SPP RSC / OMS Seams Liaison Committee Update

Adam McKinnie
Missouri Public Service Commission
Joint Quarterly Stakeholder Briefing
July 29, 2019

Goals of Presentation

- Discuss July 21, 2019 Seams Liaison Committee meeting items
- Discuss possibility of joint comments on Interregional Planning incentives in FERC Docket PL19-3
- Discuss next steps

Overview - Members

- SPP RSC Committee Members
  - Shari Feist Albrecht, Kansas (lead)
  - Kristie Fiegen, South Dakota
  - Kim O'Guinn, Arkansas
  - DeAnn Walker, Texas
- Organization of MISO States (OMS) Committee Members
  - Daniel Hall, Missouri (lead)
  - Eric Skrmetta, Louisiana
  - Julie Fedorchak, North Dakota
  - Matt Schuerger, Minnesota
  - Nick Wagner, Iowa (*ex officio*)

Overview - Events

- Meetings so far
  - Telephone call in September 2018
  - In-person meeting at NARUC, November 2018 (Orlando)
  - In-person meeting at NARUC, February 2019 (Washington D.C.)
  - Telephone call, March 1, 2019
  - Telephone call, March 15, 2019
  - Telephone call May 24, 2019
  - In-person meeting at NARUC July 21, 2019 (Des Moines)

July 21, 2019 Seams Liaison Committee meeting items

- Review of Market Monitor work
  - SPP's Market Monitoring Unit (MMU) and the MISO Independent Market Monitor (IMM) have been working on analysis of markets and operations issues on Tier 1 issues
    - Have developed work scopes with due date
  - Tier 2 issues will be discussed at a later date

Market Monitor work – Tier 1 Issues

Issue	Market Monitor performing the analysis	Expected due date
Market to Market Coordination	MISO IMM	October 30, 2019
Joint Dispatch	MISO IMM	October 30, 2019
Rate Pancaking	SPP MMU	September 30, 2019

July 21, 2019 Seams Liaison Committee meeting items

- Interregional Planning
  - The Seams Liaison Committee is investigating possibility of performing an Interregional Planning Analysis
  - Soon, the Seams Liaison Committee is expected to issue a 30 day comment opportunity to stakeholders, asking what items would go in a possible future Interregional Planning Analysis

Interregional Planning

- The Seams Liaison Committee also received presentations on interregional planning activities
  - Previous SPP-MISO annual Interregional Planning reviews and studies
  - "Affected System Studies", studying how connecting generators to the grid and moving energy in one RTO impacts the neighboring RTO

Interregional Planning

- Update was provided on the 2019 SPP-MISO Interregional Planning Effort
- That effort has a telephone call scheduled for August 19, 2019

Potential FERC comments opportunity

- The Seams Liaison Committee discussed the possibility of submitting comments, with approval from the SPP RSC and OMS Boards, in FERC Docket No. PL19-3
  - FERC Docket No. PL19-3 concerns incentives for electric transmission
  - Any comments from the Seams Liaison Committee would be limited to the issue of Interregional Planning

FERC Docket No. PL19-3

- PL19-3 was opened as a Notice on Inquiry on March 21, 2019
- Considers whether incentives for building electric transmission projects are appropriate
  - Incentives include ROE adders, abandoned plant, hypothetical capital structure
- Initial comments were filed June 26, 2019
  - OMS filed comments on June 26, 2019
- Reply comments are due August 24, 2019

FERC Docket No. PL19-3

- Following slides are borrowed from the 7-21-2019 Seams Liaison Committee presentation
- They provide information about the questions posed in the NOI on interregional transmission planning
- Included in the appendix of this presentation are first round comments the Seams Liaison Committee may wish to respond to

Comments made in PL19-3 related to Interregional Planning.

INTERREGIONAL PLANNING IN ROE INCENTIVES DOCKET

FERC's NOI

An interregional transmission project has the potential to improve interregional coordination, help to eliminate seams issues, and provide more efficient power flow among regions. Although Order No. 1000 required coordination among neighboring transmission planning regions to identify potential interregional transmission facilities, such projects have been scarce to date.

Three Questions Asked:

- Should incentives be used to encourage interregional projects?
- Should ALL interregional projects be eligible?
- What incentive(s) would be appropriate?

Next steps

- Will continue to update SPP RSC on progress on Market Monitor analysis and any potential Interregional Planning analysis
- Interest in pursuing comments in FERC Docket No. PL19-3 with the Seams Liaison Committee / OMS?

End of Presentation

- Any questions?

Appendix – additional slides from Seams Liaison Committee presentation

NOI response summary (1)

R Street Institute

- Should incentivize
- Interregional projects fall w/in existing risks & challeneges framework
- Almost no utilities on MISO-SPP seam have financial incentives to improve efficiency across seam

Advanced Energy Economy

- Should adopt policy to enable greater utilization of low-cost energy.
- Interregional planning processes have not adequately addressed needs
- Should consider incentives

NOI response summary (2)

Ameren

- Commission should remove planning barriers
- Provide incentives only when project provides demonstrated value to customers
- Interregional transmission projects arguably address the needs of a greater number of customers

TAPS

- Should not assume all interregional projects inherently produce benefits
- Using ROE-adder incentives will make it harder to approve interregional projects
- Should strengthen Order 1000's interregional coordination process instead

NOI response summary (3)

LS Power

- Interregional projects face other hurdles that incentives do not address (e.g., cost allocation) and therefore should not be used

National Electrical Manufacturers

- Order 1000 isn't strong enough to require interregional planning
- Requiring planning is a non-monetary incentive of great value
- FERC should order interregional planning

NOI response summary (4)

American Council on Renewable Energy

- FERC should establish cost allocation policies that recognize full benefits of interregional Transmission
- FERC should require RTOs to harmonize planning processes and models

Holistic Integrated Tariff Team Report

Joint Quarterly Stakeholder Briefing

July 2019

HITT Membership

SPP Board	Jim Eckelberger (Director) Graham Edwards (Director)
Regional State Committee	Shari Feist Albrecht (Commissioner Kansas Corporation Commission) Dennis Grennan (Commissioner Nebraska Power Review Board)
Investor Owned Utilities	Richard Ross (AEP) Denise Buffington (KCPL) Greg McCauley (OG&E) Bill Grant (SPS)
Cooperatives	Mike Wise (Golden Spread) Mike Risan (Basin) Al Tamimi (Sunflower)
Independent Power Producers	Rob Janssen (Dogwood Energy) – **Vice-Chair** Holly Carias (NexEra)
Municipals	Dennis Florom (LES)
State Agencies	Tom Kent (Nebraska Public Power District) - **Chair**
Independent Transmission Companies	Brett Leopold (ITC Great Plains)
CAWG Liaison	Cindy Ireland (Arkansas PSC Staff)

HITT GOALS & DRIVERS

Ensuring reliability for a changing generation mix and new technologies

Enhancing Integrated Marketplace to reliably deliver low-cost energy to customers

Aligning transmission planning and cost allocation with SPP's market and consolidated Balancing Authority

HITT RECOMMENDATIONS

Stakeholder presentations

Date	Group	Presenters and Lead (L)	Location	Status
5/9-5/10	SPC retreat	Tom Kent (L), Rob Janssen	Branson, MO	Completed
5/29	SAWG	Rob Janssen (L), Gary Cate	AEP Dallas	Completed
5/30	RSC/CAWG	Tom Kent (L), Paul Suskie, Cindy Ireland John Krajewski	DFW-Hyatt	Completed
6/13	ESWG	Paul Suskie (L), Antoine Lucas, Al Tamimi	AEP Dallas	Completed
6/14	TWG	Paul Suskie (L), Antoine Lucas, Gary Cate	WebEx	Completed
6/19	MWG	Paul Suskie (L), Richard Ross, Gary Cate	AEP Dallas	Completed
6/24	RSC/CAWG	Paul Suskie, Cindy Ireland, John Krajewski	DFW-Hyatt	Cancelled
6/27	ORWG	Paul Suskie (L), Gary Cate, CJ Brown	WebEx	Completed
6/27	RTWG	Rob Janssen (L), Gary Cate	AEP Dallas	Completed
7/16	SPC/MOPC	Tom Kent (L), Rob Janssen	Des Moines, IA	Completed

HITT Report Overview

21 recommendations in four categories

- **5 Reliability**
- **4 Marketplace**
- **9 Transmission Planning & Cost Allocation**
- **3 Strategic**

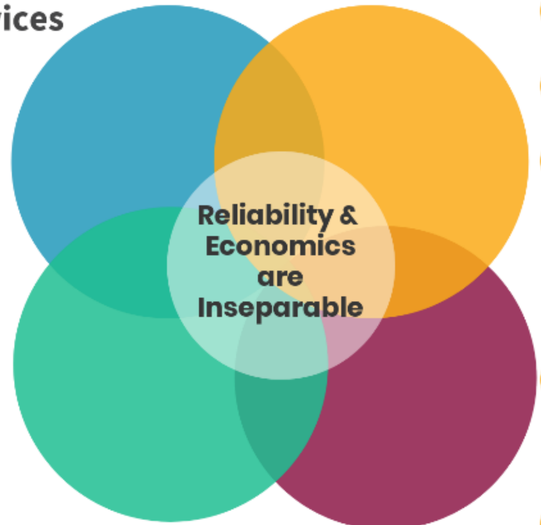
12 recommendations are actions

9 recommendations are evaluations/studies

Holistic Integrated Tariff Team Recommendations

Reliability

- Essential & other reliability services (ERS/ORS)
- GO ERS/ORS compensation model
- GO Marketplace enhancements
- GO Uncertainty market product
- Additional operational tools



Marketplace

- GO Congestion hedging improvements
- Offer requirements for variable resources
- Mitigation of unduly low offers that create uneconomic dispatch
- Economic evaluations of reliability

GO Implement

Study/Evaluate

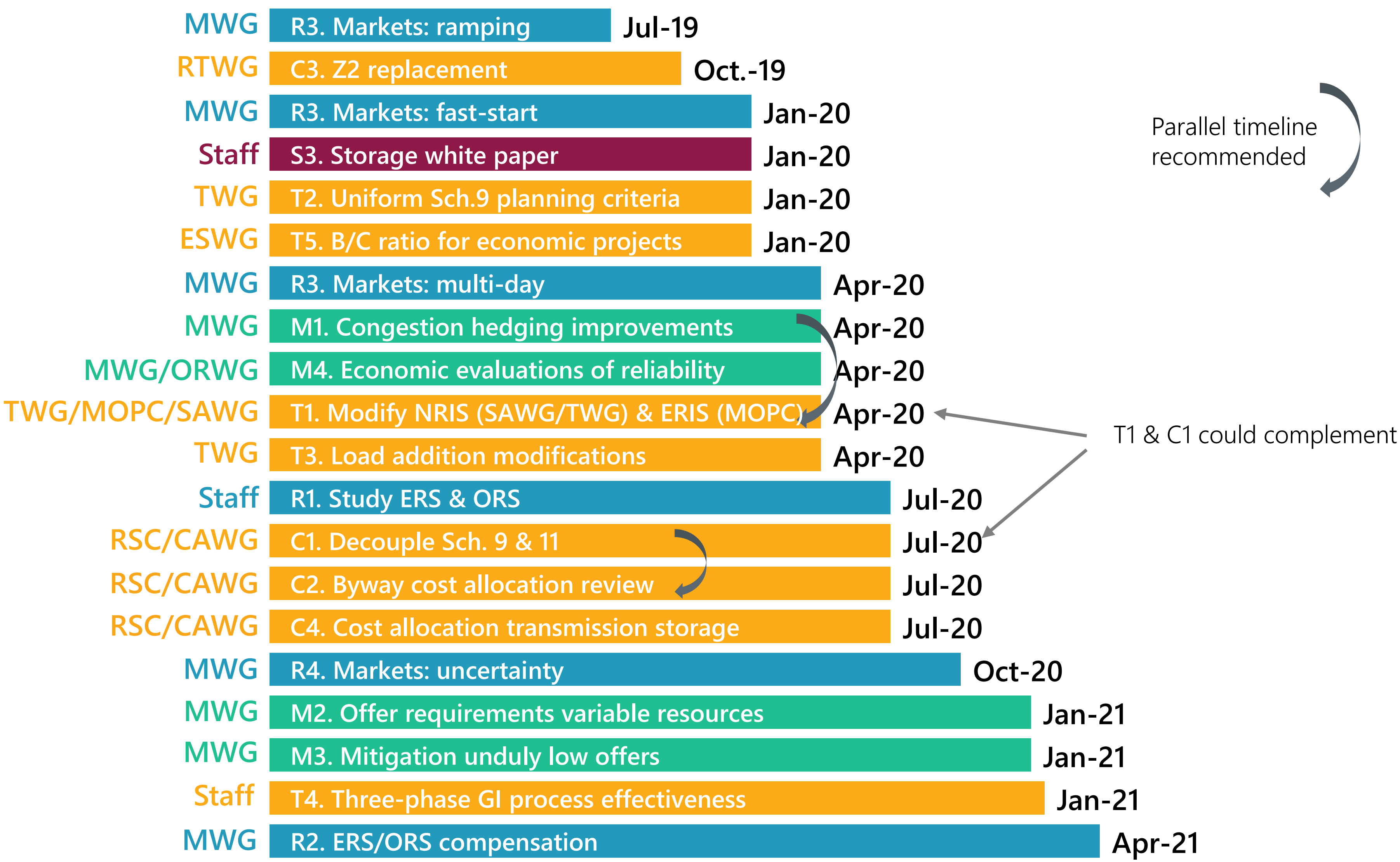
Planning & Cost Allocation

- GO NRIS/ERIS modifications
- GO Uniform Sch. 9 local planning criteria
- GO New load addition modifications
- Three-phase GI process effectiveness
- B/C ratio for economic projects
- GO Decouple Sch. 9 & 11 pricing zones
- Byway cost allocation review process
- GO Eliminate Z2 revenue crediting
- Cost allocation for transmission storage

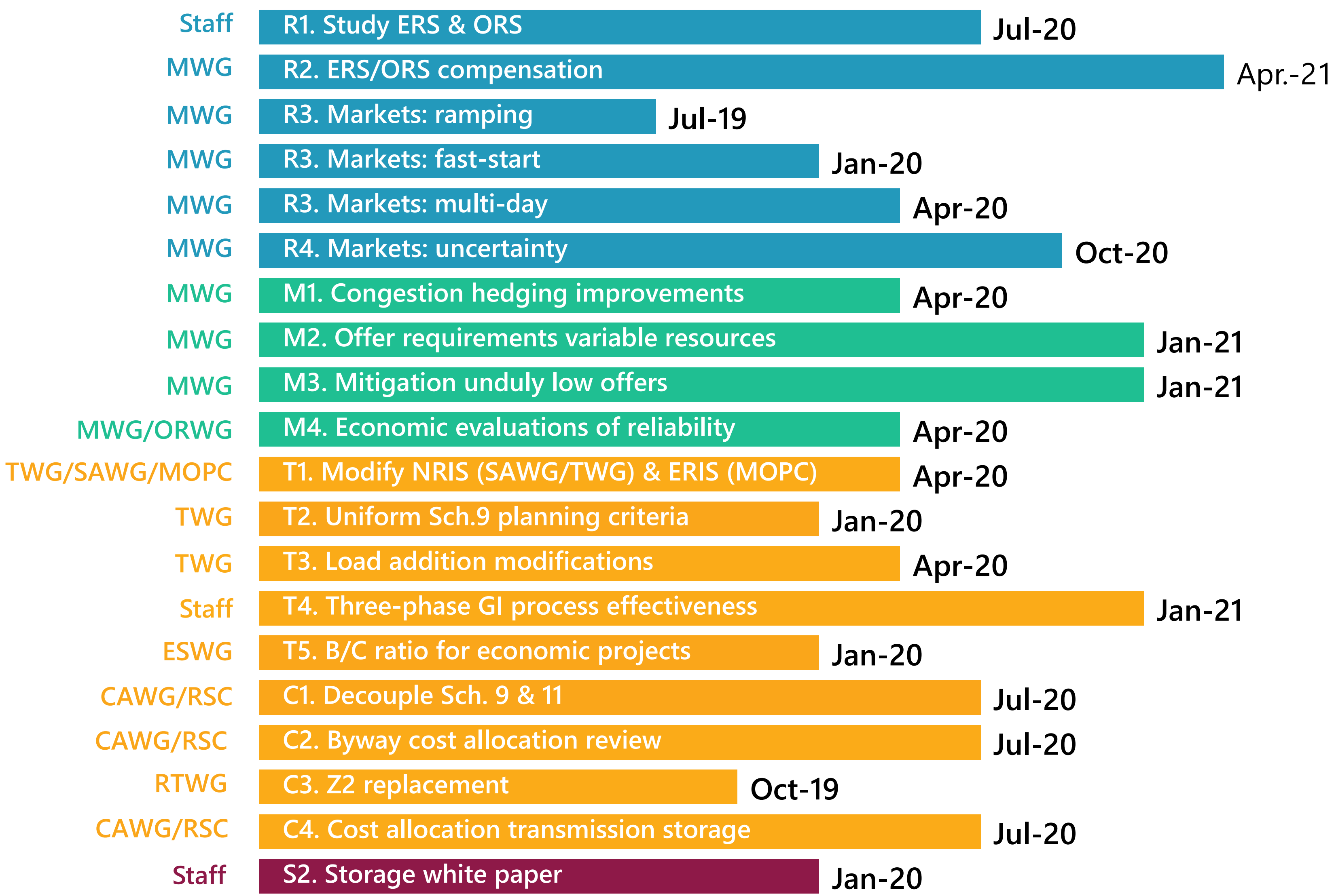
Strategic

- GO Add tech advances to strategic plan
- GO Keep seams a priority in strategic plan
- GO Create storage white paper

Timeline by date (Proposed)



Timeline by recommendation (Proposed)



ACTION PLAN

Action Plan (Proposed)

Assignment/Task	Secondary group	Stakeholder process completion Goal
Strategic Planning Committee		
Oversee & track HITT recommendation implementation	N/A	Until complete
S1. Add technological advances to SPP Strategic Plan	N/A	Next update
S2. Continue to include seams in SPP Strategic Plan	N/A	Ongoing
Regional State Committee/Cost Allocation Working Group		
C1: Decouple Schedule 9 & 11 pricing zones	RTWG	July 2020
C2: Establish byway facility cost allocation review process	ESWG/RTWG	July 2020
C4. Study cost allocation for transmission storage devices	TWG/MWG/RTWG	July 2020
Markets and Operations Policy Committee		
T1: ERIS modifications	MWG/CAWG/RSC	April 2020

Action Plan (Proposed)

Supply Adequacy Working Group		
T1: NRIS modifications	MWG/CAWG/RSC	April 2020
Market Working Group		
R3. Market enhancements: ramping	N/A	July 2019
R3. Market enhancements: fast-start	N/A	Jan. 2020
R3. Market enhancements: multi-day, longer-term	N/A	April 2020
M1. Implement congestion hedging improvements	RSC/CAWG	April 2020
M4. Study economic evaluations of reliability (markets)	TWG/RCWG	April 2020
R4. Implement uncertainty market product	ORWG	Oct. 2020
M2. Study offer requirements for variable resources	N/A	Jan. 2021
M3. Study mitigation of unduly low offers	N/A	Jan. 2021
R2. Implement ERS/ORS compensation model	ORWG	April 2021

Action Plan (Proposed)

Operating Reliability Working Group		
M4. Study economic evaluations of reliability (reliability)	TWG/RCWG	April 2020
Transmission Working Group		
T1: NRIS modifications: long-term deliverability	MWG/CAWG/RSC	April 2020
T2: Establish uniform Schedule 9 local planning criteria	RTWG/RCWG	Jan. 2020
T3: Implement new load addition modifications	RTWG/RCWG	April 2020
Regional Tariff Working Group		
C3: Eliminate Z2 revenue crediting	RSC/CAWG	Oct. 2019
Economic Studies Working Group		
T5: B/C ratio for economic projects	N/A	Jan. 2020
Staff		
R1. Study ERS and ORS	MWG/ORWG/SAWG	July 2020
R5. Study additional operational tools	ORWG/MWG	Ongoing
T4. Study three-phase GI process effectiveness	MOPC	Jan. 2021
S3. Storage white paper	RSC/MOPC	Jan. 2020

Recommend parallel timeline

T1: NRIS/ERIS

M1: Congestion hedging

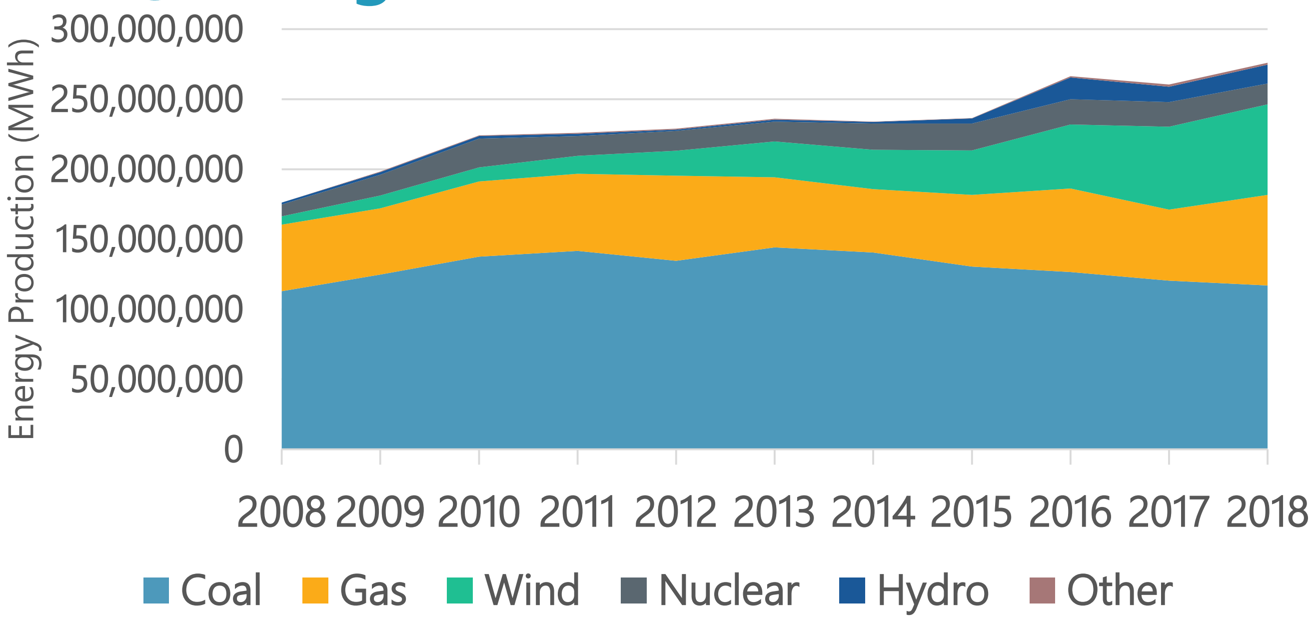
Recommend parallel timeline

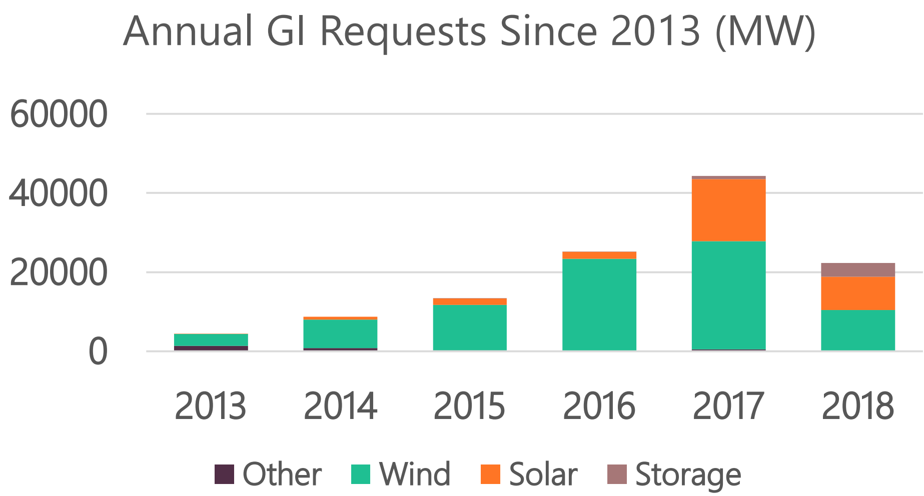
C1:
Decouple
Sch. 9 & 11

C2:
Byway cost
allocation
review

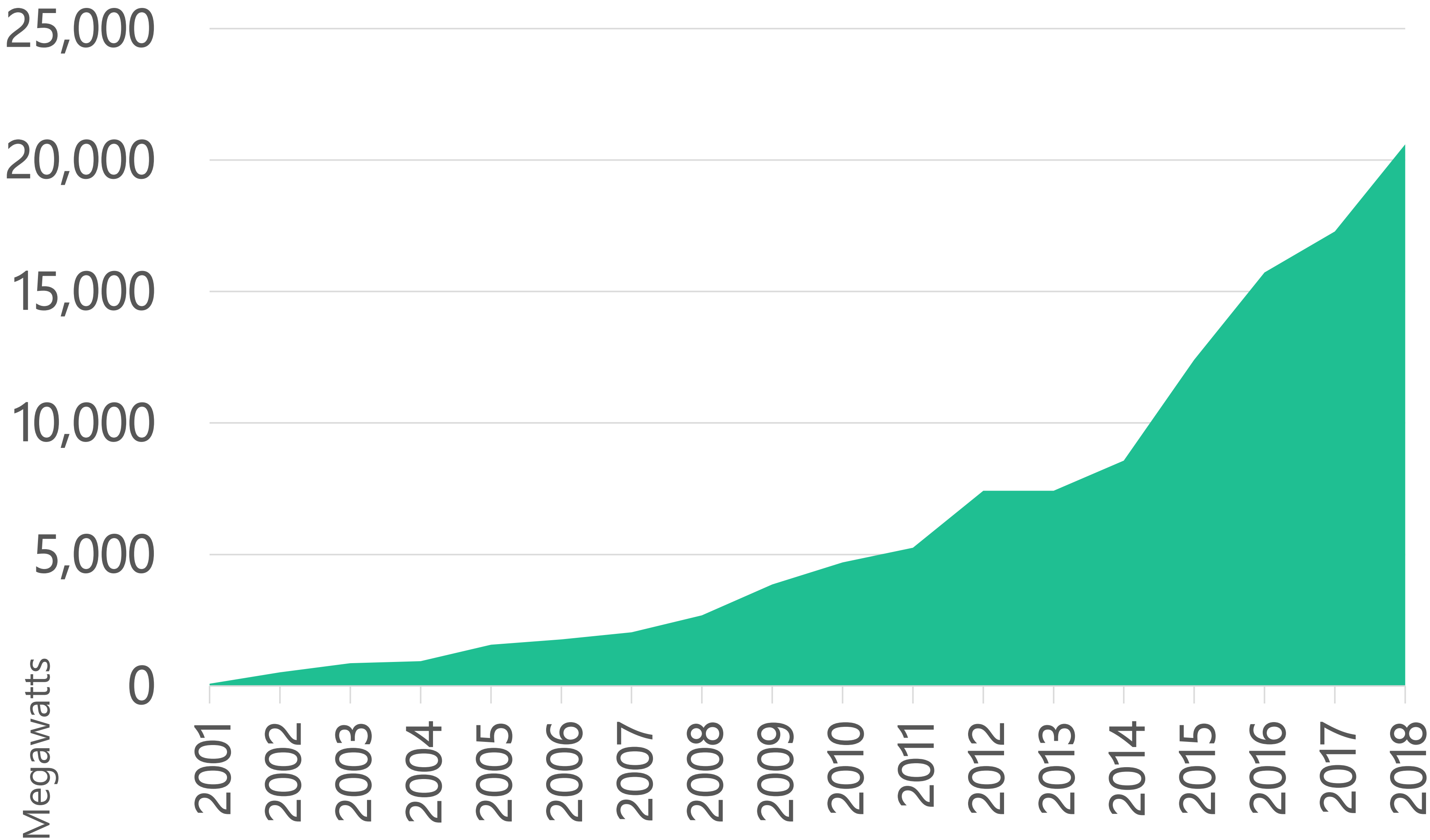
QUESTIONS

Ensuring reliability for a changing generation mix and new technologies

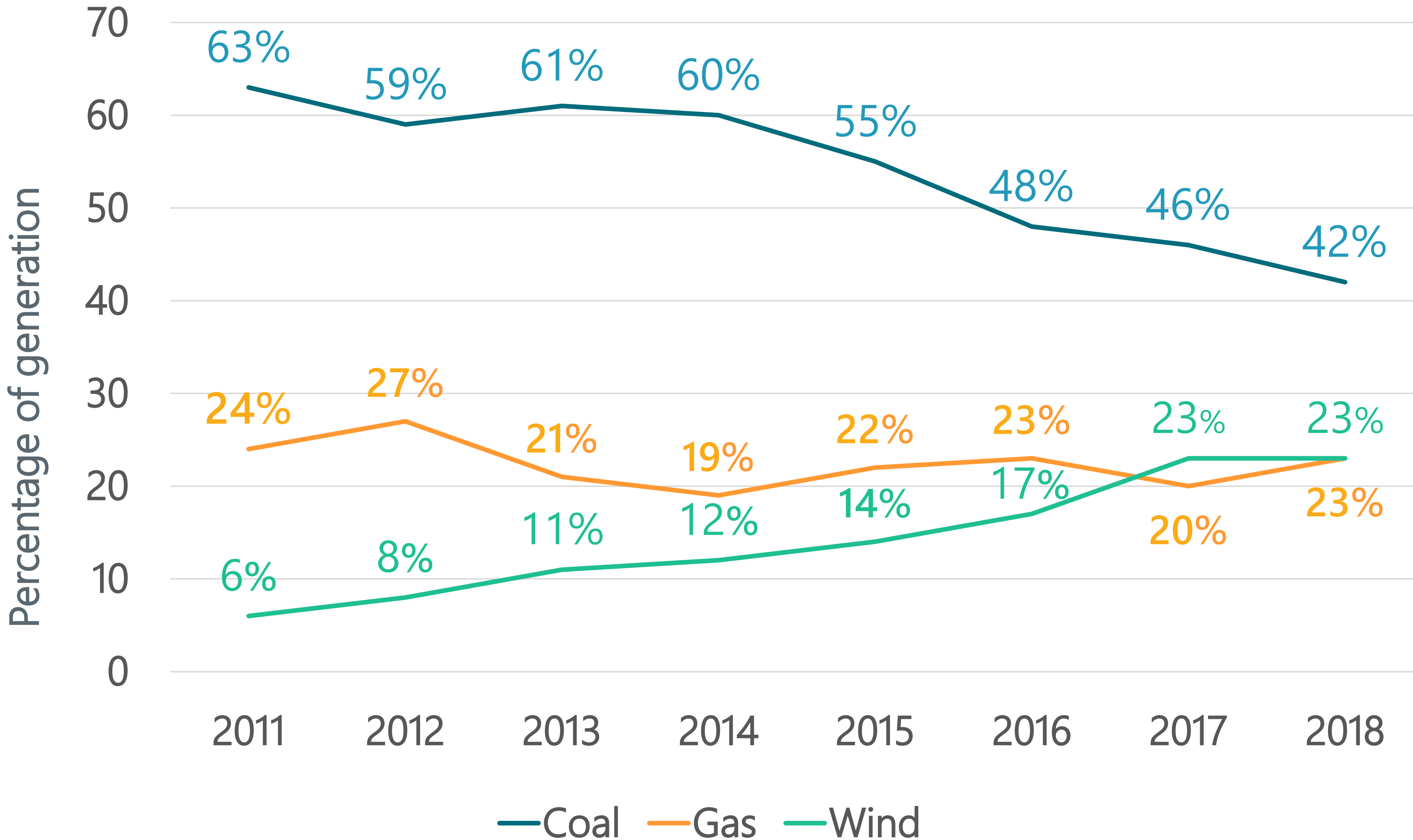




Installed Wind Capacity

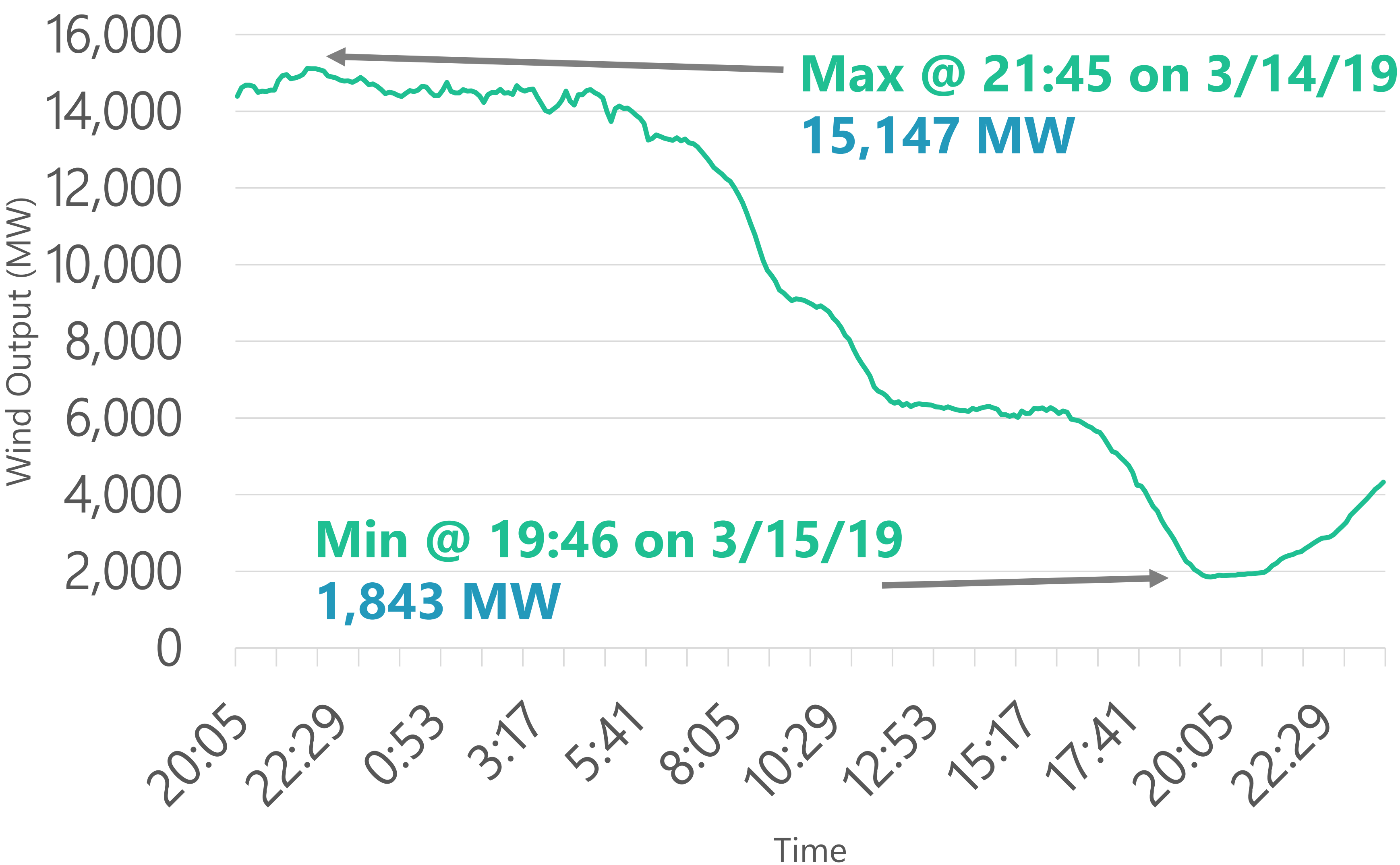


Evolving Energy Mix



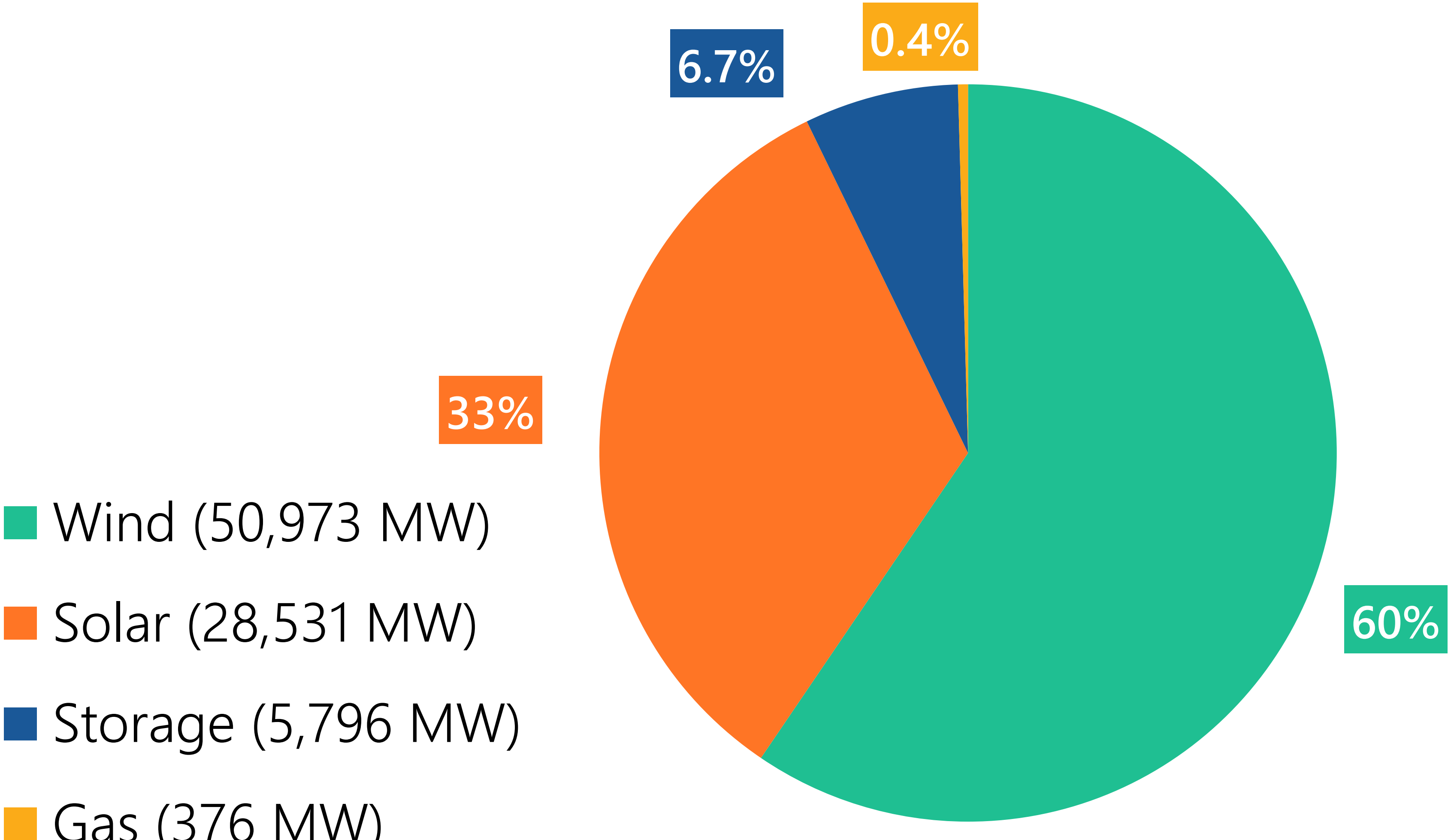
Why generation diversity matters:

SPP's record wind swing (13 GW in 22 hours)

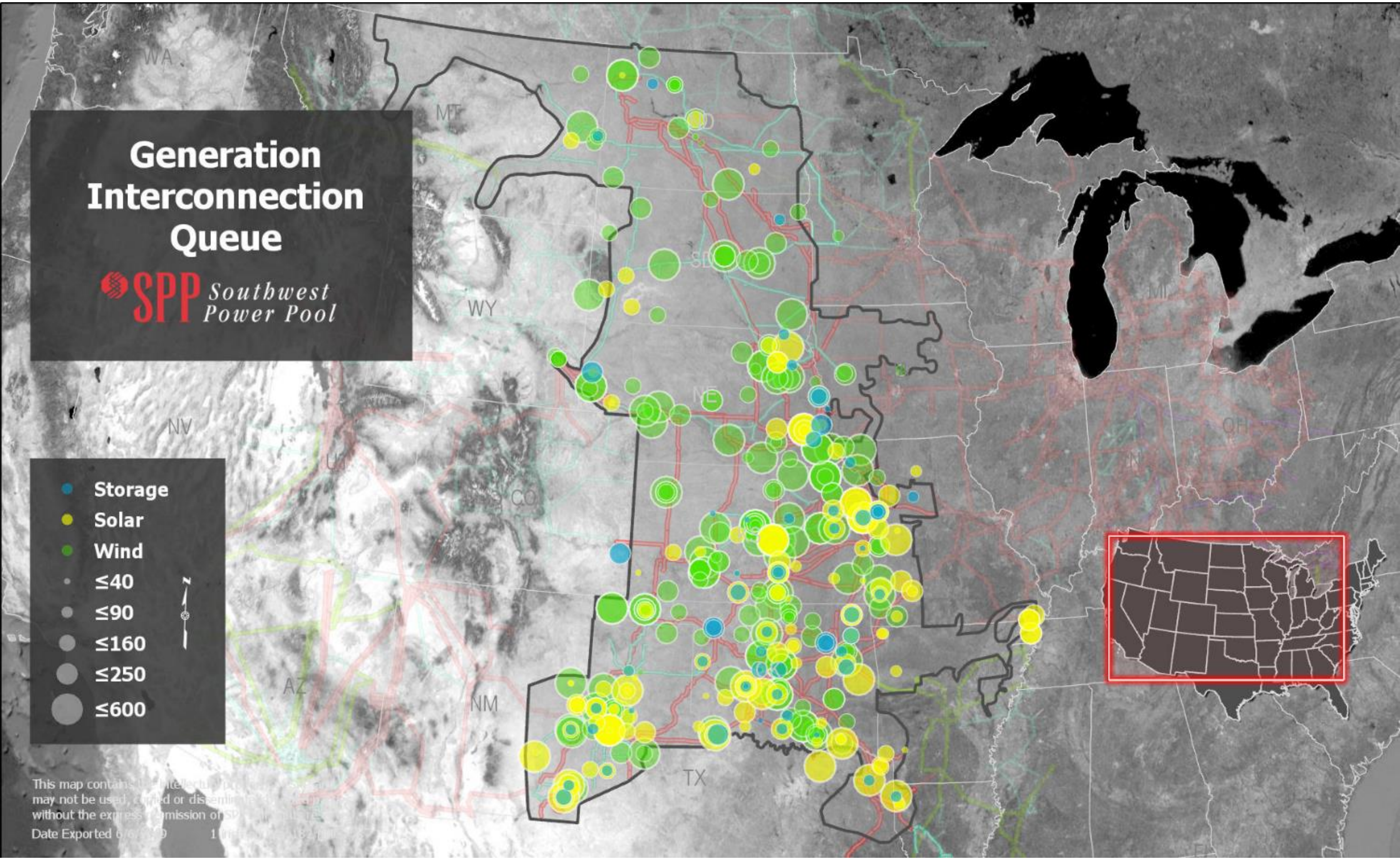


Generation Interconnection Queue

85,676 MW

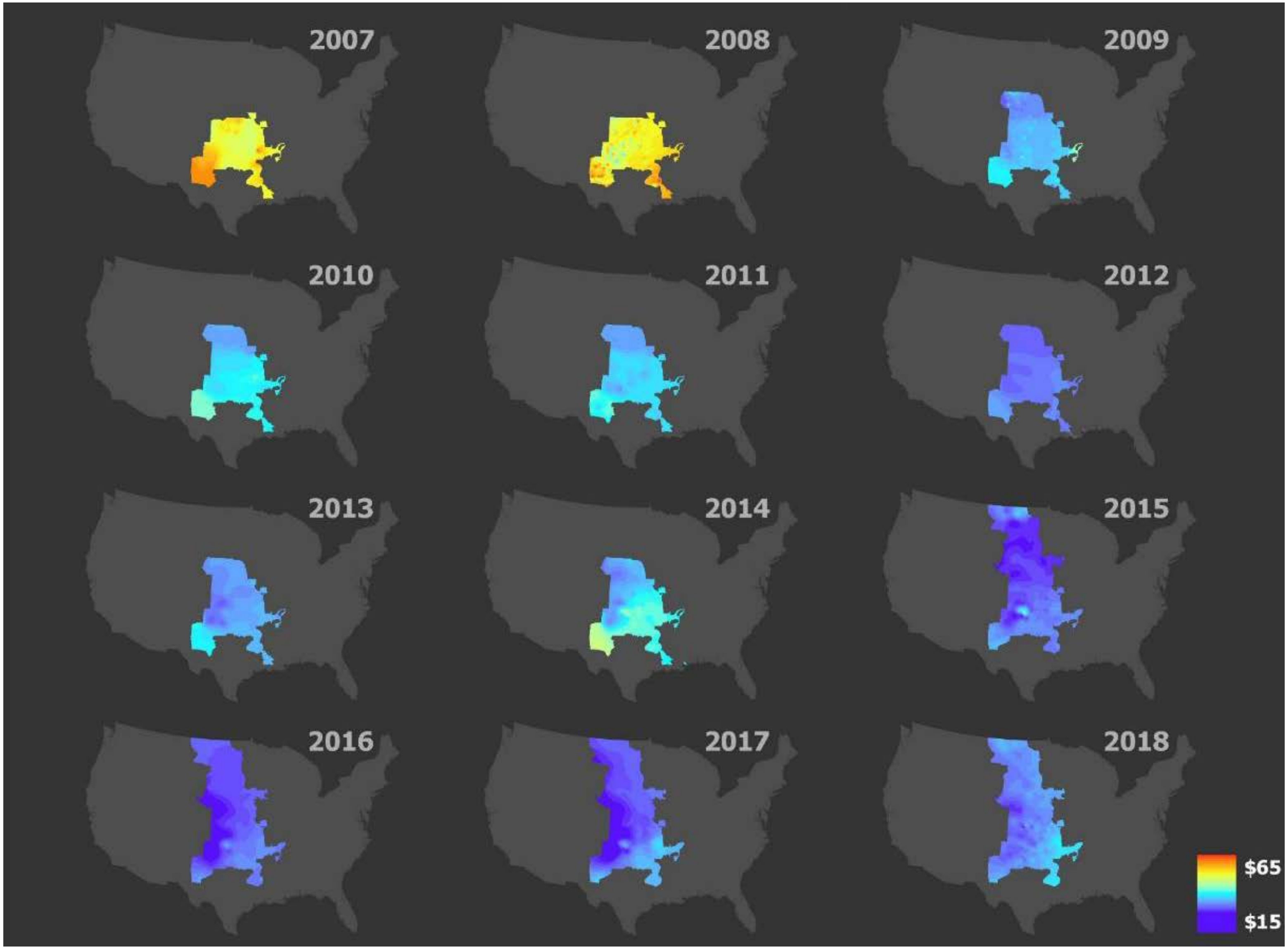


As of June 2019



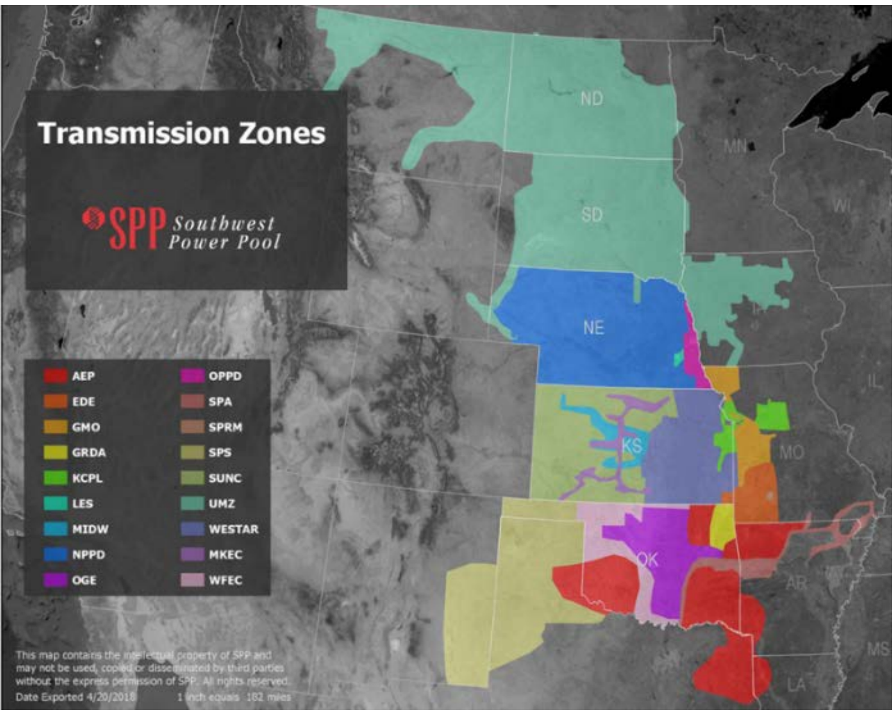
Generation Interconnection Queue
SPP Southwest Power Pool
Storage
Solar
Wind
≤40
≤90
≤160
≤250
≤600
WA
MT
ND
SD
WY
NE
NV
UT
CO
AZ
NM
TX
MI
OH

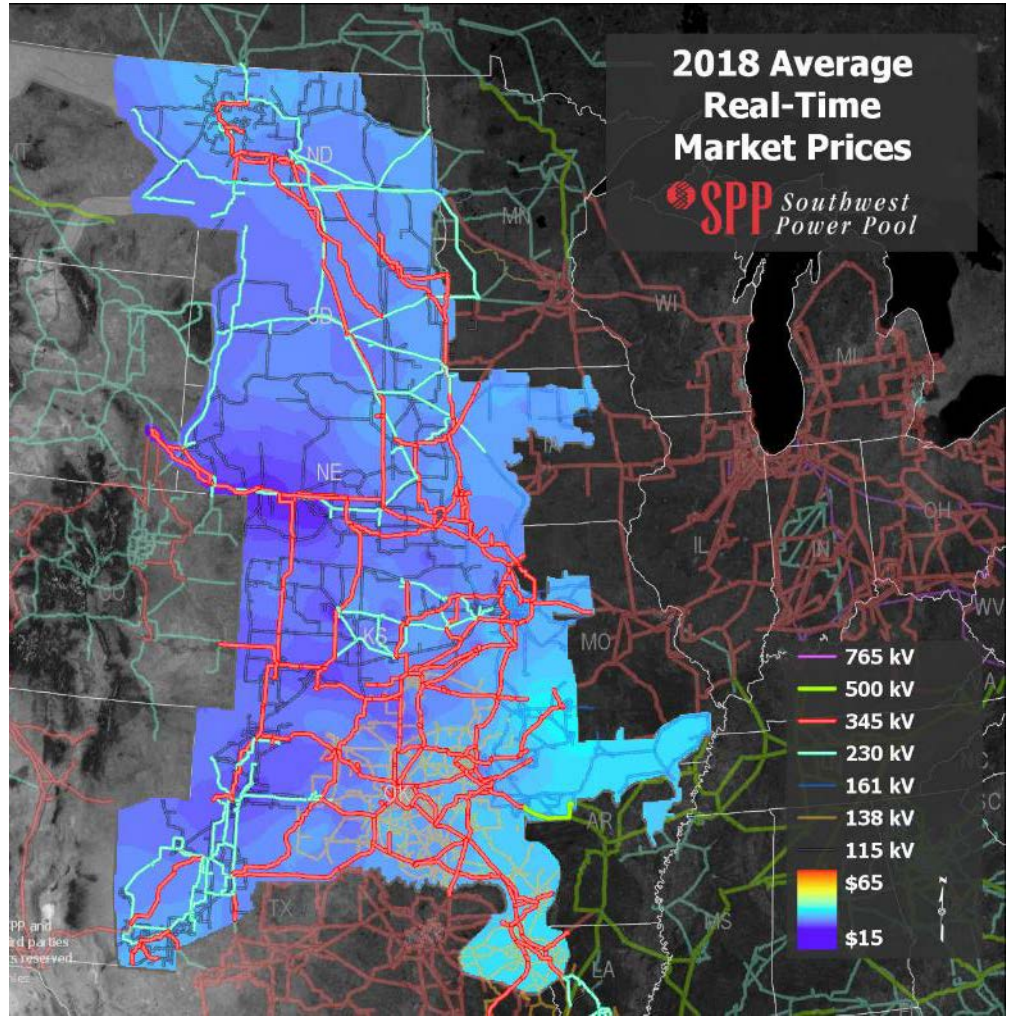
Enhancing Integrated Marketplace to reliably deliver low-cost energy to customers



Average annual real-time market prices

Aligning transmission planning and cost allocation with SPP's market and consolidated Balancing Authority





SUMMARY OF RECOMMENDATIONS

Slides for each recommendation include

- **High-level stakeholder process steps & schedule**
- **Goal dates for stakeholder process completion**
  - **Implementation dates are to be decided**
- **Lead and secondary groups**
- **HITT team vote**
- **Icon indicating if recommendation is to be implemented or studied/evaluated**

Reliability

#1 Study Essential Reliability Service (ERS) and Other Reliability Service (ORS)

- NERC defines ERS as:
  - Frequency support
  - Ramping and balancing
  - Voltage support
- ORS takes into account that as grid changes, SPP is not confident all reliability needs are captured in NERC's ERS definition
- ORS includes new technologies that change underlying nature of grid operations that are not traditional operator tools
- "Uncertainty product" is an example of ORS

Reliability

#1 Study ERS and ORS

- SPP should perform comprehensive study to evaluate reliability challenges with changing generation resource mix
- Study should identify all ERS and ORS needed in future to keep the lights on

Reliability

#1 Study ERS and ORS

2019					2020						
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July
Coordinate, develop and complete study requirements with MWG, SAWG and ORWG input											Staff report to MOPC

Stakeholder completion goal	**July 2020**
Lead group	**Staff**
Secondary group	**MWG, ORWG, SAWG**
HITT vote	**Consensus**

Reliability

GO

#2 Implement ERS/ORS compensation model

- Use study results from reliability recommendation #1 to establish compensation model for each ERS and/or ORS
- Review regulation service compensation to determine if service is appropriately valued
- Consider cost causation and whether technology that reduces need for regulation service should receive some of the compensation

Reliability

#2 Implement ERS/ORS compensation model

GO

2020					2021			
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.
MWG to assess results of ERS/ORS study					MWG develop report and coordinate with ORWG			MWG report to MOPC

Stakeholder completion goal **April 2021**
Lead group **MWG**
Secondary group **ORWG**
HITT vote **Consensus**

Reliability

GO

#3 Implement marketplace enhancements

Continue Integrated Marketplace enhancements including:

- Ramping capability
- Fast-start resource logic
- Multi-day, longer-term market product

Reliability

GO #3 Implement marketplace enhancements

	2019						2020					
	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June
Ramp product *	MWG develop RR		MWG endorse RR	MOPC endorse	FERC filing							
Fast-start Resources**	MWG develop RR		MWG endorse RR	MOPC endorse	FERC filing							
Multi-day market	MWG develop straw proposal				MWG develop policy		MWG develop RR		MWG endorse RR	MOPC endorse	FERC filing	

Stakeholder completion goal	July 2019* (ramp), Jan. 20** (fast-start), Apr. 20 (multi-day
Lead group	MWG
Secondary group	N/A
HITT vote	Consensus

* HITT report lists July 2019 completion date for ramp product. RTWG did not approve RR in June; completion is now projected in Oct. 2019.

** HITT report lists Jan. 2020 date for fast-start product. A recent FERC order directs SPP to make a compliance filing in Dec. 2019. Completion is projected in Oct. 2019.

Reliability

GO

#4 Implement uncertainty market product

Continue to develop uncertainty product that addresses potential reliability issues associated with increased reliance on forecastable generation

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<tr><th colspan="11">2020</th></tr>
<tr><td>Feb.</td><td>Mar.</td><td>Apr.</td><td>May</td><td>June</td><td>July</td><td>Aug.</td><td>Sept.</td><td>Oct.</td><td>Nov.</td><td>Dec.</td></tr>
<tr><td colspan="3">MWG develop straw proposal</td><td colspan="2">MWG develop policy</td><td colspan="2">MWG develop RR</td><td>MWG endorse RR</td><td>MOPC endorse</td><td colspan="2">FERC filing</td></tr>
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Stakeholder completion goal	**Oct. 2020**
Lead group	**MWG**
Secondary group	**ORWG**
HITT vote	**Consensus**

Reliability

#5 Study additional operational tools

Determine what additional operational tools are needed to ensure BES remains reliable in the future

2019					2020			
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.
Staff to continue evaluating needed operational tools								

Stakeholder completion goal	**Ongoing**
Lead group	**Staff**
Secondary group	**ORWG, MWG**
HITT vote	**Consensus**

Marketplace

#1 Implement congestion hedging improvements

- Continue with market mechanism to hedge load against congestion charges
- Existing design should include modifications to implement counter-flow optimization limited to excess auction revenues

Marketplace

GO #1 Implement congestion hedging improvements

2019					2020								
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.
Staff straw proposal			MWG develop policy white paper					MOPC/ RSC endorse	Draft tariff language		MOPC/ RSC endorse	FERC filing	

Stakeholder completion goal **April 2020**
Lead group **MWG**
Secondary group **RSC, CAWG**
HITT vote **14 to 0 with 1 abstention**

Marketplace

#2 Study offer requirements for variable resources

- Evaluate whether variable energy resources should have requirement to offer at specific level in day-ahead market
- Review incentives
- Consider market rule changes to improve day-ahead participation for wind resources

Marketplace

#2 Study offer requirements for variable resources

2019		2020												2021
Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.
MMU educate MWG					MWG develop policy recommendation report									MWG report to MOPC

Stakeholder completion goal	**Jan. 2021**
Lead group	**MWG**
Secondary group	**N/A**
HITT vote	**Consensus**

Marketplace

#3 Study automatic mitigation of unduly low offers

Evaluate whether generation (including renewables) offer requirements provide adequate safeguards against uneconomic production

2019		2020												2021
Nov.	Dec.	Jan.	Feb.	Mar	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.
MMU educate MWG					MWG develop policy recommendation report									MWG report to MOPC

Stakeholder completion goal	**Jan. 2021**
Lead group	**MWG**
Secondary group	**N/A**
HITT vote	**Consensus**

Marketplace

#4 Study economic evaluations of reliability

- Evaluate cost and benefits of more advanced economic evaluations of reliability
- Evaluation should educate and encourage use of dynamic line ratings, topology optimization and economic outage coordination when practical, economic and reliable

Marketplace

#4 Study economic evaluations of reliability

	2019					2020			
	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.
Markets	MWG education			MWG/ORWG develop policy white paper					MWG/ ORWG report to MOPC
Reliability	ORWG education			ORWG/MWG develop policy white paper					

Stakeholder completion goal **April 2020**
Lead group **MWG, ORWG**
Secondary group **TWG, RCWG**
HITT vote **Consensus**

Planning & Cost Allocation

Transmission Planning

GO **#1 NRIS/ERIS modifications**

Develop policy that creates appropriate balance between costs assessed and value attained from:

- ERIS (energy resources interconnection service) and NRIS (network resources interconnection service) generator interconnection products
- Generating resources with long-term firm transmission service

Planning & Cost Allocation

#1 NRIS/ERIS policy should:

- Add more value to NRIS by making it eligible for benefits comparable to those awarded to designated resources without required transmission service study
- Tighten thresholds for mitigation of ERIS system impacts
- Include deliverability on larger sub-regional basis
- Address capacity accreditation
- Maintain cost/value balance throughout all transmission services, transmission planning and Integrated Marketplace processes
- Ensure effectiveness and equity for all impacted stakeholders

Planning & Cost Allocation

GO

#1 NRIS/ERIS modifications

	2019					2020										
	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.		Apr.		May	June	July	Aug.	Sept.
ERIS - Modifications	Staff develop straw proposal			MOPC develop policy white paper				MWG review	MOPC endorse	MWG endorse	MOPC endorse	Develop tariff language		MOPC endorse	FERC filing	
NRIS - Accreditation	Staff develop straw proposal			SAWG develop policy white paper				CAWG/ MWG review	SAWG endorse	CAWG/ MWG endorse	MOPC/ RSC endorse	Develop tariff language		MOPC/ RSC endorse	FERC filing	
NRIS - Deliverability	Staff develop straw proposal			TWG develop policy white paper				MWG review	TWG endorse	MWG endorse	MOPC endorse	Develop tariff language		MOPC endorse	FERC filing	

Stakeholder completion goal	**April 2020**
Lead group	**TWG, SAWG, MOPC**
Secondary group	**MWG, RSC, CAWG**
HITT vote	**15 to 0**

Planning & Cost Allocation

GO

#2 Establish uniform Schedule 9 local planning criteria

- Establish uniform local planning criteria within each Schedule 9 pricing zone
- Criteria can vary between zones
- Transmission Owners (TOs) within each zone should be subject to same local criteria in determining need for zonal reliability upgrades within zone
- Host TO should invite zone's TOs & transmission customers to participate when developing zonal criteria before submitting to SPP

Planning & Cost Allocation

GO #2 Establish uniform Schedule 9 local planning criteria

<table>
<tr><th colspan="7">2019</th><th colspan="3">2020</th></tr>
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<tr><td colspan="3">Staff draft RR and proposed schedule</td><td>TWG review RR</td><td>RTWG review RR</td><td>TWG endorse RR</td><td>RTWG endorse RR</td><td>MOPC approve RR</td><td colspan="2">FERC filing</td></tr>
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Stakeholder completion goal	**Jan. 2020**
Lead group	**TWG**
Secondary group	**RTWG**
HITT vote	**15 to 0**

Planning & Cost Allocation

GO

#3 Implement new load addition modifications

- Modify Attachment AQ process
  - Delivery-point additions, modifications, or abandonments
- Attachment AQ process should
  - Be more transparent
  - Allow for quicker results to facilitate potential load growth
  - Be modified to limit application to new load, modification to loads, and load retirements that need to be addressed outside ITP due to timing or other significant reason

Planning & Cost Allocation

#3 Implement new load addition modifications

2019					2020								
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.
Staff straw proposal			Coordinate policy white paper with TWG, RTWG and RCWG					MOPC endorse	Draft tariff language		MOPC endorse	FERC filing	

Stakeholder completion goal	**April 2020**
Lead group	**TWG**
Secondary group	**RTWG, RCWG**
HITT vote	**Consensus**

Planning & Cost Allocation

#4 Study three-phase GI process effectiveness

Evaluate effectiveness of three-phase generator interconnection study process following implementation

2019						2020												2021
July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.
Staff evaluate and collect data																		Staff report to MOPC

Stakeholder completion goal	**18 months after GI process implementation**
Lead group	**Staff**
Secondary group	**MOPC**
HITT vote	**Consensus**

Planning & Cost Allocation

#5 Evaluate benefit-to-cost ratio for economic projects

- Evaluate increasing B/C ratio margin threshold for economic upgrades
- Increase from 1.0 B/C to 1.05 to 1.25

2019					2020
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.
ESWG evaluate and develop report					ESWG report to MOPC

Stakeholder completion goal	**Jan. 2020**
Lead group	**ESWG**
Secondary group	**N/A**
HITT vote	**9 to 6 with 1 abstention**

Planning & Cost Allocation

Cost Allocation

GO

#1 Decouple Schedule 9 & Schedule 11 pricing zones

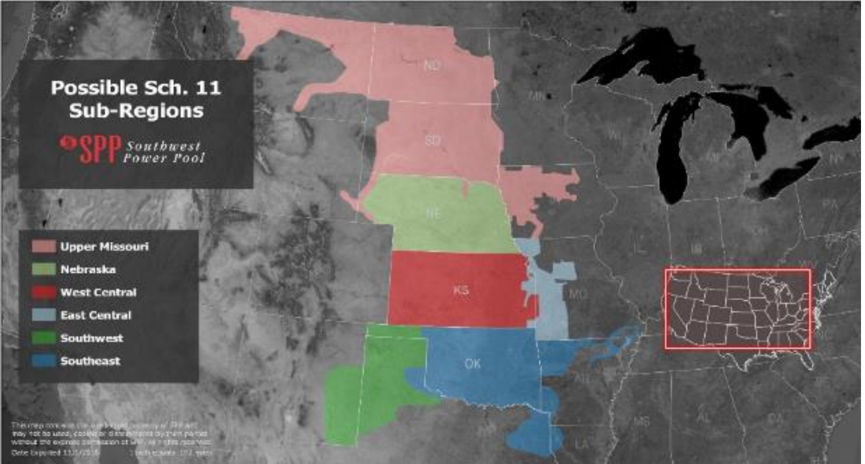
- Decouple Schedule 9 and 11 transmission pricing zones
- Create larger Schedule 11 pricing zones and/or Schedule 9 sub-zones prospectively
- When creating new pricing zones, consider new deliverability sub-regions, distribution factor calculations, and market and power flows
- If RSC adopts policy to reallocate existing costs within new Schedule 11 zones — to mitigate cost shifts, zones should be consolidated over a 5 to 10-year transition period

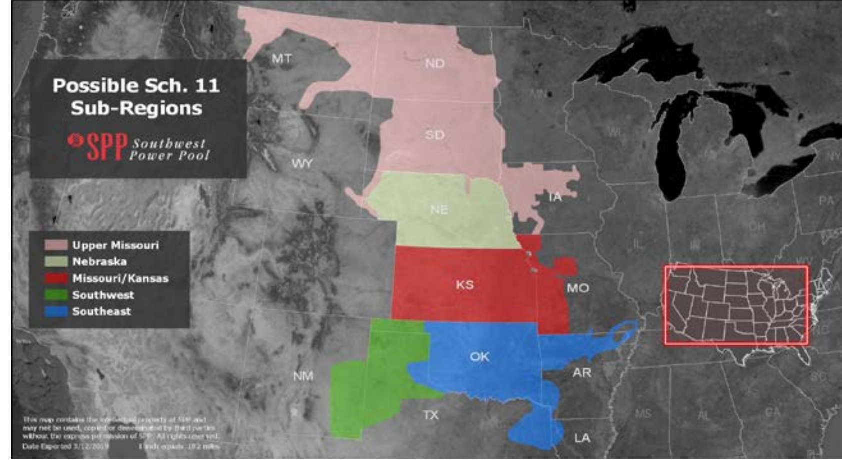
Planning & Cost Allocation

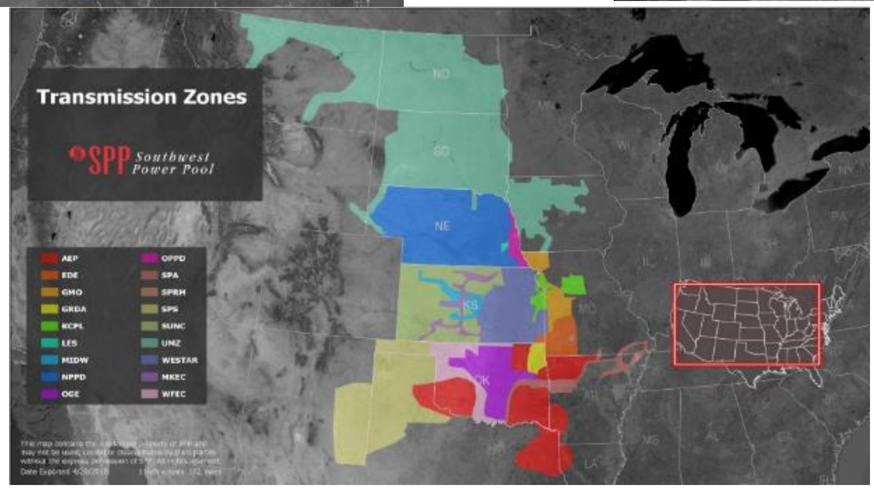
GO #1 Decouple Schedule 9 & Schedule 11 pricing zones

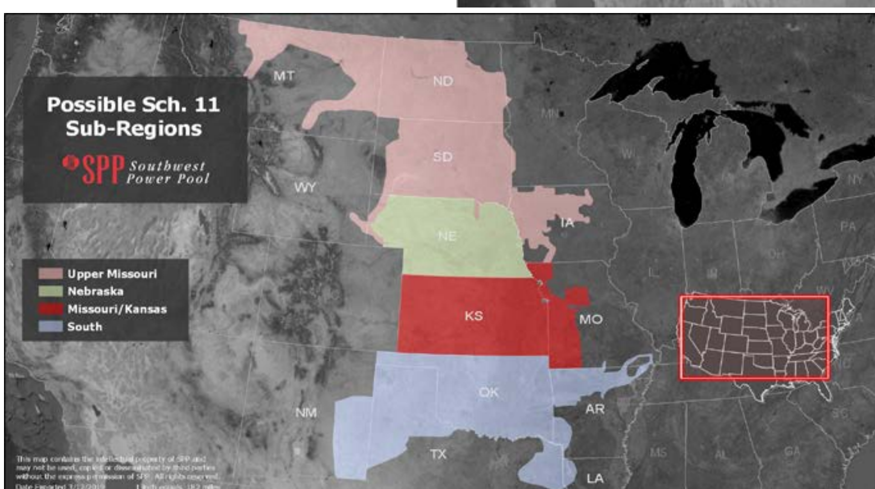
<table>
<tr><th colspan="5">2019</th><th colspan="11">2020</th></tr>
<tr><td>Aug.</td><td>Sept.</td><td>Oct.</td><td>Nov.</td><td>Dec.</td><td>Jan.</td><td>Feb.</td><td>Mar.</td><td>Apr.</td><td>May</td><td colspan="2">June</td><td colspan="2">July</td><td>Aug.</td><td>Sept.</td></tr>
<tr><td colspan="5">Staff coordinate with CAWG to develop scope and requirements</td><td colspan="5">CAWG develop policy recommendation report</td><td>CAWG review report</td><td>RTWG review report</td><td>CAWG approve report</td><td>MOPC/ RSC endorse</td><td colspan="2">FERC filing</td></tr>
<tr><td colspan="12">Staff evaluate impacts to zonal placement process</td><td colspan="2">Staff report to SPC</td><td colspan="2"></td></tr>
</table>

Stakeholder completion goal	**July 2020**
Lead group	**RSC, CAWG**
Secondary group	**RTWG**
HITT vote	**11 to 1 with 3 abstentions**


Possible Sch. 11
Sub-Regions
SPP Southwest Power Pool
Upper Missouri
Nebraska
West Central
East Central
Southwest
Southeast
ND
SD
NE
KS
OK


Possible Sch. 11
Sub-Regions
SPP Southwest Power Pool
Upper Missouri
Nebraska
Missouri/Kansas
Southwest
Southeast
MT
ND
SD
WY
NE
IA
KS
MO
OK
AR
NM
TX
LA


Transmission Zones
SPP Southwest Power Pool
AEP
EDE
GMO
GRDA
KCPL
LES
MIDW
NPPD
OGE
OPPD
SPA
SPRM
SPS
SUNC
UMZ
WESTAR
MKEC
WFEC
ND
SD
NE
KS
OK


Possible Sch. 11
Sub-Regions
SPP Southwest Power Pool
Upper Missouri
Nebraska
Missouri/Kansas
South
MT
ND
SD
WY
NE
IA
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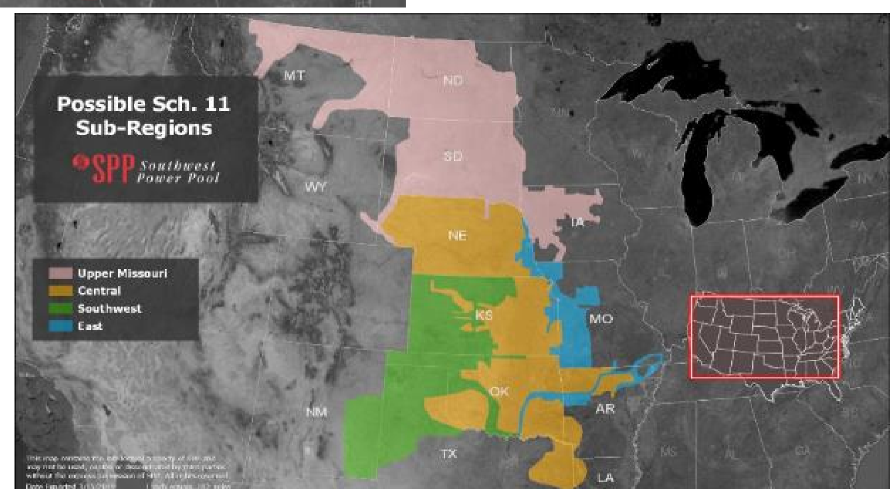
MO
OK
AR
NM
TX
LA


Possible Sch. 11
Sub-Regions
SPP Southwest Power Pool
Upper Missouri
Central
Southwest
East
MT
ND
SD
WY
NE
IA
KS
MO
OK
AR
NM
TX
LA

Planning & Cost Allocation

#2 Establish byway facility cost allocation review process

- Evaluate creating narrow process through which costs for specific projects between 100-300 kV can be fully allocated on region-wide basis
- Consider regional benefits resulting from the facilities
  - Including energy exports from transmission pricing zone where project is located

Planning & Cost Allocation

#2 Establish byway facility cost allocation review process

2019					2020						
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July
Staff to provide data for CAWG to develop policy recommendation report									CAWG ESWG RTWG review report	CAWG ESWG approve report	CAWG report to RSC

Stakeholder completion goal **July 2020**
Lead group **RSC, CAWG**
Secondary group **ESWG, RTWG**
HITT vote **11 to 4**

Planning & Cost Allocation

GO

#3 Eliminate Attachment Z2 revenue crediting for new upgrades

- Keep incremental long-term congestion rights (ILTCRs) prospectively for new upgrades
- Recommended for new upgrades wholly or partially funded through directly-assigned upgrade costs (DAUC)
- Entity that incurs such costs would no longer be eligible for compensation through revenue credits under Attachment Z2
- DAUC sponsor eligible to receive compensation through ILTCRs
- ILTCRs would continue to function as currently described in Attachment Z2, except total compensation limited to upgrade's DAUC plus interest

Planning & Cost Allocation

GO

#3 Eliminate Attachment Z2 revenue crediting for new upgrades

2019						
Aug.		Sep	Oct.		Nov.	Dec.
Staff develop RR	RTWG review RR	CAWG review RR	CAWG endorse RR	MOPC/RSC endorse	FERC filing	

Stakeholder completion goal	**Oct. 2019**
Lead group	**RTWG**
Secondary group	**RSC, CAWG, TWG**
HITT vote	**15 to 0**

Planning & Cost Allocation

#4 Study cost allocation for transmission storage

Evaluate whether SPP should establish cost allocation and rates under tariff for energy storage resources to treat them as transmission assets if used as transmission assets

Planning & Cost Allocation

#4 Study cost allocation for transmission storage

2019					2020							
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	
CAWG develop policy white paper								MWG RTWG TWG review policy			CAWG approve policy paper	RSC endorse policy paper

Stakeholder completion goal	**July 2020**
Lead group	**RSC, CAWG**
Secondary group	**MWG, RTWG, TWG**
HITT vote	**14 to 0**

Strategic

GO

#1 Add technological advances to SPP strategic plan

- Technology is changing more rapidly than we've seen in SPP's nearly eight decades
- To be better prepared for these changes, HITT recommends the Strategic Planning Committee add understanding and evaluation of technological advances to SPP's strategic plan

Strategic

GO #1 Add technological advances to SPP strategic plan

2019					2020
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.
SPC to add technological advances to SPP strategic plan					

Stakeholder completion goal	**Next plan update**
Lead group	**SPC**
Secondary group	**N/A**
HITT vote	**Consensus**

Strategic

GO #2 Continue to include seams in SPP strategic plan

- Seams with neighboring regions continue to be an area that's challenging and for which there are potential improvements
- HITT recommends SPP continue to make seams a high priority and continue to include seams as a part of SPP's strategic plan
- Seams Steering Committee should continue to provide direction to SPP staff on seams issues

Strategic

GO #2 Continue to include seams in SPP strategic plan

2019					2020
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.
SPC to keep seams issues a priority in SPP strategic plan					

Stakeholder completion goal	**Ongoing**
Lead group	**SPC**
Secondary group	**N/A**
HITT vote	**Consensus**

Strategic

GO #3 Energy storage white paper

- Energy storage – particularly batteries – is an immediate challenge and opportunity
- Future storage impacts are evident by increasing amount of batteries in SPP's GI queue and FERC's Order 845
- HITT recommends SPP staff create white paper on storage issues
- Goal is to develop better understanding of storage and how SPP should address it
- Paper will be delivered to MOPC, RSC and board in January 2020
- Paper should include tactical and strategic recommendations
- In the interim, MOPC working groups will continue their efforts

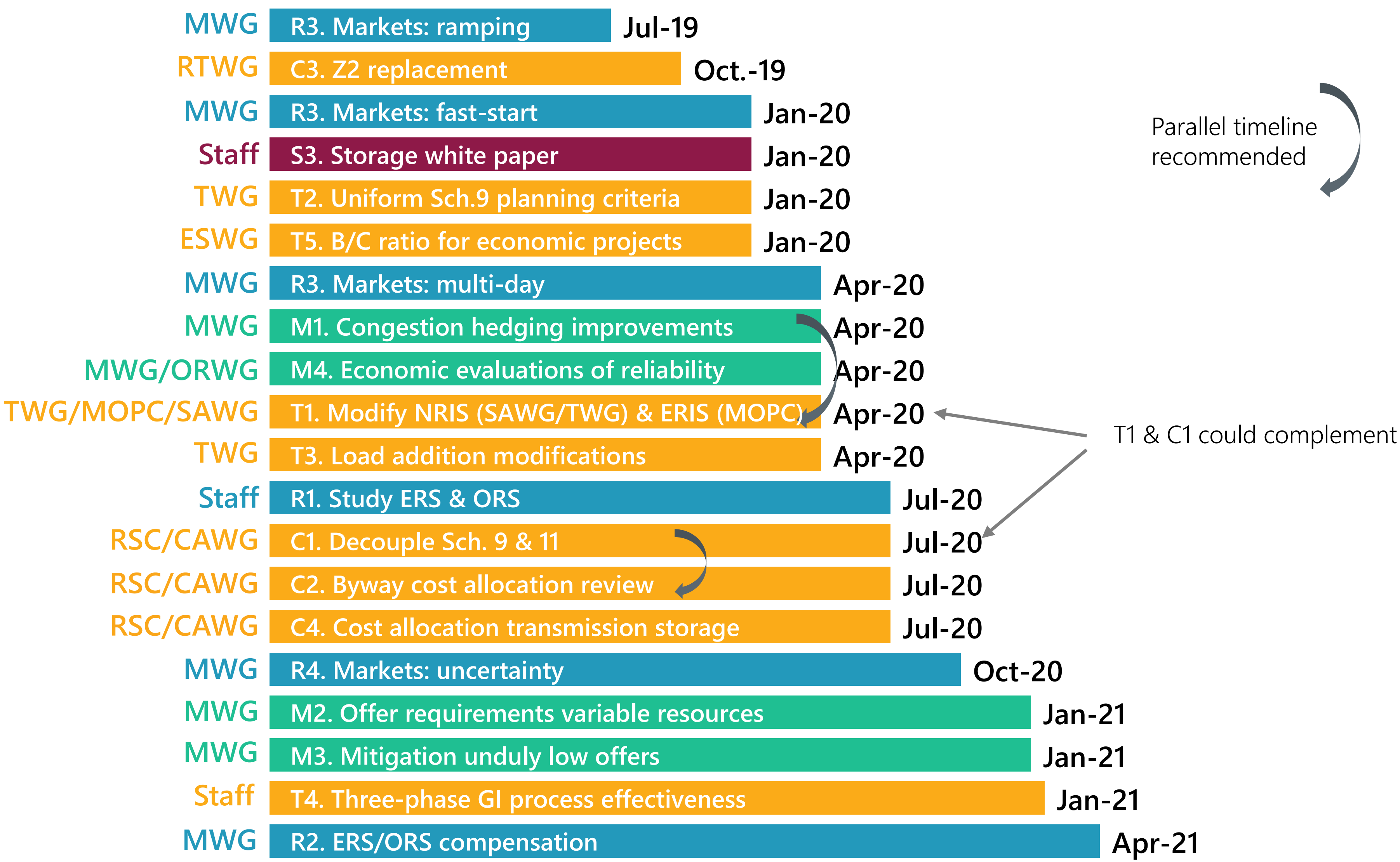
Strategic

GO #3 Storage white paper

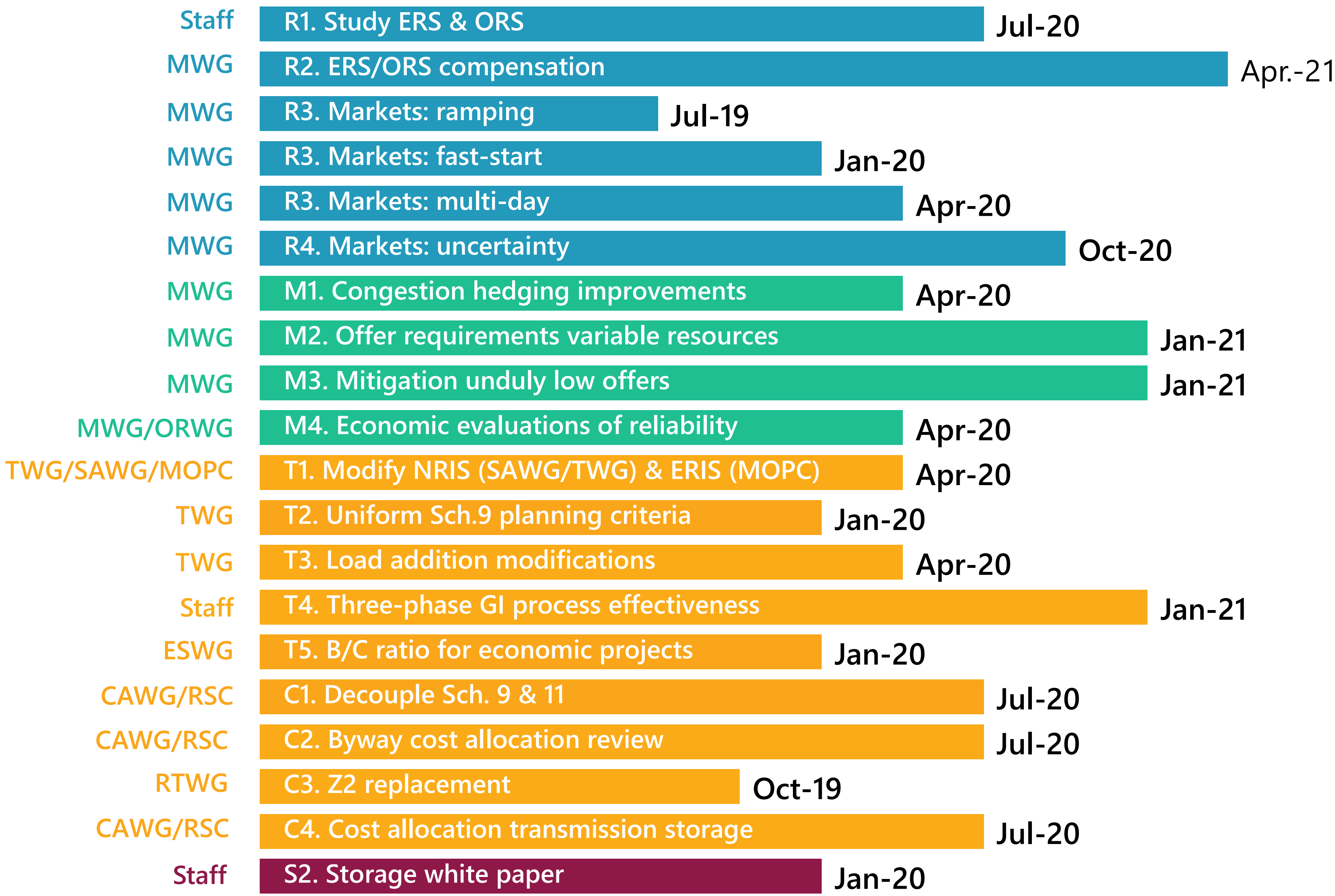
2019					2020
Aug.	Sept.	Oct.	Nov.	Dec.	Jan.
Staff develop white paper and develop working group interactions					Staff report to MOPC and RSC

Stakeholder completion goal	**Jan. 2020**
Lead group	**Staff**
Secondary group	**RSC, MOPC**
HITT vote	**Consensus**

Timeline by date (Proposed)



Timeline by recommendation (Proposed)



QUESTIONS

Holistic Integrated Tariff Team Report

Preparing for a reliable and cost-effective future

July 23, 2019

CONTENTS

EXECUTIVE SUMMARY

The regional and national electric grid is rapidly evolving. A changing generation mix, new technologies, and federal and state regulations are impacting how the electric industry does business. Demand for electricity is leveling off overall, while new economic development opportunities are occurring throughout the region. Southwest Power Pool, Inc. (SPP) and its members must prepare to meet these challenges.

In March 2018, the SPP Board of Directors and Members Committee created the Holistic Integrated Tariff Team (HITT) to comprehensively review SPP's cost allocation model, transmission planning processes, Integrated Marketplace services, and disconnects or synergies between planning and real-time reliability and economic operations. The HITT's goal was for this integrated review to be broad and holistic, taking into consideration the highly interdependent nature of SPP's processes and how changes to one area would impact other business functions.

The team was tasked with recommending solutions to the challenges SPP and its members face. The board appointed 15 stakeholders to the HITT, including board members, state regulators from the Regional State Committee, and members representing diverse sectors. A senior SPP executive served as the staff secretary.

In conducting this holistic review, the HITT met 17 times over the course of a year. In-person meetings included team members and invited guests, while all stakeholders were invited to attend remotely. The group held educational sessions, reviewed 94 requests for information, and reviewed and listened to stakeholder presentations before drafting recommendations.

After vigorous debate and discussion, the HITT agreed on 21 high-level recommendations for the board's consideration. The recommendations were made from a broad perspective rather than a more narrow view of SPP's functions. The recommendations are presented in four categories: reliability, marketplace enhancements, transmission planning and cost allocation, and strategic.[1]

In reaching these recommendations, the HITT used volumes of educational information, data and industry knowledge. Team members settled on recommendations that were the result of extensive discussions, debates, brainstorming, collaboration and compromise. The final package of high-level recommendations represents a holistic, consensus-based set of solutions to implement and/or evaluate to improve many of SPP's critical functions, with the principal goal of reliably providing the lowest-cost electricity to end-use customers.

Upon the board's approval of the HITT's 21 recommendations, the HITT expects these recommendations will be assigned to SPP's committees and working groups for implementation. The HITT has recommended an implementation action plan for board consideration with timelines under oversight of the Strategic Planning Committee. Coordination between the Strategic Planning

[1] The report combines transmission planning and transmission cost allocation in the same category due to the interdependent nature of the two lists of recommendations.

Committee and the Markets and Operations Policy Committee (MOPC), under which much of the work is expected to be performed, will be an important facet of implementation management.

The HITT's recommendations are listed below by category:

Reliability Recommendations

#1 Study Essential Reliability Services and Other Reliability Services
SPP should perform a comprehensive study to evaluate the region's reliability challenges with a changing generation resource mix. The study should identify all Essential Reliability Services (ERS) and Other Reliability Services (ORS) needed in the future to keep the lights on.

#2 Implement ERS and ORS compensation models based on study results
SPP should use the results of the study in Reliability Recommendation #1 to gain a better understanding of how to best establish an appropriate compensation model for each ERS and ORS, based on the needs and timing required for each service.

#3 Implement market enhancements
SPP should continue enhancements to the Integrated Marketplace, including fast-start resource logic, ramping capability and a multi-day, longer-term market product.

#4 Implement uncertainty market product
SPP should continue to develop an uncertainty product that allows for addressing the potential reliability issues associated with an increased reliance on forecastable generation.

#5 Study additional operational tools
SPP should determine what operational tools are needed to ensure the Bulk Electric System remains reliable in the future.

Marketplace Enhancement Recommendations

#1 Implement congestion hedging improvements
SPP should continue with a market mechanism to hedge load against congestion charges. The existing market design should include modifications to implement counter-flow optimization that is limited to excess auction revenues.

#2 Study offer requirements for variable energy resources
SPP should evaluate whether variable energy resources should have a requirement to offer at a specific level related to their forecasted generation output in the day-ahead market. SPP should review incentives and consider market rule changes to improve day-ahead participation for variable resources.

#3 Study mitigation of unduly low offers that create uneconomic dispatch

SPP should evaluate whether generation offer requirements, including those for renewable resources, provide adequate safeguards against uneconomic production.

#4 Study economic evaluations of reliability

SPP should evaluate the costs and benefits of more advanced economic evaluations of reliability. This evaluation should help educate and encourage the use of dynamic line ratings, topology optimization and economic outage coordination when practical, economic and reliable.

Transmission Planning Recommendations

#1 Implement modifications to NRIS and ERIS

SPP should develop and adopt a policy that creates the appropriate balance between cost assessed and value attained from SPP energy resources interconnection service (ERIS) and network resources interconnection service (NRIS) generator interconnection products and generating resources with long-term firm transmission service.

#2 Establish uniform Schedule 9 local planning criteria for each zone

SPP should establish uniform local planning criteria within each Schedule 9 pricing zone[2]. The criteria can vary between zones, but all Transmission Owners (TOs) within each zone should be subject to the same local criteria in determining the need for zonal reliability upgrades within the zone. With the additional recommendation that the host TO invite TOs and transmission customers of that zone to participate when developing the zonal criteria before submitting to SPP.

#3 Implement new load addition modifications

SPP should modify the Attachment AQ process (delivery-point additions, modifications, or abandonments) to be more transparent and allow for quicker results to facilitate potential load growth within SPP. Attachment AQ should be modified to limit its application to new load additions.

#4 Evaluate three-phase generation interconnection process effectiveness

SPP should evaluate the effectiveness of the three-phase generation interconnection study process following implementation.

#5 Evaluate benefit-to-cost ratio for economic projects

SPP should evaluate increasing the current benefit-to-cost ratio margin threshold for economic upgrades from the current 1.0 benefit-to-cost ratio to between 1.05 to 1.25.

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[2] Section II of Attachment O of the SPP tariff.

Cost Allocation Recommendations

#1 Decouple Schedule 9 & Schedule 11 transmission pricing zones

SPP should decouple Schedule 9 and Schedule 11 transmission pricing zones, which would allow the creation of larger Schedule 11 pricing zones and/or Schedule 9 sub-zones prospectively. When creating the new pricing zones, consideration should be given to new deliverability sub-regions, distribution factor calculations, and market and power flows.

#2 Evaluate a byway facility cost allocation review process

SPP should evaluate creating a narrow process through which costs for specific projects between 100 kV and 300 kV can be fully allocated prospectively on a region-wide basis. The process should take into consideration regional benefits resulting from the facilities, including energy exports from the transmission pricing zone where each project is located.

#3 Eliminate Attachment Z2 revenue crediting

SPP should eliminate Attachment Z2 revenue credits and keep incremental long-term congestion rights (ITCLRs) prospectively for new upgrades. The ILTCRs will function as currently described in Attachment Z2, except that the total compensation will be limited to each upgrade's directly assigned upgrade costs plus interest.

#4 Evaluate cost allocation for transmission storage devices

SPP should evaluate whether to establish cost allocation and rates under its Open Access Transmission Tariff for energy storage resources to treat them as transmission assets if used as transmission assets.

Strategic Recommendations

#1 Add technological advances to SPP's strategic plan

Technology is changing more rapidly than we have seen in SPP's nearly eight decades of existence. To be better prepared for these changes, the HITT recommends that the Strategic Planning Committee add to SPP's strategic plan an understanding and evaluation of technological advances.

#2 Continue to include seams in SPP's strategic plan

As noted in the Synergistic Planning Project Team's 2009 report, seams with our neighboring regions continue to be an area that is challenging and for which there are potential improvements. The HITT recommends that SPP continue to make seams a high priority and to continue including seams as a part of SPP's strategic plan. The Seams Steering Committee should continue to provide direction to SPP staff on seams issues.

#3 Create energy storage white paper

While technological changes are rapidly developing in the electric industry, energy storage – particularly batteries – is an immediate challenge and opportunity. The impact storage will have on the future is evident by the increasing amount of batteries in SPP's generation interconnection queue and the Federal Energy Regulatory Commission's (FERC) Order 845.

The HITT recommends that SPP staff create a white paper on the many issues related to storage to gain a better understanding of storage and how SPP should address these issues in the future. This white paper will be delivered to the MOPC, Regional State Committee and Board of Directors and Members Committee in January 2020. The white paper should include tactical and strategic recommendations. In the interim, MOPC working groups will continue their efforts.

BACKGROUND

The HITT was modeled on the highly successful Synergistic Planning Project Team (SPPT) that was created in 2008 to address deficiencies in SPP's planning processes and cost allocation challenges. The SPPT was comprised of regulators, members, SPP senior staff and an independent non-SPP stakeholder as an outside facilitator. After several months of meetings, the SPPT recommended the following in its report[3]:

- Five new transmission planning principles.
- A new planning process to create a robust, flexible and cost-effective transmission network for the SPP region.
- RSC development and approval of a simplified "highway/byway" cost allocation methodology for new transmission upgrades.
- Timelines for implementing the recommendations through the stakeholder process.
- Resolution of a number of outstanding issues.

The SPPT's report was adopted by the SPP Board of Directors and Members Committee in April 2009.[4] The recommendations were facilitated through SPP's stakeholder process, followed by FERC's approval of the Integrated Transmission Planning (ITP) process and highway/byway cost allocation methodology.[5]

The ITP and highway/byway enabled the approval and construction of 643 transmission projects totaling $5.8 billion in transmission facilities in the SPP region. This transmission buildout reduced customers' energy costs by enabling the reliable delivery of lower-cost electricity through SPP's Integrated Marketplace. Launched in 2014, the Integrated Marketplace has created $2.7 billion in cumulative benefits since its creation.

Since the SPPT's work in 2009, SPP and the electric industry have experienced major changes driven and influenced by state and federal tax policies, environmental and energy market regulations, technological advances in generating capabilities, and a leveling in electricity demand by consumers. Another major change was the new Integrated Marketplace, which included the consolidation of Balancing Authorities and implementation of the day-ahead energy market.

The regional generation mix has changed dramatically in the last ten years. SPP's current generation mix is primarily coal, gas and wind. On average, these fuel types made up 42%, 24% and 23% of generation in 2018. Coal has been on a continual decline since 2014, when it contributed 65% of SPP's

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[3] *Report of the Synergistic Planning Project* (2009)
[4] Board of Directors/Members Committee meeting minutes, agenda item 7 (2009)
[5] FERC Docket No. ER10-1069 approving SPP highway/byway cost allocation mythology and Docket No. ER10-1269 approving SPP's ITP.

total generation. No new coal generation is being planned, and older plants are projected to be retired. In 2018, SPP members retired over 1,800 megawatts (MW) of conventional capacity.

The amount of wind energy in SPP has been rapidly rising. At the end of 2009, the SPP region had 3,858 MW of wind generating facilities, compared to 21,578 MW as of April 2019. The average wind penetration is now 25%, compared to 4% in 2009. SPP has the potential for more wind development, with approximately 51,000 MW in the planning queue as of June 2019. Wind capacity in SPP is already above the 2018 minimum load of 21,150 MW. SPP's peak load in 2018 rose slightly to 49,659 MW while the average load was 30,922 MW. SPP's highest peak load of 50,622 MW occurred on July 21, 2016.

While there is only a small amount of solar energy installed in SPP, solar is growing as well as battery storage. As of June 2019, there are 28,531 MW of solar and 5,796 MW of storage in the planning queue. These emerging technologies are expected to continue to evolve and become more prevalent, presenting as utility-scale resources or transmission assets when connected to the transmission system and as reduced load when connected to the distribution system.

The shift in SPP's generation mix over such a short period of time is staggering. When viewing the generation queue and retirement schedule for conventional resources, the grid is in for even more change.

While load in the SPP region has been flat overall for several years, there are pockets of load growth. Commercial and industrial customers seeking low-cost, renewable service options are increasingly attracted to the SPP region. For instance, companies have contracted with renewable generators to power their data centers or to meet their carbon-emission-reduction goals. In 2018, SPP had 90 requests for new delivery-point additions representing 2,600 MW of potential load additions over the next 10 years.

After gaining a holistic perspective of these challenges and opportunities facing the SPP region, the HITT's goal was for a diverse group of stakeholders to make high-level recommendations to ensure the continued reliable delivery of low-cost electricity to end-use customers. Similar to the SPPT's work in 2009, a decade later, this suite of recommendations is a set of solutions to prepare SPP for the evolving grid of the future.

HITT CREATION, PROCESS, GOALS & REPORT

Almost a decade after the SPPT, dynamic industry changes created the need for another holistic look at the many issues challenging the SPP region. The SPP board created the HITT in March 2018 to conduct a comprehensive yearlong review of SPP's processes and recommend high-level solutions to the region's challenges. The team was asked to report back to the board by April 2019.

The SPP board chairman appointed 15 stakeholders to the team, including board members, state regulators, and representatives from investor-owned utilities, cooperatives, independent power producers, a state agency, a municipal and an independent transmission company. A senior SPP executive served as the staff secretary (Appendix 1).

The board tasked the HITT with exploring and assessing:

- SPP's transmission planning and study processes, including, but not limited to: generation interconnections (GI); the GI queue; aggregate studies; ERIS and NRIS capacity requirements, including more attributes than energy; and related FERC planning requirements.
- Transmission cost allocation issues, including but not limited to: highway/byway, directly assigned costs, Attachment Z2 credits, cost allocation impacts on transmission pricing zones with large wind resources, and state-by-state supply resource mix requirements and/or goals.
- Integrated Marketplace impacts related to a changing resource mix, access to lower-cost generation, potential changes in production tax credits, approach of using market-based compensation for varying attributes of different types of generators, etc.
- Disconnects or potential synergies between transmission planning and real-time reliability and economic operations.
- Additional areas and/or issues as appropriate and reasonably related to its scope of work.

The HITT met 17 times from April 2018 to June 2019. In-person meetings included team members and invited guests. Stakeholders attended some meetings in-person, while all stakeholders were invited to participate via web conference and/or phone to share their thoughts at all HITT meetings.

During the first few months, the HITT focused on education. Beginning in August, SPP stakeholders presented their companies' perspectives and experiences and suggested solutions to these challenges (Appendix 2). In December, the group began developing specific recommendations to deliver to the board.

During the early HITT meetings, the team developed the following specific goals based on their mandate from the board:

- Develop high-level policy recommendation as to how SPP can align its transmission planning processes and resource adequacy needs with SPP's Integrated Marketplace and tariff requirements. (Issue 1A)

- Review existing transmission cost allocation methodologies in light of Integrated Marketplace implementation and significant changes in generating resources. Upon completing the review, and in consideration of recommendations from the HITT for issue 1A, the team will develop any needed high-level cost allocation policy recommendations for the consideration by the RSC/CAWG. (Issue 1B)

- Develop a holistic understanding of SPP's Integrated Marketplace and the essential services needed for the region in light of significant changes in generating resources and developing technology. Additionally, develop a better understanding of market products in other regions/markets. Upon obtaining this understanding, develop high-level policy recommendations as to how to enhance SPP's Integrated Marketplace and tariff requirements. (Issue 2)

- Review potential load growth opportunities for the SPP region and make recommendations as to how SPP can assist member companies in realizing load growth. After completing the review, the HITT will develop high-level policy recommendation as to how SPP can enhance or change existing processes, including AQ, to help facilitate load growth opportunities in the SPP region. (Issue 3)

Using these goals as a guide, team members requested information from SPP staff on numerous topics and posed specific questions for follow-up. SPP staff responded to 94 requests for information (RFIs) to ensure team members were well-educated on the topics being discussed (Appendix 3). Most RFIs were provided by SPP staff, with several provided by SPP stakeholders.

The team considered a wide range of potential recommendations using an interdependencies matrix chart that depicts how interrelated each recommendation is on SPP's many functions and processes (Appendix 4).

The HITT coordinated its efforts to gain synergies and support, rather than interfering with, the activities of other SPP groups, including the Cost Allocation Working Group (CAWG), Market Working Group (MWG), Operating Reliability Working Group (ORWG), Regional State Committee (RSC), Reliability Compliance Working Group (RCWG), Supply Adequacy Working Group (SAWG), Strategic Planning Committee (SPC), and Transmission Working Group (TWG).

At the conclusion of more than a year's work, the team used significant amounts of information and industry expertise to make 21 recommendation for the SPP board's consideration. The HITT report is a result of a collaborative process of extensive information gathering, policy discussions and debates. The final document is a product of collaboration and compromise. All recommendations had majority support and many had broad support.[6] The recommendations provide a holistic approach for SPP, its members, and stakeholders to continue to reliably provide the lowest cost electricity while meeting the challenges and opportunities the region faces today and in the future.

The 21 recommendations are sorted into four categories: reliability, marketplace enhancements, transmission planning and cost allocation, and strategic. Reliability recommendations are needed to ensure SPP and its members can reliably provide electricity in a rapidly changing environment. Marketplace enhancements are intended to keep SPP's markets cost-effective and efficient. Transmission planning and cost allocation recommendations will help SPP and its members provide generation to customers in the most equitable manner. Strategic recommendations are to ensure SPP is prepared for technological changes and able to interact effectively with our neighbors.

These categories and recommendations are interdependent. For instance, transmission build-out impacts marketplace congestion. The HITT selected the category which best represents the recommendation's most significant impacts or benefits. Transmission planning and cost allocation are particularly interconnected, which is why they are grouped together.

Within each category, recommendations are listed in order of SPP staff's assessment of potential impacts. Each recommendation includes background information, actions to be taken, assigned working groups and stakeholder presentations or comments that were given on the topic. The recommendation's impacts on other issues are listed to identify particularly important interconnections with other recommendations and topics of interest. The strategic recommendations do not have detailed action plans, as they are more strategic than tactical. Each category lists issues that the HITT debated but ultimately decided not to include in the suite of recommendations. Appendix 5 is a glossary of terms and acronyms used in this report.

[6] While the final package of high-level recommendations had broad support, as these high-level recommendations become more detailed via SPP's stakeholder processes, HITT members who supported the report can certainly oppose as the policies are developed in more detail.

HITT RECOMMENDATIONS

Reliability Recommendations

As in many areas of our nation, the SPP region is experiencing significant changes in the types of generating resources available to meet consumers' needs. SPP's electric generating capacity has been shifting from primarily conventional generators to more renewables and intermittent generators. This shift changes how to reliably provide electricity due to the dramatic increase in intermittent and inverter-based resources (IBRs).

Between 2009 and 2019, the amount of wind energy in the SPP region increased fivefold. SPP has the potential for even more new generating capacity that may not have traditional reliability capabilities. Solar generation and storage technology are rapidly growing. Solar, storage and wind now represent over 85 GW in the GI queue. Many older plants that have historically provided reliability functions are projected to retire. This newly planned generation does not provide the fuel assurance SPP historically had. These reliability issues need thoughtful deliberation as the region looks toward the future.

Low natural gas prices and wind – which has zero fuel cost and enjoys significant federal tax incentives – is enabling an economic dispatch of SPP's changing generating fleet that reduces energy prices to the benefit of consumers and shifts the region away from traditional generation. This economic dispatch is feasible due to SPP's robust transmission system investment since 2004 and the launch of the Integrated Marketplace in 2014.

Illustrative of these changes is that SPP's wind penetration was 25% in 2018, compared to just 4% in 2009. In April 2019, SPP experienced an instantaneous wind-serving load peak of 67%. SPP's real-time average market prices dropped from $31.42/MWh in 2014 to $25.08/MWh in 2018.

While the changing generation mix has led to lower wholesale electricity prices benefiting end-use consumers and a reduction in carbon emissions across the SPP Balancing Authority (BA), these opportunities have created new operational and financial challenges. To address these challenges, SPP must have mechanisms in place to ensure the proper procurement and compensation of the system's core reliability needs.

The region's primary operational challenge is maintaining grid reliability as we become increasingly reliant on energy delivered from intermittent resources and IBRs. Many of the primary services needed for grid reliability and resilience – more commonly referred to as Essential Reliability Services (ERS) [7] and Other Reliability Services (ORS)[8] – are either implicitly or explicitly provided by conventional generation. As the grid moves towards more intermittent and IBRs, SPP must ensure that proper

[7] NERC defines "Essential Reliability Services" as frequency, net demand ramping, and voltage. *NERC Essential Reliability Services Task Force Measures Framework Report* (2015).
[8] NERC defines "Other Reliability Services" as services needed to maintain grid reliability that are not defined by NERC. Due to the rapid pace at which SPP's grid is changing, new technologies may require services that were previously undefined by NERC.

reliability mechanisms are in place to ensure ERS and ORS are available to be procured from the generation mix that is online at any given time.

SPP's primary financial challenge is ensuring that, given declining energy prices, resources capable of providing ERS and ORS are available and appropriately compensated and incentivized to offer and deliver these services to the grid. A significant challenge is developing a compensation model for generators needed to provide ERS and ORS in a wholesale market in which prices are based primarily on the incremental cost of electric energy production – not on vital capabilities required for reliability. These challenges are expected to continue to become more significant in the future given the current trajectory of SPP's generation portfolio.

The electric utility industry's traditional tools for determining generation resource adequacy were created under a paradigm that had a very different generation mix and regulatory construct than exist today. Due to the nation's changing grid, FERC has recognized the need to change its early market rules for regional transmission organizations (RTOs) and independent system operators (ISOs) and required those markets to implement new policies and products.[9]

To meet the challenges of a changing generation environment, SPP needs to conduct a comprehensive study to assess the operational characteristics necessary in this new generation portfolio to ensure that ERS and ORS are provided to maintain reliability while delivering electricity to consumers at the lowest cost. SPP's market rules may also need to adapt. The HITT makes the following recommendations to ensure a reliable electric grid in the future.

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[9] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,127 (2018).

Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187 (2011).
Sw. Power Pool, *Inc.*, 161 FERC ¶ 61,296 (2017).

Reliability Recommendation #1

Study ERS and ORS[10]

SPP should perform a comprehensive study to evaluate the region's reliability challenges with a changing generation resource mix. The study should identify all ERS and ORS needed in the future to keep the lights on.

Additional information

The North American Electric Reliability Corporation (NERC) defines, at a high-level, ERS for reliable grid operation as frequency, ramping and balancing, and voltage. Based on NERC control performance standards and other measures of grid stability, SPP and its members, participants and stakeholders recognize the need for ERS.

A comprehensive study of ERS and ORS can be insightful in determining whether SPP is projected to have the generating resources needed in the future and whether the region's electricity market has a product/service for all identified ERS and ORS.

Action

Due to these questions about the region's future needs, SPP should perform a comprehensive ERS/ORS study to help identify all ERS and ORS needed to maintain reliability into the future. The results can assist with gaining a better understanding of the most cost-effective and efficient ways for the region to economically maintain reliability for the benefit of consumers and with a preference for market-based solutions. This study should be recurring so the footprint can continuously work toward maintaining reliability in the future.

Assignments

Lead group:	SPP staff
Secondary group:	MWG, ORWG, SAWG
Goal:	Study complete by July 2020

Impacts on other identified issues

- New market products (fast-start, ramping, multi-day)
- ERS

Stakeholder comments/presentations

- August 1 brainstorming topics 22, 23, 26, & 28
- SAWG and NextEra presentations

[10] Approved by HITT consensus April 3-4, 2019

Reliability Recommendation #2

Implement ERS and ORS compensation models based on study results[11]

SPP should use the results of the study in Reliability Recommendation #1 to gain a better understanding of how to best establish an appropriate compensation model for each ERS and ORS, based on the needs and timing required for each service.

Additional information

A primary question for the future is whether SPP's compensation methods for ERS and ORS properly incent market participants to continue to provide these services. With a changing grid, resource retirements and new generation investment possibilities on the horizon, there is concern that without proper compensation, the SPP footprint could be left without necessary resources to address ERS.

Development of such a compensation model should include a determination as to whether SPP has a product/service for all identified ERS and ORS, and if the current compensation model for that service is appropriate and meets SPP's needs. If a missing product/service is identified, a determination should be made regarding whether it should be developed. The results of the study in Reliability Recommendation # 1 should contribute to answering key questions about a compensation model for ERS and ORS services. Services expected to be analyzed as part of this effort include, but are not limited to, voltage, inertia and frequency response.

Action

The MWG should begin assessing an ERS/ORS compensation model after the study in Reliability Recommendation # 1 is completed.

Assignments

Lead group:	MWG
Secondary group:	ORWG
Goal:	Develop appropriate and necessary compensation models by April 2021

Impacts on other identified issues

- Flexibility
- Renewable forecast error
- Changing resource mix

Stakeholder comments/presentations

- August 1 brainstorming topics 14, 20, 23, 27 & 28
- Golden Spread, SPP Market Monitoring Unit (MMU), NextEra and Southern Power presentations
- Sunflower and Midwest Energy comments

[11] Approved by HITT consensus April 3-4, 2019

Reliability Recommendation #3

Implement Marketplace enhancements[12]

SPP should continue Integrated Marketplace enhancements that include fast-start resource logic, ramping capability and a multi-day, longer-term market product.

Additional information

The HITT recommends timely completion of the following three efforts that are under consideration by the MWG.

Fast-start resources

Fast-start resources are essential to the reliable provision of energy. These resources typically have short startup times, low minimum run time requirements and faster than average ramp rates. These characteristics provide the needed flexibility for managing the operational challenges SPP faces.

Although the need for fast-start resources could potentially decrease with the implementation of ramp market products, SPP anticipates continuing to encounter unforeseen circumstances that will require a fast-start market product/service. While SPP currently has a participation model for fast-start resources, many market participants believe the model's compensation principles are lacking and do not adequately incent participation of fast-start resources.

FERC and some stakeholders are concerned about the inclusion of start-up and no-load costs into the locational marginal price (LMP) calculation. SPP and its stakeholders had initiated fast-start market product enhancements; however, FERC docket no. EL18-35 addresses this topic specifically within SPP. Regardless of the outcome at FERC, SPP and its membership should plan to move forward with either the stakeholder-vetted changes or the FERC-ordered initiatives.[13]

Ramping capability

Ramping capability of resources is an essential component of efficiently and economically meeting the energy needs of SPP's market participants. A resource's ability to ramp is impacted by its technology and asset age. The SPP market does not directly value the ability to perform ramping functions. This could potentially result in new technology ignoring ramp as a valued product and older assets not necessarily optimizing their offers or maintenance to produce enough ramping capability to meet the region's needs.

With the continuing development of intermittent resources, the ability to procure and value excess ramping capability to handle potential errors in renewable forecasts will help ensure a stable, reliable and economic grid for SPP and its members. This issue is not new in the industry, and other RTOs have

[12]Approved by HITT consensus April 3-4, 2019

[13] On June 12, 2019, FERC issued an order in no. docket EL18-35 that will impact the HITT's fast-start recommendation.

implemented this market product. SPP should review and evaluate those implementations to help economically procure and manage the region's ramping needs.

Multi-day market
SPP's fuel mix continues to move toward low or negative marginal cost intermittent resources with energy output that can vary significantly in short time frames due to the lack of available wind or sun. SPP's current ability to only commit resources economically one day at a time creates significant operational uncertainty in procuring energy generation from resources with high start costs, long start times, long minimum run times and multi-day fuel procurement requirements.

Implementing a longer-term, multi-day economic assessment, with appropriate safeguards to mitigate potential market manipulation opportunities, is likely to support more cost-effective market commitment decisions by market participants and reduce the levels of resource self-commitment currently experienced in the SPP market.

Action
The MWG should continue its effort to develop and implement the described products for SPP's Integrated Marketplace, per the schedule below.

Assignments

Lead group:	MWG
Goal:	Ramping by July 2019
	Fast-start by January 2020
	Multi-day, longer-term by April 2020

Impacts on other identified issues
- Flexibility
- Renewable forecast error
- Changing resource mix

Stakeholder comments/presentations
- August 1 HITT brainstorming topics 14, 20, 23, 27 & 28
- Golden Spread, MMU, NextEra, Southern Power presentations
- Sunflower and Midwest Energy comments

Reliability Recommendation #4

Implement uncertainty market product[14]

SPP should continue to develop an uncertainty product that allows for addressing the potential reliability issues associated with an increased reliance on forecastable generation.

Additional information

As the grid shifts to a generation fleet with more renewable resources, there are many times when the majority of the day's planned operating capacity is available from an intermittent resource. Due to changes in temperature, humidity, cloud cover and human behavior, these resource forecasts are not always accurate. This phenomenon can lead to SPP relying on capacity that will not actually be supplying energy when needed to meet demand.

SPP should develop products that account for uncertainty in energy production from available capacity to ensure there is enough to be committed to produce energy during these events. An uncertainty product should be developed for one or more appropriate time horizons that are yet to be determined. Other markets have addressed this issue with products in the 30-minute time horizon. In SPP's analyses to date, results look promising for one or more products in time ranges of up to four hours. The working groups should analyze the results of SPP's study on uncertainty and develop one or more products, as deemed appropriate based on the results.

Action

The MWG and SPP staff should develop a white paper on an uncertainty product. After approval from MOPC and board, the MWG should begin the Revision Request process to implement the white paper.

Assignments

Lead group:	MWG
Secondary group:	ORWG
Goal:	Develop product by October 2020

Impacts on other identified issues

- Flexibility
- Renewable forecast error
- Changing resource mix

Stakeholder comments/presentations

- August 1 brainstorming topics 14, 20, 23, 27 & 28
- Golden Spread, MMU, NextEra and Southern Power presentations
- Sunflower and Midwest Energy comments

[14] Approved by HITT consensus April 3-4, 2019

Reliability Recommendation #5

Study additional operational tools[15]

SPP should determine what operational tools are needed to ensure the BES remains reliable in the future.

Additional information

With changing grid dynamics and the continued integration of intermittent and inverter-based resources, it is vital that SPP stay at the forefront of evaluating and utilizing tools to ensure BES reliability to keep the lights on for consumers.

With the addition of voltage and transient stability analysis tools, SPP has increased its situational awareness and studied more complex power flow issues. SPP has used this information to more reliably operate the region's BES. SPP's variable energy resource (VER) forecasting provider has provided advanced forecasting and increased awareness of weather events and potential losses. SPP should continue similar efforts and continue to research advanced technologies.

Any new operational tool should be economically assessed to ensure it adds positive value to SPP and its members. The approval and implementation of new tools should follow SPP's budgeting processes.

Action

SPP staff, working with applicable working groups, should continue to evaluate and determine what operational tools are needed to ensure the BES remains reliable with the changing generation mix.

Assignments

Lead group:	Staff
Secondary group:	ORWG, MWG
Goal:	Ongoing analysis with annual presentations to ORWG and MWG

Stakeholder comments/presentations

- August 1 brainstorming
- SPP presentations

[15] Approved by HITT consensus April 3-4, 2019

Marketplace Enhancement Recommendations

Electricity markets in the United States continue to evolve and adapt due to changes in the generation mix and technological advances. These markets also continue to fine-tune, with changes directed by FERC or proposed by ISOs/RTOs.

The goal of SPP's wholesale market is to provide reliable delivery of electricity to consumers at the lowest reasonable cost. In 2007, SPP launched the Energy Imbalance Services (EIS) market. The EIS market enabled compensation for differences between scheduled and actual withdrawal of energy or between scheduled and actual output of generating resources across the entire SPP region without regard for BA borders. The savings from the EIS market exceeded cost/benefit study expectations, saving end-use customers millions of dollars annually.

Following the EIS market, SPP launched its Integrated Marketplace in 2014. This market expansion was the latest and most complex incremental step in SPP's evolutionary addition of market functionality. The marketplace coordinates next-day generation across the region to maximize cost-effectiveness. It provides participants with greater access to reserve energy, improves regional balancing of electricity supply and demand, and facilitates the integration of renewable resources. SPP's Integrated Marketplace provides significant benefits to end-use consumers and has saved market participants more than $2.7 billion since 2014.[16]

The Integrated Marketplace includes:

- Day-ahead market with transmission congestion rights (TCRs).
- Reliability unit commitment process.
- Real-time balancing market replacing SPP's EIS market.
- Incorporation of a price-based operating reserve market.
- Combining all previously existing BAs in SPP into a single SPP BA.

Consistent with SPP's evolutionary approach to adding services for its members, several enhancements were implemented after the Integrated Marketplace's start. These improvements included three FERC-mandated and several member-requested projects. Phase two included:

- Market-to-market (FERC requested)
- Long-term congestion rights (FERC requested)
- Regulation compensation (FERC requested)
- Multi-configuration for combined cycle generation resources (member requested)
- Pseudo-tie out (member requested)
- Environment build-out (member requested)

[16] 2018 SPP Annual Report

During the HITT's assessment of SPP's Integrated Marketplace, the team was briefed on concerns about the market's design. The team also discussed ideas for improving the market's economic efficiency and providing additional value to end-use customers. To continue enhancing the Integrated Marketplace, the HITT makes the following recommendations.

Marketplace Enhancement Recommendation #1

Implement congestion hedging improvements[17]

SPP should continue with a market mechanism to hedge load against congestion charges. The existing market design should include modifications to implement counter-flow optimization that is limited to excess auction revenues.

Additional information

Stakeholders selected a market-based congestion hedging mechanism in 2009 as part of the development of the Integrated Marketplace. They also selected auction revenue rights (ARRs) and the TCR auction as the functionality for a competitive and liquid market. The current approach used to allocate congestion rights attempts to value firm rights by striking a balance between market mechanisms and traditional firm reservations. While there are certain inefficiencies associated with this design, the allocation of congestion rights has improved each year since the beginning of the Integrated Marketplace as SPP and its members gained experience with the process and implemented incremental improvements.

Stakeholders and SPP staff have frequently discussed how congestion rights instruments are awarded and the efficiency of the current process. The discussion was primarily about the lack of counterflow positions by market participants. Discussion also included the pro-rata allocation of the congestion hedging rights when multiple parties over requested a path.

Significant stakeholder discussions have focused on the desire to improve hedging for load-serving entities (LSEs). Stakeholders have discussed whether to continue with a market-based congestion hedging mechanism or change to a non-market-based product. The HITT recommends that SPP continue with a market-based mechanism for congestion hedging of load.

The HITT extensively discussed how to improve hedging of load and how it relates to SPP's other processes from a holistic perspective. Importantly, effective congestion hedging was determined to play a key role in differentiating between resources designated under firm transmission service versus resources without such firm transmission service. The financial incentives for investing in firm transmission service should be clearly maintained and differentiated from resources without such transmission.

Recommendations later in this report propose further differentiation between NRIS and ERIS. Other recommendations include the removal of revenue crediting from Attachment Z2 for transmission facility upgrades and relying on an effective congestion hedging mechanism for the market. Collectively, these recommendations are designed to help ensure load is adequately hedged from a

[17] Approved at the April 3-4, 2019 HITT meeting by a unanimous vote of 14-zero with one abstention. Motion by Bill Grant (SPS) and second by Richard Ross (AEP).

holistic perspective considering the many interconnected components of SPP's energy market, transmission services and planning processes.

The HITT reviewed numerous proposals from members and SPP staff, including market and non-market solutions, and agreed on a mechanism that applies an automated optimization during the ARR simultaneous feasibility test for counterflow positions. This solution preserves the benefits of current ARR market-based processes that has been important to SPP's members and market participants. The recommended optimization of counterflow positions would be limited to the TCR auction's ARR excess revenues for funding such counterflow positions.

This approach allows additional nominations to be granted from the firm TSRs previously sold and recognizes that the ARR excess revenues are indicative of counterflow positions that were valued, but not nominated by market participants. Remaining ARR excess revenues will be distributed either under the previously existing methodology or a new methodology determined to be appropriate as a result of the methodology changes recommended by the HITT.

This recommendation is integral to the implementation of other HITT recommendations, and its completion should be reported with the other recommendations. Further evaluation of the effectiveness of this congestion hedging recommendation and any unintended consequences should be undertaken after an appropriate time period following implementation.

Action

The MWG should develop a market design that includes modifications to implement counter-flow optimization that is limited to excess auction revenues.

Assignments

Lead groups:	MWG
Secondary group:	CAWG, RSC
Goal:	Present white paper of modifications to RSC by April 2020

Impacts on other identified issues

- Transmission planning
- Market-based ARRs/TCRs
- Attachment Z2 credit alternative

Stakeholder comments/presentations

- August HITT brainstorming topics 3, 18, & 19
- American Electric Power and Southern Power presentations
- Education session Feb. 28, 2019 and RFI 89

Marketplace Enhancement Recommendation #2

Study offer requirements for variable energy resources[18]

SPP should evaluate whether VERs should have a requirement to offer at a specific level related to their forecasted generation output in the day-ahead market. SPP should review incentives and consider market rule changes to improve day-ahead participation for VERs.

Additional information

Stakeholders have expressed concerns about price divergence between the day-ahead and real-time markets. Currently, there is no requirement to offer at a specific forecast percentage in the day-ahead market. The tariff explicitly exempts VERs from a determination of day-ahead market manipulating through physical withholding.

Forecasting VER output has improved since the market's start, and exemptions from physical withholding may no longer be appropriate or justifiable given that other resources are not exempt from physical withholding determinations. SPP's MMU has raised the issue of VER offer requirements as an area of concern in its market reports.[19]

Other RTOs have addressed this issue in similar ways, subject to regional differences. ISO New England requires renewable generation that is counted for capacity to offer the forecasted amount in the day-ahead market. California ISO posts the shortage amount so market participants can adjust offers accordingly.

The majority of SPP's generation commitments come from the day-ahead market process. This potential change for VERs could lead to a more economic and accurate commitment of SPP's generation fleet in the day-ahead market, as well as increased price convergence/assurance between the day-ahead and real-time markets.

Action

The MMU should educate the MWG on this issue and recommend a solution or set of solutions to the MWG.[20]

Assignments

Lead group:	MWG
Goal:	Complete evaluation by January 2021

Impacts on other identified issues

- Price convergence
- Virtual participation

Stakeholder presentations

- August 1 brainstorming topics 14, 20, 23, 27 & 28
- MMU presentation

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[18] Approved by HITT consensus April 3-4, 2019

[19] SPP Market Monitoring Unit, *2018 Annual State of the Market Report*.

[20] The MMU is advisory and not decisional in the SPP stakeholder process.

Marketplace Enhancement Recommendation #3

Study mitigation of unduly low offers that create uneconomic dispatch[21]

SPP should evaluate whether generation offer requirements, including those for renewable resources, provide adequate safeguards against uneconomic production.

Additional information

Stakeholders have expressed concerns about negative prices in the SPP markets. In cases where an unduly low offer is negatively affecting market outcomes, the tariff does not contain mitigation to allow the low offer to be automatically replaced by a cost-based offer, unlike the case of unduly high offer prices.

Several frequently constrained areas have congestion driven by high wind output. This recommendation would impact situations when congestion is driven by offers that are unduly negative. Additionally, the concept of offer requirements for unduly low offers could potentially lead to more efficient dispatch of the SPP generation fleet.

Action

The MMU should educate the MWG on this issue and recommend a solution or set of solutions to the MWG for consideration.[22]

Assignments

Lead group:	MWG
Goal:	Complete evaluation by January 2021

Impacts on other identified issues

- Negative prices
- Generator revenue adequacy
- Generation-caused transmission congestion

Stakeholder presentations

- August 1 brainstorming topics 14, 20, 23, 27 & 28
- MMU presentation
- Sunflower and Midwest Energy comments

[21] Approved by HITT consensus April 3-4, 2019
[22] The MMU is advisory and not decisional in the SPP stakeholder process.

Marketplace Enhancement Recommendation #4

Study economic evaluations of reliability[23]

SPP should evaluate the costs and benefits of more advanced economic evaluations of reliability. This evaluation should help educate and encourage the use of dynamic line ratings, topology optimization and economic outage coordination when practical, economic and reliable.

Additional information

While SPP and its members have always treated economics and reliability as inseparable, the processes, studies and solutions SPP uses to manage the grid have integrated this philosophy with varying degrees of success. As the SPP system has matured, SPP and its members have opportunities for a more robust evaluation of grid management economics. Dynamic line ratings, topology optimization and economic outage coordination are three areas where potential cost savings to members may be advantageous and quantifiable.

Dynamic line ratings refer to usage of a more frequent and up-to-date rating for transmission lines. Typically, TOs and Transmission Operators use seasonal ratings to account for weather differences that might allow for a higher or lower rating of a transmission facility due to the ambient temperature surrounding it. However, ambient temperatures can fluctuate greatly from seasonal projections. To address these fluctuations, dynamic line ratings employ a temperature-based algorithm to adjust the line rating based on the current temperature in the area. This can lead to more accurate line ratings and increased transmission capability on the system.

Topology optimization is in different stages of acceptance at many RTOs/ISOs. At any given time, there are a significant number of transmission lines or transformers that are not congested. Usually there are transmission topology reconfigurations (such as line switching or bus splitting) that can reliably route power around the congested facilities. Transmission Operators use reconfigurations to manage some challenges, identifying them based on their experience and system knowledge. Topology control algorithms could potentially automatically identify reconfiguration options to reduce transmission congestion, eliminate overloads or lessen the burden of transmission outages.

Economic outage coordination can mean many different things. From the HITT's perspective, it means using the economic impacts of an outage (congestion, pricing and production cost) as an additional metric when considering approving an outage. This could be on the generation or transmission side, although the generation side has the most potential for benefit. A more economic evaluation of outages could lead to decreased production costs for the footprint, a less congested transmission system and more availability of generation where it is needed by the grid. SPP has employed, on a very limited basis, dynamic line ratings and topology optimization. However, they have only been used as a reliability-based solution and not for an economic outcome.

[23] Approved by HITT consensus April 3-4, 2019

SPP stakeholders have discussed economic outage coordination in multiple venues, but little traction has been gained. With continuing changes in our fuel mix and grid economics – along with the continuing need to provide value to members – SPP should evaluate expanded use of these concepts. The evaluation should include economic and reliability benefits.

Action
SPP staff should facilitate efforts with the assigned working groups to evaluate whether SPP should implement the use of dynamic line ratings, topology optimization and economic outage coordination with recommendations to the MOPC and board.

Assignments

Lead groups:	MWG, ORWG
Secondary group:	TWG, RCWG
Goal:	Evaluation and education at April 2020

Impacts on other identified issues

- TCR congestion rents
- ARR allocation
- Day-ahead and real-time price convergence
- Market transmission charge

Stakeholder comments/presentations

- August 1 brainstorming topics 14, 20, 23, 27 & 28
- Golden Spread presentation

Marketplace recommendations HITT considered but did not recommend

During the HITT's evaluation of SPP's Integrated Marketplace, a potential recommendation was made to change SPP's hedging processes, including moving away from a market-based hedge to a non-market process to hedge load. This was referred to as HITT potential recommendation 1A-7.2.[24]

During the HITT's discussions on how to address congestion hedging, there was much dialogue about the option of the SPP region moving away from a market-based approach. After several presentations, debates and dialogue the HITT reached a consensus to stay with a market-based hedging process and modify it with counterflow optimization, as described in Marketplace Enhancement Recommendation # 1.

[24] Appendix 4

Transmission Planning & Cost Allocation Recommendations

To operate an effective wholesale electricity market, it is critical to have transmission facilities that can deliver reliable, low-cost power from generators to end-use customers. SPP's planning processes and cost allocation methodologies are imperative to successfully building transmission facilities.

As SPP evolved to become an RTO, the region's transmission planning scope expanded beyond focusing primarily on local electric utility planning areas to focusing on a regional perspective. SPP and its stakeholders develop solutions that address the entire footprint's needs as well as solving local issues. This regional view considers reliability, economic and public policy requirements. The major vehicle for SPP's regional planning effort is the SPP Integrated Transmission Plan.

In 2010, SPP approved a strategic plan with a goal to "build a robust transmission system." The current strategic plan's goal is to "maintain an economical, optimized transmission system." SPP and its stakeholders have been successful in meeting these strategic goals by modernizing the region's electric grid. Since 2004, SPP members have invested $10 billion in new transmission facilities; $7.7 billion is in-service. While modernization ensures system reliability, this transmission build-out has been a significant economic investment that enables low-cost electricity to be delivered to end-use customers. These upgrades to SPP's transmission system have resulted in a current annual transmission revenue requirement of over $850 million for SPP-initiated projects.

Determining who should pay for electric transmission upgrades is a highly debated and challenging public policy issue. For decades, the industry has struggled with determining whether generators or loads should pay, which loads should pay and how much different parties should pay.

SPP's allocation of transmission costs has been largely influenced and defined through policies established by FERC.[25] The cost allocation methods are defined by sections of the SPP Open Access Transmission Tariff including Schedule 11 (base plan zonal charge and region-wide charge), Attachment J (recovery of costs associated with new facilities), Attachment V (generator interconnection procedures) and Attachment Z2 (compensation for upgrade sponsors).

SPP's highway/byway cost allocation methodology allocates most of the SPP-directed transmission costs under Schedule 11, as developed by the RSC and approved by FERC. When determining cost

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[25] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003) ("Order No. 2003"), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 (2004) ("Order No. 2003-A"), *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287, *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,404 (2005) and *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,323 (2011), order on reh'g and clarification, Order No. 1000-A, 139 FERC ¶ 61,132, order on reh'g and clarification, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41 (D.C. Cir. 2014)

allocation under Schedule 11, a significant factor is the geographic boundaries of SPP's 18 transmission pricing zones.

Most of the SPP region's transmission pricing zones are based primarily on individual TO's systems that pre-date the SPP RTO. These legacy geographic zones are the basis for much of SPP's Schedule 11 transmission cost allocation, even though SPP's planning processes develop solutions for both regional and local needs and result in projects that facilitate access to generation resources across all zones. The SPP region has been consolidated into a single BA, and the Integrated Marketplace is based on the economic commitment and dispatch of generating resources for the region.

SPP's ERIS and NRIS have become significant issues for many SPP stakeholders. FERC established these services in Order 2003 as part of an effort to create fair and consistent generator interconnection rules across the country. They were implemented by SPP in 2005. Compared to SPP's physical transmission rights system before 2014, in the current financial transmission rights system and day-ahead energy market structure with congestion hedging, the differences between these two interconnection services and rights received from firm transmission service have diminished. These issues have led to much debate and discussion in SPP committees and working groups.

Areas of concern include the processes for obtaining ERIS or NRIS service, the cost allocation impacts of generating facilities obtaining either of these interconnection services, and the lack of distinction between NRIS and ERIS services in SPP's Integrated Marketplace as implemented.

The HITT finds that SPP needs to better align its transmission planning processes, Integrated Marketplace and transmission cost allocation methodologies. It is important to address the cost responsibility of loads and generators as well as cost allocation among loads.

The HITT makes the following recommendations to ensure that SPP's transmission planning processes and cost allocation methodologies are more equitable and better align with today's regional planning and regional market dispatch.

Transmission Planning Recommendation #1

Implement modifications to NRIS and ERIS[26]

SPP should develop and adopt a policy that creates the appropriate balance between cost assessed and value attained from SPP ERIS and NRIS generation interconnection products and generating resources with long-term firm transmission service. The policy should add more value to the NRIS product by making NRIS eligible to attain benefits comparable to those awarded to designated network resources (DNR) without the requirement for a transmission service study while also tightening thresholds for mitigation of ERIS system impacts. This includes the concept of deliverability on a sub-regional basis. The policy should also address capacity accreditation. The value proposition should be maintained throughout all transmission services, transmission planning and Integrated Marketplace processes to ensure effectiveness and equity for all impacted stakeholders.

General discussion

The policy should add more value to NRIS by making NRIS eligible to attain capacity accreditation and deliverability benefits comparable to those awarded to designated resources (DRs) without requiring an additional transmission service study. This recommendation includes the concept of deliverability on a larger sub-regional or regional basis. This recommendation is consistent with how NRIS has been implemented by other RTOs.

The policy should address system upgrade cost responsibility for ERIS by tightening thresholds for mitigation of ERIS system impacts. SPP's Generator Interconnection Improvement Task Force (GIITF) has already made a proposal for tightened thresholds to MOPC. SPP and its stakeholders should consider whether that proposal is adequate given the related recommendations being made in this report or if a modification to the GIITF recommendation would be appropriate.

These recommended changes, along with others in this report, are an important step toward ensuring the benefit/cost balance is maintained throughout all transmission services, transmission planning and Integrated Marketplace processes to ensure effectiveness and equity for all impacted stakeholders.

Additional information

Today, entities seeking to integrate a DR go through the transmission service process to attain Network Integration Transmission Service (NITS). If the prospective DR is not already interconnected to the SPP network, the resource will also need to go through the GI process.

The GI process identifies upgrades necessary for reliable interconnection based on the type of service requested (ERIS or NRIS), assesses costs and scheduled goals to provide service, and shares costs of studies and upgrades among study participants. GI upgrade costs may include both interconnection

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[26] Approved at April 3-4, 2019 HITT meeting by a unanimous vote of 15-zero. Motion by Mike Wise (Golden Spread) and second by Al Tamimi (Sunflower).

facility costs and network upgrade costs. All GI upgrade costs are directly assigned to GI customers. The magnitude of upgrade costs may differ based on the GI product chosen.

The two available GI services are ERIS and NRIS. ERIS allows generators to connect to the transmission system with eligibility to deliver the generating facility's electric output using the transmission system's existing firm or non-firm capacity on an as-available basis. It is generally considered an "energy-only" interconnection service and makes available the dispatch of an interconnected generator up to the output consistent with congestion pricing based on transmission facility constraints.

Conversely, an NRIS interconnection integrates generators with the transmission system in a manner comparable to how TOs historically integrated generating facilities to serve native load customers as network resources.

Compared to ERIS studies, NRIS studies have more stringent system impact limits, or "thresholds", to identify needed network upgrades. As a result, NRIS studies are likely to assess more directly-assigned network upgrade costs than ERIS studies. However, as these services have been implemented in SPP, the potential additional investment in the transmission network associated with NRIS does not provide much, if any, incremental benefit compared to ERIS. Upon interconnection, both ERIS and NRIS resources have access to the Integrated Marketplace, although neither ERIS nor NRIS translates into transmission service.

Currently, the transmission service study process determines capacity deliverability in SPP by evaluating specific source-to-sink transfers within, into, out of or through SPP. Transmission service studies aggregate requests for service, streamlining and sharing costs of studies and new transmission upgrades among study participants who may need those upgrades to reliably accommodate service.

The transmission service process also determines ARRs candidacy. ARRs may be converted to transmission rights for hedging congestion. Network upgrades associated with DRs may be eligible for base plan funding.

NRIS modifications

This recommendation makes NRIS resources within a planning sub-region, to be designated, eligible to meet both load and planning reserve requirements for load responsible entities (LREs) within that same sub-region. As a result, additional transmission service studies would not be required to utilize NRIS resources to meet capacity requirements within the planning sub-region where the resource is located.

In addition to the NRIS sub-region studies, NRIS resources may be studied for transmission service to specific LRE loads within or outside of the sub-region for NITS or point-to-point on request. It is not anticipated that congestion hedges would be granted based on an NRIS interconnection without firm transmission service. Congestion hedges could still be received when selected as compensation for the construction of necessary directly-assigned network upgrades identified through the GI process consistent with the current rules in place for compensation for construction of such network facilities.

The SAWG is the stakeholder group responsible for the region-wide, short-term resource deliverability process for the planning reserve component of LREs' resource adequacy requirement in SPP. The TWG is the stakeholder group responsible for the long-term resource deliverability process associated with transmission service.

The SAWG is establishing modeling sub-regions for supply adequacy studies as a result of implementing new software for such studies. The SAWG would need to consider this recommendation's requirements along with developing those sub-regions. The TWG is responsible for establishing the basis for long-term deliverability through NRIS as part of this recommendation. These evaluations would likely lead to further policy considerations that would need to be reviewed and approved by the MOPC, SPC, RSC and board prior to implementation of this recommendation.

ERIS modifications
This recommendation would modify system impact limits to be more stringent in identifying needed network upgrades in ERIS studies. As a result, ERIS resources may be assessed more directly-assigned upgrade costs associated with their impacts to the transmission network. The GIITF recommended such a change to the MOPC in late 2018. The MOPC and its working groups, or possibly a new GI-related MOPC task force, should evaluate the GIITF's recommendation in light of the changes recommended in this report. The groups should particularly evaluate the HITT's recommendations related to NRIS and congestion hedging to determine if the GIITF recommendation is adequate or should be reconsidered. A congestion study should be considered to develop a thorough basis of support for any such changes to ERIS thresholds.

Summary
This recommendation:

- Adds to the NRIS value proposition and differentiates NRIS from ERIS through an incentive-based approach.
- Promotes the construction and funding of transmission facility upgrades by generators rather than LSEs.
- Reduces by half the time necessary to convert an NRIS resource to a DR within a planning sub-region.
- Expands options for LREs to acquire capacity resources by pre-qualifying resources with NRIS.
- Improves consistency in assessments that qualify generating resources for capacity, since NRIS resources and DRs could be studied with the same thresholds.

Action
The TWG and SAWG should draft a white paper on how to implement the HITT's NRIS modifications, with input from the appropriate secondary groups. After stakeholders approve the NRIS modification white paper, a Revision Request to implement the modifications shall be initiated. For changes to ERIS thresholds, the MOPC should decide what actions are appropriate.

Assignments

Lead group:	TWG (long-term deliverability through NRIS) SAWG (NRIS modifications) MOPC (ERIS modifications)
Secondary group:	MWG, RSC, CAWG
Goal:	Complete white paper on NRIS modifications and reassess appropriate ERIS thresholds by April 2020

Impacts on other identified issues

- Resource adequacy
- Attachment Z2
- Decoupling of Schedule 9 and Schedule 11 transmission pricing zones

Stakeholder comments/presentations

- August 1 brainstorming topics 1, 2, 4, & 7
- GIITF and Golden Spread presentations
- Sunflower presentation and comments
- Midwest Energy comments

Transmission Planning Recommendation #2

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

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

Additional information

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

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

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

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

Action

SPP staff should propose a timeline and process to the stakeholders and host TOs to initiate the implementation process. The HITT recognizes that developing local planning criteria as a result of this

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

[28] Section II of Attachment O of the SPP tariff.

recommendation cannot be mandated. Staff's focus should be on guiding and facilitating the process for developing local planning criteria.

Assignments

Lead group:	TWG
Secondary group:	RTWG
Goal:	Tariff and implementation schedule recommendations by January 2020.

Impacts on other identified issues

- Zonal rates
- Upgrade sponsorship
- Planning analysis

Stakeholder comments/presentations

- August 1 brainstorming topic 24
- Sunflower presentation on TO compensation

Transmission Planning Recommendation #3

Implement new load addition modifications[29]

To facilitate potential load, SPP should modify the Attachment AQ process (delivery point additions, modifications or abandonments) to be more transparent and allow for quicker results to facilitate potential load growth within SPP. Attachment AQ should be modified to limit its application to new load, modification to loads and load retirements that need to be addressed outside of the ITP due to timing or some other significant reason.

Summary

Delivery point additions, modifications, or abandonments must be evaluated pursuant to Attachment AQ of the SPP tariff. To initiate an evaluation, the customer submits the request to the host TO and SPP. First, the host TO performs local studies for the delivery point changes. The requesting customer funds any upgrade costs resulting from local studies. In parallel with local studies, SPP performs a transmission network impact assessment to determine if any network upgrades are needed to accommodate the load changes. Then SPP issues the TO a Notification to Construct (NTC) for any identified network upgrades.

Network upgrade costs resulting from these studies are currently allocated based on the highway/byway cost allocation methodology. This process is coordinated only between the requesting TC, TO, and SPP staff and takes approximately 120 days.

To attract and facilitate the addition of new load in the region, SPP should provide potential customers with study results within a shorter timeframe. The process should add transparency where reasonably possible in consideration of potential network upgrade cost sharing.

Per NERC standards, SPP is required to perform steady state, short circuit and stability analysis as necessary for changes to a load delivery point. To reduce overall process time and meet compliance obligations, the HITT recommends SPP proactively perform analysis to determine how much load can be accommodated at each node on the SPP transmission system without incremental investment. This approach would essentially pre-approve load additions within existing system capability and eliminate study time from the process once a request is received, leaving only the minimally necessary administrative time to complete the process.

In the event there is not enough Available Transfer Capability (ATC) at the chosen node, SPP would perform a full system impact analysis to assess the delivery point addition, modification or abandonment consistent with the current process. If network upgrades are required to support these requests, SPP could publicly post study reports and open a short comment window to increase transparency.

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[29] Approved by HITT consensus April 3-4, 2019

While SPP believes the full pre-approval process is a feasible long-term goal, it recognizes challenges in pre-approving short circuit and stability analysis that may take some time to develop. SPP could undertake an interim step towards this approach. Under an interim approach, SPP could perform a steady state analysis to identify the ATC at each node on the SPP system and make this information available to the appropriate parties for more informed decision making. Delivery point requests related to nodes that have enough ATC would be pre-approved for steady state impacts, which would limit the analysis that SPP would need to perform to short circuit and stability analyses only, significantly reducing study time.

Action
SPP staff should develop policy and tariff language for the assigned working groups for approval to implement recommended changes to Attachment AQ.

Assignments

Lead group:	TWG
Secondary group:	RTWG, RCWG
Goal:	Complete tariff changes by April 2020

Impacts on other identified issues
None

Stakeholder comments/presentations
Omaha Public Power District

Transmission Planning Recommendation #4

Study three-phase generator interconnection process effectiveness[30]

SPP should evaluate the effectiveness of the three-phase GI study process following its implementation.

Additional information

As the conduit for adding new generating resources in the SPP region, SPP's GI process is essential to the long-term reliable and economic operation of the grid for consumers in the region. For several years, the GI process has been overwhelmed by the demand to construct new renewable generating facilities in the SPP region. This pressure has been building over time, and SPP's stakeholders have initiated and approved several sets of improvements to the process during the past decade.

Most recently, in January 2017, the MOPC created the GIITF to review the SPP GI process and recommend improvements to address the extremely high-level of new requests being submitted to the GI queue. In April 2018, the GIITF presented a second set of recommendations to the MOPC which included:

1. Adopting a simplified application process.
2. Adopting a three-stage study process.
3. Changing the amount and timing of required financial security deposits.
4. Changing the risk structure for financial security deposits.
5. Penalty-free withdrawal when costs increase above 25% or $10,000/MW.

These recommendations are expected to streamline and simplify the GI study process. They should result in a majority of upgrades being identified in phase one, which would permit GI customers to make an informed decision before committing to a lengthy and expensive stability analysis. The proposed recommendations should reduce the number of GI requests withdrawing late in the study process, reducing re-studies and uncertainty for GI customers.

The MOPC approved the GIITF's recommendation in April 2018 and directed the RTWG to draft tariff language to implement it. In January 2019, the MOPC approved the tariff revisions necessary to implement the recommendation. SPP filed the tariff revisions with FERC seeking an effective date of June 1, 2019.

To determine whether the three-phase study process improves the GI queue, 18 months after the process is implemented SPP should report on the status of the queue and the effect of the GIITF's cumulative recommendations to MOPC. At that time, MOPC should determine whether further modification of the GI process is required.

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[30] Approved by HITT consensus April 3-4, 2019

Action

Eighteen months after implementation of the three-phase GI process, SPP staff should report to the MOPC on the effectiveness of the new processes. The report should include recommendations on what steps, if any, should be taken based on the report's findings.

Assignments

Lead group:	Staff
Goal:	Submit report to the MOPC 18 months after implementation of the three-phase GI study process

Impacts on other identified issues

GI queue

Stakeholder comments/presentations

GIITF and American Wind Energy Association presentations

Transmission Planning Recommendation #5

Evaluate benefit-to-cost ratio for economic projects[31]

SPP should evaluate increasing the current benefit-to-cost (B/C) ratio margin threshold for economic upgrades from the current 1.0 B/C to between 1.05 to 1.25.

Additional information

SPP's buildout of $10 billion in transmission upgrades has facilitated discussion and concerns about costs. While these transmission expenditures have increased stakeholder discussions about costs, other stakeholders have articulated the reliability and economic benefits of these investments that have lowered energy prices in the SPP region.

Related to concerns about the cost of SPP's transmission buildout, the HITT heard from some stakeholders that economic planning projects to date have exceeded minimum requirements. The SPP economic planning process requires a minimum one-year B/C ratio of .9 or 40-year B/C ratio of 1.0. This ratio is based on adjusted production costs for projects to be considered for approval.

The minimum one-year B/C ratio requirement for economic projects is below the financial breakeven point and relies on benefit growth over time to reach financial breakeven. The 40-year B/C ratio for economic projects considers a full benefit growth period, but the projects need only to achieve breakeven to be considered for approval. Neither criteria requires a positive net benefit for consideration of project approval.

SPP should evaluate the merits of adding a requirement for positive net benefit over an appropriate benefit assessment period. This would provide more confidence that economic projects will prove cost beneficial over time. The range of minimum net benefit should be between 5% and 25%.

This recommendation garnered the lowest level of consensus out of all the HITT-approved recommendations with a 9-6 vote.

This recommendation should be assigned to the ESWG. The HITT expects it may generate significant further debate and discussion around the broad topic of economic upgrades that the HITT was not able to fully delve into given time constraints. Recommendations for governing document changes that result from further deliberations should be made by January 2020. Every attempt should be made to limit these changes to the ITP Manual only, but if it becomes necessary, any changes outside of the ITP Manual should be filed for FERC approval to be effective for the 2021 ITP process.

Action

The ESWG should evaluate and make a recommendation to the MOPC on whether SPP should increase the B/C ratio for economic projects to between 1.05 to 1.25. Schedule

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[31] Approved by a vote of nine to six with one abstention. Motion by Tom Kent (NPPD) and second by Mike Wise (Golden Spread).

Assignments

Lead group: ESWG

Goal: Propose any changes by January 2020

Impacts on other identified issues

Cost allocation, market impacts

Stakeholder comments/presentations

- August 1 HITT brainstorming topic 15
- American Wind Energy Association and NextEra presentations
- Sunflower presentation and comments
- Midwest Energy comments

Transmission planning recommendations the HITT considered but did not recommend

During the HITT's evaluation of SPP's transmission planning processes, a potential recommendation was to change how SPP evaluates economic and reliability projects for non-firm resources. This was referred to as potential recommendation 1A-3.[32] Based on the HITT-approved package of recommendations related to transmission planning, congestion rights and cost allocation changes, the team decided not to propose this recommendation.

[32] Appendix 4

Cost Allocation Recommendation #1

Decouple Schedule 9 & Schedule 11 pricing zones[33]

SPP should decouple Schedule 9 and Schedule 11 transmission pricing zones, which would allow the creation of larger Schedule 11 pricing zones and/or Schedule 9 sub-zones, prospectively. When creating the new pricing zones, consideration should be given to new deliverability sub-regions, distribution factor calculations, and market and power flows.

Additional information

SPP's current Schedule 9 and Schedule 11 transmission pricing zones are largely based on legacy zones that predate the SPP RTO or date to when TOs joined SPP. With SPP's regional planning processes, Integrated Marketplace and consolidated BA, the decoupling of Schedule 9 and Schedule 11 transmission pricing zones would be more reflective of today's planning and use of the transmission assets built pursuant to SPP's planning process.

The HITT expects this recommendation to have various impacts related primarily to transmission planning and cost allocation of transmission facilities prospectively. It potentially interacts with the formation of sub-regions for deliverability of NRIS resources, described in an earlier recommendation.

If approved, the HITT expects this recommendation will modify cost allocation for future byway transmission facility upgrades to be broader and better align with renewable generation sources and loads that are absorbing their energy output. The next recommendation in this report – establishing a byway cost allocation review process – would allow a potentially necessary prospective true-up of the existing cost allocation for byway facilities prior to the change this recommendation represents.

The HITT coordinated closely with CAWG and RSC representatives in deliberating numerous proposed modifications to SPP's existing transmission facility cost allocation design. The HITT deemed this recommendation and Cost Allocation Recommendation #2 (establish byway cost allocation review process) as the best fit for this report's overall package of recommendations. If the RSC does not approve these two recommendations, the board and SPC may need to reconsider some of the report's other recommendations.

If the RSC adopts a policy to reallocate existing costs within new Schedule 11 transmission pricing zones, rather than just prospective costs as recommended, the costs should be phased in over a five- to 10-year transition period to mitigate cost shifts. This recommendation does not include consolidation of Schedule 9 transmission pricing zones.

SPP staff should assess impacts this recommendation may have on SPP's existing zonal placement processes.

[33] Approved by a vote of 11 to one with three abstentions. Motion by Tom Kent (NPPD) and second by Shari Albrecht (KCC).

Action
The CAWG and RSC should develop cost allocation policies to create larger transmission pricing zones. SPP staff should evaluate impacts the adoption of this recommendation may have on SPP's existing zonal placement process and report to the SPC.

Assignments

Lead group:	CAWG, RSC
Secondary group:	RTWG
Goal:	Complete by July 2020

Impacts on other identified issues
- Zonal base plan cost allocation (including Attachment Z2)
- Zonal placement
- Wind-rich regions
- GI studies
- Deliverability model

Stakeholder comments/presentations
- August 1 brainstorming topics 4, 9, 12, 17, & 21
- CAWG presentation
- Sunflower presentation/comments
- Midwest Energy comments
- GridLiance, Nebraska Public Power District, City Utilities of Springfield, American Wind Energy Association presentations

Cost Allocation Recommendation #2

Evaluate a byway facility cost allocation review process[34]

SPP should evaluate creating a narrow process through which costs for specific projects between 100 kV and 300 kV can be fully allocated prospectively on a region-wide basis. The process should take into consideration regional benefits resulting from the facilities, including energy exports from the transmission pricing zone where each project is located.

Additional information

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

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

Action

The CAWG and RSC should evaluate the creation of a byway facility cost allocation review process.

Assignments

Lead group:	CAWG, RSC
Secondary group:	ESWG, RTWG
Goal:	Complete by July 2020

Impacts on other identified issues

- Base plan cost allocation
- Wind-rich regions
- GI studies
- Transmission service studies
- Deliverability model

Stakeholder comments/presentations

- CAWG materials
- Sunflower presentation/comments

[34] Approved by a vote of 11 to four. Motion by Bill Grant (SPS) and second by Shari Albrecht (KCC).

Cost Allocation Recommendation #3

Eliminate Z2 revenue crediting[35]

SPP should eliminate Attachment Z2 revenue credits and keep incremental long-term congestion rights (ILTCRs) prospectively for new upgrades.[36] The ILTCRs will function as currently described in Attachment Z2, except that the total compensation will be limited to each upgrade's directly assigned upgrade costs (DAUC) plus interest.

Additional information

This recommendation would result in the elimination of the Attachment Z2 revenue crediting process for new upgrades. This would leave ILTCRs as the compensation mechanism for transmission facility upgrades in Attachment Z2. This change is recommended for new upgrades that are wholly or partially funded through DAUC. As a result, an entity that incurs such costs would no longer be eligible for compensation through revenue credits under Attachment Z2. Instead, the DAUC sponsor would be eligible to receive compensation that may be available through ILTCRs. ILTCRs would continue to function as currently described in Attachment Z2, except that the total compensation should be limited to each upgrade's DAUC plus interest.

Currently, Attachment Z2 provides for compensation to entities that incur DAUC (sponsors). This compensation can be provided through revenue credits or ILTCRs. The ILTCR option has not been utilized by sponsors to obtain compensation; however, it should be established as the sole means of compensation for sponsors of new upgrades. The revenue crediting approach under Attachment Z2 has added substantial complexity and uncertainty to the transmission settlements process. It has increased transmission service rates by roughly 2% on average and has created additional DAUC.

In 2016, the Z2 Task Force asked Wright & Talisman to conduct research which indicated that ISO New England, New York ISO and PJM Interconnection provide compensation to sponsoring entities only through some form of incremental ARRs. The Midcontinent Independent System Operator and California ISO offer this type of compensation to sponsoring entities (including GI customers) and allow compensation to GI customers through revenue credits paid by the TO. The HITT anticipates that the congestion hedging improvements recommended earlier in this report should improve sponsors' ability to receive compensation through ILTCRs.

Action

The RTWG should draft tariff language to implement this recommendation, which will be sent to the RSC and other stakeholder groups.

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[35] Approved at April 17-18, 2019 HITT meeting by a unanimous vote of 15-zero. Motion by Holly Carias (NextEra) and second by Jim Eckelberger (SPP director).

[36] The HITT recommendation is that credible upgrades currently receiving or currently eligible to receive Attachment Z2 revenue credits will continue to do so, but all new creditable upgrades will receive ILTCRs.

Assignments

Lead group:	RTWG
Secondary groups:	RSC, CAWG, TWG
Goal:	Complete tariff changes by October 2019

Impacts on other identified issues

- Zonal and/or region-wide rates
- Direct assignment of costs
- Attachment Z2 credit and ILTCRs

Stakeholder comments/presentations

- Wright & Talisman revenue crediting research memo dated Sept. 2, 2016 (posted under Attachment Z2 Task Force materials).
- Sunflower presentation/comments

Cost Allocation Recommendation #4

Evaluate cost allocation for transmission storage devices[37]

Evaluate whether SPP should establish cost allocation and rates under the tariff for energy storage resources to treat them as transmission assets if used as transmission assets.

Summary

Developments at the federal level and in other RTOs are pointing toward a comprehensive view of energy storage resources as assets that can provide transmission services as well as energy. SPP stakeholders should evaluate whether to develop transmission cost allocation for these facilities and, if so, what form it should take.

SPP is engaged in significant activity regarding the integration of energy storage resources for the Integrated Marketplace and for capacity accreditation. Investment tax credits supporting the development of energy storage will most likely limit the use of such resources to being exclusively paired with solar resources for at least the next five years. The HITT believes that exploring and establishing cost allocation for energy storage resources as transmission assets would allow the benefits of such resources to be incorporated more directly into the SPP region more rapidly.

Action

The CAWG and RSC should evaluate the establishment of cost allocation and rates for energy storage resources used as a transmission asset.

Assignments

Lead group:	CAWG, RSC
Secondary group:	MWG, RTWG, TWG
Goal:	Complete evaluation by July 2020

Impacts on other identified issues

- Zonal and/or region-wide rates
- Coordination with market services

Stakeholder comments/presentations

- August 1 brainstorming topics 27 & 28
- FERC policy statement, January 2017
- CAISO white paper
- MISO white paper and presentation

[37] Approved at April 17-18, 2019 HITT meeting by a unanimous vote of 14 to zero. Motion by Dennis Florom (LES) and second by Holly Carias (NextEra).

Transmission cost allocation recommendations HITT considered but did not recommend

During the HITT's evaluation of SPP's transmission cost allocation, the team worked closely with CAWG and RSC members who participated in HITT meetings. The RSC has authority over cost allocation via SPP's governing documents. The HITT, RSC and CAWG were frequently briefed about each other's activities to ensure work was synchronized and that group efforts did not conflict.

The HITT evaluated potential recommendations related to transmission cost allocation that were not included in the final recommendation report. A summary of recommendations not included in the report are described below:

Changes to byway cost allocation – For new transmission upgrades between 100 kV and 300 kV, SPP allocates 1/3 of the costs to the region and 2/3 to local transmission pricing zones. CAWG members presented the HITT with potential changes in the percentages. These were referred to as HITT potential recommendations 1B-2.1 and 1B-2.2.[38] The HITT decided the other recommendations dealt with the issues and this recommendation was not necessary.

Market transmission service charge – SPP does not charge generators for transmission service to bid into the day-ahead or real-time markets. CAWG members and SPP staff presented the HITT with a market transmission service charge concept that could be charged in various ways for certain generators with different types of services. These were referred to as HITT potential recommendation 1B-3.1 and 1B-5.[39] Among other considerations, the increase in expected market bid prices due to these charges – which would result in increased costs to customers and increased revenue for all generators clearing the market – led to the recommendation not being included in the final report.

Zonal allocation adjustment for energy and zonal access charge – CAWG members and a stakeholder presented the HITT with a concept of a zonal allocation adjustment for energy charge and a zonal access charge as a means to reallocate transmission costs based on exports and imports of energy between transmission pricing zones. The CAWG has discussed the zonal access charge, and it was discussed when SPP was contemplating the highway/byway cost allocation methodology. The zonal allocation adjustment charge was referred to as HITT potential recommendation 1B-4.[40]These recommendations were not included in the final report, in part due to the challenges of after-the-fact reallocation of transmission costs and the potential for market bidding price impacts.

[38] Appendix 4
[39] *Id.*
[40] *Id.*

ACTION PLAN

R = Reliability T = Transmission planning C = Cost Allocation

M = Market enhancements S=Strategic

Assignment/Task	Secondary group	Goal
Strategic Planning Committee		
Oversee & track HITT recommendation implementation	N/A	Until complete
S1. Add technological advances to SPP strategic plan	N/A	Next update
S2. Continue to include seams in SPP strategic plan	N/A	Ongoing
Regional State Committee/Cost Allocation Working Group		
C1: Decouple Schedule 9 & 11 pricing zones	RTWG	July 2020
C2: Establish byway facility cost allocation review process	ESWG/RTWG	July 2020
C4. Study cost allocation for transmission storage devices	TWG/MWG/RTWG	July 2020
Markets and Operations Policy Committee		
T1: ERIS modifications	MWG/CAWG/RSC	April 2020
Supply Adequacy Working Group		
T1: NRIS modifications	MWG/CAWG/RSC	April 2020
Market Working Group		
R3. Market enhancements: ramping	N/A	July 2019
R3. Market enhancements: fast-start	N/A	Jan. 2020
R3. Market enhancements: multi-day, longer-term	N/A	April 2020
M1. Implement congestion hedging improvements	RSC/CAWG	April 2020
M4. Study economic evaluations of reliability (markets)	TWG/RCWG	April 2020
R4. Implement uncertainty market product	ORWG	Oct. 2020
M2. Study offer requirements for variable resources	N/A	Jan. 2021

M3. Study mitigation of unduly low offers	N/A	Jan. 2021
R2. Implement ERS/ORS compensation model	ORWG	April 2021
Operating Reliability Working Group		
M4. Study economic evaluations of reliability (reliability)	TWG/RCWG	April 2020
Transmission Working Group		
T1: NRIS modifications: long-term deliverability	MWG/CAWG/RSC	April 2020
T2: Establish uniform Schedule 9 local planning criteria	RTWG/RCWG	Jan. 2020
T3: Implement new load addition modifications	RTWG/RCWG	April 2020
Regional Tariff Working Group		
C3: Eliminate Z2 revenue crediting	RSC/CAWG	Oct. 2019
Economic Studies Working Group		
T5: B/C ratio for economic projects	N/A	Jan. 2020
Staff		
R1. Study ERS and ORS	MWG/ORWG/SAWG	July 2020
R5. Study additional operational tools	ORWG/MWG	Ongoing
T4. Study three-phase GI process effectiveness	MOPC	Jan. 2021
S3. Storage white paper	RSC/MOPC	Jan. 2020

APPENDIX 1: TEAM MEMBERS AND MEETINGS

The HITT is a 16-member team comprised of representatives of the SPP board, RSC, membership and senior staff. Tom Kent served as chairman and Rob Janssen as vice chairman.

Type	Member
Board of Directors	Jim Eckelberger Graham Edwards
Regional State Committee	Shari Feist Albrecht, Kansas Corporation Commission Dennis Grennan, Nebraska Power Review Board
Investor-owned utilities	Richard Ross, American Electric Power Denise Buffington, Kansas City Power & Light Greg McAuley, Oklahoma Gas & Electric Bill Grant, Southwestern Public Service Co.
Cooperatives	Mike Wise, Golden Spread Electric Cooperative Mike Risan, Basin Electric Power Cooperative Al Tamimi, Sunflower Electric Power Corporation
Independent power producers	Rob Janssen, Dogwood Energy LLC Holly Carias, NextEra Energy Resources
Municipals	Dennis Florom, Lincoln Electric System
State agencies	Tom Kent, Nebraska Public Power District
Independent transmission companies	Brett Leopold, ITC Great Plains
Senior SPP staff	Paul Suskie, SPP staff

HITT Meetings	
April 24-25, 2018	Kansas City, MO
May 16, 2018	Dallas, TX
June 8, 2018	Dallas, TX
July 9, 2018	Dallas, TX
July 31-August 1, 2018	Omaha, NE
August 21-22, 2018	Dallas, TX
September 5, 2018	Dallas, TX
October 23, 2018	Dallas, TX
November 6, 2018	Dallas, TX
December 5, 2018	Dallas, TX
January 23-24, 2019	Dallas, TX
February 28-March 1, 2019	Dallas, TX
March 22, 2019	Web conference
April 3-4, 2019	Dallas, TX
April 17-18, 2019	Tulsa, OK
April 25, 2019	Dallas, TX
June 18, 2019	Web conference

APPENDIX 2: STAKEHOLDER PRESENTATIONS & COMMENTS

The following stakeholder presentations and comments are posted to SPP.org.

Stakeholder Presentations

- NextEra Energy: Day in the life of an interconnection customer
- Nebraska Public Power District: Cost allocation
- American Wind Energy Association: Transmission planning, cost allocation
- GridLiance: Cost allocation
- NextEra Energy: Storage
- Golden Spread Electric Cooperative: Deliverability model
- NextEra Energy: Essential Reliability Services and storage
- PJM: Generator deliverability
- Sunflower Electric Power Corporation: Host TO compensation
- Sunflower Electric Power Corporation: Wind, cost allocation
- Golden Spread Electric Cooperative: Ramping
- City Utilities of Springfield: Cost allocation
- Midwest Regulatory Consulting: Zonal access charge
- Southern Power: Market design
- Cost Allocation Working Group: 20% wind rule
- Cost Allocation Working Group: Progress update
- Omaha Public Power District: Load growth
- Cost Allocation Working Group: Cost allocation
- NextEra Energy: Long term congestion rights
- Cost Allocation Working Group: Zonal withdrawal rate

Stakeholder Comments

- Southern Power: Essential Reliability Services
- Nebraska Public Power District: Network service revenue allocations
- Sunflower Electric Power Corporation: Transmission planning and study processes
- East Texas Electric Cooperative/Northeast Texas Electric Cooperative: Transmission planning
- American Wind Energy Association: Transmission planning, seams, congestion hedging, cost allocation, changing technology, load growth
- Tenaska: Transmission planning
- Kansas Electric Power Cooperative: Resource adequacy, transmission planning, cost allocation, marketplace enhancements, load growth
- Golden Spread Electric Cooperative: Resource adequacy
- Western Area Power Administration: Impacts of recommendations on federal service exemption
- Midwest Energy: Transmission planning, congestion hedging, cost allocation, NRIS/ERIS, marketplace enhancements, load growth
- GridLiance: Cost allocation
- Omaha Public Power District: Marketplace enhancements
- Omaha Public Power District: Comments on all potential recommendations
- Omaha Public Power District: Generation interconnection
- XTO/Chevron: Cost allocation
- Nebraska Public Power District: Cost allocation
- Nebraska Public Power District: Marketplace enhancements
- Oklahoma Municipal Power Authority: Resource adequacy, new technologies, load growth
- East Texas Electric Cooperative: Marketplace enhancements
- East Texas Electric Cooperative: Cost allocation
- East Texas Electric Cooperative: Load growth

- City Utilities of Springfield: Transmission planning
- City Utilities of Springfield: Cost allocation
- Oklahoma Gas & Electric: Comments on all potential recommendations
- Westar: Transmission planning

APPENDIX 3: REQUESTS FOR INFORMATION

RFI presentations are posted to SPP.org.

#	Issue	HITT Issue	Summary	SME/ group providing info	Status
April 24, 2018 RFIs					
1	Rates by zone	1B	Provide a list of rates by zone, both legacy/pre-SPP and post-SPP.	Charles Locke/ Antoine Lucas	Complete
2	ERIS vs. NRIS	1A	Provide a presentation on what the GIITF is seeing, doing, etc. What is GIITF doing or not doing with ERIS and NRIS?	GIITF	Complete
3	SPP zonal maps	1B	Provide maps of SPP zones.	Ben Bright	Complete
4	BP zonal transfers	1B	Provide cost/transfer numbers for Balanced Portfolio upgrades & cost allocation.	Charles Locke	Complete
5	SPPT parking lot	N/A	Provide the parking lot issues from the SPPT.	Paul Suskie	Complete
April 25, 2018 RFIs					
6	ERIS/NRIS info	1A	Share the ERIS/NRIS presentation staff provided to SPP stakeholders.	Al Tamimi	Complete
7	GIs holding service	1A	Provide information on how GI requestors/customers are holding service that that is not being used.	Tessie Kentner	Complete
8	ERIS question	1A	Provide information about how "ERIS - as available" is impacting congestion. How is ERIS - as available impacting NRIS/firm service?	Antoine Lucas	Complete
9	GI queue info	1A	Provide how much wind generation in the GI queue has signed interconnection agreements.	Antoine Lucas	Complete
10	GI queue info	1A	How much solar is in the GI queue? (7.7 GW vs. 16 GW question)	SPP staff	Complete

11	AQ info	1A	Details about the AQ process. How many? Magnitude/load? How often are upgrades required? What is driving the AQ requests? Public vs. non-public information. How have the costs for AQ upgrades been allocated historically? What are the transparency issues?	Antoine Lucas	Complete
12	Sponsored upgrades	1A/1B	More education. Staff's RR 261.	Antoine Lucas	Complete
13	ERS and compensation	2	What are the Essential Reliability Services for keeping the lights on and how are they compensated in SPP?	HITT	Complete
14	Reserve zones	2	Has SPP studied/updated the six reserve zones?	CJ Brown/ Richard Dillon	Complete
15	Gas generators	2	What is the breakdown of gas by types? Provide info on capacity and energy, then deeper dive if needed at a later meeting.	CJ Brown/ Richard Dillon	Complete
16	Quick-starts	2	Provide information about quick-start compensation. FERC quick-start NOPR.	CJ Brown/ Richard Dillon	Complete
17	Load forecasting	2	What are SPP load forecasting errors?	CJ Brown/ Richard Dillon	Complete
18	Wind zonal info	2	Provide the minimum amount of wind by zones.	CJ Brown/ Richard Dillon	Complete
19	FERC orders/NOPR	2	Provide white papers on FERC 841, 844 & 845 (new GI NOPR).	Tessie Kentner	Complete
20	Operational tools	2	Identify potential future enhancements to operations tools, market products, etc.	CJ Brown	Continuous
21	Wind curtailment	2	Provide a summary of wind curtailment during high wind penetration periods. Provide info on capacity and energy, then deeper dive if needed at a later meeting.	CJ Brown/ Richard Dillon	Complete
22	MWG wind web conference	N/A	Provide information about upcoming SPP wind web conference.	SPP staff	Complete
23	Forbes article	N/A	Provide Forbes article on wind.	Tom Kent	Complete

24	Resource inventory	2	Provide resource inventory in the SPP footprint. Provide info on capacity and energy, then deeper dive if needed at a later meeting.	CJ Brown/ Richard Dillon	Complete
25	Solar/storage GIs	1A	Provide a presentation on solar/storage (packaged) GIs.	Future stakeholder presentation	Complete
May 16, 2018 RFIs					
26	GIITF	1A	Presentation on GIITF efforts.	Al Tamimi	Complete
27	Deliverability model	1A	What do other markets do for deliverability?	Mike Wise/ Richard Dillon	Complete
28	Congestion issues around too much low-cost generation	2	How does too much low-cost generation raise prices on the other side of a constraint? How often?	Staff/MMU	Complete
29	HITT topics and Schedule 9 impacts	1B	Do the topics HITT is assessing impact Schedule 9 costs? Increased O&M, decreased costs, etc. Sponsored upgrade costs to host TO zone.	Members with examples/ Charles Locke	Complete
30	Storage	1A/1B/2	Presentation on how storage can be used as a transmission asset to address HITT issues. FERC Order 841.	NextEra/ SPP staff	Complete
31	NERC white paper	N/A	Provide a copy of NERC Essential Reliability Resources report.	Staff	Complete
32	Inertia/ spinning mass	2	Provide a briefing on what facilities can provide inertia/spinning mass for the system.	Richard Dillon/ CJ Brown/ Gary Cate	Complete
33	Products needed by SPP market	2	Provide a briefing on the required products (essential services) needed by the SPP market.	Richard Dillon/CJ Brown	Complete
34	Disconnect between Transmission Service and ARR/TCRs	1A/2	Provide a briefing on the disconnects.	Richard Dillon	Complete
35	Essential Services	2	Ask stakeholders to provide their views on essential services needed/provided by market.	SPP stakeholders	Complete

36	Potential for load growth	3	Briefing on the potential for load growth. What is the potential for data centers, cryptocurrency, block chain technology, AQ studies, etc.?	OPPD	Complete
June 8, 2018 RFIs					
37	Glossary of terms	N/A	Provide a glossary of terms as the HITT proceeds that defines terms used during development of the report and recommendations to the board.	SPP staff/ Ben Bright	Ongoing
38	Safe harbor limit applicability to solar	1B	SPP has a safe harbor limit for wind (20% wind rule). Provide information on expanding to solar.	CAWG	Complete
39	Battery technology	1A/1B/2	Provide a briefing on battery storage technology and to what type of facility this technology can provide service. Generator, load, or transmission? (RFI 30)	NextEra/ SPP staff	Complete
40	GI studies correlate with ITP	1A	Provide a briefing on how SPP's GI and ITP processes correlate and synchronize.	Antoine Lucas	Complete
41	ERIS & impacts on local zone	1A	GIITF is looking at improvements. Continue to be briefed on GIITF's work on ERIS impacts on needed upgrades ERIS does not fund.	Al Tamimi & SPP staff	Ongoing
42	Costs paid by interconnection customers	1A, 1B	Review costs paid by interconnecting customers by host TOs. E.g., ongoing O&M costs related to network upgrades constructed but for the interconnecting customer (RFI 29).	SPP staff Charles Locke	Complete
43	Curtailment of ERIS resources	2	Provide a briefing on the curtailment of ERIS resources via the Integrated Marketplace and differences in curtailment, dispatchable, and non-dispatchable.	SPP staff – operations	Complete
44	NRIS resources - how meaningful?	1A/2	Presentation on value given to NRIS resources. What does FERC require? How to make NRIS valuable or drop NRIS?	SPP staff	Complete
45	NRIS & ERIS definitions	1A/2	Presentation on definitions of ERIS and NRIS and its meaning and application. Order 845	SPP staff	Complete

July 9, 2018 RFIs					
Data & FERC Orders					
46	Gas generator resource breakdown	2	How many gas generators are quick-start?	CJ Brown/ Gary Cate	Complete
47	Wind forecasting	2	Statistical spread on wind forecasting errors.	CJ Brown/ Gary Cate	Complete
48	Wind data	2	More specific data on wind. How often is wind zero, by percentages, zone and RTO footprint? Detailed analysis on the data/breakdown.	CJ Brown/ Gary Cate	Complete
49	Order 845	2	Can an electric storage facility request only to be a transmission solution, not a generator?	Tessie Kentner	Complete
50	Order 844 data	2	When can SPP provide the data required under Order 844 to the HITT?	Tessie Kentner	Complete
Hedging/Congestions					
51	Hedge challenges	2	When and how are hedges (ARRs, TCRs) not providing the hedge to have no impact in FTR holders?	SPP staff	Complete
52	Planning vs. market issues	1(a) & 2	Customer issues: Hedge problems (ERIS causing congestions), Attachment Z2, ERIS generators causing ITP upgrades). See #28.	Antoine Lucas/ CJ Brown	Complete
ERIS/NRIS related issues					
53	Economic DVER curtailment data	2	Where are the curtailments? Further breakdown of data by location. Breakdown by manual curtailment, economic signals, etc. How much self-commitment was on line when curtailment/economic signals were impacting wind?	Gary Cate/ CJ Brown	Complete
54	ERIS/NRIS data	1A	Data on number of requests that are duel (both ERIS/NRIS). Issues re: timing delays, costs, etc.	Antoine Lucas	Complete
55	ERIS/NRIS	1A	What are other regions/RTOs doing about ERIS/NRIS?	Al Tamimi	Complete
56	ERIS study parameter	1A	Questions about studies. Issues with percent vs. MW overload, generators in the models vs. generators not in the models.	Antoine Lucas	Complete
57	Planning models	1A	How much generation is not in certain models? Which models, type of generation, etc. Chart listing by study model.	Antoine Lucas	Complete

58	NRIS/ERIS/ firm service	1A	History about NRIS/ERIS/firm. Data on the numbers for each type of service in the SPP footprint.	Antoine Lucas	Complete
59	ERIS causing reliability upgrades in ITP planning process	1A	Staff analysis on ERIS resources causing reliability upgrades in ITP reliability planning processes.	Antoine Lucas	Complete
60	History of ERIS & ERIS	1A	Provide a memo on the history of ERIS and NRIS.	Tessie Kentner	Complete
July 31, 2018 RFIs					
61	Question in transmission planning/ service	1B	How is the determination of need calculated?	Charles Locke/ Antoine Lucas	Complete
62	Look at load ratio share of Schedule 11	1B	Calculate load ratio share of Schedule 11.	Charles Locke	Complete
August 1, 2018 RFIs					
63	Curtailment data	1B & 2	Provide the VER curtailment data chart with wind installation & new wind coming online.	CJ Brown/ Richard Dillon	Complete
64	ERIS/NRIS	1B & 2	How far can SPP go with FERC's approval regarding ERIS and NRIS service? Other RTOs?	Tessie Kentner	Complete
65	PJM ERIS/NRIS	1B	What has PJM implemented from ERIS/NRIS? How was it implemented? Has ERIS/NRIS in PJM been combined?	Richard Dillon	Complete
66	Planning zones	1B	How are zones created? (slide 8, RFI 54 presentation)	Antoine Lucas	Complete
67	ERIS data	1B	Breakdown of ERIS in-service generators (firm service, etc.) (slide 2, RFI 54 presentation)	Antoine Lucas	Complete
68	Sponsored upgrades	1B	Question about "need" tests to determine eligibility for credits.	Antoine Lucas	Complete
69	Compensation	1A/1B	Look at compensation for incumbent TOs.	Member companies	Complete

70	TWG flowgate	1A	TWG flowgate processes regarding reservation of transmission reliability margin on flowgates.	Antoine Lucas	Complete
71	SAWG presentation	1A	Presentation on SAWG efforts.	Brad Hans	Complete
August 21-22, 2018 RFIs					
72	Deliverability model	1A/1B	What other deliverability models exist?	Antione Lucas/ SPP staff	Complete
73	Wind-rich zones	1A/1B	Analysis of energy costs in wind-rich zones (RFI 79).	CJ Brown/ Richard Dillon	Complete
74	ERIS – NRIS upgrades	1A/1B	Any differences with ERIS and NRIS upgrades before getting firm service?	Antoine Lucas	Complete
75	Inertia	2	What studies have been done on inertia? (Hawaii/ERCOT/Ireland)?		Complete
76	Essential energy resources	2	What Essential Reliability Services markets exist?	Richard Dillon	Complete
77	Congestion rights	2	MMU presentation on congestion rights.	Greg Sorenson	Complete
78	Generation retirements	1A/1B	Staff presentation on proposed generation retirements process.	Antoine Lucas/CJ Brown/ Gary Cate	Complete
September 5, 2018 RFIs					
79	Wind rich zone data	1A/1B	More granular data and analysis on RFI 73.		Complete
80	Congestion rights/ARRs	2	More granular data and analysis from RFI MMU presentation on congestion rights (RFI 77, slide 8).	Greg Sorenson	Complete
October 23, 2018 RFIs					
81	MMU data on hours of non-market ramp	2	How much manually committed capacity does SPP see? Spikes, durations, range and distribution curve, etc.	MMU	Complete

82	Self-commitment & base load (load)	2	Data on self-committed units vs. base load (load)	MMU/Gary Cate	Complete
November 6, 2018 RFIs					
83	Black start	2	What requirements/regulations exist for black start services/obligations?	Richard Dillon	Complete
84	ERCOT	2	ERCOT's ERS service studies and research (RFI 76).	Richard Dillon	Complete
85	Highway/byway funding of upgrades justified by upgrades for generators with no TSRs	1A/1B	Better understanding of issue.	Antoine Lucas	Complete
December 4, 2018 RFIs					
86	AQ info	4	General information on AQ study projects.	Antoine Lucas	Complete
January 23-24, 2019 RFIs					
87	ERIS	1A/1B	Curtailment of ERIS – PJM methodology.	Richard Dillon	Complete
88	Congestion rights	2	Have other markets been implemented with non-market-based allocation of congestion rights?	Richard Dillon/ Tessie Kentner	Complete
89	Hedging	2	Who is not getting hedges? Counterflow?	Ty Mitchell	Complete
February 28-March 1, 2019 RFIs					
90	PJM transmission service	1A/1B	Provide information on how PJM sells transmission service (generation to market vs. market to load)	Richard Dillon/ Antoine Lucas/ Charles Locke	Complete

91	Order 2003/681	1A/1B	Provide information on how GI customers crediting mechanism – like MWTG proposal – could work in SPP.	Richard Dillon/ Antoine Lucas	Complete
92	Maps of TPZ zonal consolidation options	1B	Provide maps of potential consolidated transmission pricing zones (TPZ).	Ben Bright	Complete
93	SPP maps of energy prices	1A/1B/2	Energy transmission pricing maps. TPZ pricing maps.	Ben Bright/Greg Sorenson	Complete
94	Zonal cost allocation adjustments for energy	1B	Provide example of how this process would work.	John Krajewski/ CAWG	Complete

APPENDIX 4: INTERDEPENDENCIES MATRIX

R - Reliability Recommendations **M** - Market Enhancement Recommendations
T - Transmission Planning & Cost Allocation Recommendations
✔ Contained in staff's straw proposal
☐ Box indicates recommendations need more discussion ■ Box indicates HITT consensus

1A Resource Adequacy (RA)	1A Transmission Planning	1A Congestion Rights (CR)	1B TPZ & Schedule 11-Zonal	1B TO Comp & Upgrades	2 Market & Other Products	3 Load Growth & AQ
R **1A-1.1** ✔ *Keep Existing RA Rules*	T **1A-2** ✔ *Increase Value for NRIS Service (Deliverability) & change thresholds for ERIS Service*	M **1A-7.1** ✔ **(Option 1)** *CR Market w/ Counter-flow Optimization Using Excess Auction $s.*	T **1B-1** ✔ *Decouple Sch. 9 & 11 TPZ and potentially est. larger Sch. 11 TPZ*	**1B-3.1** *Establish Market Transmission Service (MTS) Charge*	R **2-1** ✔ *Continue: 1) fast-start; 2) ramping; & 3) multi-day market efforts*	T **3-1** ✔ Trans-parency & Limited to New Loads
R **1A-1.2** ✔ *Determine ERS Req'ts*	**1A-3** *Econ. & reliability upgrades w/non-firm resources*	~~**1A-7.2** **(Option 2)** *Move towards elimination of tradable rights.*~~	**1B-2.1** **(Option 1)** *Change Byway Cost Allocation to 2/3-1/3*	T **1B-JE Proposal** ✔ *Establish Byway Cost Allocation Review Process*	R **2-2** ✔ *Identify ERS requirements and appropriate compensation*	T **3-2** ✔ Speed
Others?	**1A-4** *Modify economic planning criteria*	**Others?**	**1B-2.2** **(Option 2)** *Change Byway Cost Allocation to 50/50*	**1B-4** *Zonal Cost Allocation Adjustments for Energy*	R **2-3** ✔ *Implement an uncertainty product*	
	T **1A-5** ✔ *Est. local TPZ planning criteria and processes*		T **1B-1 & 2** ✔ *Any existing cost allocation changes phased in 5-10 years*	**1B-5** *MTS Charge for TO Comp. for GI O&M & Sch. 9 Costs?*	M **2-4 (MMU)** ✔ *Evaluate generator offer req'ts for safeguards for negative prices*	
	T **1A-6** ✔ *Evaluate New 3-Phase Process 18 Months after implementation*		**Others?**	T **1B-6** ✔ *Evaluate potential revenue requirement & recovery methodology for TSD.*	M **2-5 (MMU)** ✔ *Evaluate VER offer at a specific level in the day-ahead market*	
	Others?			**1B-7** *Establish cost allocation rules for solar similar to wind*	M **2-6** ✔ *Evaluate more advanced economic evaluation of reliability*	
				T **1B-8** ✔ *Eliminate & Replace Z2 Payment Obligations Prospectively*	R **2-7** ✔ *Operations Tools*	
				Others?	**Others?**	

APPENDIX 5: GLOSSARY

Term	Acronym	Definition
Advanced economic evaluations		Philosophy of including economic forecasting in SPP processes, i.e. outage coordination and multi-day reliability unit commitment.
Aggregate studies		A facilities study performed under the aggregate transmission service study process described in Attachment Z1.
Annual transmission revenue requirement	ATRR	The annual transmission revenue requirement is the amount of revenue allocated to each zone and may consist of zonal ATRR, per Schedule 9 of the tariff, or base plan zonal or base plan regional ATRR, per Schedule 11.
ARR excess revenues		Revenues from TCR auctions in excess of the payment for ARRs and TCRs sold in an auction paid per Attachment AE, Section 8.7.4.
Attachment AQ		SPP OATT delivery point addition process is used when it becomes necessary or desirable to make changes in delivery point facilities, to upgrade, retire, replace or establish a new delivery point, including metering or other facilities at such location.
Attachment J		SPP OATT recovery of costs associated with new facilities
Attachment O		SPP OATT transmission planning process
Attachment V		SPP OATT generator interconnection procedures
Attachment Z2		SPP OATT compensation for upgrade sponsors

Auction revenue rights	ARR	A right, awarded during the annual ARR allocation process and the monthly ARR allocation process, which entitles the holder to a share of the auction revenues generated in the applicable TCR auction(s) and entitles the holder to self-convert the ARR to a TCR.
Available transfer capability	ATC	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Base plan zonal charge		Zonal component of the charge assessed by the Transmission Provider in accordance with Schedule 11 to recover the revenue requirement of facilities classified as base plan upgrades.
Battery storage		Storing energy using a battery technology, to be used at a later date, ensuring a steady flow of power even when the main grid is down.
Benefit/cost ratio	B/C	An indicator, used in benefit/cost analysis, that attempts to summarize the overall value for money of a project or proposal.
Bulk Electric System	BES	All transmission elements operated at 100 kV or higher and real power and reactive power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy and can be modified by certain NERC inclusions/exclusions.
Capacity accreditation		Capacity accreditation is the capacity, by resource, submitted to meet the resource adequacy requirement that meets both the testing and performance requirements. As per SPP Planning Criteria Section 7.1.5.2(2), "The total seasonal net capability rating shall be that available regularly to satisfy the daily load patterns of the member and shall be available for a minimum of four continuous hours taking into account possible fuel curtailments and thermal limits."
Congestion hedging		A strategy used to reduce the risk of adverse price movements in an asset due to transmission overcrowding.

Consolidated Balancing Authority	CBA	A single responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority area and supports interconnection frequency in real-time.
Conventional generation		Thermal energy sources using oil, gas and coal. Includes hydropower generation by a conventional way of using dams on rivers.
Cost allocation methodology		Method used to allocate the ATRR among SPP pricing zones; may include traditional base plan funded methodology using mega-watt mile or highway/byway methodology based on an upgrade's voltage.
Cost Allocation Working Group	CAWG	The CAWG reports to the RSC and assists the RSC in addressing matters for which the RSC has primary responsibility as defined in Section 7.2 of the SPP Bylaws.
Counterflow		Adjustments to firm ATC as determined by the Transmission Provider and specified in its available transfer capability implementation document.
Day-ahead (energy) market		The financially binding market for energy and operating reserve that is conducted on the day prior to the operating day (as defined in section 1 of the tariff).
Delivery point		A location that the Transmission Provider specifies on its transmission system where an interchange transaction leaves or a load serving entity receives its energy.
Designated resource	DR	Any designated generation resource owned, purchased, or leased by a TC to serve load in the SPP region. Designated resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the TC's load on a non-interruptible basis (as defined in Section 1 of the tariff).

Directly-assigned upgrade costs	DAUC	An eligible customer's share of the cost of a service upgrade or network upgrade, or a project sponsor's share of the cost of a sponsored upgrade, determined in accordance with Attachments J, V and Z1, which includes any network upgrade costs that are (i) directly assigned to an eligible customer for a service upgrade in excess of the normally applicable transmission access charges for the associated transmission service; (ii) directly assigned to an eligible customer that are in excess of the safe harbor cost limit for service upgrades associated with new or changed designated resource; (iii) directly assigned to a project sponsor for a sponsored upgrade; or (iv) directly assigned to a generation interconnection customer resulting from a request for generation interconnection.
Distribution system		The system that delivers electricity over medium- and low-voltage lines to electricity consumers.
Dynamic line ratings		An electric power transmission operation philosophy aiming at maximizing load, when environmental conditions allow it, without compromising safety.
Economic Studies Working Group	ESWG	The ESWG advises and assists SPP staff, working groups and task forces in the development and evaluation principles for economic studies. The ESWG ensures the proper regional data sets and economic methodology, parameters and metrics are used in these studies and for ensuring SPP staff annually update stakeholders' data.
Economic requirement		Upgrades or other investments, per FERC Order 890, that reduce the overall cost of serving native load.
Energy Imbalance Service	EIS	The Energy Imbalance Services Market was SPP's market before the Integrated Marketplace.
Energy resource interconnection service	ERIS	Interconnection service that allows the interconnection customer to connect its generating facility to the transmission system to be eligible to deliver the generating facility's electric output using the existing firm or non-firm capacity of the transmission system

		on an as available basis. ERIS in and of itself does not convey transmission service.
Energy storage resources		Enables a lower-cost generating source to produce electricity at a different point in time to be stored and then used to meet times of peak demand (e.g., batteries).
Essential Reliability Services	ERS	The frequency response, generation ramping and voltage support needed to reliably operate particular areas, Balancing Areas or interconnections.
Fast-start resource		Energy resource that can start up in 10 minutes or less, has a minimum run time of one hour or less, and has submitted an economic energy offer to a market run by an RTO or ISO (FERC defined).
Federal Energy Regulatory Commission	FERC	Quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates and gas pipeline certification.
Frequently constrained areas		An electrical area identified by the SPP market monitoring unit that is defined by one or more binding transmission constraints or binding reserve zone constraints that are expected to be binding for at least 500 hours during a given 12-month period and within which one or more suppliers are pivotal.
Fuel assurance		Refers to the cost and delivery of fuel being known as part of commitment.
Fuel mix		The mix of fuels to generate electricity; includes natural gas, coal, wind, hydro, nuclear, solar and other.
Generating resources		Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s) or other prime mover(s) operated together to produce electric power.

Generation interconnection	GI	A generation interconnection request is an interconnection customer's request to interconnect a new generating facility, or to increase the capacity of, or make a material modification to the operating characteristics of, an existing generating facility that is interconnected with the transmission system.
Generation Interconnection Improvement Task Force	GIITF	SPP task force formed to identify improvements in the transmission study process to address the extreme amounts of new generation in the SPP GI queue and to address new requirements arising from new FERC proposed rulemaking initiatives.
Generation interconnection queue	GI queue	A Transmission Provider separately maintained queue for valid generation interconnection requests.
Generator		The part of the power plant that converts the mechanical power of a spinning shaft to electricity; may be used synonymously with the term "power plant."
Gigawatt	GW	1,000 megawatts (MW)
Hedge congestion		A strategy used to reduce the risk of adverse price movements in an asset due to transmission overcrowding.
Highway/byway cost allocation methodology		A cost allocation methodology approved by FERC and effective for all base plan upgrades for which SPP issues an NTC after June 19, 2010. For new transmission upgrades between 100 kV and 300 kV, SPP allocates 1/3 of the costs to the region and 2/3 to local transmission pricing zones.
Holistic Integrated Tariff Team	HITT	The Holistic Integrated Tariff Team was created by the SPP Board of Directors and Members Committee on March 13, 2018, to review the many issues challenging the SPP region including: SPP's transmission planning and study processes, transmission cost allocation issues, Integrated Marketplace impacts, and disconnects or potential synergies between transmission planning and real-time reliability and economic operations, along with additional areas or issues related to its scope.

Host Transmission Owner		Owner of transmission facilities to which network customer's network load is physically connected (Attachment G).
Incremental long-term congestion rights	ILTCRs	An instrument that entitles an upgrade sponsor to a TCR that results from the incremental ATC created from the portion of an upgrade for which there is a directly-assigned upgrade cost, which is awarded during the Transmission Provider’s annual LTCR allocation process.
Independent system operator	ISO	An independent entity regulated by the federal government that coordinates regional transmission in a non-discriminatory manner and ensures the safety and reliability of the electric system.
Instantaneous wind-serving load peak		The real time maximum amount of wind production relative to load on the system.
Integrated Marketplace		SPP’s day-ahead market, real-time balancing market, the transmission congestion rights market and reliability unit commitment processes.
Integrated Transmission Planning	ITP	The Integrated Transmission Planning process is an annual planning cycle that assesses near- and long-term economic and reliability transmission needs. The ITP produces a 10-year transmission expansion plan each year, combining near-term, 10-year, and NERC transmission planning (TPL-001-4) assessments into one study. The 20-year assessment is performed once every five years unless otherwise directed by the SPP board of directors.
Intermittent generators		In power plants, a generator whose output depends on factor(s) that cannot be controlled by the power generator because they utilize intermittent resources such as solar energy or wind.
Inverter-based resources	IBR	Resources that connect to the grid through power electronics that convert direct current to the alternating current used on most of the country's power system, such as wind, solar and battery storage

Load growth		An electric load (or demand) growth is the increased power requirement of any device or equipment that converts electric energy into light, heat or mechanical energy.
Load responsible entity	LRE	An asset owner with registered load in the Integrated Marketplace.
Load serving entity	LSE	A distribution utility or an electric utility that has a service obligation, where a service obligation, as defined in Section 217(a) of the Federal Power Act, means a requirement applicable to, or the exercise of authority granted to, an electric utility under federal, state, or local law or under long-term contracts to provide electric service to end-users or to a distribution utility.
Load		The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the consumers' energy-consuming equipment.
Local planning criteria		Individual TOs within the SPP region may develop company-specific planning criteria that, at a minimum, conform to the NERC reliability standards and SPP Criteria.
Locational marginal pricing	LMP	The market-clearing price for energy at a given price node equivalent to the marginal cost of serving demand at the price node while meeting SPP operating reserve requirements.
Long-term congestion right	LTCR	An instrument that entitles an upgrade sponsor to a TCR over a period of more than one year, which is awarded during the Transmission Provider's annual long-term congestion rights allocation process.
Market Monitoring Unit	MMU	SPP's market monitor is responsible for monitoring SPP's markets and services. The group's primary purpose is to ensure SPP's markets are efficient and fair. The market monitor is responsible for detecting structural problems and design flaws in the operating rules, standards, procedures and practices in SPP markets. It assesses the mechanism that governs the transmission markets independently or as a result of complaints or requests for an inquiry.

Market Working Group	MWG	Responsible for developing and coordinating changes necessary to support any SPP-administered wholesale market(s), including energy, congestion management and market monitoring.
Markets and Operations Policy Committee	MOPC	The MOPC is responsible, through its designated organizational groups, for developing and recommending policies and procedures related to the technical operations for the company.
Mitigate cost shifts		Regulatory concept to minimize large cost increases or decreases of new cost or rate changes. This concept includes the phasing in of such cost or rate changes.
Multi-day longer-term market product		Concept of market solutions with settlement for periods greater than day-ahead.
Negative prices		LMP that is less than zero. When the LMP is less than zero, injections must pay SPP, and withdrawals are paid by SPP.
Network integration transmission service	NITS	Transmission service provided under Part III of the tariff.
Network resource interconnection service	NRIS	Interconnection Service that allows the interconnection customer to integrate its generating facility with the transmission system in a manner comparable to that in which the TO integrates its generating facilities to serve native load customers as a network resource.
North American Electric Reliability Corporation	NERC	A non-profit organization whose mission is to ensure that the Bulk Electric System in North America is reliable, adequate and secure.
Notification to construct	NTC	A written notice from the Transmission Provider 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.
Open Access Transmission Tariff	OATT or tariff	FERC governs the rates, terms and conditions of SPP through the SPP Open Access Transmission Tariff.

Operating Reliability Working Group	ORWG	The ORWG develops, maintains, and coordinates the implementation of policies related to the reliable and secure operation of the BES within the SPP Reliability Coordinator, BA, and SPP Reserve Sharing Group (RSG) footprints.
Other Reliability Services	ORS	Additional services needed to reliably operate particular areas, Balancing Areas, or interconnections, i.e. system inertia, uncertainty product.
Outage coordination		SPP's outage coordinators work hand-in-hand with our members to manage the impacts of forced outages, coordinate future maintenance and system expansion, and make smart decisions that benefit the region.
Planning queue		The amount of electric generating resources in SPP's planning processes.
Price convergence		Movement of the price of a futures contract towards the spot price of the underlying cash commodity as the delivery date approaches. Two prices must converge, or traders could exploit any price difference to make a risk-free profit.
Production tax credits		The federal renewable electricity production tax credit (PTC) is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources (and sold by the taxpayer to an unrelated person during the taxable year).
Public policy requirement		Requirements established by local, state or federal laws or regulations, including duly enacted statutes or regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level.
Ramping capability		Sustained rate of change of generator output, in megawatts per minute.
Real-time average market prices		Average of north and south hub prices of all real-time intervals. (Integrated Marketplace post-March 2014 and EIS market pre-March 2014.)

Regional generation mix		SPP generation mix percentage by fuel type.
Regional State Committee	RSC	A voluntary organization comprised of one designated commissioner from each participating state regulatory commission having jurisdiction over an SPP member, established to collectively provide both direction and input on all matters pertinent to the participation of SPP members pursuant to the SPP Bylaws.
Regional Tariff Working Group	RTWG	The RTWG is responsible for the development, recommendation, implementation and oversight of SPP's Open Access Transmission Tariff.
Regional Transmission Organization	RTO	An organization FERC has deemed to meet certain criteria, including independence and scope. RTOs are mandated by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity.
Region-wide charge		Regional component of the charge assessed by the Transmission Provider in accordance with Schedule 11 to recover the region-wide ATRR.
Regulation service		An amount of reserve responsive to automatic generation control, which is sufficient to provide normal regulating margin.
Reliability Compliance Working Group	RCWG	The RCWG provides guidance to SPP on policy issues related to reliability compliance activities at the federal and regional level.
Reliability requirement		The electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability may be measured by the frequency, duration and magnitude of adverse effects on consumer services.

Renewables		A source of energy that is not depleted by use, such as water, wind or solar power.
Requests for information	RFI	Standard process to collect written information, primarily to aid in deciding next steps.
Resource adequacy		Maintaining appropriate planning reserves such that the Transmission Provider will have sufficient capacity to serve the SPP BA area's peak demand.
Resource mix		How the final energy consumption in a given geographical region breaks down by primary energy source.
Schedule 11		Base plan zonal charge and region-wide charge, as set forth in the OATT.
Schedule 11 transmission pricing zones		The geographic area of the facilities of a TO or a specific combination of TOs as specified in Schedule 11.
Schedule 9 transmission pricing zone		The geographic area of the facilities of a TO or a specific combination of TOs as specified in Schedule 9.
Solar energy		Energy from the sun that is converted into thermal or electrical energy.
Solar generation		Electricity derived from radiation from the sun that is directly or indirectly converted to electrical energy.
SPP region		The geographic area of the SPP transmission system.
SPP-directed transmission		Transmission upgrades directed by SPP per its authority as a FERC-recognized RTO.

Storage		An energy storage device used for storing electric energy when needed and releasing it when required.
Strategic Planning Committee	SPC	The SPC is responsible for developing and recommending SPP’s strategic direction.
Sub-regional		A smaller region within the SPP region.
Supply Adequacy Working Group	SAWG	The SAWG is responsible for developing and implementing SPP’s supply adequacy requirements/methodologies and policies/processes to ensure reliable capacity supply to meet demand.
Synergistic Planning Project Team	SPPT	This group was formed in 2009 to search for opportunities to improve SPP's transmission planning processes and cost allocation approaches and review strategic issues concerning transmission service, generator interconnection, extra high voltage inter-regional transmission and wind integration.
Three-phase generator interconnection study process		A revision to the current GI process to implement a new streamlined, simplified GI process to be studied in three stages.
Topology optimization		An outage planning philosophy aimed at maximizing economics in serving load, when transmission reconfiguration conditions allow it, without compromising reliability.
Transmission assets		A grouping of assets related to transmittal of electricity. The equipment necessary to move energy source from its point of generation to its point of distribution or consumption.
Transmission Congestion Rights	TCR	A right that entitles the holder to be compensated or charged for congestion in the day-ahead market between two settlement locations.

Transmission Customer	TC	Any eligible customer, or its designated agent, that (i) executes a service agreement, or (ii) requests in writing that the Transmission Provider file with FERC, a proposed unexecuted service agreement to receive transmission service under Part II of the tariff. This term is used in the Part I common service provisions to include customers receiving transmission service under Part II or Part III of the tariff.
Transmission Owner	TO	Each member of SPP that has executed an SPP membership agreement as a TO and therefore has the obligation to construct, own, operate, and maintain transmission facilities as directed by the Transmission Provider and: (i) whose tariff facilities (in whole or in part) make up the transmission system; or (ii) who has accepted an NTC but does not yet own transmission facilities under SPP's functional control. Those TOs that are not regulated by FERC shall not become subject to FERC regulation by virtue of their status of TOs under the tariff; provided, however, that service over their facilities classified as transmission and covered by the tariff shall be subject to FERC regulation.
Transmission pricing zones		The geographic area of the facilities of a TO or a specific combination of TOs as specified in Schedules 7, 8, 9 and 11.
Transmission system		The facilities used by the Transmission Provider to provide transmission service under Parts II, III and IV of the tariff.
Transmission Working Group	TWG	The TWG is responsible for planning criteria to evaluate transmission additions, seasonal ATC calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations.
Uncertainty product		Ancillary service product designed to meet the longer term (30 minutes, 1 hour, etc.) balancing needs of a BA due to higher penetrations of variable generation.
Utility-scale resource		Generates power and feeds the grid.

Variable energy resource	VER	A device for the production of electricity that is characterized by an energy source that is renewable, cannot be stored by the facility owner or operator, and has variability that is beyond the control of the facility owner or operator.
Wholesale electricity prices		The price at which electricity is sold in the wholesale market by energy producers and energy retailers.
Wind generating facilities		A power plant using wind turbines to generate electricity.
Wind penetration		The fraction of energy produced by wind compared with the total generation.

OGE Energy Corp.

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July 18, 2019

Dear SPP Board of Directors and Regional State Committee Members:

Oklahoma Gas and Electric Company (OG&E) submits these comments for your consideration as you review the recommendations included in the final report of the Holistic Integrated Tariff Team (HITT). As a member of the HITT, OG&E appreciates the significant effort expended by all participants including HITT members, members of the SPP Board of Directors, Regional State Committee members, Cost Allocation Working Group members, SPP stakeholders not directly part of the HITT, as well as SPP Staff. In addition, the leadership provided by the Chair, Tom Kent of NPPD, Vice Chair, Rob Janssen of Dogwood Energy and Staff Secretary, Paul Suskie contributed to the ability of the team to achieve many of its stated objectives. OG&E appreciates the opportunity to participate directly and is encouraged by the significant progress made on so many important topics including generation interconnection study impacts, elimination of the Z2 credit process for prospective projects, congestion hedging, and benefit-to-cost ratio considerations related to economic projects. Nevertheless, because several of the report's recommendations will have potentially negative and harmful effects on end-use customers, OG&E is unable to support all of the final report's recommendations. In an effort to avoid these potentially negative impacts, OG&E is providing these comments to clarify its concerns.

COST ALLOCATION

First and foremost, the final report's Cost Allocation recommendations are misplaced. During the HITT process, Sunflower Electric and Mid-Kansas, as well as others, raised concerns about the number of Byway projects required in response to the transmission system demands imposed by uncommitted generation. Those concerns are valid. No load-serving member or its customers should be burdened with costs caused by new uncommitted generation in cases where those customers will receive little or no benefit from that generation. Unfortunately, the final report's recommendations do not completely resolve those concerns. While the report does recommend modifying the interconnection study procedures, OG&E believes the recommendations do not go far enough. Instead, the final report stops short of requiring full generation developer responsibility for Byway projects caused by uncommented generation additions.

SPP's current cost allocation rules are premised on the idea that a local zone receives a significant benefit whenever a resource connects within that zone. If the resource's output necessitates new transmission upgrades, then the local zone is allocated two-thirds of the costs of those upgrades in the case of Byway facilities, and a regional Load Ratio Share (LRS) of those costs in the case of Highway projects. This presumption of zonal benefits breaks down in the case of uncommitted generating resources. When an uncommitted generating resource interconnects with transmission facilities in an SPP zone, that resource has no commitment to the load in that zone. The resource is free to enter a contract committing its output to loads located outside the zone, or even outside the SPP region. When that happens, the vast majority of the benefits associated with the resource are provided to loads located outside the zone whereas the customers within the zone remain burdened with the costs. Clearly, in the case of an uncommitted generating resource, the local zonal transmission customers are not causing the new cost to be incurred. This mismatch between who pays the costs of transmission upgrades required to accommodate an uncommitted generating resource's interconnection and who causes and benefits from the interconnection of that resource is a fundamental flaw in the SPP Tariff's cost allocation rules.

Rather than changing SPP's cost allocation rules to socialize the cost of such projects to the entire region, each uncommitted generating resource should bear the cost responsibility for the transmission upgrades necessary to accommodate its participation in the market. This approach aligns cost responsibility with cost causation and avoids the mismatch that exists under the current rules, which saddles end-use customers with costs for assets from which they receive little or no benefit.

The HITT did make progress in this regard by recommending changes to the Generation Interconnection (GI) process, particularly related to Energy Resource Interconnection Study (ERIS) elections. OG&E agrees that the recommendations in that subject area are needed improvements and supports them but believes that the impact factor thresholds should be lower than recommended in the report, particularly in zones that already experience excess generation on a regular basis. OG&E urges SPP to approve changes to the ERIS impact factors and encourages the working groups and the SPP Board of Directors to consider even tighter thresholds for ERIS studies. The results of the proposed changes to impact factors can be evaluated for several years and, if the results indicate additional SPP Tariff modifications are needed to accurately match cost responsibility with cost causation, sufficient data would be available to develop further changes.

ZONAL CONSOLIDATION

As stated in its comments to the HITT in January 2019, OG&E remains unconvinced that consolidation of zones for purposes of Schedule 11 charges is warranted. Within the existing zonal constructs, there are variations in Schedule 11 rates. These variations have always been part of the FERC-approved methodology for addressing costs associated with transmission used to serve areas with differences in load, geography and infrastructure. The fact that some zones are rural, suburban or urban, with varying load densities is not an anomaly. It is simply the nature of the electric utility business. In a perfect world, all customers in all locations would experience the same, low-cost rates as the most cost-effective locations. However, in the real world in which we operate, the fact is that it costs more to serve customers in some areas than others.

While geography and load density can play a significant role in the cost to serve customers, it is also true that some entities have done a better job of transmission planning than others. Arbitrarily shifting costs from higher-cost zones to lower-cost zones does nothing but provide a subsidy to those areas that have failed to develop their transmission systems in a cost-effective manner—a subsidy that will be paid for by the transmission owners that have successfully provided lower-cost service to their own end-use customers.

According to the HITT recommendations, load-serving utilities that have planned, built, and operated within the applicable FERC-approved tariffs and associated criteria will be penalized for having successfully applied the criteria for the benefit of the customers within their respective zones. OG&E finds no value in such action. These penalties undermine the value of the sometimes difficult and complex cost-effective planning decisions that entities such as OG&E have made over the years. The customers in lower-cost zones should not be burdened with the higher costs that resulted from less effective planning decisions made by others, or from geographical differences that are an inherent part of our industry. Instead, end-use customers in lower-cost zones such as the OKGE zone should be allowed to continue to enjoy the low rates afforded by the efforts and decisions made on their behalf by the transmission owners within that zone.

Over the last several years, various parties have made calls for a postage-stamp rate within SPP. OG&E believes that the zonal consolidation recommendations by the HITT are merely an attempt to "tip-toe" toward such a postage-stamp approach. As an entity strongly opposed to postage-stamp rates, OG&E cannot support such action. A shift to postage-stamp rates should not be disguised as "zonal consolidation." Rather, before considering even a partial move towards postage-stamp rates, the proponents of postage-stamp rates should submit their proposal in a transparent way, which can then be fully evaluated and debated in SPP's public stakeholder process.

TOO MANY CHANGES PROPOSED AT ONE TIME

OG&E is concerned about the sheer number of changes recommended by the HITT in a single report. Because so many of the recommendations are interrelated, no one, including SPP Staff, HITT members, or other stakeholders, can predict the impacts of all of these recommendations on a "holistic" basis. Attempting so many changes in such a short time frame is analogous to a plant performance engineer attempting to improve performance deficiencies by changing more than 20 operating parameters at once and attempting to determine which were actually beneficial, which were unnecessary, or which had negative impacts. The final report's recommendations should be considered in a more deliberate way that allows for greater transparency regarding the potential benefits of each and a meaningful opportunity to evaluate the impacts of each change.

CONCLUSION

In conclusion, OG&E supports the majority of the individual recommendations contained within the final HITT report and acknowledges the successes achieved on many issues. The potential significance of the deficiencies outlined above, however, was enough to cause us to abstain from the final vote.

We appreciate your consideration of our concerns and look forward to discussing them with you further.

Kind Regards,

--Greg McAuley

Director – RTO Policy & Development
Oklahoma Gas and Electric Company
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Office: 405-553-3815

2019 Integrated Transmission Plan Update

Lanny Nickell
Board/RSC Joint Meeting

July 2019

Integrated Transmission Plan goals

- Deliver energy reliably
- Deliver energy economically
- Facilitate public policy objectives
- Optimize benefits to end-use customers

Key study drivers

Increased wind

Up to 30 GW in future 2, year 10

Fossil fuel retirements

60 years or older

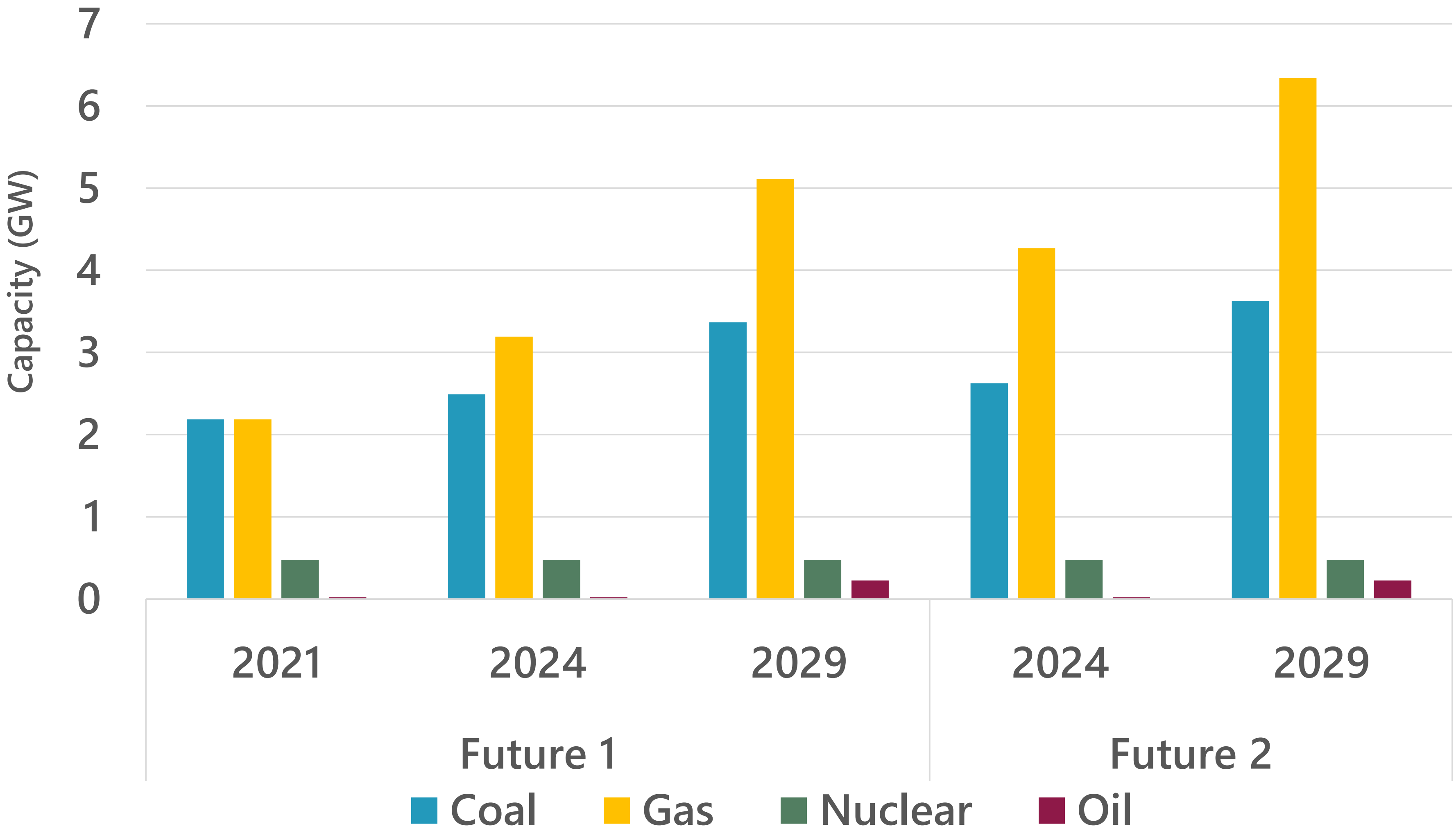
Added solar

Up to 7 GW in future 2, year 10

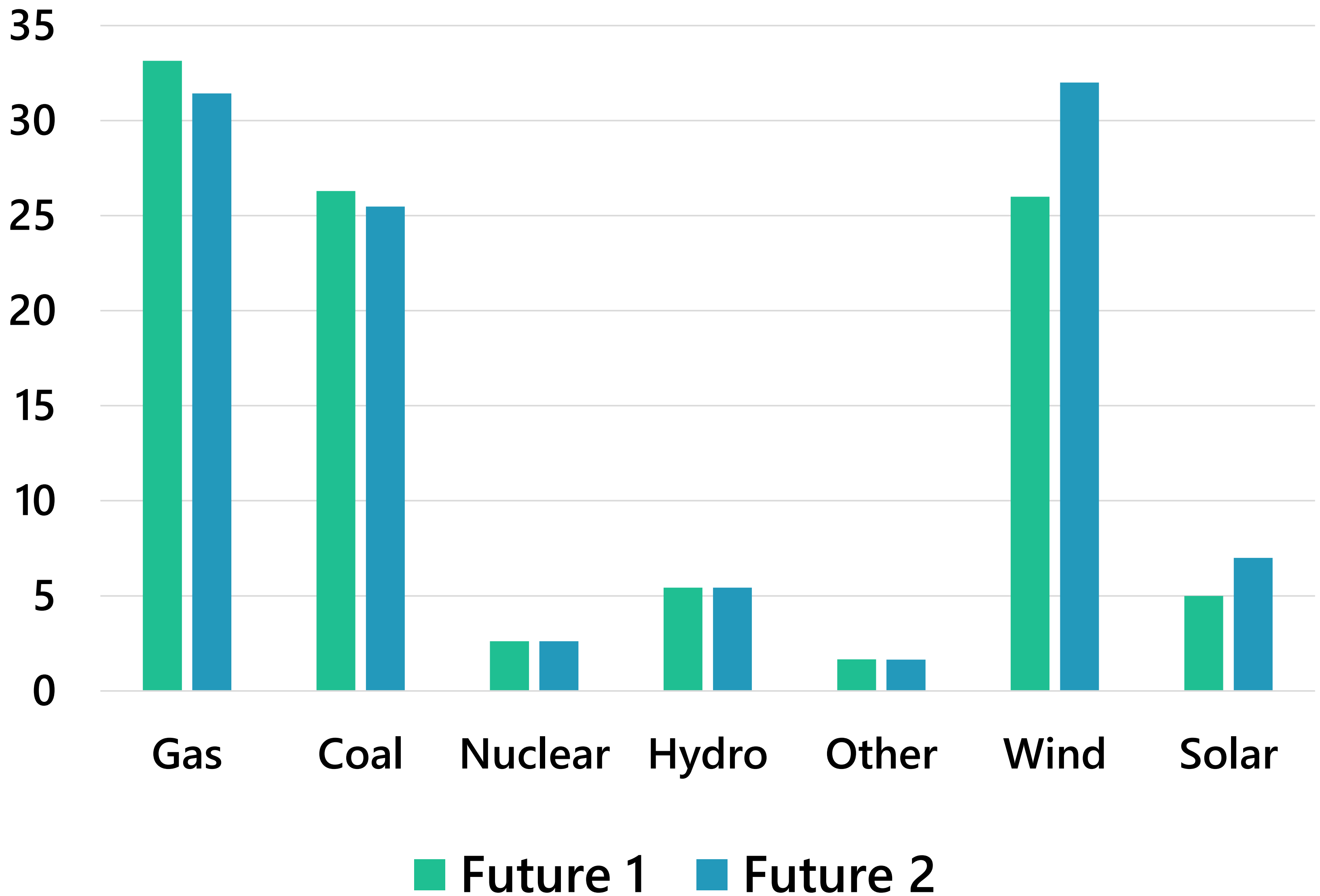
Energy growth

Increase due to electric vehicles in future 2

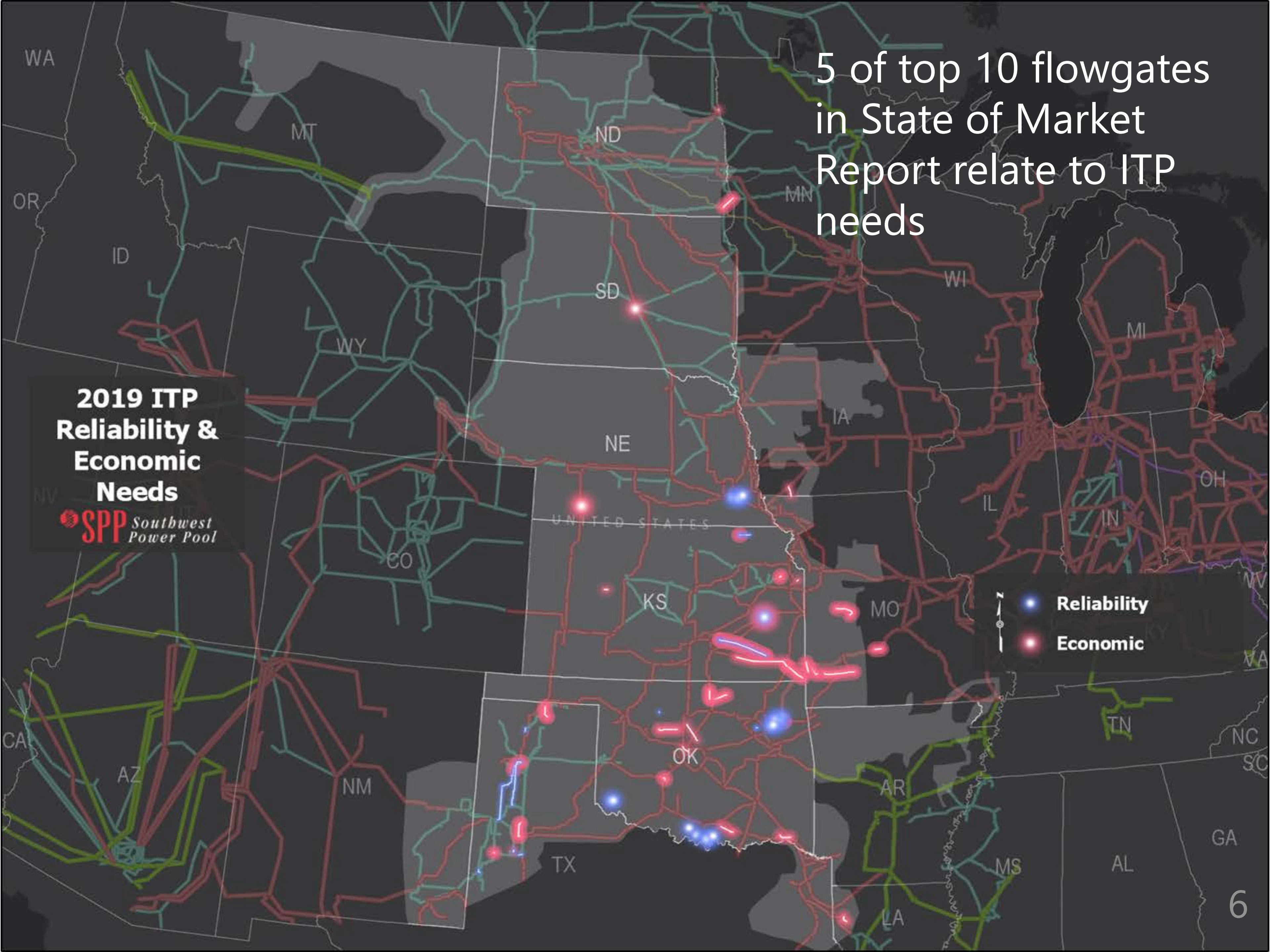
Conventional generation retirements



2029 nameplate capacity by type (GW)

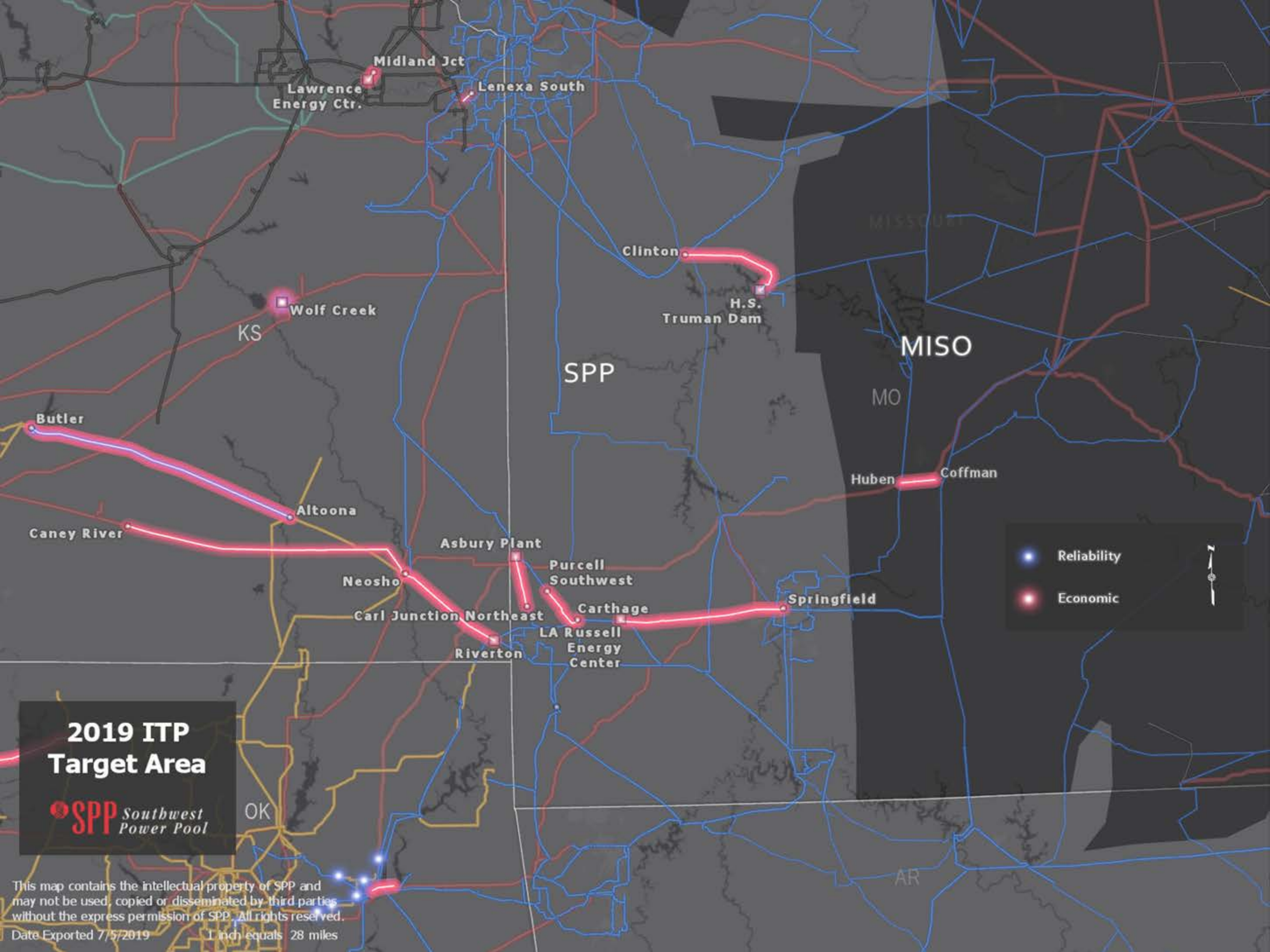


5 of top 10 flowgates in State of Market Report relate to ITP needs



Target area analysis addresses:

- Overlapping top-ranked economic and reliability needs
- Seams impacts
- Integrated Marketplace congestion
- Transient stability concerns
- Operational issues


Midland Jct
Lawrence Energy Ctr.
Lenexa South
Clinton
H.S. Truman Dam
Wolf Creek
KS
SPP
MISSOURI
MISO
MO
Butler
Altoona
Caney River
Asbury Plant
Purcell Southwest
Neosho
Carl Junction Northeast
Carthage
Springfield
LA Russell Energy Center
Riverton
Huben
Coffman
Reliability
Economic
2019 ITP Target Area
SPP Southwest Power Pool
OK
AR
This map contains the intellectual property of SPP and may not be used, copied or disseminated by third parties without the express permission of SPP. All rights reserved.
Date Exported 7/5/2019
1 inch equals 28 miles

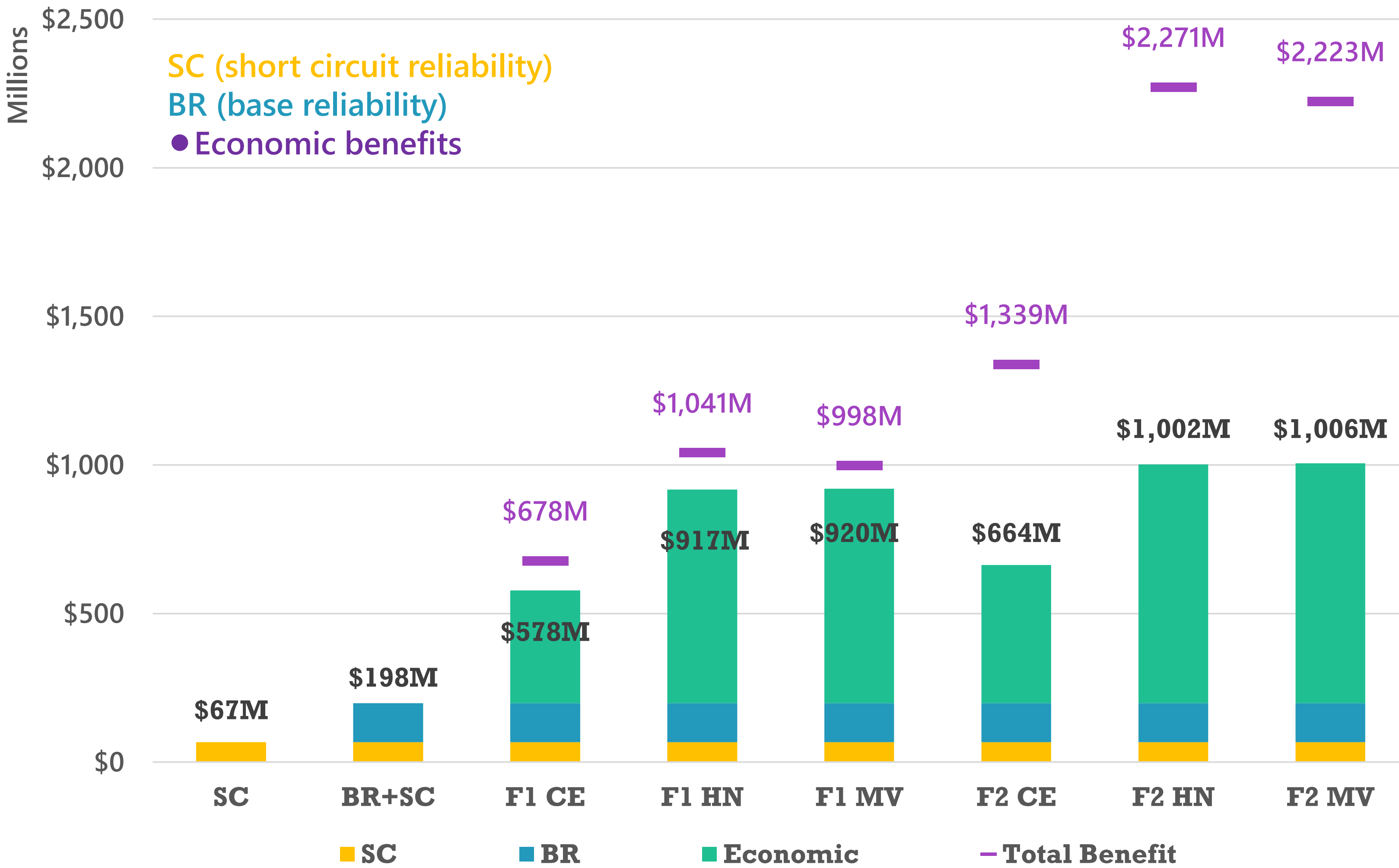
Reliability Projects

- ✓ Meet compliance
- ✓ Cost-effective
- ✓ Maintain reliability

Economic Projects

- ✓ Enable delivery of new generation
- ✓ Solve congestion, improving market for buyers and sellers
- ✓ Provide ratepayer benefits

Benefits/costs for initial groupings



* Reported benefits are indicative of APC benefit only. SC & BR projects not included in benefit calculations. All costs are 40 year NPV.

Reliability projects +

Economic projects =

Optimal grid performance

Next Steps

- Optimize futures where reliability and economic needs overlap
- Consolidate projects into recommended portfolio
- Analyze sensitivities
- Calculate benefits
- Present recommendations in October

SPP and MISO

- Filed revisions to joint operating agreement
- Initiated new coordinated system plan in 2019
- Identified several joint needs in "2019 SPP ITP" and "MISO MTEP19"
- Shared and coordinated potential interregional solutions to resolve joint needs
- Finalizing project evaluations to determine if there are mutually beneficial interregional projects

Southwest Power Pool 2019 Resource Adequacy Report

July 2019 Board/RSC

New Attachment AA in effect

- Attachment AA effective 7/1/18
- Requires Load Responsible Entity (LRE) to maintain adequate capacity to meet summer season resource adequacy requirement (RAR)
- RAR includes capacity to cover load plus planning reserves
- If LRE doesn't meet RAR, it must pay deficiency payment
- **All LREs have complied with RAR for 2019 summer**

Planning Reserve Margin (PRM)

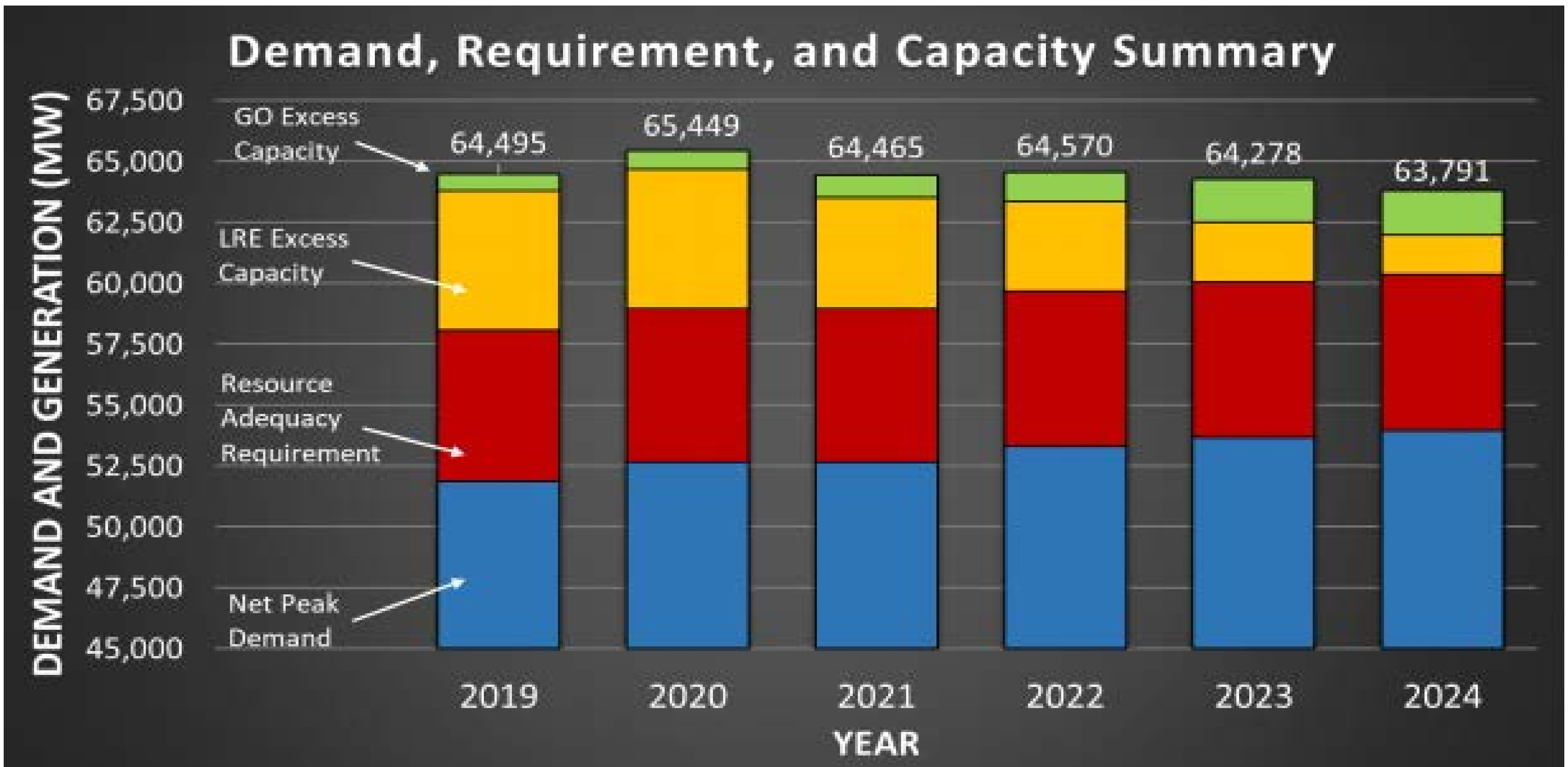
- 12% PRM requirement for 2019 summer
  - Unless a member’s capacity mix is 75% hydro; then PRM is 9.89%
  - 56 LREs with 12%; one with 9.89% requirement
- 2017 LOLE study confirmed the 12% PRM was adequate through study timeframe
- Staff working on 2019 SAWG-approved LOLE study for 2021 and 2024

Planning Reserve Margin

- Retirements are primary driver of decreasing reserve margins
- By 2024, expecting 3,452 MW confirmed & unconfirmed retirements
- Peak demand annual growth rate is .6%

SPP BA Demand and Capacity

- Forecasted net peak demand increases by ~2100 MW through 2024
- Capacity to meet LREs' RAR increases by ~2300 MW through 2024
- Firm and deliverable capacity decreases over assessment timeframe



Summary

- SPP has adequate generation capacity for resource adequacy horizon (5 years out)
- No LREs are deficient for 2019 summer
- 2017 LOLE study confirmed 12% PRM is adequate
- 2019 LOLE study has begun for 2021 and 2024

Integrated Marketplace and Operations Update

Bruce Rew, PE

Vice President, Operations

SPP Integrated Marketplace Update

- Marketplace Operational Highlights
- Historical Load and Wind Trends
- Marketplace Highlights and Information
- Enhancements implemented and under development

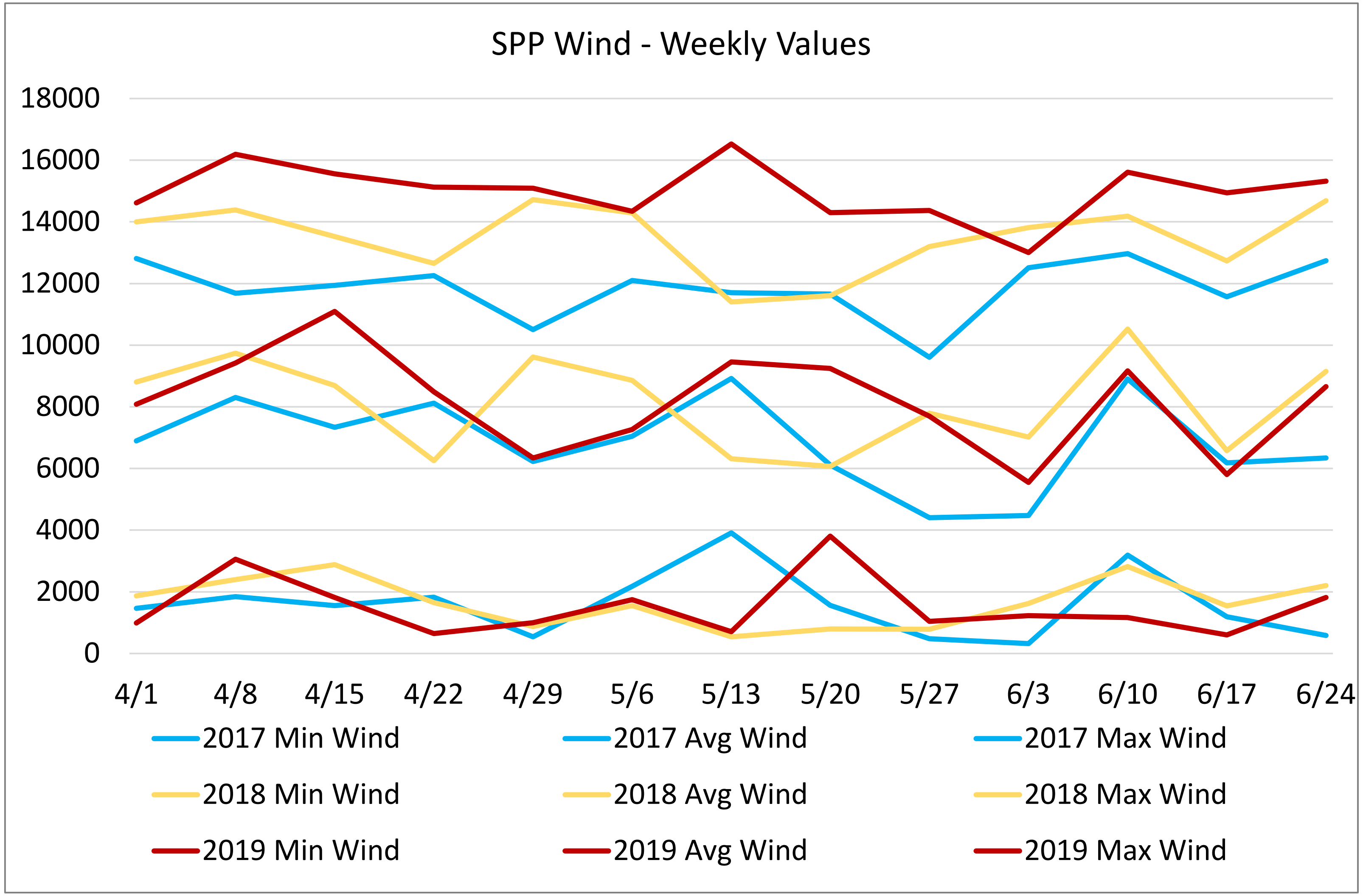
SPP

Marketplace Operational Highlights

- Two new peaks during the quarter
  - Wind reached new Penetration (67.2%) and Generation (16,524MW) peaks on 4/27 and 5/17, respectively
  - Load peaked at 46.8 GW on 6/28 (short of historical summer peak of 50.6 GW on 7/21/2016)
- SPP declared Conservative Operations 5/29 – 05/31 and again for 6/4 – 6/7
- Load forecast error was very similar to Q2 in 2018
- Wind forecast error improved for both maximum magnitude and average error when compared to Q2 2018
- Currently over 21GW of wind registered in the market

SPP

SPP Wind profile: April – June (comparing 2017, 2018, 2019 years at same date)



Wind Output: Apr – Jun 2019

	@ Max Wind Output	@ Min Wind Output
MW Wind	16,523 MW	600 MW
Time	5/17 @ 17:59:20	6/17 @ 09:47:36
SPP Load	35,823 MW	30,786 MW
Appx Gen Mix		
Coal	20.9%	41.42%
Wind	47.12%	2%
Nat. Gas	19.7%	42.32%
Nuclear	5.71%	6.68%
Hydro	5.93%	7.2%

SPP

Wind Penetration: Apr – Jun 2019

	Max Penetration	Min Penetration
Wind Penetration	67.29% of load	1.92% of load
Time	4/27 @ 01:26:32	6/17 @ 10:34:24
SPP Load	22,526 MW	31,977 MW
Wind Output	15,167 MW	612 MW
Appx Gen Mix		
Coal	19%	41.22%
Wind	61%	2%
Nat. Gas	8.76%	43%
Nuclear	8.13%	6.41%
Hydro	3.66%	6.94%

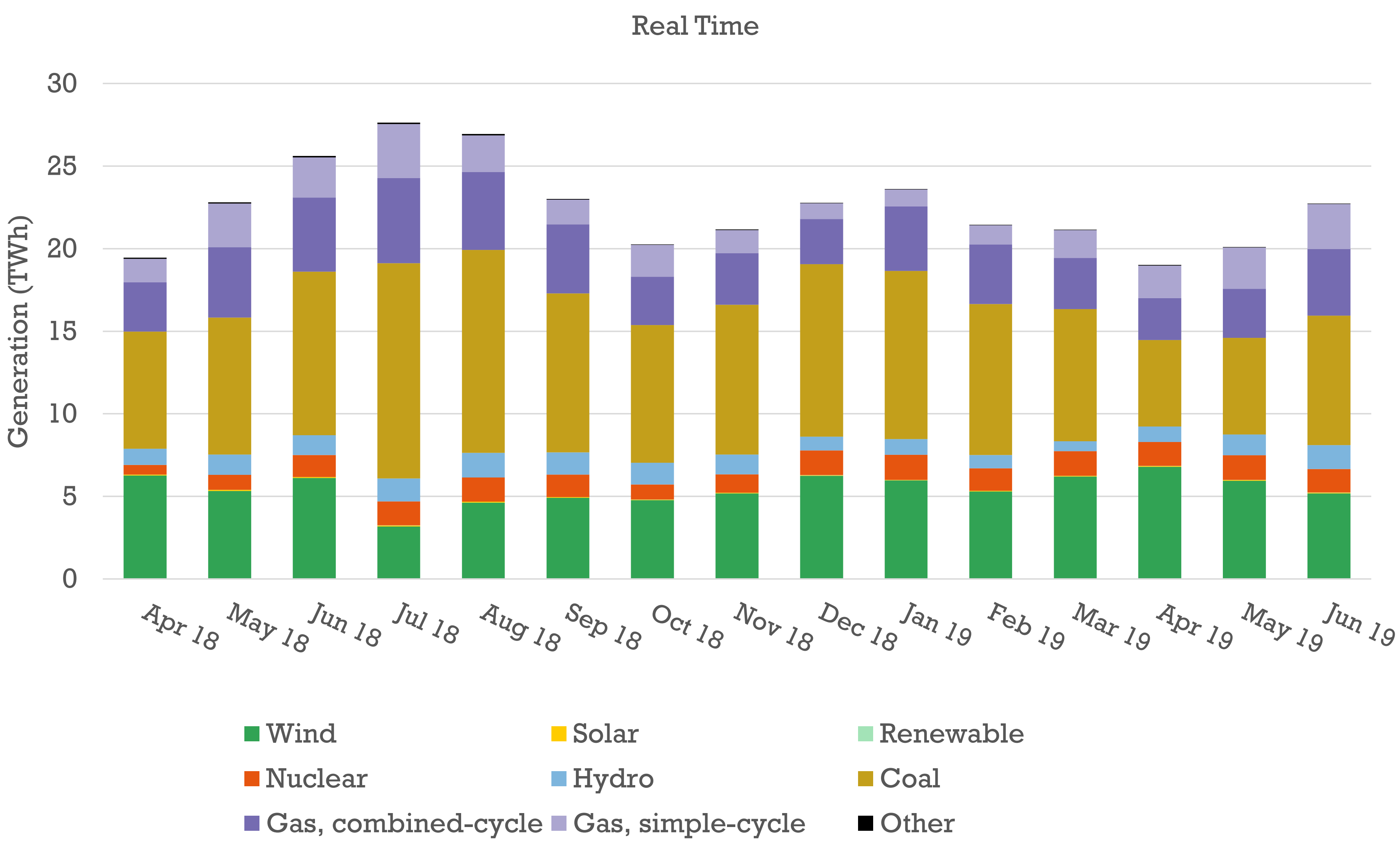
SPP

Marketplace Over Last 12 Months

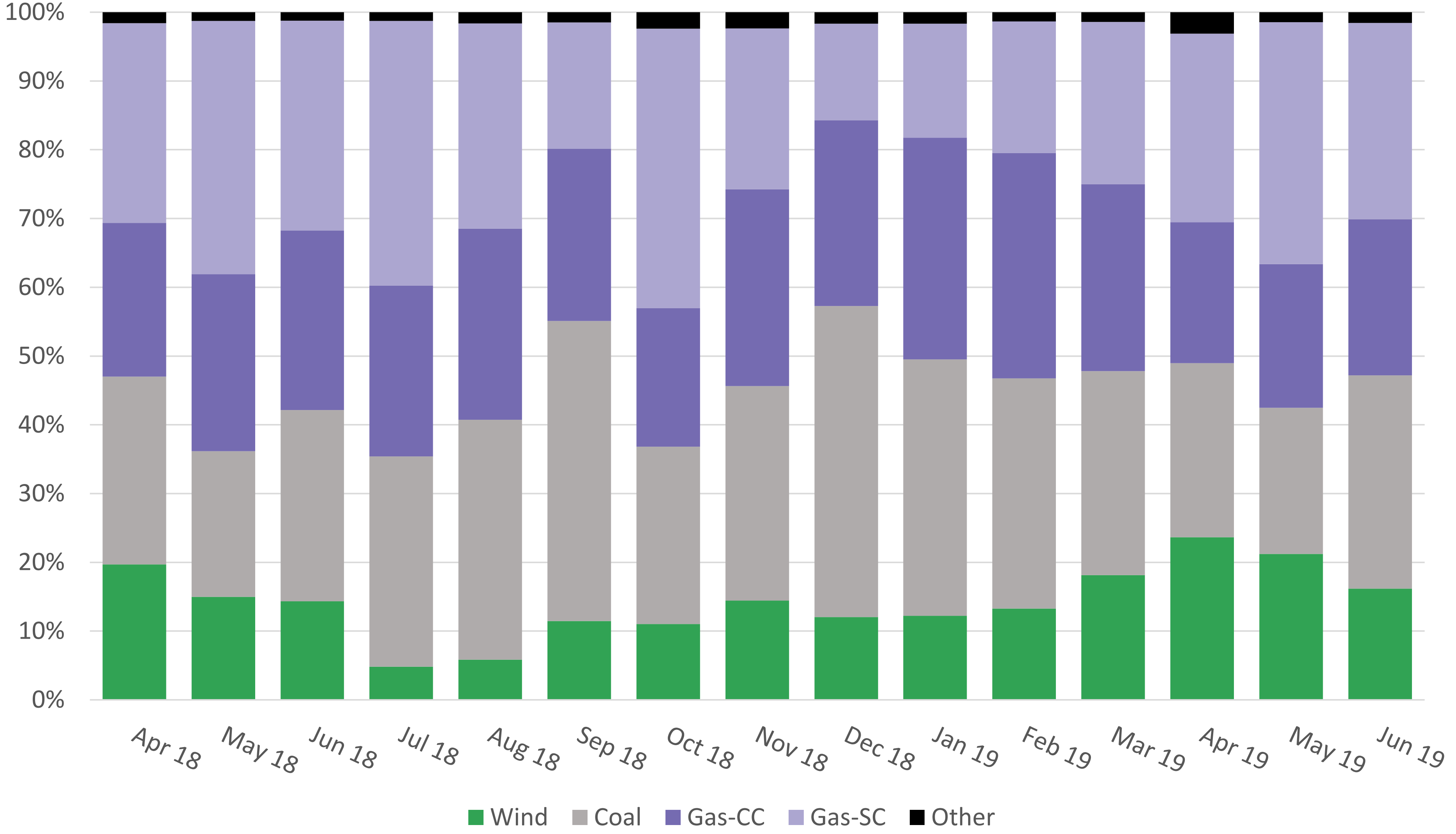
- 228 Market Participants
  - 147 financial only and 81 asset owning
- SPP BA has successfully maintained NERC control performance standards (BAAL & CPS)
- High System availability
  - Day-Ahead Market results have posted late 1 times in past 12 months
    - 1 late posting in 2018 Q3 due to issues resulting from new market system release
  - Real-Time Balancing Market has successfully solved 99.8% of all intervals

SPP

Dispatch by Fuel Type

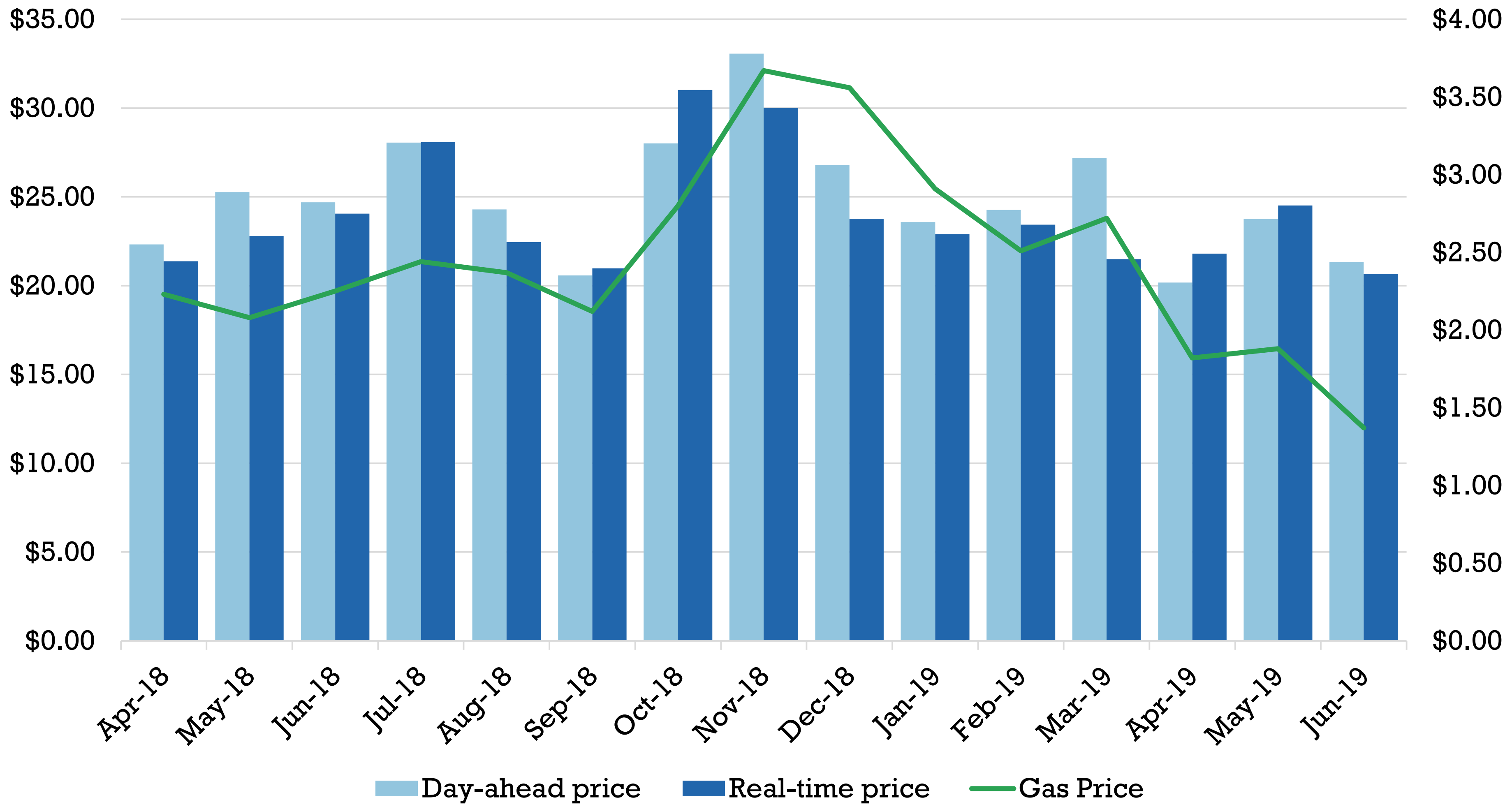


Fuel on the Margin in Real-Time

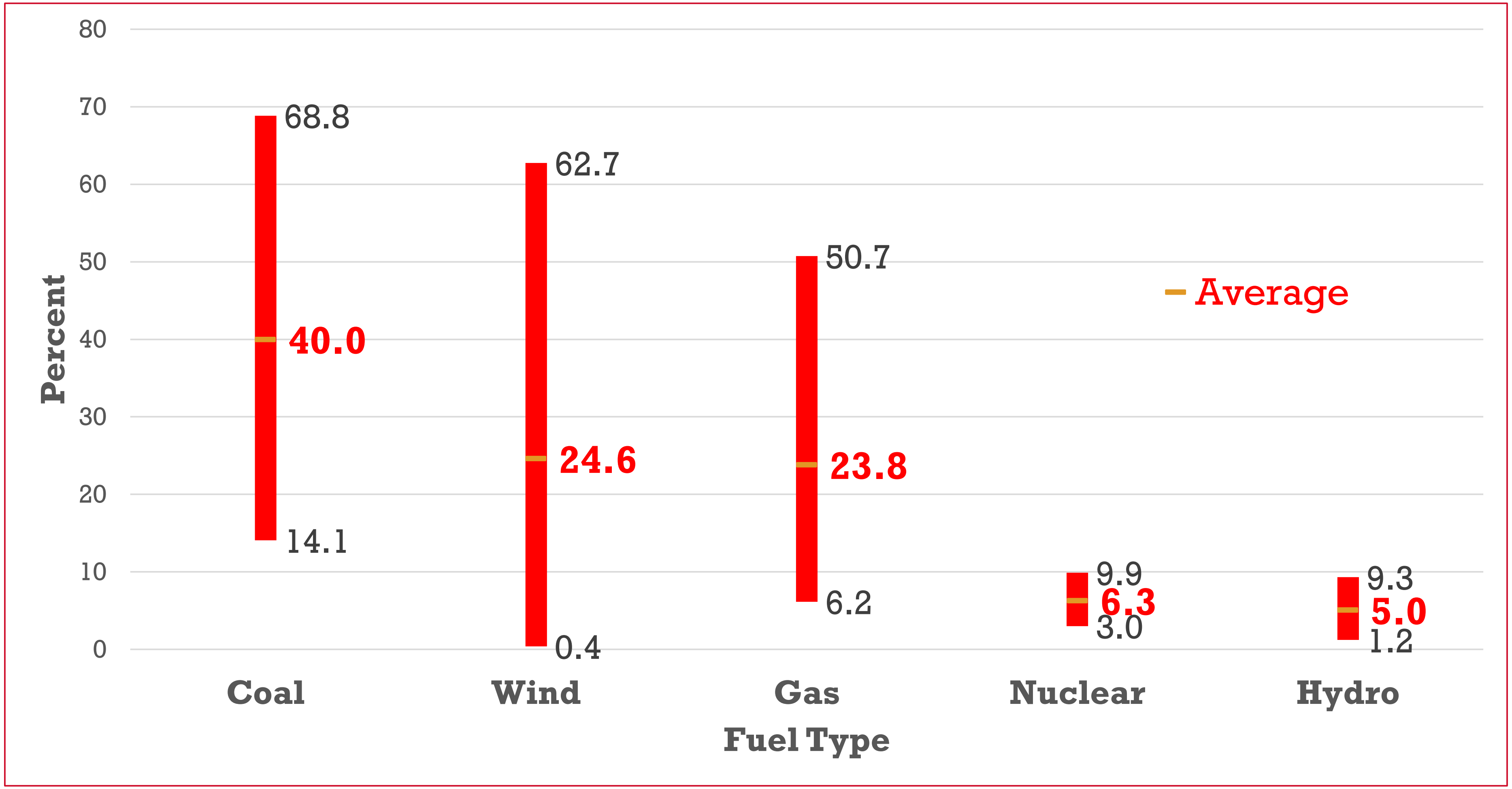


SPP

Real-Time versus Day-Ahead pricing

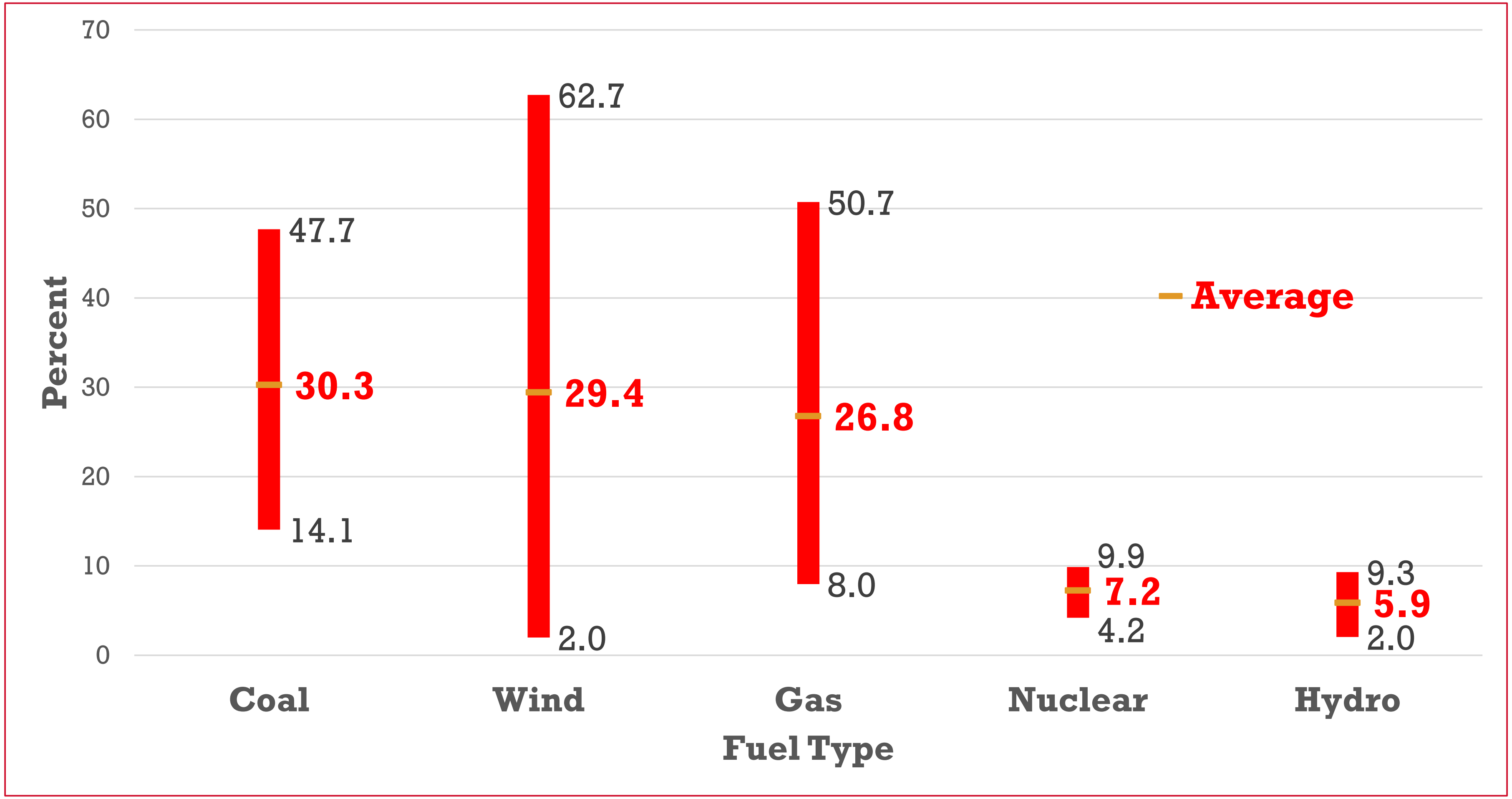


Min and Max Percent of Generation Mix Per Fuel Type - Last 12 Months



SPP

Min and Max Percent of Generation Mix Per Fuel Type – Q2 2019



Integrated Marketplace Enhancements

Implementation September 2019:

- RR316 – MCR Plant and Group Min Down time
- RR318 – Contingency Reserve Requirement Calculation Change

Implementation with Settlement System Replacement Project

- RR229 and RR333 – FERC ORDER 831 (Offer Caps)
- RR252 – OOME Cap and Floor Enhancement
- RR259 – Market Settlement Timelines
- RR273 – Market Settlements RNU Rounding
- RR328 – Settlement Automation for CR Deployment Tests

SPP

Our Mission

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