Market Economic study models, especially those that include winter and summer months, should identify that Holcomb is a must-run unit during non-shoulder periods.
  - Holcomb (350-MW) is Sunflower's flagship unit, placed into service in 1983, and is the only EGU operated on a continuing basis by Sunflower.

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2022 ITP

WIND HUB HEIGHT METHODOLOGY

BROOKE KEENE

BACKGROUND

- Previous ESWG Action Item 202 to reevaluate the existing wind 80/100 meter turbine height
- Issue: 2012 NREL WIND Toolkit profiles assume 100-meter hub height which results in over-estimation of wind energy by approximately 5% for 80-meter hub heights
- PROMOD 11.3 includes an enhancement that scales and redistributes energy within profile such that the peak is preserved on per generator basis

HUB HEIGHT METHODOLOGY

- Utilize available (EIA, SPP market registration, etc.) data for wind turbine hub heights for all translated areas
  - Round hub heights either to 100m or 80m
  - If 80-m,
    - apply 5% reduction to capacity factor
    - calculate new annual energy
    - input annual energy into PROMOD and set flag to scale energy
- If data is unavailable, assume:
  - Commission date on or before 12/31/2018 = 80m
  - Commission date on or after 1/1/2019 = 100m

20-YEAR ASSESSMENT – SCOPE AND STUDY EXECUTION ACTION ITEMS - UPDATED

SHERRI MAXEY

MARCH 2021

OVERVIEW

- Staff's Approach
- Action Items identified – Updates from February 2021 presentation shown in red

STAFF'S APPROACH

- Identify 20-Year Assessment scope and study execution items to be addressed with stakeholders
- Take chronological approach by ITP study milestone
- Bring back 1-2 months prior to start of milestone work for stakeholder discussion and decision

ACTION ITEMS

ID	Description	Milestone(s)
1	Load growth distribution and approach to non-conforming load (partial overlap with item 2)	Powerflow Models / Load Review
2	Implementing future drivers in generation and load review, and market economic model (MEM) Supply side items: • Emissions target and gas retirements (F3/F4), modeling and monitoring • Electric storage additions - transmission, energy or capacity asset, or all of the above? • Distributed resource forecasts and modeling • Fuel forecasts extrapolation and adjustments Demand side items: • Load shape changes • General electrification (*eg.*, 20YR - F3/F4) • Electric vehicle growth and distribution • Demand response • Energy efficiency	Generation and Load Review / Resource Plan (RP2) / MEM
3	Renewable Pricing and PTC assumptions/expirations	Generation Review / RP2 / MEM

ACTION ITEMS – CONT.

ID	Description	Milestone(s)
4	Renewable policy extrapolation	Renewable Policy Review
5	Possible use of resource planning software in 20-Year Assessment; or should we adjust the traditional resource additions?	RP2
6	Renewable and storage ownership, and accreditation assignment; CT-to-CC ratio; ELCC implementation	RP2
7	Identification of additional batteries beyond F1 and F2 scoped amounts (requires Scope change); including hybrid issues	RP2
8	External region resource plan and siting approaches	RP2
9	Review 12% cap on renewables for reserve margin requirements	RP2
10	Renewable accreditation	RP2
11	Determine resource addition strategy	Siting / GOFs / Constraint Assessment

ACTION ITEMS – CONT.

ID	Description	Milestone(s)
12	EPRI transmission capacity hosting tool/SPP initiative for siting	Siting / GOFs / Constraint Assessment
13	Hybrid Solar/Renewable and Battery Modeling and GI Surplus Capacity	Siting / MEM
14	Constraint Assessment on each future; come up with EHV portfolio; monitor everything 100 kV and above? Not clear how that will be done so request to bring that methodology review back	Constraint Assessment
15	20-Year objective function for developing portfolios by future - Approaches to non-SPP APC savings benefits (*eg.*, SPP-Other, SPP economy export APC savings benefits to non-SPP regions) - Approach to seams issues and solutions	Portfolio Development
16	HV and EHV needs versus HV and EHV solution tradeoffs	Portfolio Development
17	Identification of sensitivities	Sensitivity Analysis

SPP Southwest Power Pool

20 YEAR

20-YEAR LOAD REVIEW METHODOLOGY

20-YEAR ASSESSMENT SCOPE

	DRIVERS			
KEY ASSUMPTIONS	**Future 1 (F1) - 2022 ITP Reference Case**	**Future 2 (F2) - 2022 ITP Emerging Technologies**	**Future 3 (F3) - Accelerated Decarbonization (New administration and aggressive energy/ environmental policy change)**	**Future 4 (F4) - Based on SPP F3 with hurdle rate of zero between MISO and SPP**
YEAR	**20**	**20**	**20**	**20**
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast	Moderate increase due to switching to electric home heating and increased electric transportation, potential shift to a winter peaking SPP	Moderate increase due to switching to electric home heating and increased electric transportation, potential shift to a winter peaking SPP
Energy Demand Growth Rates	As submitted in load forecast	Increase due to electrification growth	Higher demand due to electrification compared to F2 due to aggressive policy	Higher demand due to electrification compared to F2 due to aggressive policy
Distributed Generation (Solar)	As submitted in load forecast	900MW	Increase from F2 due to policy shift and significant incentives to behind-the-meter installation	Increase from F2 due to policy shift and significant incentives to behind-the-meter installation
Additional Assumptions				
Emissions Reduction Target	N/A	N/A	93% to 95% Emissions Reductions Target in 2042 from 2017 Levels	93% to 95% Emissions Reductions Target in 2042 from 2017 Levels

20 YEAR

DEMAND RESPONSE

- Assume certain percentage of EVs have direct load control (DLC) capability
- Assume certain percentage of electric heat pumps have DLC capability

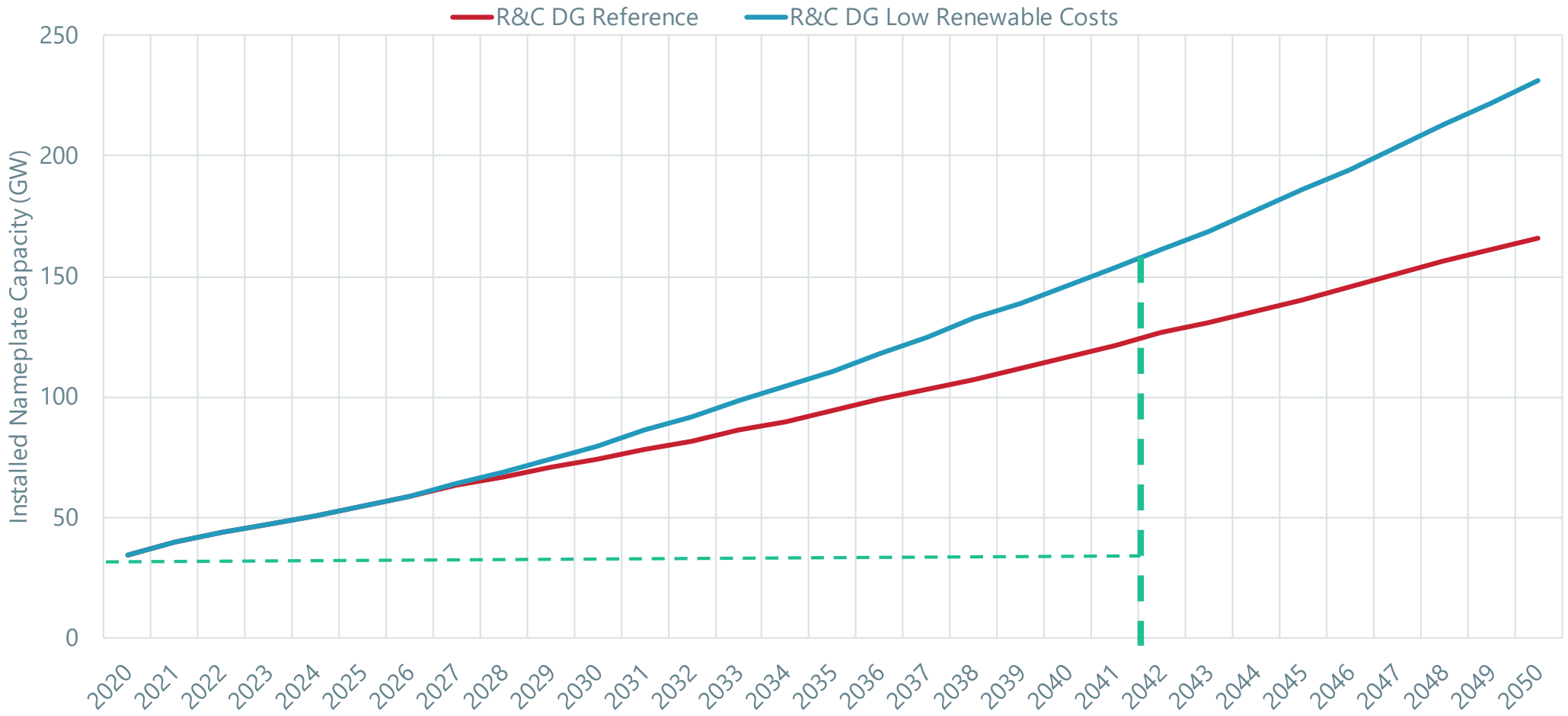
DEMAND RESPONSE

- Model as a dispatchable resource
  - Annual and monthly energy limits are enforced
  - Dispatch cost set to a "trigger price" to avoid excessive utilization
- Benefits:
  - Allows for easy adjustment of annual generation and capacity
  - Accurately captures the flexibility offered to system operators
  - Captures annual and monthly energy limits
- Drawbacks
  - Event duration and frequency are not constrained
  - Does not incorporate "energy shifting" impacts
  - Less granular than modeling program-specific impacts

DISTRIBUTED GENERATION

- Existing Futures:
  - Future 1: As submitted in load forecast
  - Future 2: +900 MW
- EIA 2021 Annual Energy Outlook (AEO) Study
  - Reference case is ~3.7 times higher than current levels by 2042
  - Low Renewable Cost case is ~4.7 times higher than current levels by 2050

AEO DISTRIBUTED GENERATION OUTLOOK - NATIONWIDE

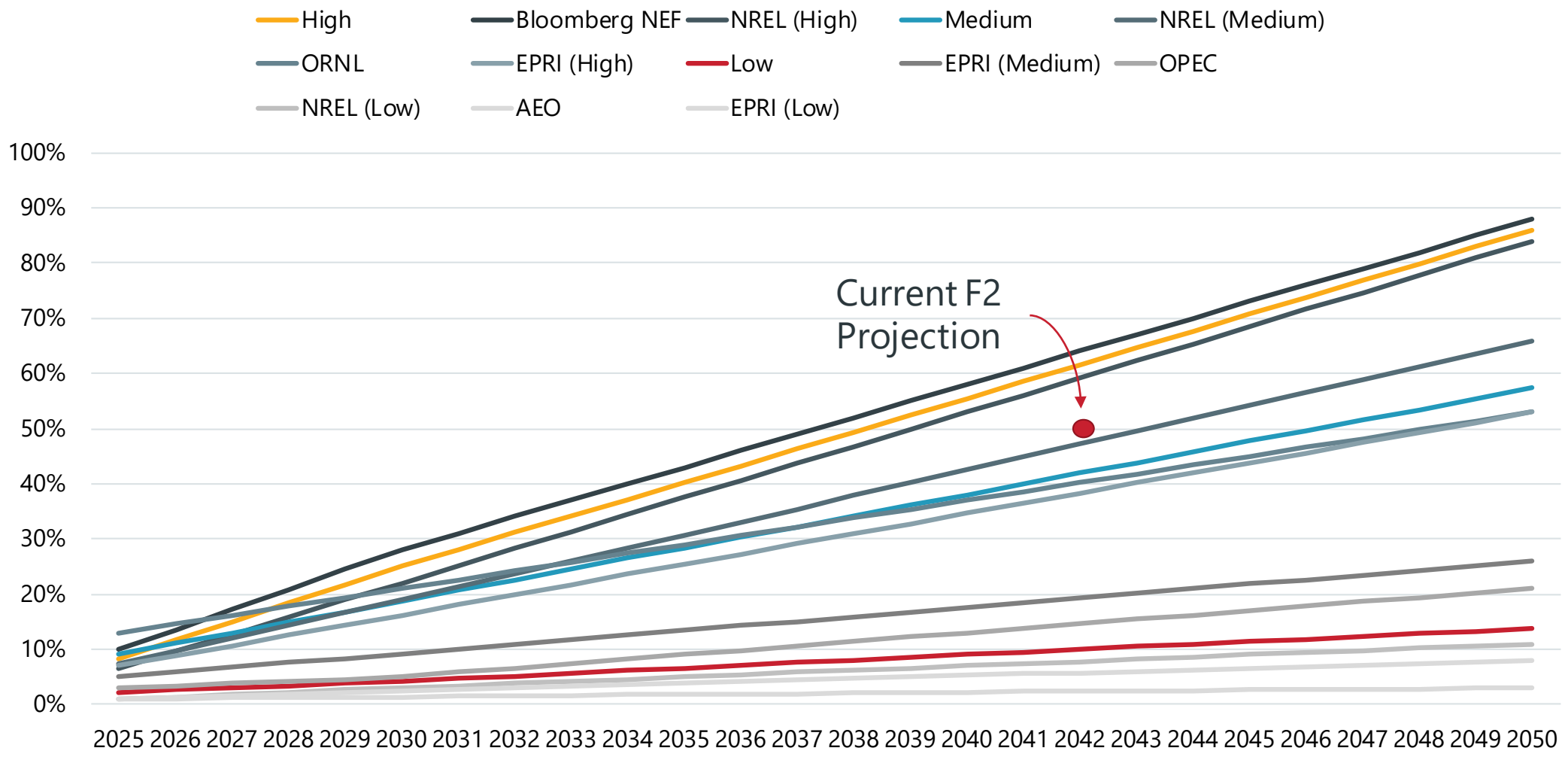


20 YEAR

DISTRIBUTED GENERATION

- Model as a traditional transaction
  - Hourly generation profile
- Individual generators modeled on top 10% load buses per demand group
  - Scoped amounts added on a pro-rata basis
  - Incorporation of feedback from stakeholders submitted in previous ITP cycles
- Option: Increase 10% of load busses to ~20% for F3/F4
- Benefits:
  - Allows for easy adjustment of annual generation and capacity

EV ADOPTION (% OF FLEET)



20 YEAR

ELECTRIFICATION – ELECTRIC VEHICLES

- Apply EV energy amounts to existing demand group structure with valley fill load shape adjustment
  - Valley fill: Peak and minimum hour preserved with adjustment distribution toward low loads
- Option F3/F4: Shift peak upward to account for increase in EV load and continue to use the valley fill option
- Benefits:
  - Considers DLC and/or smart charging capabilities for off-peak charging
- Drawbacks:
  - Less granular than creating an hourly shape for each demand group

ELECTRIFICATION – SPACE HEATING

- Model as incremental demand group(s)
  - Potentially develop multiple for unique weather patterns
- Hourly profile will be shaped based on heating demand and requirements
- Annual peak and energy will be set based on anticipated adoption of electric heating
- Benefits:
  - Allows us to capture the locational shape and area specific adoption rates separately
- Drawbacks:
  - Determining the hourly profile will require additional research
  - Indicative weather patterns will have to be determined
  - Fixed hourly profile may not incorporate potential rate design, DSM/DLC, energy efficiency, or public appeals

OTHER ELECTRIFICATION OPPORTUNITIES

- Charging Stations
- Other electric vehicles: heavy-duty trucks, aviation, public transportation, non-road vehicles
- Water Heating
- Industrial processes: boilers, process heating and cooling, machinery

ENERGY EFFICIENCY

- Trends to overall energy intensity forecast in the 2021AEO
  - Residential customers reduce intensity 12% by 2050
  - Commercial customers reduce intensity 8% by 2050
  - Industrial customers reduce intensity 18% by 2050
- Apply improvements to each customer class in load forecast

ENERGY EFFICIENCY

- Model as an "across-the-board" reduction in energy and demand consumption
  - Applied as a flat reduction to peak demand and annual energy
- Benefits:
  - Easy to incorporate into the model
  - Does not alter the existing load shape
- Drawbacks:
  - May not capture the seasonality of technologies' peak and energy impacts
  - Capturing impacts of specific incentives and actions is more difficult with this method

EMISSIONS REDUCTION TARGET

- Potential implementation hurdles
- Considerations for meeting 93% and 95% emissions reduction target
  - Carbon capture
  - Hydrogen fuel conversion
  - Renewable energy credits

SOURCES

- EIA Annual Energy Outlook:

https://www.eia.gov/outlooks/aeo/

- 2021 AEO Reference Case tables:

https://www.eia.gov/outlooks/aeo/tables_ref.php

- 2021 AEO Side Case Tables (Low renewable cost specifically):

https://www.eia.gov/outlooks/aeo/tables_side.php

- NREL Electrification Futures:

https://www.nrel.gov/analysis/electrification-futures.html

- NREL Electrification Report PDF link:

https://www.nrel.gov/docs/fy21osti/72330.pdf

- Department of Energy EVI-Pro:

https://afdc.energy.gov/evi-pro-lite

- OpenEI Hourly Consumption Profiles:

https://openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states/resource/b341f6c6-ab5a-4976-bd07-adc68a2239c4?inner_span=True

*Not all sources were used in this presentation, but could help inform discussion