Southwest Power Pool

Economic Studies/Transmission Working Group

September 25, 2018

Conference Call

• SUMMARY OF ACTIONS TAKEN •

2020 ITP Futures:

1. Approved a recommendation for age based retirement dates at 56 years for coal units and 50 years for gas/oil units, being subject to stakeholder review in future 1 only, but to allow repowering (life extension) or emissions upgrades exceptions in Future 2
2. Approved a motion to accept 20% of projected solar amounts in future 1 and 35% of projected solar amounts in future 2 as the storage additions in the respective futures
3. Approved a motion to increase the projected solar amounts in the 2020 ITP Study for each future

Supplemental Activities:

1. On September 17th, 2018, the ESWG voted to approve RR 321 with the language revisions included in the SPP Comment Form, as posted with the meeting materials for the 9/25/2018 joint ESWG/TWG net meeting

Southwest Power Pool

Economic Studies/Transmission Working Group

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• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair and Vice-Chair Travis Hyde (OGE) and Tim Owens (NPPD) called the meeting of the Economic Studies Working Group (ESWG) and Transmission Working Group (TWG) to order at 8:00 a.m., welcomed those in attendance, and asked for introductions.

There were 102 web conference participants, representing 15 of 17 ESWG members and 19 of 24 TWG members. (Attachment 1 – September 25, 2018 Attendance List)

Agenda Item 1b – Receipt of Proxies

Travis Hyde (OGE) and Tim Owens (NPPD) asked for any proxy statements; eight proxies were identified. (Attachment 2 – Proxy Statements)

ESWG:

- Randy Collier (CUS) named John Boshears (CUS) as his proxy
- Anita Sharma (AEP) named Jim Jacoby (AEP) as her proxy
- Alan Myers (ITC) named Michael Wegner (ITC) as his proxy
- Jeremy Severson (BEPC) named Matthew Stoltz (BEPC) as his proxy
- John Olsen (Evergy) named Derek Brown (Evergy) as his proxy

TWG:

- Alan Myers (ITC) named Michael Wegner (ITC) as his proxy
- Scott Benson (LES) named Kurt Stradley (LES) as his proxy
- Chris Pink (TSG&T) named Cody Sickler (TSG&T) as his proxy
- Nathan McNeil (MIDW) named Jence Mendizha (MIDW) as his proxy

Agenda Item 1c – Review of Agenda

Vice-Chair Tim Owens (NPPD) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – September 25, 2018 ESWG Agenda).

ESWG: Kurt Stradley (LES) made a motion; seconded by Jon Iverson (OPPD) to adopt the agenda. The motion was approved unanimously.

TWG: Jason Shook (GDS) made a motion; seconded by Cliff Franklin (SUNC) to adopt the agenda. The motion was approved unanimously.

Agenda Item 1d – Antitrust Reminder

Amber Greb (SPP) provided an antitrust reminder to the group.

Agenda Item 2 – Consent Agenda

The consent agenda included the following items:

a. Lubbock Powerflow Models

This Consent Agenda item was approved unanimously by the TWG.

b. 2019 ITP Scope (Attachment 4 – 2019 ITP Scope Update)

This Consent Agenda item was approved unanimously by the TWG and ESWG.

Agenda Item 3 – 2020 ITP Futures

Solar and Storage

Ben Elsey, SPS, discussed a recent RFP the Public Service Commission of Colorado which included multiple installations of solar generation paired with electric storage resources (ESRs). TWG and ESWG members asked questions on the proposed ESR output durations, installation timelines, and other information related to the proposals received by SPS. (Attachment 5 - Solar and Storage Presentation)

2020 ITP Futures

Kirk Hall (SPP) reviewed a presentation on 2020 ITP Futures. The discussion moved quickly to the key assumption for the futures, including the retirement dates per future. Keith Collins (SPP MMU) spoke in support of the staff recommended retirement ages. (Attachment 6 – 2020 ITP Futures)

Jim Jacoby (AEP) made a motion; seconded by Michael Wegner (ITC) to approve age based retirement dates at 56 years for coal units and 50 years for gas/oil units, being subject to stakeholder review in future 1 only. The motion was approved unanimously. A friendly amendment was made by Jon Iverson (OPPD): to allow repowering (life extension) or emissions upgrades exceptions in Future 2. The amendment was accepted.

The conversation moved to the staff proposed projected storage amounts, stakeholders felt that it makes sense to ties storage additions to projected solar additions.

Jon Iverson (OPPD) made a motion; seconded by Kurt Stradley (LES) to accept 20% of projected solar amounts in future 1 and 35% of projected solar amounts in future 2 as the storage additions in the respective futures. The motion was approved, with 2 no votes; Al Tamimi (SUNC) and Jim Jacoby (AEP).

Reason for "no" vote:

AEP: I vote No on the motion for storage amounts mainly due to the increase in Future 2 to 35% of solar level. My concern was mainly driven from the following concerns.

1. This is the first study we are studying storage in the SPP ITP. At this point it is unclear how we will model and/or site the storage. Before we increase the storage amounts we need to understand that and I looked at this year as primarily a learning opportunity for how to study storage.
2. The GI queue indicates roughly 20% teaming of Solar/Storage which is more in the range of what we should model in this study.
3. The investment credits run out in 5 years and this is a primary driver for storage and solar installations.

I would rather see 20%-25% this year and then re-evaluate next year in the following ITP.

Kirk began discussing the previously approved solar amounts noting SPP's observation on current factors impacting the amount of solar resources that could be interconnected into the SPP region. Kirk mentioned decreasing costs, a large increase in the amount of storage resources being submitted into the GI Queue, and the investment tax credits that are available led staff to believe a higher solar amount should be considered in the 2020 ITP.

Leon Howell (OGE) made a motion; seconded by Michael Wegner (ITC) to increase the projected solar amounts in the 2020 ITP Study for each future. The motion was approved, with 3 no votes; Al Tamimi (SUNC) and Bennie Weeks (Xcel), and Tim Owens (NPPD), and one abstention; Natasha Henderson (GSEC).

Reason for "no" vote:

NPPD: NPPD voted no on the motion to increase the projected solar amounts in Futures 1 and 2 for the 2020 ITP. I felt that the original assumptions, approved during the September 12-13 ESWG meeting, were reasonable and a change is premature at this time.

Kirk moved on to discuss options for a potential third future to be studied in the 2020 ITP assessment. He reviewed three options with stakeholders. Option A is driven primarily by the assumption that environmental regulations will be implemented due to a shift in the current political climate, it includes accelerated retirements and a carbon adder. Option B is intended to be an accelerated emerging technologies future driven primarily by the assumption that electric vehicles, and storage will have a major impact on load and energy growth rates, it includes higher projected renewables that either future 1 or 2. Option C is a combination of Options A and B and considers the implementation of multiple industry regulation changes that affect the direction of the electric utility industry, it includes decreased growth rates and a carbon adder. A straw poll was taken to determine which of the three futures staff should continue developing. The results showed that the majority of stakeholders preferred option A, but also showed that the majority of stakeholders did not see the value in an additional future. Staff will continue with option A.

Agenda Item 4 – RR 321 – ITP Manual Cleanup

This item was not covered during the meeting. ESWG would requested to approve this RR by an email vote.

Closing Items

There were no action items from the meeting.

The meeting was adjourned at 11:30 AM.

Supplemental Activities

On September 17th, 2018, the Tim Owens (NPPD) made a motion; seconded by Kurt Stradley (LES) to approve RR 321 with the language revisions included in the SPP Comment Form, as posted with the meeting materials for the 9/25/2018 joint ESWG/TWG net meeting. The motion carried with 16 votes to approve. (Attachment 7 - Recommendation Report RR 321_v2)

Respectfully Submitted,

Amber Greb

ESWG Secretary

Kirk Hall

TWG Secretary

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	Amber Greb	Conference

Amber/Alan,
John Boshears has my proxy for the ESWG/TWG call on 9/25/18.

Thanks,
Randy Collier
Contract Manager-Electric Supply
O: 417.831.8323

Hello Amber,

I will not be able to attend the ESWG meeting tomorrow due to a conflict. I give my proxy to Jim Jacoby.

Thanks
-Anita

Hi Amber and Alan,

Matthew Stoltz will have my proxy next week for the ESWG meeting.

Thanks,

Jeremy..

All:

Michael Wegner will have my proxy for the subject WebEx.

Thanks,
Alan K. Myers, P.E.
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Alan / Amber,

Derek Brown will have my proxy for this meeting.

Thanks,

John Olsen
Sr. Dir, DSO and Emergency Ops

SPP Southwest Power Pool

ECONOMIC STUDIES/TRANSMISSION WORKING GROUP JOINT MEETING

September 25th, 2018

Conference Call

• AGENDA •

1. Administrative Items
   a. Call to Order, Introductions .... Tim Owens/Travis Hyde (5 minutes)
   b. Receipt of Proxies .... Amber Greb/Kirk Hall (1 minute)
   c. Review of Agenda[1] .... Tim Owens/Travis Hyde (1 minute)
   d. Antitrust Reminder .... Amber Greb/Kirk Hall (1 minute)
2. Consent Agenda
   a. Lubbock Powerflow Models[1] (TWG Approval)
   b. 2019 ITP Scope (ESWG/TWG Approval Item)
3. 2020 ITP Futures[1] (ESWG Approval Item, TWG Informational) .... Kirk Hall (150 minutes)
   a. Solar & Storage
4. RR 321 – ITP Manual Cleanup[1] (ESWG Approval Item) .... SPP Staff (20 minutes)
5. Closing Items .... All (5 minutes)
   a. Summary of Action Items (Amber Greb/Kirk Hall)

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[1] Background Material Included

Antitrust: SPP strictly prohibits use of participation in SPP activities as a forum for engaging in practices or communications that violate the antitrust laws. Please avoid discussion of topics or behavior that would result in anti-competitive behavior, including but not limited to, agreements between or among competitors regarding prices, bid and offer practices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that might unreasonably restrain competition.

2019 INTEGRATED TRANSMISSION PLANNING ASSESSMENT SCOPE

Published on DATE

By SPP Engineering

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
10/12/2017	SPP Staff	Initial Draft	
08/06/2018	SPP Staff	Add LP&L Sensitivity study, updated economic operational solution evaluation section	Approved by joint TWG/ESWG on June 29, 2018
9/20/2018	SPP Staff	Updated Total Renewable Capacity in Table 1: Future Drivers	
	MOPC	MOPC Approval	

CONTENTS

SECTION 1: OVERVIEW

This document presents the scope and schedule of work for the 2019 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 2019 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 2019 ITP Scope contains assumptions to be utilized in the 2019 ITP Assessment that are not standardized in the ITP Manual[1]. These documents should be reviewed together for a comprehensive view of the 2019 ITP process and assumptions.

[1] https://www.spp.org/documents/22887/itp%20manual%20version%202.0.pdf

SECTION 2: ASSUMPTIONS

This section details the additional assumptions for the development of the SPP balancing authority (BA) economic models not already detailed in the ITP Manual.

SPP BA ECONOMIC MODEL OVERVIEW

FUTURES

The ESWG developed two futures with input from the Strategic Planning Committee (SPC) and TWG. The MOPC approved both futures in October 2017.

Reference Case Future (Future 1)

The reference case future will reflect the continuation of current industry trends and environmental regulations. Coal and gas-fired generators over the age of 60 will be retired subject to input from stakeholders. Long-term industry forecasts will be used for natural gas and coal prices. Solar and wind additions will exceed current renewable portfolio standards (RPS) due to economics, public appeal, and the anticipation of potential policy changes, as reflected in historical renewable installations.

Emerging Technologies Future (Future 2)

The emerging technologies future will be driven primarily by the assumption that electrical vehicles, distributed generation, demand response, and energy efficiency will impact energy growth rates. Coal and gas-fired generators over the age of 60 will be retired. As in the reference case future, current environmental regulations will be assumed and natural gas and coal prices will use long-term industry forecasts. This future assumes higher solar and wind additions than the reference case due to advances in technology that decrease capital costs and increase energy conversion efficiency.

	DRIVERS				
KEY ASSUMPTIONS	**YEAR 2**	**REFERENCE CASE YEAR 5**	**REFERENCE CASE YEAR 10**	**EMERGING TECHNOLOGIES YEAR 5**	**EMERGING TECHNOLOGIES YEAR 10**
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
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	Age-based 60+, subject to stakeholder input	Age-based 60+, subject to stakeholder input		Age-based, 60+	
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[2]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Distributed Generation (Solar) [2]	As submitted in load forecast	As submitted in load forecast		+300MW	+500MW
Energy Efficiency[2]	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Export Lines	No	No		No	

[2] As defined in the MDWG Model Development Procedure Manual: https://www.spp.org/Documents/12959/SPP%20MDWG%20Model%20Development%20Procedure%20Manual%20(public)_v15_Posted.docx

	DRIVERS				
KEY ASSUMPTIONS	**YEAR 2**	**REFERENCE CASE YEAR 5**	**REFERENCE CASE YEAR 10**	**EMERGING TECHNOLOGIES YEAR 5**	**EMERGING TECHNOLOGIES YEAR 10**
New/Re-Powered Renewables	Increased capacity factor	Increased capacity factor		Increased capacity factor	
Storage	None	None		None	
Total Renewable Capacity					
Solar (GW)	~0.25+	3	5	4	7
Wind (GW)	~18+	24.25~~5~~	24.66~~6~~	27~~9~~	30~~2~~

Table 1: Future Drivers

EXTERNAL LOAD FORECASTS

Table 2 details the data sources of load forecasts external to SPP for the BA economic models. These regions will have the opportunity to provide feedback.

External Entity	Load Data Source
AECI	2019 Base Reliability Model[3]
MISO	MTEP18
SaskPower	MTEP18
Manitoba Hydro	MTEP18
TVA	MTEP18
Other Regions	2019 Base Reliability Model[4]

Table 2: External Load Data Sources

PHASE-SHIFTING TRANSFORMERS

In the SPP BA models, SPP phase-shifting transformers (PSTs) with auto-adjust enabled in the base reliability models may adjust up to the full angle range. For PSTs with auto-adjust disabled, the PSTs will be modeled at a fixed angle.

[3] AECI actively participates in the SPP model development process that produces the base reliability model set
[4] Data for most regions external to SPP will be acquired from the 2017 series ERAG MMWG model set

DC TIES

For direct current (DC) ties that connect SPP to the Texas and western interconnections, hourly profiles will be developed based on at least three years of historical flows across each DC tie and will be capped at long-term firm transmission service amounts. These transactions will be modeled as fixed with no assumed curtailment price.

MUST-RUN UNITS

Must-run designations will be assigned only to hydroelectric generation, co-generation, and nuclear units, unless an exception is requested during the generation review and approved by the ESWG.

RESOURCE PLAN

CONVENTIONAL GENERATOR PROTOTYPES

Generator prototype parameters will be set using the Lazard Levelized Cost of Energy[5] high-cost combined cycle (CC) prototypes, low-cost combustion turbine (CT) prototypes, and large-scale reciprocating engines, while eliminating nuclear and coal as options. This will include a reciprocating engine prototype using an average of the Lazard (high- and low-cost) data with a 50 megawatt (MW) installation increment.

GENERATION TYPE	SIZE (MW)	TOTAL CAPITAL COST ($/KW)[6]	VARIABLE O&M ($/MWH)	FIXED O&M ($/KW-YR)	HEAT RATE (BTU/KWH)
Combined Cycle	550	1,333	2.05	5.64	6,900
Combustion Turbine	216	820	4.82	5.13	10,300
Reciprocating Engine	50	897	12.82	17.94	8,500

Table 3: Generator Prototype Parameters

RENEWABLE ACCREDITATION

Accreditation of existing renewable units will follow SPP Planning Criteria 7.1.5.3.7[7]. A new resource that is assigned ownership to a load serving entity within the modeled SPP footprint is eligible for capacity credit. New wind resources will have a 20 percent capacity accreditation. New

[5] https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf
[6] All values are reported in 2017 dollars.
[7] https://www.spp.org/documents/33003/spp%20effective%20planning%20criteria_v1.4_10092017.pdf

utility scale solar will have a 70 percent capacity accreditation. Accredited renewable capacity will be capped at 12 percent of a load serving entity’s total load.

SECTION 3: SOLUTION EVALUATION & PORTFOLIO DEVELOPMENT

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

Persistent economic operational flowgate needs will be provided for informational purposes. Solutions to mitigate these persistent economic operational needs due to flowgates will not be evaluated in the operational models.

MANUAL COMMITMENT OF GENERATORS

Some transmission system issues require the manual commitment of generation 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 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 commitment will be considered during project selection.

CONSOLIDATION

SPP staff 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
   - $Net\ APC\ benefit_{P1,AVE}$
   - $Net\ APC\ benefit_{P2,AVE}$
   - $Net\ APC\ benefit_{Max} = Maximum(Net\ APC\ benefit_{P1,AVE}, Net\ APC\ benefit_{P2,AVE})$
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[8] multiplied by the points possible, up to 10.

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

OR

$$Points\ awarded = \left(\frac{Hours\ of\ system\ reconfiguration_{12\ months}}{X\%^{9} \times 8{,}760}\right) \times 10$$

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 staff may use engineering judgement to support or oppose results of the systematic approach described above. SPP staff 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.

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

[9] X equals 25% for operational thermal issues. X equals 10% 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:

- Natural gas price at a 95 percent confidence level (2 standard deviations)
- Demand levels at a 67 percent confidence level (1 standard deviation)

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

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.

LUBBOCK POWER & LIGHT (LP&L) SYSTEM EXIT ANALYSIS

Analysis will be conducted to address study results impacted by LP&L's proposal to move a portion of the LP&L system from the SPP transmission system to the Electric Reliability Council of Texas (ERCOT) transmission system as approved by a joint ESWG/TWG meeting on June 29, 2018 and MOPC on July 17, 2018. Any new criteria violations resulting from LP&L system moving to ERCOT will be reported for informational purposes only.

During the needs assessment, SPP staff will determine what operational and planning reliability needs, as well as operational and planning economic and policy needs can be mitigated or relieved as a result of the LP&L system moving to ERCOT. These potentially mitigated and relieved needs will be posted with the final needs assessment.

In addition, SPP staff will identify needs that may warrant additional effort during portfolio consolidation to perform additional project analysis to provide information on any potential large-scale project recommendations in the area.

SECTION 5: SCHEDULE

The 2019 ITP assessment began in July 2017 and will be completed by October 2019. Figure 1 and Table 6 detail the study timeline.

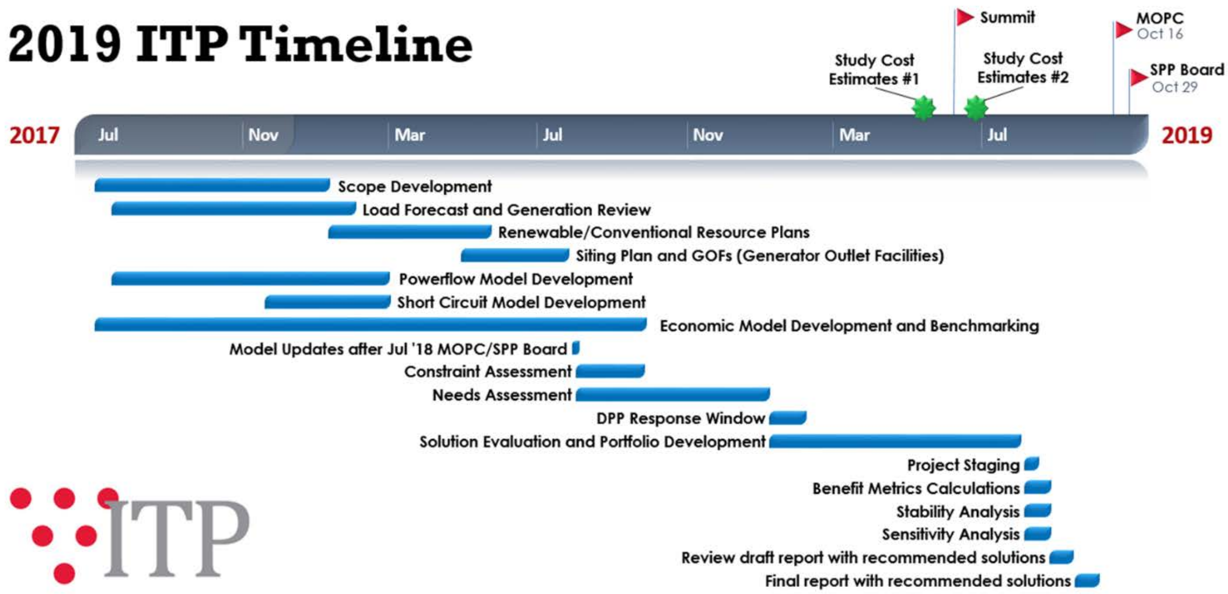


Figure 1: 2019 ITP Timeline

Milestone	Group(s) to Review/Endorse	Start Date	Completion Date
Scope Development	ESWG, TWG, MOPC, SPC	July 2017	January 2018
Load and Generation Review	ESWG, TWG, MDWG	July 2017	February 2018
Renewable Resource Plan	ESWG	January 2018	March 2018
Conventional Resource Plan	ESWG	February 2018	May 2018
Siting Plan	ESWG	April 2018	July 2018
Generator Outlet Facilities (GOFs)	TWG	May 2018	July 2018
Powerflow Model Development	TWG	July 2017	March 2018
Short Circuit Model Development	TWG	November 2017	March 2018
Economic Model Development	ESWG	July 2017	September 2018
Model Benchmarking	ESWG, TWG	December 2017	April 2018
Model Updates after July 2018 MOPC/Board (NTC/Re-evaluations)	TWG	July 2018	August 2018
Constraint Assessment	TWG	August 2018	September 2018
Needs Assessment	ESWG, TWG	September 2018	January 2019
Detailed Project Proposal (DPP) Window	ESWG, TWG	January 2019	February 2019
Solution Development	ESWG, TWG	January 2019	March 2019
Project Grouping	ESWG, TWG	March 2019	July 2019
Study Cost Estimates (Round 1)		April 2019	May 2019
Summit		June 2019	June 2019
Study Cost Estimates (Round 2)		June 2019	June 2019
Final Reliability Portfolios	TWG	June 2019	August 2019
Portfolio Optimization / Consolidation	ESWG, TWG	July 2019	August 2019
Project Staging	ESWG, TWG	August 2019	September 2019
Benefit Metrics Calculations	ESWG	August 2019	September 2019
Stability Analysis	TWG	August 2019	September 2019
Sensitivity Analysis	ESWG	August 2019	September 2019
Final Reliability Assessment	TWG	August 2019	September 2019
Review Draft Report with Recommended Solutions	ESWG, TWG	August 2019	September 2019
Final Report with Recommended Solutions	ESWG, TWG	September 2019	September 2019
	RSC, SPC, SSC	October 2019	
	MOPC, SPP Board		

Table 5: 2019 ITP Schedule

SECTION 6: CHANGES IN PROCESS AND ASSUMPTIONS

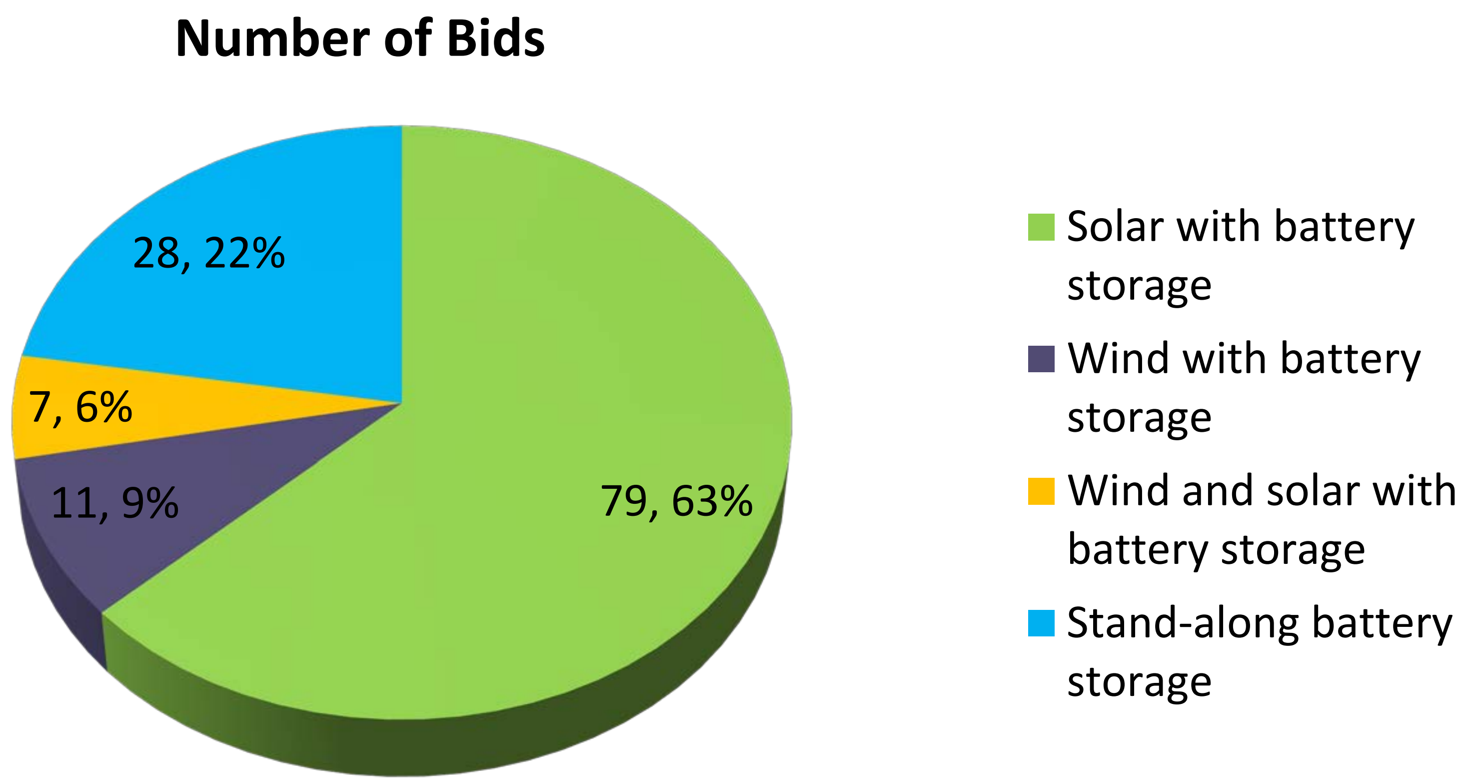
To protect against changes in process and assumptions that could present a significant risk to the completion of the 2019 ITP Assessment, any changes to this scope or assessment schedule must be appropriately vetted and follow the process outlined in the stakeholder accountability section of the ITP Manual.

SOLAR AND STORAGE

PSCO 2017 ERP

- In 2017 SPS' affiliate company Public Service Company of Colorado issued an RFP seeking up to 1,113 MW of firm capacity.
- PSCo received a total of 418 bids, of which 125 (~30%) bids included battery storage
- Solar + storage proposals were amongst the lowest seen in the U.S.
- After evaluation PSCo proposed to proceed with three solar + storage projects with a total of 275MW of nameplate storage.
- PSCo's plan was recently approved by the CO PUC.

BATTERY STORAGE BIDS BY GENERATION TECHNOLOGY



BENEFIT OF SOLAR + STORAGE

INVESTMENT TAX CREDIT

- Developers are maximizing ITCs for Solar and Storage projects
- To prevent incentivizing arbitrage energy from the grid, there are requirements for storage to qualify for ITC.
- In short, developers are requesting that during the first five years of operations the battery is to be charged with the solar generation.
- Stand-alone batteries did not qualify.

Date construction begins	Placed in-service date	ITC amount
Before 1/1/2020	Before 1/1/2024	30%
1/1/2020 – 12/31/2020	Before 1/1/2024	26%
1/1/2021 – 12/31/2021	Before 1/1/2024	22%
Before 1/1/2022	On or after 1/1/2024	10%
On or after 1/1/2022	Any	10%

BATTERY SIZE AND DURATION

BATTERY SIZE AND DURATION

- Of the 79 solar + storage we bids received, approximately 65% of the batteries were 4 hour duration and 20% were 2 hour duration.
- Nameplate capacity ranged from ~10MW to 400MW.
- Final portfolio included three batteries rated at 50MW, 100MW and 125MW with durations of either 2 or 4 hours.
- Generally - Increased $/kW-month cost of batteries with >4 hour duration batteries exceeded the value of accredited capacity.

ACCREDITED CAPACITY

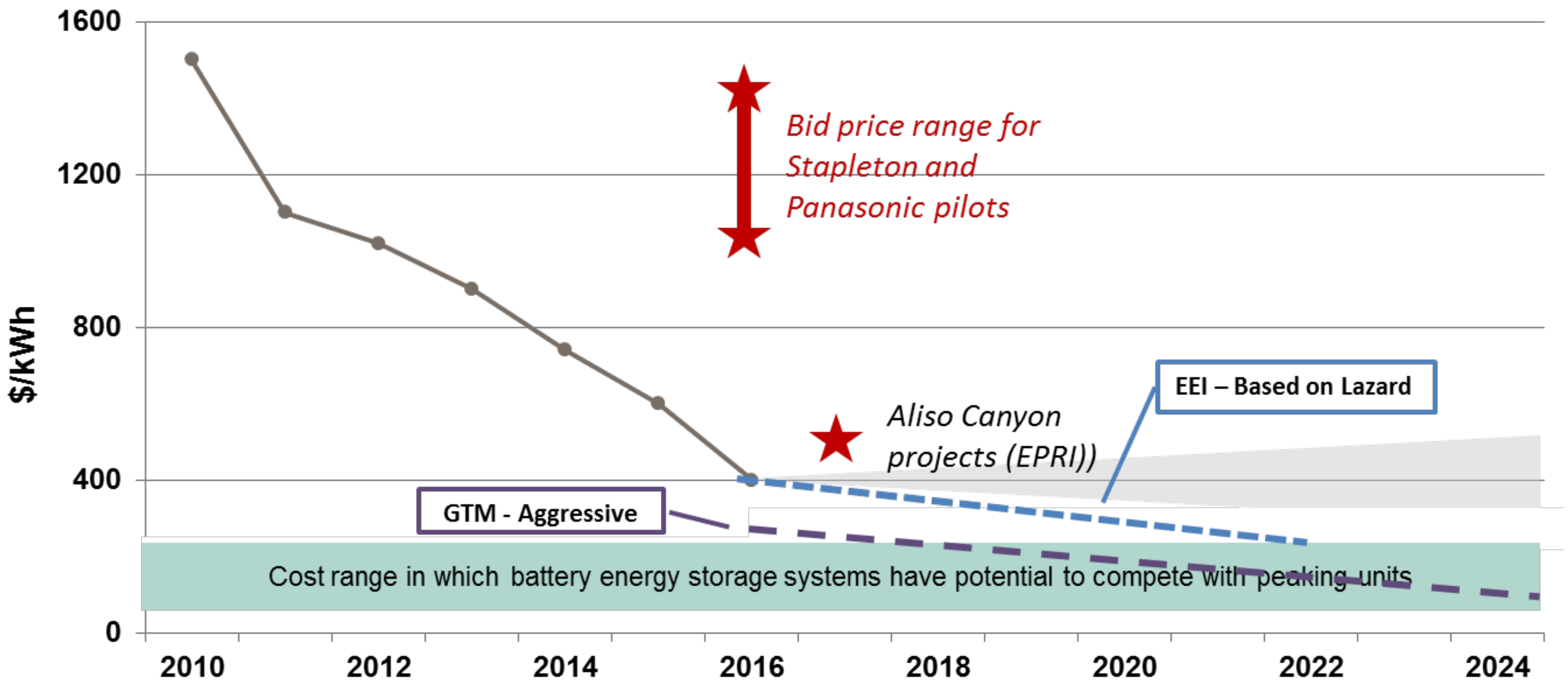
- The greater the duration of the battery, the greater of the accredited capacity assigned was.

Duration (hours)	ELCC (% of Nameplate MW)
1	40%
2	55%
4	75%
8	95%
10	98%

QUESTIONS?

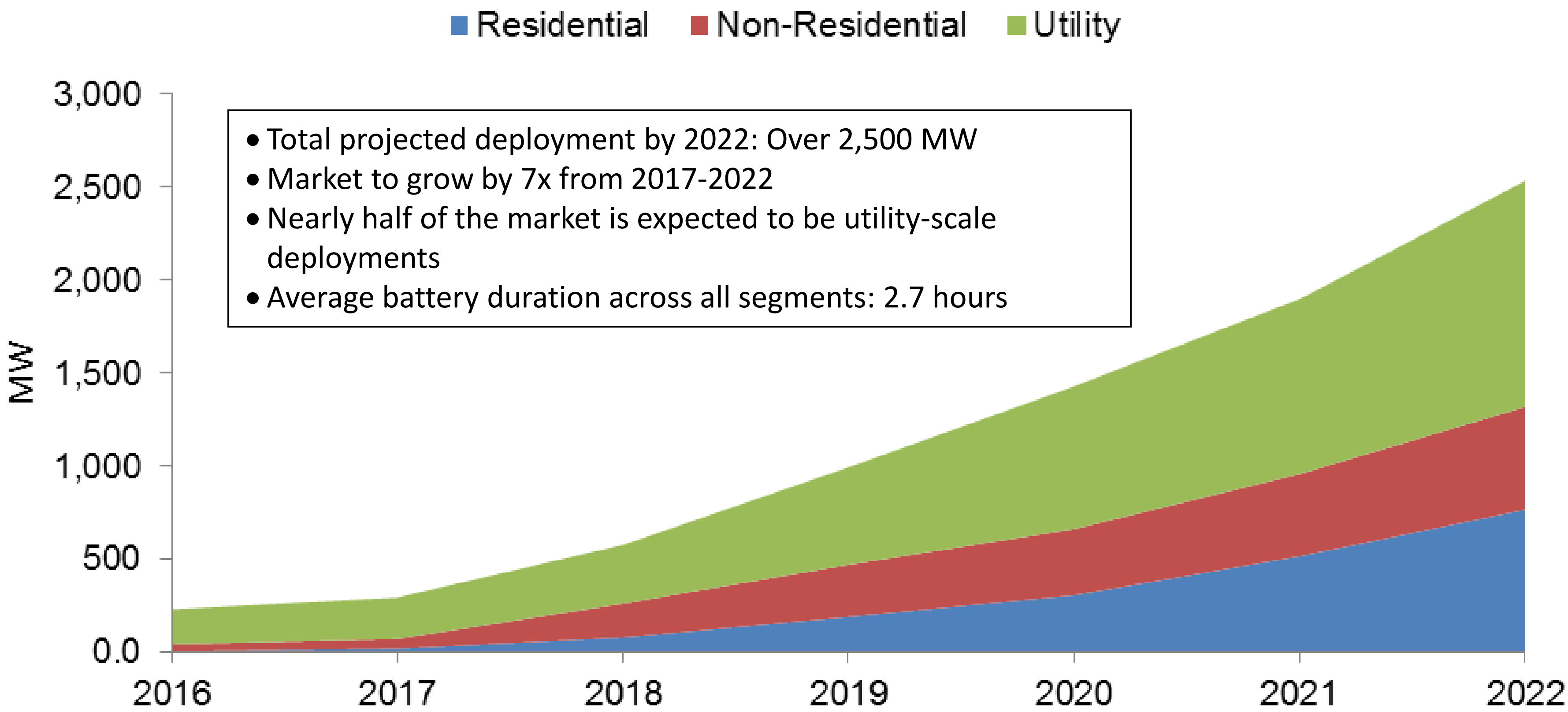
APPENDIX

Lithium-Ion Battery Costs



- Cost declines of 70% from 2010-2016
- 5-10% annual cost declines projected for the next 5-10 years

Projected Market Growth



- Residential Storage: 2-5% of U.S. additions
- Non-Residential Storage: 1-2% of U.S. additions
- Utility Storage: 2-3% of U.S. additions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2020 ITP Futures

Kirk Hall

Objective

- Futures 1 and 2
  - Review frameworks
  - Approve Generator Retirements
  - Approve Storage Amounts
  - Reconsideration of Utility Scale Solar amounts**
- Future 3
  - Discuss F3 frameworks and assumptions
  - Discuss cost impacts for 3rd future**
  - Determine recommendation for development of 3rd future

**Additional information will be added at a later date

F1 and F2

Reference Case

The reference case will reflect the current trends of the power system industry. Natural gas and coal prices follow current long term forecasts. In the reference case, new environmental regulations are not anticipated. Coal and gas retirements will be based on average lifespan considering fuel type (i.e. coal vs gas). Renewable generation (Solar and Wind) additions will exceed current Renewable Portfolio Standard Requirements (RPS) due to economics, public appeal, and the potential for future policy changes, as reflected in historical renewable installations.

- Peak Demand and energy growth rates as submitted
- Natural gas prices are consistent with industry long-term reference forecasts
- Renewable additions continue following current GI queue trends
- Renewable resources continue to be competitive
- Coal and gas units will be retired reflecting average lifespan
- Initial deployment of energy storage devices

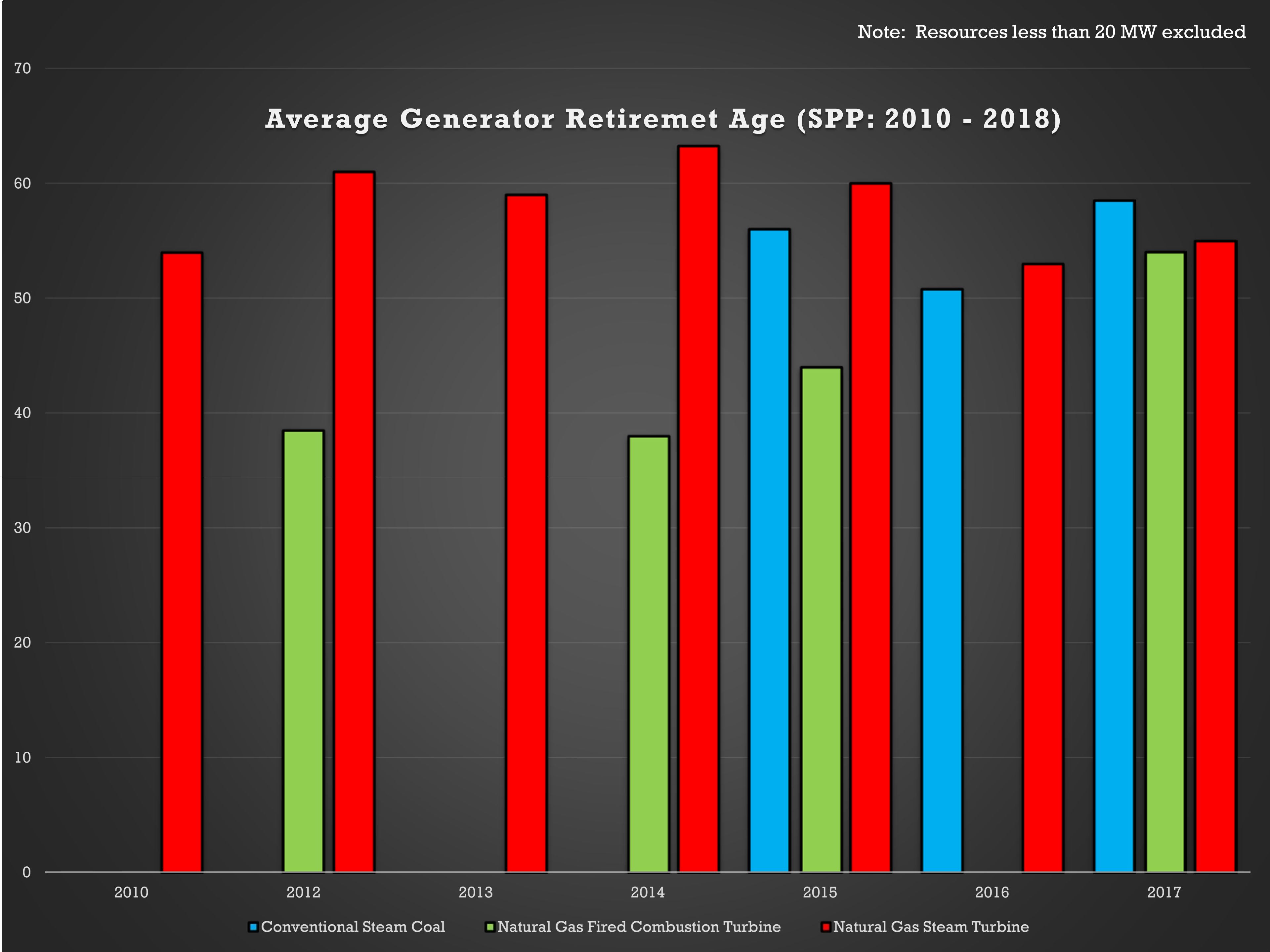
Emerging Technologies

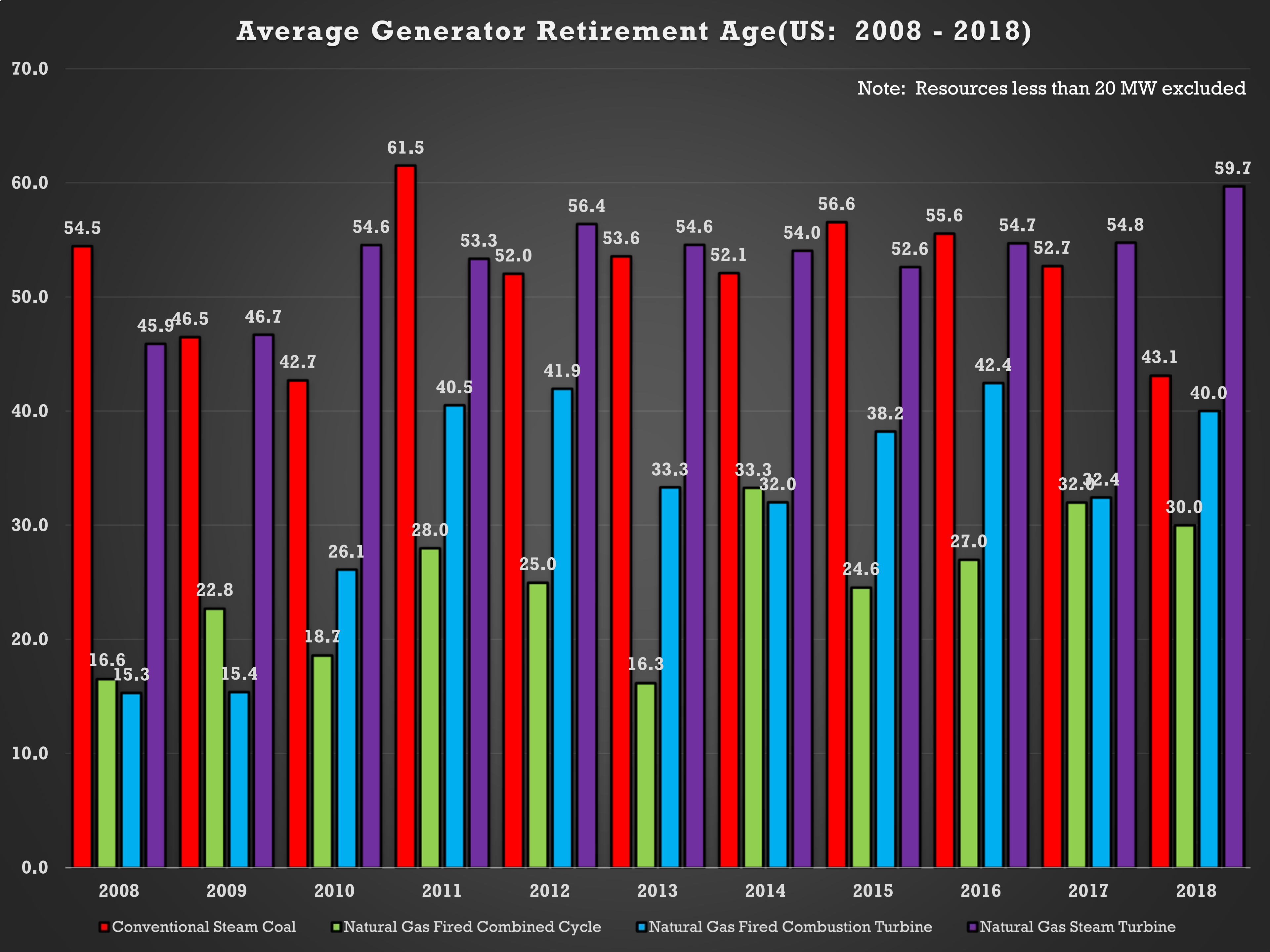
The emerging technology future is driven primarily by the assumption that distributed generation, demand response, energy efficiency, and storage will increase energy growth rates, while peak demand is not affected. Coal retirements will be based on average lifespan considering unit type (i.e. coal vs gas). Installed capacity for wind and solar will see a sustained increase higher than levels observed in the Reference Case. New technologies will increase the capacity factor at new or re-built wind farms.

- Peak demand growth rates as submitted in load forecast, while energy growth rates see an increase
- Natural gas prices are consistent with industry long-term reference forecasts
- Coal and gas units will be retired reflecting average lifespan
- New technologies will increase the capacity factor at new or re-built wind farms
- A increase in deployment of energy storage devices

Key Assumptions	Drivers				
	Reference Case			Emerging Technologies	
	Year 2 (2022)	Year 5 (2025)	Year 10 (2030)	Year 5 (2025)	Year 10 (2030)
Peak Demand Growth Rates	As Submitted in Load Review			As Submitted in LR	
Energy Demand Growth Rates	As Submitted in Load Review			Increase	
Natural Gas Prices	Current Forecast			Current Forecast	
Coal Prices	Current Forecast			Current Forecast	
Emissions Prices	Current Forecast			Current Forecast	
Fossil Fuel Retirements	Current Forecast	Age-Based-56 yr for coal, 50 yr for gas/oil, subject to GO review		Age-Based-56 for coal, 50 for gas/oil, repowering (life extension) or emissions upgrades exceptions	
Environmental Regulations	Current Regulations			Current Regulations	
Demand Response	As Submitted in LF			As Submitted in LF	
Distributed Generation (Solar)		Assumed in LF		+300 MW	+500 MW
Energy Efficiency	As Submitted in LF			As Submitted in LF	
Export Lines	No			No	
New/Re-powered Renewables	Increased capacity factor			Increased capacity factor	
Storage	Existing + RAR	20% of projected solar		35% of projected solar	
Total Renewable Capacity					
Solar (GW)	Existing + RAR	~~3~~	~~5~~	4	~~7~~
Approved Wind (GW)	Existing + RAR	26	28	30	33
Approved Solar (GW)		4	7	5	9

Generation Retirements


Note: Resources less than 20 MW excluded
Average Generator Retiremet Age (SPP: 2010 - 2018)
70
60
50
40
30
20
10
0
2010
2012
2013
2014
2015
2016
2017
Conventional Steam Coal
Natural Gas Fired Combustion Turbine
Natural Gas Steam Turbine



Average Generator Retirement Age(US: 2008 - 2018)
Note: Resources less than 20 MW excluded
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
54.5
16.6
15.3
45.9
46.5
22.8
15.4
46.7
42.7
18.7
26.1
54.6
61.5
28.0
40.5
53.3
52.0
25.0
41.9
56.4
53.6
16.3
33.3
54.6
52.1
33.3
32.0
54.0
56.6
24.6
38.2
52.6
55.6
27.0
42.4
54.7
52.7
32.0
32.4
54.8
43.1
30.0
40.0
59.7
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
Conventional Steam Coal
Natural Gas Fired Combined Cycle
Natural Gas Fired Combustion Turbine
Natural Gas Steam Turbine

Average Retirement by Age

Fuel Type and Area		2002-2018	2008-2018	2014-2018
Coal	SPP	53.8	53.4	55.1
	US	53.2	53.8	53.8
Gas CC	SPP	N/A	N/A	N/A
	US	26.9	28.5	30.7
Gas CT	SPP	41.0	47.6	45.7
	US	30.4	34.2	36.8
Gas ST	SPP	57.9	58.7	61.3
	US	50.8	52.7	53.7

Resource Plan Solar Amount Reconsideration

Solar Amount Reconsideration

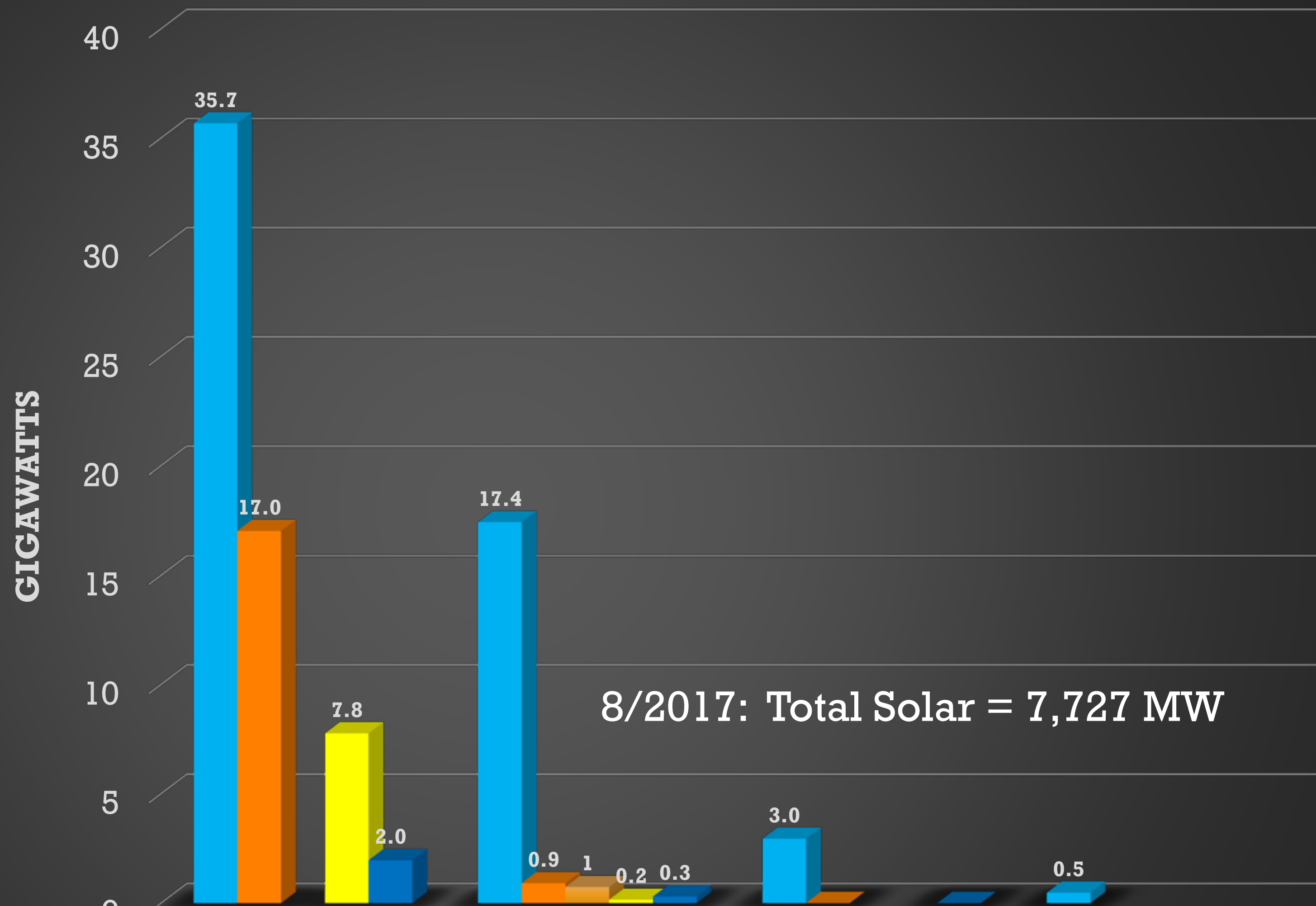
- Investment Tax Credits still available
  - Tax credit schedule on next slide
- GI Queue request for solar have more than doubled over the last year
- Costs continue to decrease
- Solar provides high level accreditation value

Investment Tax Credit Schedule

Resource type	Begin construction deadline	Placed in service deadline	Tax credit amount
Solar	Dec. 31, 2019	Dec. 31, 2023	30%
	Dec. 31, 2020	Dec. 31, 2023	26%
	Dec. 31, 2021	Dec. 31, 2023	22%
	Future years	after Dec. 31, 2023	10%

Note: Units on suspension are not considered in this graphic

Current Queue Status



	Wind	Solar	Battery	Thermal
DISIS STAGE	35687	17447	2951	488
FACILITY STUDY STAGE	17045	922	20	
FEASIBILITY STUDY STAGE		750		
IA FULLY EXECUTED/ON SCHEDULE	7776	170		
IA PENDING	1970	314	20	

ITP 2020

Storage Amounts

Energy Storage

- 2991 MW of Battery Storage in the GI Queue
  - 2951 MW in DISIS
  - 20 MW in Facility Study
  - 20 MW IA Pending
- Reviewed GI Queue for common POIs for battery storage and solar requests
  - 15 sites
  - 916 MW storage (152 MW/19.8 MW)
  - 4218 MW solar (750 MW/ 50 MW)
  - Avg. = 21.7% of storage MW at common POIs
- Storage amounts based on current solar amounts
  - F1: 630 MW (Y5), 1.05 GW (Y10)
  - F2: 840 MW (Y5), 1.47 GW (Y10)

Future 3

Third Future (Option A)

The third future is driven primarily by the assumption that environmental regulations will be implemented due to a shift in the current political climate. The main driver for this future will be the implementation of a carbon tax and Production Tax Credits (PTCs). The combination of a carbon tax and re-instatement of PTCs will lead to an even greater increase in renewable generation. Coal retirements will be accelerated based upon an expected decrease in capacity factor. As a result of coal retirements and available renewable energy and fracking regulations, gas prices will increase over the current forecast. New technologies will increase the capacity factor at new or re-built wind farms.

- Carbon Tax adder*
- Natural gas prices increase slightly due to regulations on fracking
- Accelerated coal unit retirements based upon expected capacity factor reductions
- Increased deployment of energy storage devices and distributed generation
- New technologies will increase the capacity factor at new or re-built wind farms

*$22 adder discussed for 2019 Futures

Third Future (Option B)

The third future is intended to be an accelerated emerging technologies future driven primarily by the assumption that electric vehicles, and storage will have a major impact on load and energy growth rates. Coal retirements will be based on average lifespan. New technologies will increase the capacity factor at new or re-built wind farms along with a renewable resource plan forecast higher than the emerging technologies future.

- Natural gas prices are consistent or slightly higher than industry long-term forecasts
- A rapid increase in deployment of energy storage devices and adoption rate of electric vehicles
- Overall increase in peak demand and energy growth rates
- New technologies will increase the capacity factor at new or re-built wind farms
- Renewable penetration higher than expected in Future 2
- Coal units will be retired reflecting average lifespan

Third Future (Option C)

The third future is a combination of Options A and B and considers the implementation of multiple industry regulation changes that affect the direction of the electric utility industry. The two main drivers include a carbon adder and the reinstatement of Production Tax Credits (PTCs) for renewables. These policy changes will cause the price for natural gas to rise. Increase prices across the footprint will increase desire for energy efficiency decreasing both peak demand and energy growth rates. Implementation of the carbon adder and PTCs will increase the renewable amounts higher than those determined in Future 2.

- Carbon Adder
- Natural gas prices increase based upon gas demand and fracking regulations
- Retirements accelerated based upon capacity factor subject to repowering or emissions upgrades
- Increased energy efficiency decreasing peak demand and energy growth rates
- Increased renewable amounts (wind and solar) higher than identified in F2

Future 3 Options

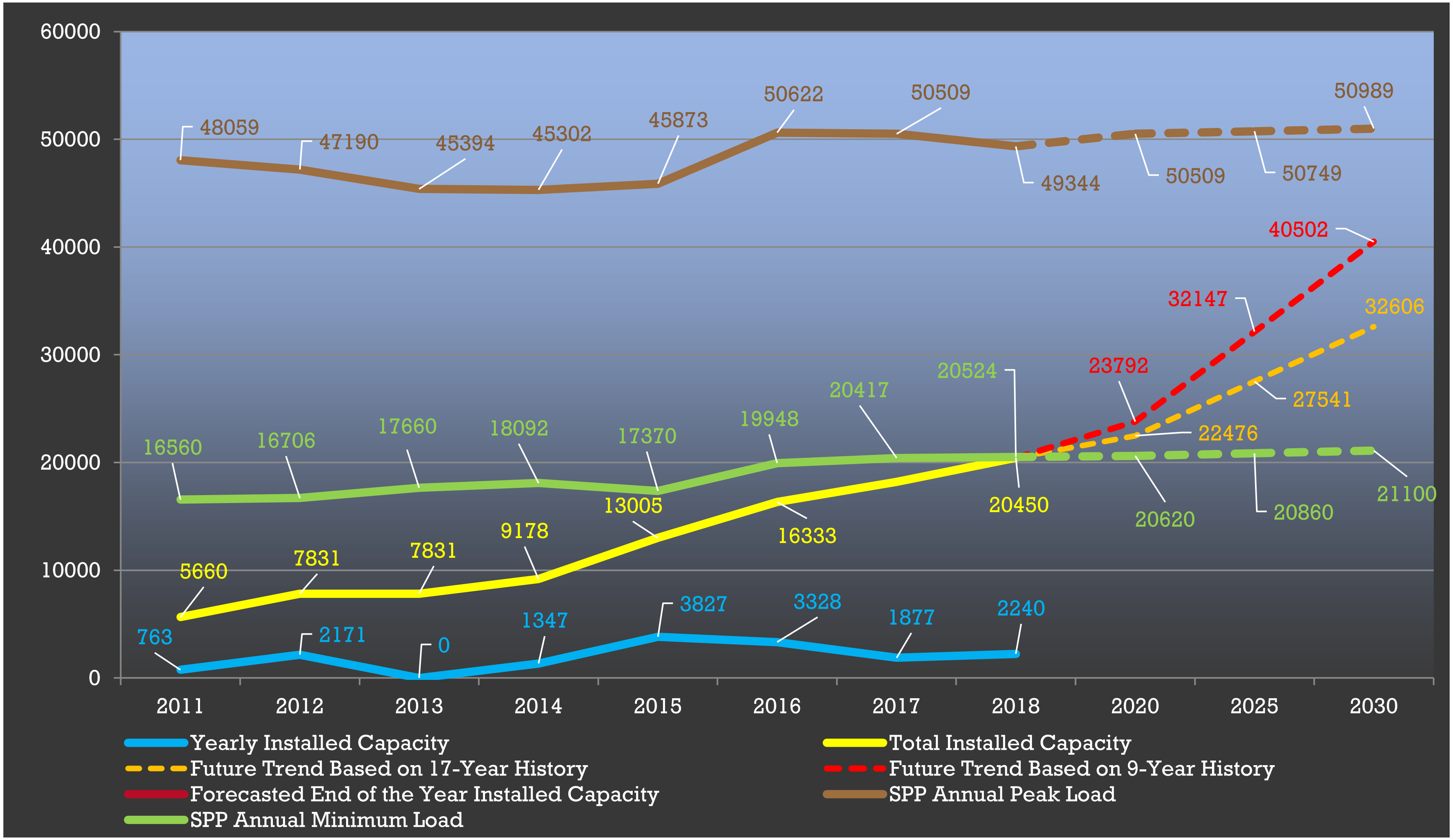
Key Assumptions	Option A Year 5 (2025)	Option A Year 10 (2030)	Option B Year 5 (2025)	Option B Year 10 (2030)	Option C Year 5 (2025)	Option C Year 10 (2030)
Peak Demand Growth Rates	As Submitted in LF		As Submitted in LF		Decreased	
Energy Demand Growth Rates	As Submitted in LF		Increased		Decreased	
Natural Gas Prices	Increased		Current Forecast		Increased	
Coal Prices	Current Forecast		Current Forecast		Current Forecast	
Emissions Prices	Current Forecast		Current Forecast		Current Forecast	
Fossil Fuel Retirements	Accelerated, based on capacity factor		Age-Based-56 for coal, 50 for gas/oil, subject to repowering or emissions upgrades exceptions		Accelerated, based on capacity factor, subject to repowering or emissions upgrades exceptions	
Environmental Regulations	Carbon Adder		Current Regulations		Carbon Adder	
Demand Response	As Submitted in LF		As Submitted in LF		As Submitted in LF	
Distributed Generation (Solar)	Increased		More increased		Increased	
Energy Efficiency	As Submitted in LF		Increased		Increased	
Storage	Increased		More Increased		Increased	
Total Renewable Capacity						
Solar (GW)	4	7	Higher	Higher	4	7
Wind (GW)	30	33	Higher	Higher	32	40
Staff Recommended Solar (GW)	5	9	5	9	5	9

SPP

Future 3 Considerations

- What is the value added?
  - Do you consider Future 3 on an equal footing as F1 and F2?
  - Will a 3rd future provide the value you are looking for when compared to its cost?
- Affects on NTC Issuance
  - Are the assumptions in the future reasonable when considering the potential for an NTC to be issued?
  - Transmission expansion has become increasingly harder to justify to regulators

Wind Capacity Installed by Year (9/2/2018)



Note: Expected ~21 GW by 12/31/2018

SPP

Southwest Power Pool

Revision Request Recommendation Report

RR #: 321	**Date: 9/17/2019**
RR Title: ITP Manual Cleanup	
SUBMITTER INFORMATION	
Submitter Name: Amber Greb	**Company:** SPP
Email: agreb@spp.org	**Phone:** 501-614-3561
EXECUTIVE SUMMARY AND RECOMMENDATION FOR MOPC AND BOD ACTION	
After the initial approval of the ITP Manual to implement the new ITP process resulting from the Transmission Planning Improvement Task Force work, staff noticed cleanup items, grammatical errors, and small improvements that could be made in the Manual. This RR addresses these issues identified by staff.	
OBJECTIVE OF REVISION	
Objectives of Revision Request: This RR is intended to standardize one item approved in the 2019 ITP Scope as well as clarify minor issues discovered in the ITP Manual since its initial approval. As part of the 2019 ITP Scope approval, the DC Tie settings for the Economic model were approved to be standardized in the ITP Manual. Other minor issues addressed in this Revision Request include changing the names of the models to more accurately reflect what they represent in the ITP planning process, removal of Year 2 from the Renewable Policy Survey based upon the decision to not develop a resource plan for Year 2, and other clarifications including corrections to footnotes.	
SPP STAFF ASSESSMENT	
As the submitter for this RR, staff is in agreement with the RR.	
IMPACT	
Will the revision result in system changes ☒ **No** ☐ **Yes** **Summarize changes:** **Will the revision result in process changes?** ☒ **No** ☐ **Yes** **Summarize changes:**	
Is an Impact Assessment required? ☒ **No** ☐ **Yes** **If no, explain:**	
Estimated Cost: $	**Estimated Duration:** months
Primary Working Group Score/Priority:	

SPP DOCUMENTS IMPACTED		
☐ **Market Protocols**	**Protocol Section(s):**	**Protocol Version:**
☐ **Operating Criteria**	**Criteria Section(s):**	**Criteria Date:**

☐ **Planning Criteria**	**Criteria Section(s):**	**Criteria Date:**
☐ **Tariff**	**Tariff Section(s):**	
☐ **Business Practice**	**Business Practice Number:**	
☐ **Integrated Transmission Planning (ITP) Manual**	**Section(s): Sections 2, 2.2.1.2-3, 2.2.1.6.3, 2.2.2.2.4, 2.2.3, 4.2, 4.2.2, 5.1.1, 5.3.2, 6.1.1, 6.1.4, 6.4, 7, 11.1**	
☐ **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):**	
WORKING GROUP REVIEWS AND RECOMMENDATIONS List Primary and any Secondary/Impacted WG Recommendations as appropriate		
Primary Working Group: TWG	**Date: 9/12/2018** **Action Taken: Approved unanimously** **Abstained:** **Opposed:**	
Reason for Opposition:		
Primary Working Group: ESWG	**Date: 9/25/2018** **Action Taken:** **Abstained:** **Opposed:**	
Reasons for Opposition:		
Secondary Working Group:	**Date:** **Action Taken:** **Abstained:** **Opposed:**	
Reasons for Opposition:		
Secondary Working Group:	**Date:** **Action Taken:** **Abstained:** **Opposed:**	
Reasons for Opposition:		

MOPC	**Date:** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	
BOD/Member Committee	**Date: N/A** **Action Taken:** **Abstained:** **Opposed:**
Reasons for Opposition:	

COMMENTS
Comment Author: Rodney Massman
Date Comments Submitted: 8/17/2018
Description of Comments: Clarification comments were submitted for the Renewable Policy Review section
Status: These comments were approved by the TWG, ESWG is the primary owner of this section
Comment Author:
Date Comments Submitted:
Description of Comments:
Status:

PROPOSED REVISION(S) TO SPP DOCUMENTS
Market Protocols

SPP Tariff (OATT)

SPP Operating Criteria

SPP Planning Criteria

2 Model Development

Table 1 lists the model sets for the ITP assessment cycle. After the model sets are finalized, no topology changes will be accepted to update the model. Any identified model changes will be required to be submitted during the detailed project proposal (DPP) window as detailed in the Model Adjustments section.

Description	Year 2	Year 5	Year 10	Total
Base Reliability	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	9
Market Economic Model ~~SPP BA (Economic)~~	One Future (1)	Each Future (1-3)	Each Future (1-3)	3-7
Market Powerflow Model ~~SPP BA Powerflow (Reliability)~~	One Future's Peak and Off-Peak (2)	Each Futures' Peak and Off-Peak (2-6)	Each Futures' Peak and Off-Peak (2-6)	6-14

Table 1: ITP Model Sets

Commented [KH1]: NOTE: This will be a global change throughout the manual, however, for ease of reviewing the changes all instances of this correction are not included in the RR.

2.2.1.2 Load and Energy Forecasts

The ITP assessment will require load forecasts for areas within and outside the SPP footprint for each of the study years. The load will represent each individual load-serving entity's peak conditions without losses per season (*i.e.*, non-coincident peak conditions for the SPP region). Resource obligations will be determined for the footprint taking into consideration non-scalable and scalable loads.

For the economic model development process, SPP will obtain load data to utilize in the ITP assessment by the following unless directed otherwise by the ESWG:

- Peak load: The source shall be the no-loss aggregated bus load totals (MW) based on the current base reliability models.
- Hourly load shape: The primary source shall be third-party vendor data. If the primary source is not available or is not appropriate, SPP will create a synthetic load shape based on historical data points and FERC Form 714 information.
- Monthly peak and energy percentages: The primary source shall be third-party vendor data. If the primary source is not available or is not appropriate, SPP will calculate the monthly peak and energy percentages by using hourly load shape data.

- Load factor: As a primary source, annual load factors shall be provided by SPP stakeholders. If the primary source is not available or is not appropriate, SPP will calculate load factors by utilizing hourly load shapes.
- Transmission loss factor: As a primary source annual loss factors shall be provided by SPP stakeholders. If the primary source is not available or is not appropriate, SPP will utilize previous ITP study values.
- Demand mapping: The primary source shall be the economic load ownership legend[1] reviewed as part of the SPP annual data request. If the primary source is not available or is not appropriate, SPP stakeholders will provide load bus and ID mappings to demand groups.

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~~scope~~.

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 percentages in Table 3 will be used to calculate the mandate or goal 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 values 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. 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 ~~shall be presumed to have~~ do not have RPS requirement for the purposes of this renewable policy review.

[1] Table within the SPP annual data request that maps loads according to their attributes to groups of demands for the economic model

State	RPS Type	Generation Type	Capacity- or Energy-Based	~~Year 2 %~~	Year 5 %	Year 10 %
Kansas	Goal	Both	Capacity	~~20~~	20	20
Minnesota	Mandate	Both	Energy	~~20~~	20	25
Missouri	Mandate	Both	Energy	~~15~~	15	15
Montana	Mandate	Both	Energy	~~15~~	15	15
North Dakota	Goal	Both	Energy	~~10~~	10	10
New Mexico	Mandate	Wind	Energy	~~15~~	15	15
New Mexico	Mandate	Solar	Energy	~~4~~	4	4
South Dakota	Goal	Both	Energy	~~10~~	10	10
Texas	Mandate	Both	Capacity	~~5~~	5	5

Table 2: 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.

2.2.1.6.3 DC Ties

For direct current (DC) ties that connect SPP to the Texas and western interconnections, hourly profiles will be developed based on at least three years of historical flows across each DC tie and will be capped at long-term firm transmission service amounts. These transactions will be modeled as fixed with no assumed curtailment price.

2.2.2.2.4 Siting for External Regions

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

2.2.3 Constraint Assessment

SPP maintains a list of flowgates to monitor based on reliability and economic issues seen in real-time. The constraint assessment is used to identify potential future constraints for each future and year of study.

To create these additional constraints, SPP will perform economic simulations to identify additional or breaching elements in the system that occur during the reliability peak and off-peak hours[2]. System flows under two levels of constraint will be analyzed:

- Copper Plate: No defined constraints.
- Initial constraint list based on NERC and SPP flowgates.

4.2 Reliability Needs Assessment

The reliability needs assessment will be performed in parallel with the economic, public policy, and operational needs assessments. All needs will be identified by assessing the performance of the SPP transmission system under system intact and contingency conditions. SPP will utilize Table 1 from the NERC Standard TPL-001 as the basis for the contingencies to be assessed during the study. Contingencies that do not allow for non-consequential load loss (NCLL) or the interruption of firm transmission service (IFTS) will be analyzed during the reliability needs assessment. SPP P~~p~~lanning C~~c~~riteria[3] will be utilized to determine if a potential regional reliability violation will be considered as a reliability need.
Thermal violations identified in the SPP BA powerflow model during the reliability assessment may not have met the constraint assessment criteria to be defined as a constraint or may be related to a defined constraint in the economic model. Reliability needs will be evaluated for reclassification as an economic need during or after the needs assessment to ensure proper evaluation of system needs. If reclassification is justified, SPP will inform stakeholders via email or the SPP website.

4.2.2 S~~PP BA~~Market Powerflow Model

Contingency analysis for the ~~BA~~ Market powerflow models will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 6.

[2] Defined in the ~~SPP BA Powerflow~~Economic Powerflow Model ~~Base Reliability Model~~ Overview section
[3] SPP Planning Criteria

	P0, P1, P2.1	
	Monitored Element	Contingent Element
Reference Case Year 2 Peak	100 kV+ with select 69 kV facilities	100 kV+ with select 69 kV facilities
Reference Case Year 2 Off-Peak		
Reference Case Year 5 Peak		
Reference Case Year 5 Off-Peak		
Reference Case Year 10 Peak	100 kV+	100 kV+
Reference Case Year 10 Off-Peak		
F_X Year 5 Peak		
F_X Year 5 Off-Peak		
F_X Year 10 Peak		
F_X Year 10 Off-Peak		

Table 3: NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

The remaining contingencies in Table 1 of the NERC Standard TPL-001 that do not allow for NCLL or IFTS will be analyzed if a violation was observed in the same year/season of the base reliability model as detailed in Table 7.

	Other Planning Events[4]	
	Monitored Element	Contingent Element[5]
Reference Case Year 2 Peak	100 kV+	100kV/300 kV+
Reference Case Year 2 Off-Peak	100 kV+	100kV/300 kV+
Reference Case Year 5 Peak	100 kV+	100kV/300 kV+

~~T~~able 4: Remaining Contingencies for Monitored and Contingent Elements

5.1.1 Solutions

During the DPP window, all DPP submittals must be submitted through SPP's RMS for tracking purposes using the most current DPP submittal form, located on the SPP website. This allows SPP to track the submission as well as ~~correspond~~ communicate with the individual project submitter. SPP will develop solutions to the needs posted in the needs assessment in accordance with the project schedule.

[4] Other planning events include P2.2, P2.3, P3.1-P3.5, P4.1-P4.5, and P.5

[5] Some ~~P~~planning ~~E~~events allow/disallow NCLL or IFTS based upon the voltage level of the contingent element.

5.3.2 Reliability Solution Evaluation

All solutions[6] will be evaluated against reliability needs. SPP will use the following metrics to evaluate potential benefits-to-proposed cost:[7]

- Cost per loading relief (CLR[7][8] ~~)~~)– ~~compares~~ relates the cost of a proposed solution to the amount of thermal loading relief for a need ~~provided to the cost of the proposed solution~~
- Cost per voltage relief (CVR[7][9]) – ~~compares~~relates the cost of a proposed solution to the amount of voltage support relief for a need ~~provided to the cost of the proposed solution~~

The CLR and CVR metrics will be calculated for every solution against each need it mitigates. The metric calculations will provide a ranking of the solutions for each need. SPP will use the metrics as a tool during project selection for the reliability portfolio development.

Potential seams projects will be identified and flagged as such if they meet either of the following criteria:

- Interconnects SPP with a non-SPP TO.
- Addresses an identified first-tier potential reliability issue.

SPP will determine what level of cost-sharing of any potential seams project would make it viable for the SPP region and whether or not there is an opportunity for cost-sharing with a neighboring entity. SPP will work with the appropriate neighboring entity to evaluate any potential seams projects and determine if there is a willingness to proceed jointly.

6.1.1 Economic Portfolio Development

Solutions mitigating economic needs are ranked by their cost effectiveness, net APC benefit and qualitative benefits for each need or set of needs and categorized into one or more of the following groupings:

- Cost effective: Solutions with the lowest cost with respect to the congestion relief they provide on individual flowgates will be selected.
- Highest net APC benefit: Solutions with the highest difference between one-year APC benefit and one-year project cost will be selected.
- Multi-variable: Top-ranking projects in the other two groupings, as well as qualitative benefits that the other groupings may not capture, will be considered when selecting projects.

In addition to economic performance, consideration of the following information may be given to the top-ranking solutions:[10]

1. One-year project cost, APC benefit, and B/C.
2. 40-year NPV cost, APC benefit, and B/C.
3. Congestion relief that a project provides for the economic needs of that future and year.
4. Project overlap, or when two or more projects that relieve the same congestion are in a single portfolio.
5. The potential for a project to mitigate multiple economic needs.
6. Any potential routing or environmental concerns with projects.
7. Any long-term concerns about the viability of projects.
8. Seam and non-seam project overlap.
9. Relief of downstream and/or upstream issues, tested by~~Individual project robustness, which includes,~~ event file modification.
10. The potential for a project to mitigate reliability, operational, and public policy needs, which covers current market congestion.
11. The potential for a project to address non-thermal issues.
12. The need for new infrastructure versus leveraging existing infrastructure.

[6] Regardless of the type of need the solution was submitted to address

[7] Relief score calculations can be found in the reliability metrics document approved by the TWG

[8] ~~TWG~~

[9] ~~TWG~~

[10] Additional consideration may result in changes in top-ranking solutions, including elimination of solutions.

13. Larger-scale solutions that provide more robustness and additional qualitative benefits.

Study estimates for the top-ranking projects from each economic grouping will be developed consistent with the Cost Estimates section of this manual. Once study estimates are applied to the top-ranking solutions in each grouping, the limited set of solutions will be ranked again to reflect the cost refinement. The top-ranking economic projects will be tested in a new set of base models that include the corresponding reliability, policy, and operational economic portfolios. The economic projects will be tested individually within each group to assure only those with at least a 0.9 one-year B/C or 1.0 40-year NPV B/C move forward.

6.1.4 Persistent Operational Portfolio Development

Solutions mitigating persistent operational needs are ranked by the appropriate metrics depending on whether the need is economic or reliability based. Solutions identified to mitigate persistent operational issues will be compared with the other portfolios to ensure efficiencies are gained by identifying the most cost effective ~~minimum number of~~ projects to meet all needs. Economic solutions will be ranked based on their project cost compared to the cost incurred without the project. SPP and stakeholders will determine the criteria for development of the operational portfolio, which will be included in each study scope. Reliability solutions will be evaluated using the CLR and CVR metric concept.

F~~inal Assessments~~

~~6.4.1 Benefit Metrics~~

~~Benefit metrics will be used to measure the value and economic impacts of the final consolidated portfolio to be expected from the ITP assessment. Generally, a single portfolio will be tested in the approved future(s) by computing benefits and costs over a 40-year timeframe. For further detail on the metrics in Table 8, refer to the Benefit Metrics Manual.~~[11]

~~ITP Assessment Benefit Metrics~~
~~ted Production Cost~~
~~gs Due to Lower Ancillary Service Needs and Production Costs~~
~~ed or Delayed Reliability Projects~~
~~nal Energy Losses Benefit~~
~~ity Cost Savings Due to Reduced On-Peak Transmission Losses~~
~~tion of Emission Rates and Values~~
~~Policy Benefits~~
~~ned Benefit of Mandated Reliability Projects~~
~~ation of Transmission Outage Costs~~
~~sed Wheeling Through and Out Revenues~~

~~Table 8: ITP Assessment Benefit Metrics~~

~~Sensitivity Analysis~~

~~Sensitivity analyses will be defined in the scope and conducted to measure the flexibility of the final portfolio in each ITP assessment. Generally, these sensitivities will not be used to select the proposed transmission projects, nor to filter out projects. The sensitivities to be performed on the final portfolio of each ITP assessment shall include, at a minimum:~~

~~High natural-gas price~~
~~Low natural-gas price~~
~~High demand~~
~~Low demand~~

~~[11] Benefit Metrics Manual~~

~~Typically, for the demand sensitivities, one standard deviation on either side of the expected values will be used, and for the natural gas price sensitivities, two standard deviations of expected values will be used.~~

6.4 Final Reliability Assessment

To evaluate and confirm the effectiveness of all identified upgrades for the recommended portfolio, a final reliability assessment will be performed. The base reliability and SPP BA powerflow models will be modified to include the recommended portfolio and model adjustments identified during solution development, regardless of project classification. A contingency analysis will be performed to identify any new reliability violations on this updated set of powerflow models.

If any new reliability violations are observed in the modified base reliability models, the recommended portfolio may be modified with a new or modified solution. The final portfolio will include the changes determined from the incremental reliability assessments.

If any new reliability violations are observed in the modified SPP BA powerflow models, they will be documented in the ITP assessment report: however, no solutions will be developed. SPP will perform a spot check contingency analysis on economic solutions. This analysis will be used to determine the effect of potential dispatch changes as constraints are removed or adjusted due to the solutions and ensure that those changes do not result in additional reliability violations.

The analyses described in this section will begin as SPP develop draft portfolios to identify projects that may have adverse impacts to the transmission system as quickly as possible.

The results of the final reliability assessment on the recommended portfolio will be documented in the ITP assessment report. Any upgrades added to the recommended portfolio as a result of the final reliability assessment will be identified.

7 Informational Portfolio Analysis

7.1 Benefit Metrics

Benefit metrics will be used to measure the value and economic impacts of the final consolidated portfolio to be expected from the ITP assessment. Generally, a single portfolio will be tested in the approved future(s) by computing benefits and costs over a 40-year timeframe. For further detail on the metrics in Table 8, refer to the Benefit Metrics Manual.[12]

ITP Assessment Benefit Metrics
Adjusted Production Cost
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Marginal Energy Losses Benefit
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Reduction of Emission Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Table 5: ITP Assessment Benefit Metrics

[12] Benefit Metrics Manual

7.2 Sensitivity Analysis

Sensitivity analyses will be defined in the scope and conducted to measure the flexibility of the final portfolio in each ITP assessment. Generally, these sensitivities will not be used to select the proposed transmission projects, nor to filter out projects. The sensitivities to be performed on the final portfolio of each ITP assessment shall include, at a minimum:

- High natural-gas price
- Low natural-gas price
- High demand
- Low demand

Typically, for the demand sensitivities, one standard deviation on either side of the expected values will be used, and for the natural gas price sensitivities, two standard deviations of expected values will be used.

11.1 History of the ITP Assessment

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

The SPPT recommended that the organization adopt a new set of planning principles, develop and implement an ITP assessment, develop a plan to monitor the construction of projects approved through the ITP assessment, identify priority projects that continue to appear in system reviews to relieve congestion on existing constraints, and connect SPP's eastern and western regions. The SPPT recommended the Regional State Committee (RSC) establish a "highway/byway" cost allocation methodology for approved projects.13

The SPPT developed an integrated set of principles that should guide SPP in the development of its comprehensive ITP assessment:

1. SPP's primary function is to "keep the lights on," and one way that is accomplished is to provide transmission service for customers within the SPP region. In order to meet this long-term function, SPP must plan for and construct a robust transmission system. This robust transmission system should be large in both scale and geography so as to provide flexibility to meet SPP's future needs.

2. SPP's planning process for a robust transmission system must consider transmission as an enabler to meet short-term and long-term needs. Planning of SPP's transmission system must take into consideration the anticipated location of future generation facilities and should incorporate various scenarios regarding load growth, demand response, energy efficiency, fuel prices, environmental and governmental regulations and policies, and other factors.

3. SPP's planning processes should take a long-term view (20 or more years) of the benefits and costs of all projects while also expediting priority system investments.

4. As a priority, through the RSC and the membership, SPP should resolve the uncertainties associated with financing transmission projects by establishing the appropriate regional cost allocation methodologies. This effort should result in a reduction of the number of cost allocation mechanisms that exist today. SPP members, customers, and interested parties must participate in this effort with their regulators to establish the appropriate cost recovery methods.

5. Once SPP has developed and obtained the approval of a robust transmission plan for the region, the BOD and RSC should ensure that construction is commenced and completed according to an established timeline.

SPP began performing its planning duties in accordance with the ITP assessment in July 2010.

[13] The Highway/Byway methodology was approved by FERC on June 17, 2010.

11.4 Definitions

1. B~~A~~ Market Economic Models – model set containing all economic parameters and powerflow data necessary to perform SCUC/SCED simulations
2. B~~A~~ Market Powerflow Models – model set containing all powerflow data, including load and generation dispatch from the SCUC/SCED simulations
3. Base Reliability Models – model set representative of how load responsible entities within SPP would serve load utilizing only resources with long-term firm transmission service
4. Balancing Authority – an entity responsible for maintaining a load, generation, and interchange balance within its region
5. Congestion Score – the product of a constraint's annual average shadow price and the number hours the constraint binds; value used to rank economic needs by severity and/or longevity
6. Detailed Project Proposal – a submittal form in which stakeholders may submit solutions to solve ITP needs
7. First-Tier – The non-SPP transmission system that is electrically interconnected to the SPP transmission system and extends throughout the interconnected entity's footprint.~~non-SPP powerflow areas that are interconnected to the SPP system~~
8. Grouping – specific to economic portfolio development; set of projects that are selected by economic characteristics (cost-effectiveness, net APC benefit, etc.) from initial screening runs and meet a 0.9 one-year B/C or 1.0 40-year B/C within the set of projects
9. Light Load Model – model representative of each submitting entity's one-hour system minimum load between April and May, non-coincident to the SPP system
10. Manual Commitments - a commitment of a resource outside of the automated market process to alleviate constraints
11. Net Plant Carrying Charge - annual percentage that is applied to a utility's depreciated plant costs to calculate an annual revenue requirement billed on Schedule 11 of the SPP Tariff; calculated by a transmission owner's revenue requirement divided by the net transmission plant investment.
12. Notification to Construct: A written notice from SPP directing an entity that has been selected to construct one or more transmission project(s) to begin or continue implementation of the transmission project(s) in accordance with Attachment Y of the SPP Tariff.
13. SPP Open Access Transmission Tariff: SPP governing document filed for compliance with FERC Order 888
14. Reference-Case Future – one future (of up to three) that will be included in each ITP assessment; reflective of a future scenario in which there are no major policy changes
15. Revision Request – an SPP mechanism by which SPP governing documents can be revised through the stakeholder process
16. Seams – areas of or near the boundary of the SPP footprint that are directly impacted by the operation of SPP and non-SPP systems
17. Shadow Price – the potential reduction in total production costs if the limit on a congested flowgate were to be increased by 1 MW
18. State Estimator – a standard industry tool that produces a powerflow model based on available real-time metering information; information regarding the current status of lines, generators, transformers, and other equipment; bus load distribution factors; and a representation of the electric network to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable.
19. SPP Transmission Expansion Plan – The plan that describes the transmission expansion projects being considered over the planning period and developed through the stakeholder process in accordance with the SPP Tariff and approved by the SPP Board.

20. Study Scope – document specific to each individual ITP assessment to be developed by SPP staff and stakeholders containing study assumptions to be utilized that are not included in the ITP Manual
21. Summer Peak Model – model representative of each submitting entity's one-hour system peak load between June and September, non-coincident to the SPP system
22. Winter Peak Model – model representative of each submitting entity's one-hour system peak load between December and March, non-coincident to the SPP system

Revision Request Process

Minimum Transmission Design Standards for Competitive Upgrades (MTDS)

Reliability Coordinator and Balancing Authority Data Specifications (RDS)

SPP Communications Protocols

SPP Southwest Power Pool

Revision Request Form

SPP STAFF TO COMPLETE THIS SECTION	
RR #: 321	**Date: 8/13/2018**
RR Title: ITP Manual Cleanup	
System Changes ☒ No ☐ Yes **Process Changes?** ☒ No ☐ Yes **Impact Analysis Required?** ☒ No ☐ Yes	

SUBMITTER INFORMATION	
Name: Amber Greb	**Company:** SPP
Email: agreb@spp.org	**Phone:** 5016143561
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

☒ Clarification

☐ Design Enhancement

☐ New Protocol, Business Practice, Criteria, Tariff

☐ 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):Sections 2, 2.2.1.2-3, 2.2.1.6.3, 2.2.2.2.4, 2.2.3, 4.2, 4.2.2, 5.1.1, 5.3.2, 6.1.1, 6.1.4, 6.4, 7, 11.1**
☐ **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:
Describe the problem/issue this revision request will resolve.

This RR is intended to standardize one item approved in the 2019 ITP Scope as well as clarify minor issues discovered in the ITP Manual since its initial approval. As part of the 2019 ITP Scope approval, the DC Tie settings for the Economic model were approved to be standardized in the ITP Manual.

Other minor issues addressed in this Revision Request include changing the names of the models to more accurately reflect what they represent in the ITP planning process, removal of Year 2 from the Renewable Policy Survey based upon the decision to not develop a resource plan for Year 2, and other clarifications including corrections to footnotes.

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.

Market Protocols

SPP Tariff (OATT)

SPP Operating Criteria

SPP Planning Criteria

SPP Business Practices

2 Model Development

Table 1 lists the model sets for the ITP assessment cycle. After the model sets are finalized, no topology changes will be accepted to update the model. Any identified model changes will be required to be submitted during the detailed project proposal (DPP) window as detailed in the Model Adjustments section.

Description	Year 2	Year 5	Year 10	Total
Base Reliability	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	Summer Winter Light Load Non-coincident Peak (3)	9
Market Economic Model ~~SPP BA (Economic)~~	One Future (1)	Each Future (1-3)	Each Future (1-3)	3-7
Market Powerflow Model ~~SPP BA Powerflow (Reliability)~~	One Future's Peak and Off-Peak (2)	Each Futures' Peak and Off-Peak (2-6)	Each Futures' Peak and Off-Peak (2-6)	6-14

Table 1: ITP Model Sets

Commented [KH1]: NOTE: This will be a global change throughout the manual, however, for ease of reviewing the changes all instances of this correction are not included in the RR.

2.2.1.2 Load and Energy Forecasts

The ITP assessment will require load forecasts for areas within and outside the SPP footprint for each of the study years. The load will represent each individual load-serving entity's peak conditions without losses per season (*i.e.*, non-coincident peak conditions for the SPP region). Resource obligations will be determined for the footprint taking into consideration non-scalable and scalable loads.

For the economic model development process, SPP will obtain load data to utilize in the ITP assessment by the following unless directed otherwise by the ESWG:

- Peak load: The source shall be the no-loss aggregated bus load totals (MW) based on the current base reliability models.
- Hourly load shape: The primary source shall be third-party vendor data. If the primary source is not available or is not appropriate, SPP will create a synthetic load shape based on historical data points and FERC Form 714 information.
- Monthly peak and energy percentages: The primary source shall be third-party vendor data. If the primary source is not available or is not appropriate, SPP will calculate the monthly peak and energy percentages by using hourly load shape data.
- Load factor: As a primary source, annual load factors shall be provided by SPP stakeholders. If the primary source is not available or is not appropriate, SPP will calculate load factors by utilizing hourly load shapes.

- Transmission loss factor: As a primary source annual loss factors shall be provided by SPP stakeholders. If the primary source is not available or is not appropriate, SPP will utilize previous ITP study values.
- Demand mapping: The primary source shall be the economic load ownership legend[1] reviewed as part of the SPP annual data request. If the primary source is not available or is not appropriate, SPP stakeholders will provide load bus and ID mappings to demand groups.

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~~scope~~.

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 percentages in Table 3 will be used to calculate the mandate or goal 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 values in Table 3 consider forward-looking legislation set by the states that should be met in each of the study years. 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 shall be presumed to have no RPS requirement for the purposes of this renewable policy review.

State	RPS Type	Generation Type	Capacity- or Energy-Based	~~Year 2 %~~	Year 5 %	Year 10 %
Kansas	Goal	Both	Capacity	~~20~~	20	20
Minnesota	Mandate	Both	Energy	~~20~~	20	25
Missouri	Mandate	Both	Energy	~~15~~	15	15
Montana	Mandate	Both	Energy	~~15~~	15	15
North Dakota	Goal	Both	Energy	~~10~~	10	10
New Mexico	Mandate	Wind	Energy	~~15~~	15	15
New Mexico	Mandate	Solar	Energy	~~4~~	4	4
South Dakota	Goal	Both	Energy	~~10~~	10	10
Texas	Mandate	Both	Capacity	~~5~~	5	5

[1] Table within the SPP annual data request that maps loads according to their attributes to groups of demands for the economic model

Table 2: 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.

2.2.1.6.3 DC Ties

For direct current (DC) ties that connect SPP to the Texas and western interconnections, hourly profiles will be developed based on at least three years of historical flows across each DC tie and will be capped at long-term firm transmission service amounts. These transactions will be modeled as fixed with no assumed curtailment price.

2.2.2.2.4 Siting for External Regions

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

2.2.3 Constraint Assessment

SPP maintains a list of flowgates to monitor based on reliability and economic issues seen in real-time. The constraint assessment is used to identify potential future constraints for each future and year of study.
To create these additional constraints, SPP will perform economic simulations to identify additional or breaching elements in the system that occur during the reliability peak and off-peak hours[2]. System flows under two levels of constraint will be analyzed:

- Copper Plate: No defined constraints.
- Initial constraint list based on NERC and SPP flowgates.

4.2 Reliability Needs Assessment

The reliability needs assessment will be performed in parallel with the economic, public policy, and operational needs assessments. All needs will be identified by assessing the performance of the SPP transmission system under system intact and contingency conditions. SPP will utilize Table 1 from the NERC Standard TPL-001 as the basis for the contingencies to be assessed during the study. Contingencies that do not allow for non-consequential load loss (NCLL) or the interruption of firm transmission service (IFTS) will be analyzed during the reliability needs assessment. SPP P~~p~~lanning C~~c~~riteria[3] will be utilized to determine if a potential regional reliability violation will be considered as a reliability need.
Thermal violations identified in the SPP BA powerflow model during the reliability assessment may not have met the constraint assessment criteria to be defined as a constraint or may be related to a defined constraint in the economic model. Reliability needs will be evaluated for reclassification as an economic need during or after the needs assessment to ensure proper evaluation of system needs. If reclassification is justified, SPP will inform stakeholders via email or the SPP website.

[2] Defined in the ~~SPP BA Powerflow~~Economic Powerflow Model ~~Base Reliability Model~~ Overview section
[3] SPP Planning Criteria

4.2.2 ~~SPP BA~~Market Powerflow Model

Contingency analysis for the ~~BA~~ Market powerflow models will consist of analyzing P0, P1, and P2.1 planning events identified in NERC Standard TPL-001 Table 1 for each of the models. The voltage level for monitored and contingent elements in the SPP footprint are described in more detail in Table 6.

	P0, P1, P2.1	
	Monitored Element	Contingent Element
Reference Case Year 2 Peak	100 kV+ with select 69 kV facilities	100 kV+ with select 69 kV facilities
Reference Case Year 2 Off-Peak		
Reference Case Year 5 Peak		
Reference Case Year 5 Off-Peak		
Reference Case Year 10 Peak	100 kV+	100 kV+
Reference Case Year 10 Off-Peak		
F_X Year 5 Peak		
F_X Year 5 Off-Peak		
F_X Year 10 Peak		
F_X Year 10 Off-Peak		

Table 3: NERC Standard TPL-001 Planning Events as Monitored and Contingent Elements

The remaining contingencies in Table 1 of the NERC Standard TPL-001 that do not allow for NCLL or IFTS will be analyzed if a violation was observed in the same year/season of the base reliability model as detailed in Table 7.

	Other Planning Events[4]	
	Monitored Element	Contingent Element[5]
Reference Case Year 2 Peak	100 kV+	100kV/300 kV+
Reference Case Year 2 Off-Peak	100 kV+	100kV/300 kV+
Reference Case Year 5 Peak	100 kV+	100kV/300 kV+

Table 4: Remaining Contingencies for Monitored and Contingent Elements

5.1.1 Solutions

During the DPP window, all DPP submittals must be submitted through SPP's RMS for tracking purposes using the most current DPP submittal form, located on the SPP website. This allows SPP to track the submission as well as

[4] Other planning events include P2.2, P2.3, P3.1-P3.5, P4.1-P4.5, and P.5

[5] Some ~~P~~planning ~~E~~events allow/disallow NCLL or IFTS based upon the voltage level of the contingent element.

~~correspond~~ communicate with the individual project submitter. SPP will develop solutions to the needs posted in the needs assessment in accordance with the project schedule.

5.3.2 Reliability Solution Evaluation

All solutions[6] will be evaluated against reliability needs. SPP will use the following metrics to evaluate potential benefits-to-proposed cost:[7]

- Cost per loading relief (CLR[7]~~[8]~~) – ~~compares~~ relates the cost of a proposed solution to the amount of thermal loading relief for a need ~~provided to the cost of the proposed solution~~
- Cost per voltage relief (CVR[7]~~[9]~~) – ~~compares~~relates the cost of a proposed solution to the amount of voltage support relief for a need ~~provided to the cost of the proposed solution~~

The CLR and CVR metrics will be calculated for every solution against each need it mitigates. The metric calculations will provide a ranking of the solutions for each need. SPP will use the metrics as a tool during project selection for the reliability portfolio development.
Potential seams projects will be identified and flagged as such if they meet either of the following criteria:

- Interconnects SPP with a non-SPP TO.
- Addresses an identified first-tier potential reliability issue.

SPP will determine what level of cost-sharing of any potential seams project would make it viable for the SPP region and whether or not there is an opportunity for cost-sharing with a neighboring entity. SPP will work with the appropriate neighboring entity to evaluate any potential seams projects and determine if there is a willingness to proceed jointly.

6.1.1 Economic Portfolio Development

Solutions mitigating economic needs are ranked by their cost effectiveness, net APC benefit and qualitative benefits for each need or set of needs and categorized into one or more of the following groupings:

- Cost effective: Solutions with the lowest cost with respect to the congestion relief they provide on individual flowgates will be selected.
- Highest net APC benefit: Solutions with the highest difference between one-year APC benefit and one-year project cost will be selected.
- Multi-variable: Top-ranking projects in the other two groupings, as well as qualitative benefits that the other groupings may not capture, will be considered when selecting projects.

In addition to economic performance, consideration of the following information may be given to the top-ranking solutions:[10]

1. One-year project cost, APC benefit, and B/C.
2. 40-year NPV cost, APC benefit, and B/C.
3. Congestion relief that a project provides for the economic needs of that future and year.
4. Project overlap, or when two or more projects that relieve the same congestion are in a single portfolio.
5. The potential for a project to mitigate multiple economic needs.
6. Any potential routing or environmental concerns with projects.
7. Any long-term concerns about the viability of projects.
8. Seam and non-seam project overlap.
9. Relief of downstream and/or upstream issues, tested by~~Individual project robustness, which includes,~~ event file modification.
10. The potential for a project to mitigate reliability, operational, and public policy needs, which covers current market congestion.

[6] Regardless of the type of need the solution was submitted to address
[7] Relief score calculations can be found in the reliability metrics document approved by the TWG
~~[8] TWG~~
~~[9] TWG~~
[10] Additional consideration may result in changes in top-ranking solutions, including elimination of solutions.

11. The potential for a project to address non-thermal issues.
12. The need for new infrastructure versus leveraging existing infrastructure.
13. Larger-scale solutions that provide more robustness and additional qualitative benefits.

Study estimates for the top-ranking projects from each economic grouping will be developed consistent with the Cost Estimates section of this manual. Once study estimates are applied to the top-ranking solutions in each grouping, the limited set of solutions will be ranked again to reflect the cost refinement.
The top-ranking economic projects will be tested in a new set of base models that include the corresponding reliability, policy, and operational economic portfolios. The economic projects will be tested individually within each group to assure only those with at least a 0.9 one-year B/C or 1.0 40-year NPV B/C move forward.

6.1.4 Persistent Operational Portfolio Development

Solutions mitigating persistent operational needs are ranked by the appropriate metrics depending on whether the need is economic or reliability based. Solutions identified to mitigate persistent operational issues will be compared with the other portfolios to ensure efficiencies are gained by identifying the most cost effective ~~minimum number of~~ projects to meet all needs. Economic solutions will be ranked based on their project cost compared to the cost incurred without the project. SPP and stakeholders will determine the criteria for development of the operational portfolio, which will be included in each study scope. Reliability solutions will be evaluated using the CLR and CVR metric concept.

~~**Final Assessments**~~

~~6.4.1 Benefit Metrics~~

~~Benefit metrics will be used to measure the value and economic impacts of the final consolidated portfolio to be expected from the ITP assessment. Generally, a single portfolio will be tested in the approved future(s) by computing benefits and costs over a 40-year timeframe. For further detail on the metrics in Table 8, refer to the Benefit Metrics Manual.[11]~~

~~ITP Assessment Benefit Metrics~~
~~**ted Production Cost**~~
~~**s Due to Lower Ancillary Service Needs and Production Costs**~~
~~**ed or Delayed Reliability Projects**~~
~~**nal Energy Losses Benefit**~~
~~**ity Cost Savings Due to Reduced On-Peak Transmission Losses**~~
~~**tion of Emission Rates and Values**~~
~~**Policy Benefits**~~
~~**ned Benefit of Mandated Reliability Projects**~~
~~**ation of Transmission Outage Costs**~~
~~**sed Wheeling Through and Out Revenues**~~

~~*Table 8: ITP Assessment Benefit Metrics*~~

~~6.4.2 Sensitivity Analysis~~

~~Sensitivity analyses will be defined in the scope and conducted to measure the flexibility of the final portfolio in each ITP assessment. Generally, these sensitivities will not be used to select the proposed transmission projects, nor to filter out projects. The sensitivities to be performed on the final portfolio of each ITP assessment shall include, at a minimum:~~

- ~~High natural-gas price~~
- ~~Low natural-gas price~~
- ~~High demand~~

~~[11] Benefit Metrics Manual~~

- ~~Low demand~~

~~Typically, for the demand sensitivities, one standard deviation on either side of the expected values will be used, and for the natural gas price sensitivities, two standard deviations of expected values will be used.~~

6.4 Final Reliability Assessment

To evaluate and confirm the effectiveness of all identified upgrades for the recommended portfolio, a final reliability assessment will be performed. The base reliability and SPP BA powerflow models will be modified to include the recommended portfolio and model adjustments identified during solution development, regardless of project classification. A contingency analysis will be performed to identify any new reliability violations on this updated set of powerflow models.

If any new reliability violations are observed in the modified base reliability models, the recommended portfolio may be modified with a new or modified solution. The final portfolio will include the changes determined from the incremental reliability assessments.

If any new reliability violations are observed in the modified SPP BA powerflow models, they will be documented in the ITP assessment report: however, no solutions will be developed. SPP will perform a spot check contingency analysis on economic solutions. This analysis will be used to determine the effect of potential dispatch changes as constraints are removed or adjusted due to the solutions and ensure that those changes do not result in additional reliability violations.

The analyses described in this section will begin as SPP develop draft portfolios to identify projects that may have adverse impacts to the transmission system as quickly as possible.

The results of the final reliability assessment on the recommended portfolio will be documented in the ITP assessment report. Any upgrades added to the recommended portfolio as a result of the final reliability assessment will be identified.

7 Informational Portfolio Analysis

7.1 Benefit Metrics

Benefit metrics will be used to measure the value and economic impacts of the final consolidated portfolio to be expected from the ITP assessment. Generally, a single portfolio will be tested in the approved future(s) by computing benefits and costs over a 40-year timeframe. For further detail on the metrics in Table 8, refer to the Benefit Metrics Manual.[12]

ITP Assessment Benefit Metrics
Adjusted Production Cost
Savings Due to Lower Ancillary Service Needs and Production Costs
Avoided or Delayed Reliability Projects
Marginal Energy Losses Benefit
Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
Reduction of Emission Rates and Values
Public Policy Benefits
Assumed Benefit of Mandated Reliability Projects
Mitigation of Transmission Outage Costs
Increased Wheeling Through and Out Revenues

Table 5: ITP Assessment Benefit Metrics

[12] Benefit Metrics Manual

7.2 Sensitivity Analysis

Sensitivity analyses will be defined in the scope and conducted to measure the flexibility of the final portfolio in each ITP assessment. Generally, these sensitivities will not be used to select the proposed transmission projects, nor to filter out projects. The sensitivities to be performed on the final portfolio of each ITP assessment shall include, at a minimum:

- High natural-gas price
- Low natural-gas price
- High demand
- Low demand

Typically, for the demand sensitivities, one standard deviation on either side of the expected values will be used, and for the natural gas price sensitivities, two standard deviations of expected values will be used.

11.1 History of the ITP Assessment

In January 2009, the SPP Board of Directors (Board) created the Synergistic Planning Project Team (SPPT) to address gaps and conflicts in SPP's transmission planning processes; to develop a holistic, proactive approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities.
The SPPT recommended that the organization adopt a new set of planning principles, develop and implement an ITP assessment, develop a plan to monitor the construction of projects approved through the ITP assessment, identify priority projects that continue to appear in system reviews to relieve congestion on existing constraints, and connect SPP's eastern and western regions. The SPPT recommended the Regional State Committee (RSC) establish a "highway/byway" cost allocation methodology for approved projects.13
The SPPT developed an integrated set of principles that should guide SPP in the development of its comprehensive ITP assessment:

1. SPP's primary function is to "keep the lights on," and one way that is accomplished is to provide transmission service for customers within the SPP region. In order to meet this long-term function, SPP must plan for and construct a robust transmission system. This robust transmission system should be large in both scale and geography so as to provide flexibility to meet SPP's future needs.

2. SPP's planning process for a robust transmission system must consider transmission as an enabler to meet short-term and long-term needs. Planning of SPP's transmission system must take into consideration the anticipated location of future generation facilities and should incorporate various scenarios regarding load growth, demand response, energy efficiency, fuel prices, environmental and governmental regulations and policies, and other factors.

3. SPP's planning processes should take a long-term view (20 or more years) of the benefits and costs of all projects while also expediting priority system investments.

4. As a priority, through the RSC and the membership, SPP should resolve the uncertainties associated with financing transmission projects by establishing the appropriate regional cost allocation methodologies. This effort should result in a reduction of the number of cost allocation mechanisms that exist today. SPP members, customers, and interested parties must participate in this effort with their regulators to establish the appropriate cost recovery methods.

5. Once SPP has developed and obtained the approval of a robust transmission plan for the region, the BOD and RSC should ensure that construction is commenced and completed according to an established timeline.

SPP began performing its planning duties in accordance with the ITP assessment in July 2010.

[13] The Highway/Byway methodology was approved by FERC on June 17, 2010.

11.4 Definitions

1. ~~BA~~ Market Economic Models – model set containing all economic parameters and powerflow data necessary to perform SCUC/SCED simulations
2. ~~BA~~ Market Powerflow Models – model set containing all powerflow data, including load and generation dispatch from the SCUC/SCED simulations
3. Base Reliability Models – model set representative of how load responsible entities within SPP would serve load utilizing only resources with long-term firm transmission service
4. Balancing Authority – an entity responsible for maintaining a load, generation, and interchange balance within its region
5. Congestion Score – the product of a constraint's annual average shadow price and the number hours the constraint binds; value used to rank economic needs by severity and/or longevity
6. Detailed Project Proposal – a submittal form in which stakeholders may submit solutions to solve ITP needs
7. First-Tier – The non-SPP transmission system that is electrically interconnected to the SPP transmission system and extends throughout the interconnected entity's footprint.~~non-SPP powerflow areas that are interconnected to the SPP system~~
8. Grouping – specific to economic portfolio development; set of projects that are selected by economic characteristics (cost-effectiveness, net APC benefit, etc.) from initial screening runs and meet a 0.9 one-year B/C or 1.0 40-year B/C within the set of projects
9. Light Load Model – model representative of each submitting entity's one-hour system minimum load between April and May, non-coincident to the SPP system
10. Manual Commitments - a commitment of a resource outside of the automated market process to alleviate constraints
11. Net Plant Carrying Charge - annual percentage that is applied to a utility's depreciated plant costs to calculate an annual revenue requirement billed on Schedule 11 of the SPP Tariff; calculated by a transmission owner's revenue requirement divided by the net transmission plant investment.
12. Notification to Construct: A written notice from SPP directing an entity that has been selected to construct one or more transmission project(s) to begin or continue implementation of the transmission project(s) in accordance with Attachment Y of the SPP Tariff.
13. SPP Open Access Transmission Tariff: SPP governing document filed for compliance with FERC Order 888
14. Reference-Case Future – one future (of up to three) that will be included in each ITP assessment; reflective of a future scenario in which there are no major policy changes
15. Revision Request – an SPP mechanism by which SPP governing documents can be revised through the stakeholder process
16. Seams – areas of or near the boundary of the SPP footprint that are directly impacted by the operation of SPP and non-SPP systems
17. Shadow Price – the potential reduction in total production costs if the limit on a congested flowgate were to be increased by 1 MW
18. State Estimator – a standard industry tool that produces a powerflow model based on available real-time metering information; information regarding the current status of lines, generators, transformers, and other equipment; bus load distribution factors; and a representation of the electric network to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable.
19. SPP Transmission Expansion Plan – The plan that describes the transmission expansion projects being considered over the planning period and developed through the stakeholder process in accordance with the SPP Tariff and approved by the SPP Board.
20. Study Scope – document specific to each individual ITP assessment to be developed by SPP staff and stakeholders containing study assumptions to be utilized that are not included in the ITP Manual

21. Summer Peak Model – model representative of each submitting entity's one-hour system peak load between June and September, non-coincident to the SPP system
22. Winter Peak Model – model representative of each submitting entity's one-hour system peak load between December and March, non-coincident to the SPP system

Revision Request Process

Minimum Transmission Design Standards for Competitive Upgrades (MTDS)

Reliability Coordinator and Balancing Authority Data Specifications (RDS)

SPP Communications Protocols

Revision Request Comment Form

RR #: 321	**Date: 8/17/18**
RR Title: ITP Manual Cleanup	
SUBMITTER INFORMATION	
Name: Rodney Massman	**Company: MoPSC**
Email: Rodney.Massman@psc.mo.gov	**Phone:** 573-751-7510
OBJECTIVE OF REVISION	

Provide the objective language from the revision request for which you are submitting comments. This RR is intended to standardize one item approved in the 2019 ITP Scope as well as clarify minor issues discovered in the ITP Manual since its initial approval. As part of the 2019 ITP Scope approval, the DC Tie settings for the Economic model were approved to be standardized in the ITP Manual.

Other minor issues addressed in this Revision Request include changing the names of the models to more accurately reflect what they represent in the ITP planning process, removal of Year 2 from the Renewable Policy Survey based upon the decision to not develop a resource plan for Year 2, and other clarifications including corrections to footnotes.

COMMENTS

In Section 2.2.1.3 on page 4, there are some language changes needed in the discussion regarding each state's renewable energy standards.

It is not clear from the table or the current wording that some states may have gradually increasing percentages that change over a number of years. For instance, Missouri's standard is currently 10% from 2018-2020, and does not reach 15% until 2021. However, the wording and chart appear to indicate that the standard for Missouri is currently 15%. The revisions enclosed are some suggested wording changes to reflect that the percentage noted is for the final year of a state's renewable goal or mandate, not interim years. It was also not clearly described that some states have mandatory standards, while others are merely goals. There is also some new revised language enclosed in preference to the language that currently states that there is a presumption that a state does not have a renewable standard. It seems far cleaner to simply state that states not in the attached table do not have a renewable standard.

PROPOSED REVISION

Provide proposed modifications (redlined) to the revision request for which you are providing comments. Use language from the revision request and redline with your additional edits.

Market Protocols

SPP Tariff (OATT)

SPP Operating Criteria

SPP Planning Criteria

2.2.1.2 Renewable Policy Review

After the forecasted load is finalized, renewable policy standards (RPS) will be assessed for utilities within the SPP footprint. The percentages in Table 3 will be used to calculate the mandate or goal 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 values 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 final study year[s]. 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 [shall be presumed to have] do not have an 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

Minimum Transmission Design Standards for Competitive Upgrades (MTDS)

Reliability Coordinator and Balancing Authority Data Specifications (RDS)

SPP Communications Protocols