Southwest Power Pool

Economic Studies Working Group

December 3-4, 2018

41st Floor AEP Office – Dallas, TX

• SUMMARY OF ACTIONS TAKEN •

2019 ITP:

1. Approved staff's recommendation of Southeast Kansas and Southwest Missouri region as the Target Area.

2020 ITP:

2. Approved Basin's resource addition request for the GEN-2016-151 (202 MW) Burke Wind to be included in the 2020 ITP Assessment
3. Approved Westar and NextEra resource addition request for GEN 2016-149 (300 MW) Soldier Creek Wind Energy Center to be included in the 2020 ITP Assessment
4. Approved using the EIA Conventional Combined Cycle and EIA Advanced Combustion Turbine prototypes as well as eliminating nuclear and coal as options for the 2020 ITP
5. Approved staff's recommendation that batteries be accredited at 100% and to include them in projected renewable 12% cap for the purposes of resource planning in the ITP Study
6. Approved staff's recommendation of using the sensitivities described in the ITP Manual and using the 2018 ABB fundamental forecast natural gas price data.

Other Approvals:

7. Approved the changes to the STEP report

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ECONOMIC STUDIES WORKING GROUP

December 3-4, 2018

41st Floor AEP Office – Dallas, TX

• MINUTES •

Agenda Item 1 – Administrative Items

Agenda Item 1a - Call to Order, Introductions

Chair Alan Myers (ITC) called the meeting of the Economic Studies Working Group (ESWG) to order at 1:00 p.m., welcomed those in attendance, and asked for introductions.

There were 27 in-person participants and 68 web conference participants, representing 14 of 16 ESWG members. (Attachment 1 – December 3-4, 2018 ESWG Attendance)

Agenda Item 1b – Receipt of Proxies

Alan Myers (ITC) asked for any proxy statements; two proxies were identified. (Attachment 2 – Proxy Statements)

- Bennie Weeks (Xcel) named Ben Elsey (Xcel) as her proxy

Agenda Item 1c – Review of Agenda

Chair Alan Myers (ITC) presented the agenda for review and asked for any additions or corrections. (Attachment 3 – December 3-4, 2018 ESWG Agenda).

Tim Owens (NPPD) made a motion; seconded by John Olsen (Westar) to adopt the agenda. The motion was approved unanimously.

Agenda Item 1d – Antitrust Reminder

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

Agenda Item 2 – Closed Session-Software Tools Costs

This was a closed session to discuss the costs of the software tools, this information was provided as confidential to ESWG members.

Agenda Item 3 – Review of Past Action Items

Amber Greb (SPP) reviewed the list of past action items and asked for any comments or questions. (Attachment 4 – Past Action Items)

Agenda Item 4 – Software Tool Discussion

Juliano Freitas (SPP) gave a general description of both the Plexos and the Promod E7 software tools. He reviewed the features offered and some considerations that need to be taken into account for each product. Plexos does not currently have a contingency evaluator tool and is not currently used for RTO transmission planning studies. Promod E7 does not currently have functionality to do bulk simulation runs. Representatives from each of the software companies were present and were allowed to comment on the pros and cons listed for their products. Steven Broad (Energy Exemplar) commented that Plexos has the ability to build out wind in a long term environment, and can model wind in a way the respects curtailments. Erdal Kara (ABB) informed the group that Promod can create an economic selection of renewable resources as well. He also mentioned that they are benchmarking results between the P4 and P7 versions with MISO data and are getting similar results between the tools. Stakeholders began discussing the process for evaluating the tools. The majority of the group wanted to go through more vetting of each tool before making a decision. SPP Staff will bring a plan to the January ESWG meeting to lay out the process for finalizing the analysis of the tools and choosing the best option for the group, including a deadline for the final decision. (Attachment 5 – Software Tools Discussion)

Agenda Item 5 – Joint ESWG/TWG Items

Agenda Item 5a – 2019 ITP Target Area Selection

Nikki Roberts (SPP) reviewed a presentation on 2019 ITP Target Area Selection and Additional Analysis with a goal of determining one Target Area to analyze in the 2019 ITP Assessment. She discussed Target Area considerations and the drivers behind the resulting Target Area of Southeast Kansas/Southwest Missouri. Questions were raised as to how this target area was determined. Kelsey Allen (SPP) described the reasoning behind choosing this Target Area. Nikki brought the staff recommendation of the Southeast Kansas and Southwest Missouri region as the Target Area for additional analysis in the 2019 ITP Study. (Attachment 6 - 2019 ITP Target Area Selection and Additional Analysis)

ESWG:

John Olsen (Evergy) made a motion; seconded by Jeremy Severson (BEPC) to approve staff's recommendation of Southeast Kansas and Southwest Missouri region as the Target Area. The motion was approved unanimously.

TWG:

Gayle Nansel (WAPA-UGPR) made a motion; seconded by Alan Myers (ITC) to approve staff's recommendation of Southeast Kansas and Southwest Missouri region as the Target Area. The motion was approved with one abstention, Cliff Franklin.

Agenda Item 5b – 2020 ITP Resource Addition Requests

Theva Coleman (SPP) gave a presentation summarizing the 2020 ITP Resource Addition Requests. There were presentations given by BEPC and Westar for Resource Addition Requests (RAR) and waivers. Votes for inclusion of each RAR ensued. (Attachment 7a - 2020 ITP Resource Addition Request) (Attachment 7b - 2020 ITP Resource Addition Request Summary) (Attachment 7c - 2020ITP_Burke_Wind-Waiver) (Attachment 7d - Westar and NextEra 2020 ITP RAR and Waiver for Soldier Creek Wind Farm)

Basin Request:
ESWG:
Jeremy Severson (BEPC) made a motion; seconded by Leon Howell (OGE) to approve Basin's resource addition request for GEN-2016-151 (202 MW) Burke Wind to be included in the 2020 ITP Assessment. The motion was approved with one "No" vote, Ben Elsey (Xcel).
TWG:
Jeremy Severson (BEPC) made a motion; seconded by Alan Myers (ITC) to approve Basin's resource addition request for GEN-2016-151 (202 MW) Burke Wind to be included in the 2020 ITP Assessment. The motion was approved unanimously.

Westar Request:
ESWG:
John Olsen (Evergy) made a motion; seconded by Leon Howell (OGE) to approve Westar and NextEra's resource addition request for GEN 2016-149 (300 MW) Soldier Creek Wind Energy Center to be included in the 2020 ITP Assessment. The motion was approved with one abstention, Alan Myers (ITC), and one "No" vote, Ben Elsey (Xcel).
TWG:
Derek (BEPC) made a motion; seconded by Alan Myers (ITC) to approve Westar and NextEra's resource addition request for GEN 2016-149 (300 MW) Soldier Creek Wind Energy Center to be included in the 2020 ITP Assessment. The motion was approved with one abstention, Alan Myers (ITC), and one "No" vote, Ben Elsey (Xcel).

ITC abstained because this RAR didn't have all of the same information as the previous request. – Alan Myers (ITC)

Agenda Item 5c – 2020 ITP Scope Draft

Kirk Hall (SPP) brought the scope draft to the group for review. The group discussed the various components of the scope as Kirk showed the document. Some discussion centered on what to do with operational needs for the 2020 study as there is only a waiver for the 2019 ITP study. Kirk replied that staff will continue working on it but since there is not a solution it cannot be written into the 2020 scope at this time, but may be able to be incorporated upon determining a solution. Kirk will bring the scope back for approval at a later date. (Attachment 8 - 2020 ITP scope draft)

Agenda Item 5d – STEP Report Format

John O'Dell (SPP) presented improvements to the SPP Transmission Expansion Plan (STEP) report. The report now includes StoryMap backgrounds similar to ITP reports and graphical representations for most sections rather than text and tables. Summary metrics have been added such as easy-to-read one page summaries and NTC activity and portfolio status. (Attachment 9 - 2019_SPP_Transmission_Expansion_Plan_Report) (Attachment 9 – STEP Report Improvement)

> **ESWG:**
> **Tim Owens (NPPD) made a motion; seconded by Kurt Stradley (LES) to approve the changes to the STEP report. The motion was approved unanimously.**
> **TWG:**
> **Alan Myers (ITC) made a motion; seconded by Noman Williams (Gridliance) to approve the changes to the STEP report. The motion was approved unanimously.**

Agenda Item 6 – 2019 ITP Items

Agenda Item 6a – Schedule

Juliano Freitas (SPP) reviewed a presentation on 2020 ITP schedule. Juliano reviewed on-going and up-coming milestones. (Attachment 10a - 2019 ITP Schedule)

Agenda Item 6b – Policy Needs Assessment

Nikki Roberts (SPP) reviewed a presentation on the Policy Needs Assessment. She notified the group that the policy assessment work is complete. She reminded the group that a shortfall was identified for SPS in the year 2 model which cannot be solved with non-generation solution (i.e. curtailment is not the issue). Also, there was an ITP Manual Revision Request approved at July MOPC removing policy review requirements for year 2. (Attachment 10b - Policy Needs Assessment)

Agenda Item 6c – Economic Needs Assessment

Nikki Roberts (SPP) updated the group on the Economic Needs Assessment and reported next steps in the milestone. (Attachment 10c - Economic Needs Assessment)

Agenda Item 6d – DPP Window

Ellen Bailey (SPP) reviewed a presentation on the DPP Window that described the DPP process flow, dates for the DPP Window, submission best practices, and changes to the submittal form. (Attachment 10d - DPP Window)

Agenda Item 7 – 2020 ITP Items

Agenda Item 7a – Schedule

Juliano Freitas (SPP) reviewed a presentation on 2020 ITP schedule. Juliano reviewed on-going and up-coming milestones. (Attachment 11a - 2020 ITP Schedule)

Agenda Item 7b – Scope Development

Agenda Item 7bi – Conventional Generator Prototypes

Antonio Barber (SPP) presented the Conventional Generation Prototypes, reviewing the prototype data source options of EIA Annual Energy Outlook Report and Lazard Levelized Cost of Energy Analyses. He presented busbar curves for combined cycle and combustion turbine prototypes and made the recommendation to use the EIA Conventional Combined Cycle and EIA Advanced Combustion Turbine prototypes as well as eliminating nuclear and coal as options. (Attachment 11b - Conventional Generation Prototypes)

John Olsen (Evergy) made a motion; seconded by Anita Sharma (AEP) to approve using the EIA Conventional Combined Cycle and EIA Advanced Combustion Turbine prototypes as well as eliminating nuclear and coal as options for the 2020 ITP. The motion was approved unanimously.

Agenda Item 7bii – Battery Accreditation

Joshua Norton (SPP) presented on Battery Storage Accreditation. There was discussion around whether it makes since to include batteries in the 12% cap and what impact that may have. It was asked if the batteries are assumed to have 4 hours of duration and Joshua responded that they are assumed to be 4 hour batteries and why that was chosen. He brought the recommendation that batteries be accredited at 100% and include in projected renewable 12% cap for the purposes of resource planning in the ITP Study. (Attachment 11c - Battery Storage Accreditation)

Tim Owens (NPPD) made a motion; seconded by Kurt Stradley (LES) to approve staff's recommendation that batteries be accredited at 100% and to include them in projected renewable 12% cap for the purposes of resource planning in the ITP Study. The motion was approved with one "No" vote, Ben Elsey (Xcel).

Agenda Item 7biii – Natural Gas Prices and Sensitivities

Kirk Hall (SPP) presented the 2020 ITP Scope Sensitivities. He reviewed ITP Manual language related to sensitivities and data sources for a natural gas fuel forecast. He recommended using the sensitivities described in the ITP Manual and using the 2018 ABB fundamental forecast natural gas price data. (Attachment 11d - 2020 ITP Scope - Natural Gas Prices and Sensitivities)

Kurt Stradley (LES) made a motion; seconded by Leon Howell (OGE) to approve staff's recommendation of using the sensitivities described in the ITP Manual and using the 2018 ABB fundamental forecast natural gas price data. The motion was approved with one abstention, Natasha Henderson (GSEC).

Agenda Item 7c – Generation and Load

Theva Coleman (SPP) gave an update on the Generation and Load Review milestones. She reminded the group of the deadline for pass 3 and the upcoming approval dates. (Attachment 11e - Generation and Load Review Update)

Closing Items

There were no action items from the meeting.

The meeting was adjourned at 1:00 PM.

Respectfully Submitted,

Amber Greb

ESWG Secretary

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Member	Proxy
Bennie Weeks	Ben Elsey

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ECONOMIC STUDIES WORKING GROUP MEETING

December 3-4th, 2018

41st Floor AEP Office – Dallas, TX

• AGENDA •

Monday, 1:00p.m. - 5:00p.m.

Tuesday, 8:00a.m. - 3:00p.m

1. Administrative Items
    a. Call to Order, Introductions..Alan Myers (5 minutes)
    b. Receipt of Proxies .... Amber Greb (1 minute)
    c. Review of Agenda[1] ....Alan Myers (1 minute)
    d. Antitrust Reminder .... Amber Greb (1 minute)
2. Closed Session-Software Tools Costs[1] .... Juliano Freitas (30 minutes)
3. Review of Past Action Items[1] .... Amber Greb (15 minutes)
4. Software Tool Discussion[1] .... Juliano Freitas (60 minutes)
5. Joint ESWG/TWG Items
    a. 2019 ITP Target Area Selection[1] (Approval Item) .... Nikki Roberts (60 minutes)
        i. Additional Analysis
    b. 2020 ITP Resource Addition Requests[1] (Approval Item) .... Theva Coleman (30 minutes)
    c. 2020 ITP Scope Draft[1]...Kirk Hall (20 minutes)
    d. STEP Report Format[1](Approval Item) .... John O'Dell (20 minutes)
6. 2019 ITP Items .... SPP Staff (50 minutes)
    a. Schedule[1] .... Juliano Freitas (10 minutes)
    b. Policy Needs Assessment[1].. Nikki Roberts (10 minutes)
    c. Economic Needs Assessment[1] .... Nikki Roberts (10 minutes)
    d. DPP Window[1] .... Ellen Bailey (20 minutes)
7. 2020 ITP Items .... SPP Staff (110 minutes)
    a. Schedule[1] .... Juliano Freitas (10 Minutes)

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[1] Background Material Included

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b. Scope Development[1] .... SPP Staff
   i. Conventional Generator Prototypes[1] (Approval Item) ....Antonio Barber (20 minutes)
   ii. Battery Accreditation[1] (Approval Item).............................. Joshua Norton (20 minutes)
   iii. Natural Gas Prices and Sensitivities[1] (Approval Item) ....Kirk Hall (30 minutes)
c. Generation and Load[1]... Theva Coleman (30 minutes)

8. Closing Items ....All (10 minutes)
   a. Summary of Action Items (Amber Greb)
   b. December/January ESWG Agenda Items
   c. Future Meetings
      i. December 19th, 2018: ESWG calling into TWG meeting
      ii. January 9-10th, 2019: 41st floor AEP Office, Dallas Texas
      iii. February 6-7, 2019: 41st floor AEP Office, Dallas Texas
      iv. March 12-13, 2019: 41st floor AEP Office, Dallas Texas
      v. April 10-11, 2019: GSEC Offices, Lubbock Texas
      vi. May 15-16, 2019: KCPL/Evergy Offices, KC Missouri
      vii. June 12-13, 2019: 41st floor AEP Office, Dallas Texas

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Pending Action Items Status Report

December 3-4, 2018

	Action Item	Date Originated	Status	Comments
151	SPP staff to look into optional software tools for use in ITP studies.	May 20th, 2015	In Progress SPP Staff	Staff is compiling information from multiple tools used for economic analysis and resource planning. Staff to bring an update in December
183	SPP staff to perform transmission outage analysis in the first part of 2017 to determine the appropriate APC benefit percentage to utilize for the mitigation of transmission outages benefit metric.	September 15th, 2016	In Progress SPP Staff	ESWG Approved the methodology and staff to begin analysis
190	SPP staff to perform a full transmission outage analysis before the next RCAR	October 12th, 2017	SPP Staff	
193	Discuss separate load forecasts for resource planning purposes, and how to incorporate into the ITP process	January 22nd, 2018 November 15th, 2018	SPP Staff	Has been incorporated into the Load review for 2020. Update the ITP Manual
194	Continue researching/discussing curtailment pricing for future studies	April 25th, 2018	SPP Staff	

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[redacted]

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Software Analysis

Juliano Freitas

December 3rd , 2018

Overview

- Software general description
- Pros and Cons
- Transition Plan

[redacted]

Software General Description

Plexos

- Uses industrial-strength LP/QP/MIP solvers
- Used for short, medium and long term modelling and analysis of power markets.
- Power system representation
- Security constrained dispatch, unit commitment, pricing and settlement
- Portfolio optimization and scenario analysis,
- Outages and maintenance scheduling
- Wind integration
- Transmission and ancillary services modelling,

Overview - Promod E7

- Determines the effects of:
  - Transmission congestion
  - Fuel costs
  - Generator availability
  - Bidding behavior
- Performs a daily or weekly commitment and hourly or sub-hourly dispatch
- Forecasts:
  - Hourly and sub-hourly energy prices
  - Unit generation, revenues and fuel consumption
  - Transmission flows and congestion and loss prices.
- Hourly and sub-hourly granular level and detailed generator data inputs.

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Pros and Cons

Plexos

- Pros
  - Exemplar will provide technical support for automation and software transition
  - On-site training
  - Customizable:
    - Aux load modeling
    - Simulations
    - Constraints
  - Flexibility to customize structure to achieve objective function

Plexos

- Pros
  - Capacity Expansion integrated with Plexos
  - Optimization options to reach a better solution
  - Plexos Connect cloud capability
  - Users can obtain the internal mathematical equations, so they can trace how solutions were achieved

Plexos

- Cons
  - Hardware upgrade required
  - No contingency evaluator (PAT) tested in a large system
  - Change management uncertainties
  - Large output files (flat files)
  - SPP/MISO models coordination
  - Need to be more integrated into RTO studies
  - Models not integrated between RTOs

Promod E7

- Pros
  - Database platform/structure
    - No flat files
  - Existing contingency evaluator (PAT) tested in a large system
  - Input files structure similar to PROMOD IV
  - User friendly reporting
  - ABB will provide technical support for automation and software transition
  - On-site training
  - Familiarity with PROMOD structure/technical support

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Promod E7

- Pros
  - Simulation ready data used by multiple RTOs
  - Interactive dashboards
  - No hardware upgrade
  - Microsoft cloud computing
  - Storage modeling
  - Capacity Expansion integrated with Promod
  - Custom calculations
  - Program output is Excel
  - Common database allows inputs amongst E7 programs

Pros & Cons - Promod E7

- Cons
  - Customer feedback not incorporated into new software versions
  - GUI configuration does not have the same structure for each release
  - Bulk simulation runs not developed yet

[redacted]

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Transition Plan

Plexos (2019)

- Jan – Installation & Training (SPP Staff)
- Feb – Data Management/Automation
- Mar – Data Management/Automation
- Apr – 2019 ITP Benchmark
- May – 2019 ITP Benchmark
- June – Ready for 2021 ITP Implementation
- Group Training (Members & Staff)
  - February and April

Promod E7 (2019)

- Jan - Installation
- Feb to Jun – 2019 ITP Benchmark & Automation
- Jun and Jul – Training (Members & Staff)
- Sep – Ready for 2021 ITP Implementation

Recommendation

- SPP Staff recommends the adoption of Promod E7 to perform economic analysis and simulations


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2019 ITP Target Area Selection and Additional Analysis

Nikki Roberts

Objective

- Recap Target Area identification
- Discuss identified Target Area and additional analysis for the 2019 ITP Study
- ***Goal:*** Determine one Target Area to analyze in the 2019 ITP

ITP Manual: Target Areas

- ITP Manual section 4.1.2 describes potential analysis of "target areas", or areas of increased focus with additional analysis

Target Areas

- Top constraints will be evaluated based on criteria in ITP manual section 4.1.2 and may result in Target Area(s)
- High-Level Scopes for Target Areas will be developed, as needed, and posted with the Needs List. Scopes may include:
  - Additional benefit metrics
  - Economic and Reliability Sensitivities (resource plan impacts, load forecasts, fuel prices, etc)
  - Impact of Op Guides/Transmission Operating Directives (TOD)
  - Other analysis deemed necessary to realize potential benefits (e.g. stability analysis)
- Any additional analysis will be performed on top-ranking solutions identified as a result of project screening

Target Area Considerations

- Top Congested Flowgate
- Related to another flowgate(s)
- Identified as an Operational Issue or congested in Integrated Marketplace
- Identified as an RCAR Issue
- Identified as a Seams Issue
- Identified as an Operational, reliability, and/or Policy Need
- GI/TSS study queue limitations
- Located in limited capacity transmission corridor
- PTDF represents thermal, stability, or contractual limitations

2019 ITP Identified Target Area & Drivers

Southeast Kansas/Southwest Missouri

- Drivers
  - Unresolved transmission limits identified in numerous studies
  - Historic and projected congested flowgates in area
  - Steady-state reliability violations
  - Stability concerns at Wolf Creek
  - Active TWG direction to determine a path forward to properly evaluate issues around Wolf Creek
  - Helps meet study object in developing a regional plan that provides *Reliable and economic delivery of energy,* specifically for SPP eastern load centers

Southeast Kansas/Southwest Missouri Analysis

- Calculations per Benefit Metrics Manual
  - Reduction of marginal energy losses
  - Avoided reliability cost savings*
- Angular stability analysis
  - Consistent with SPP's process to meet TPL-001-4 R4
  - 2018 MDWG stability base and sensitivity cases
    - Potential: modify sensitivity case for local area high wind or local transmission outages
- Wolf Creek TOD
  - Current operating directive to reduce output of plant under any 345 kV contingency reducing the number of transmission outlets

*Modify to leverage issues/solutions identified during development of a Base Reliability portfolio

Wolf Creek TOD Implementation

- Previously implemented in 2015 and 2017 ITP10 as a base model assumption
  - Modeled Wolf Creek as 2 machines (800MW/405MW)
  - Included additional outages of 405MW machine consistent with historical transmission outages to simulate "derate"
  - Removed PROMOD case for analysis of new 345 kV outlet solutions
- 2019 ITP Proposal
  - Refine annual "derate" schedule through analysis of more historical transmission outage data
  - Include actual transmission outages along with reduced plant output
  - Include nomogram to implement derate schedule
  - Only implement during portfolio development

Wolf Creek TOD Modeling

- Nomogram
  - Assumes normal Wolf Creek output is always at maximum unless on outage
  - Reduce Wolf Creek minimum capacity to approved derate value (per TOD)
  - Model hourly transaction to force desired Wolf Creek output, minimize transaction impact
    - Max Capacity = 1/1000 of MW desired output
    - Map transaction to EHV bus near eastern border of translated system
  - Include new gen hub with bus of Wolf Creek unit
  - Force gen hub (Wolf Creek) and transaction schedule * -1000 to net 0 MW (+/- 1 margin)
  - NOMOGRAM 'WOLFCREEK DERATE' -1.0 1.0 -1.0 1.0
    - GENERATION HUB WCGENHUB 1.0
    - TRANSACTION WLFCRKDT -1000.0
  - END

```
NOMOGRAM 'WOLFCREEK DERATE' -1.0 1.0 -1.0 1.0
   GENERATION HUB WCGENHUB 1.0
   TRANSACTION WLFCRKDT -1000.0
END
```

- Additional constraint identification using engineering judgment

Recommendation

- SPP Staff recommends the Southeast Kansas and Southwest Missouri region as the Target Area for additional analysis in the 2019 ITP Study


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HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.

2020 ITP Resource Addition Requests

December 3, 2018

Theva Coleman

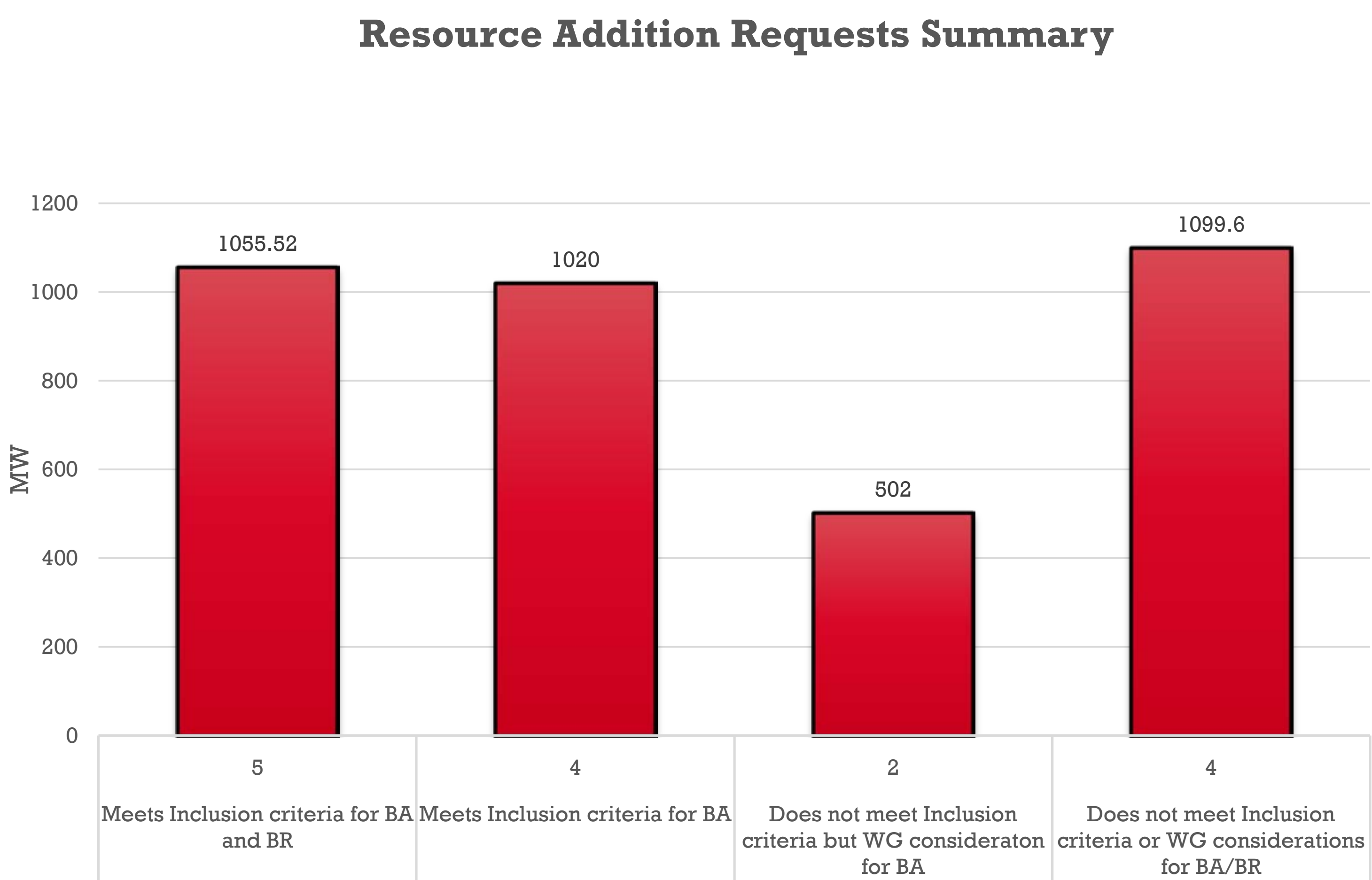
Objective

- Provide summary of Resource Addition Requests
- Approve Stakeholder Resource Addition Requests for inclusion in the Market models

Resource Addition Request (RAR)

- RAR and Waiver Request form sent out on 9/21/2018
- RAR and Waiver Request forms submitted to SPP on 10/26/2018
- Summary of RARs is included in background materials for review

Resource Addition Request (RAR)



Resource Addition Request (RAR)

- Additional presentations have been posted in background materials for stakeholder review.
  - 202 MW Wind facility interconnected at Tande 345 kV
  - 300 MW Wind facility interconnected at Stranger Creek 345 kV

SPP Recommendation

SPP recommends including the RAR submitted resource additions in the 2020 ITP.

GEN Number	*Point of Interconnection*
GEN-2012-020	TUCO 230kV
GEN-2011-025	Tap Floyd County - Crosby County 115kV
GEN-2015-016	Tap Marmaton - Centerville 161kV
GEN-2015-090	Thistle-Wichita Dbl Ckt (Buffalo Flats) 345kV
GEN-2011-025	Tap Floyd County - Crosby County 115kV
GEN-2009-001	Groton-Watertown 345kV
GEN-2015-069	Union Ridge 230kV
GEN-2010-051	Hoskins-Twin Church 230kV
GEN-2011-027	Hoskins-Twin Church 230kV
GEN-2015-089	Utica 230 kV Substation
GEN-2016-151	Tande 345kV
GEN-2016-149	Stranger Creek 345 kV
GEN-2017-004	Elm Creek - Summit 345 kV
GEN-2015-046	Tande 345kV
GEN-2015-052	Open Sky-Rose Hill 345kV
GEN-2016-123	Eddy County-Tolk (Crossroads) 345kV

Generation Type	*GI Queue Capacity (MW)*	*IA Status*
Wind	478	IA FULLY EXECUTED/ON SCHEDULE
Wind	78.76	IA FULLY EXECUTED/ON SCHEDULE
Wind	200	IA FULLY EXECUTED/ON SCHEDULE
Wind	220	IA FULLY EXECUTED/ON SCHEDULE
Wind	78.76	IA FULLY EXECUTED/ON SCHEDULE
Wind	200	Constr.Pend
Wind	300	IA FULLY EXECUTED/ON SCHEDULE
Wind	200	IA FULLY EXECUTED/ON SCHEDULE
Wind	120	IA FULLY EXECUTED/ON SCHEDULE
Wind	200	IA FULLY EXECUTED/ON SCHEDULE
Wind	202	FACILITY STUDY STAGE
Wind	300	FACILITY STUDY STAGE
Wind	201.6	DISIS STAGE
Wind	300	IA PENDING
Wind	300	IA FULLY EXECUTED/ON SCHEDULE
Wind	298	FACILITY STUDY STAGE

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Wind Resource Addition Request
2020 ITP
ESWG & TWG

Jeremy Severson

BEPC Resource Addition Request - 2020 ITP

- SPP request for resource additions
  - Looking for any PPA's or self build projects not currently in models
- Project : 202 MW wind farm
  - Located near Tioga ND
  - In Service EOY 2020
  - BEPC PPA for full amount
- Past : 2019 ITP - This was one of two projects that (300 MW's) was accepted by the ESWG for the previous 2019 ITP analysis

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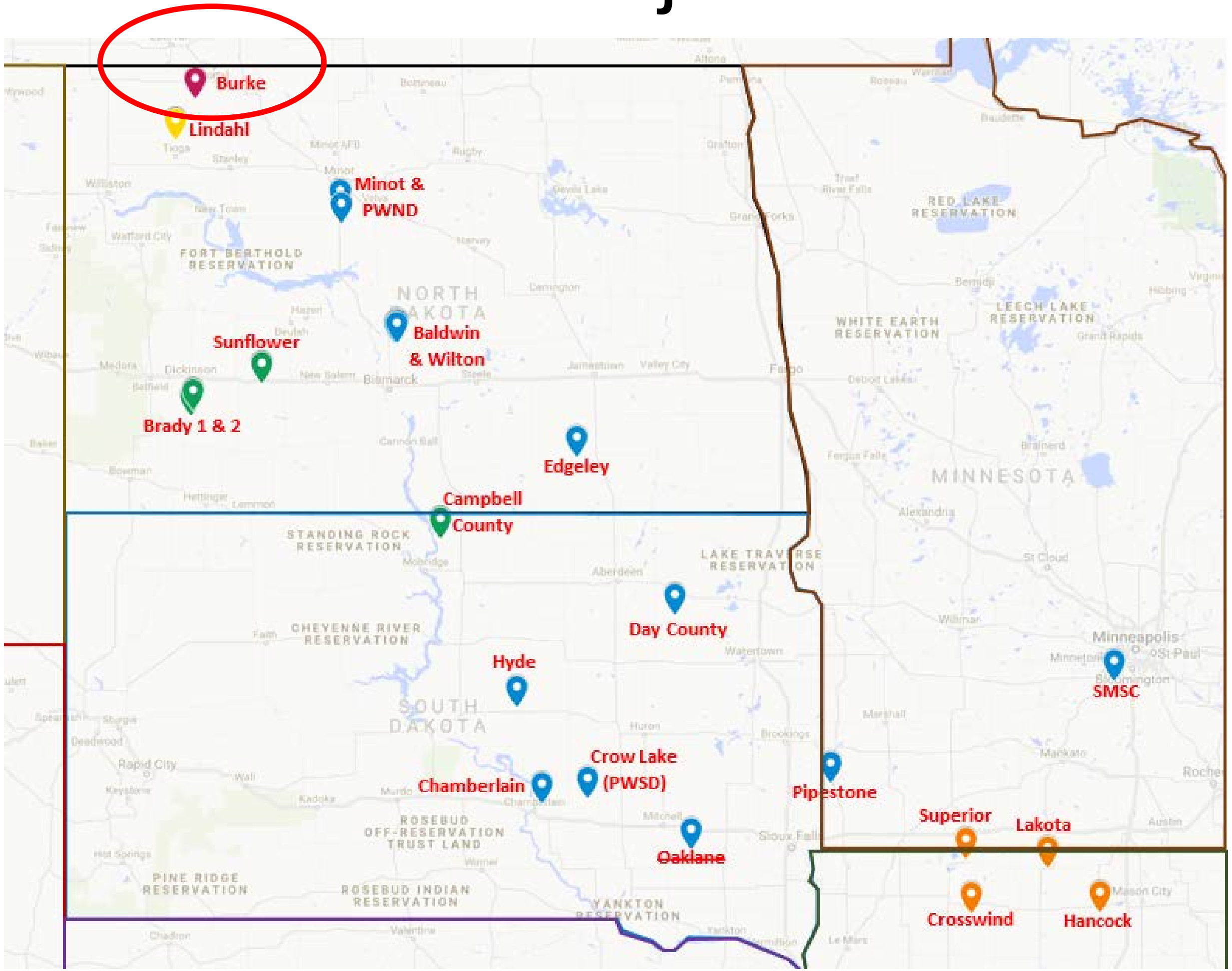
Wind Project Locations



1360 MW's

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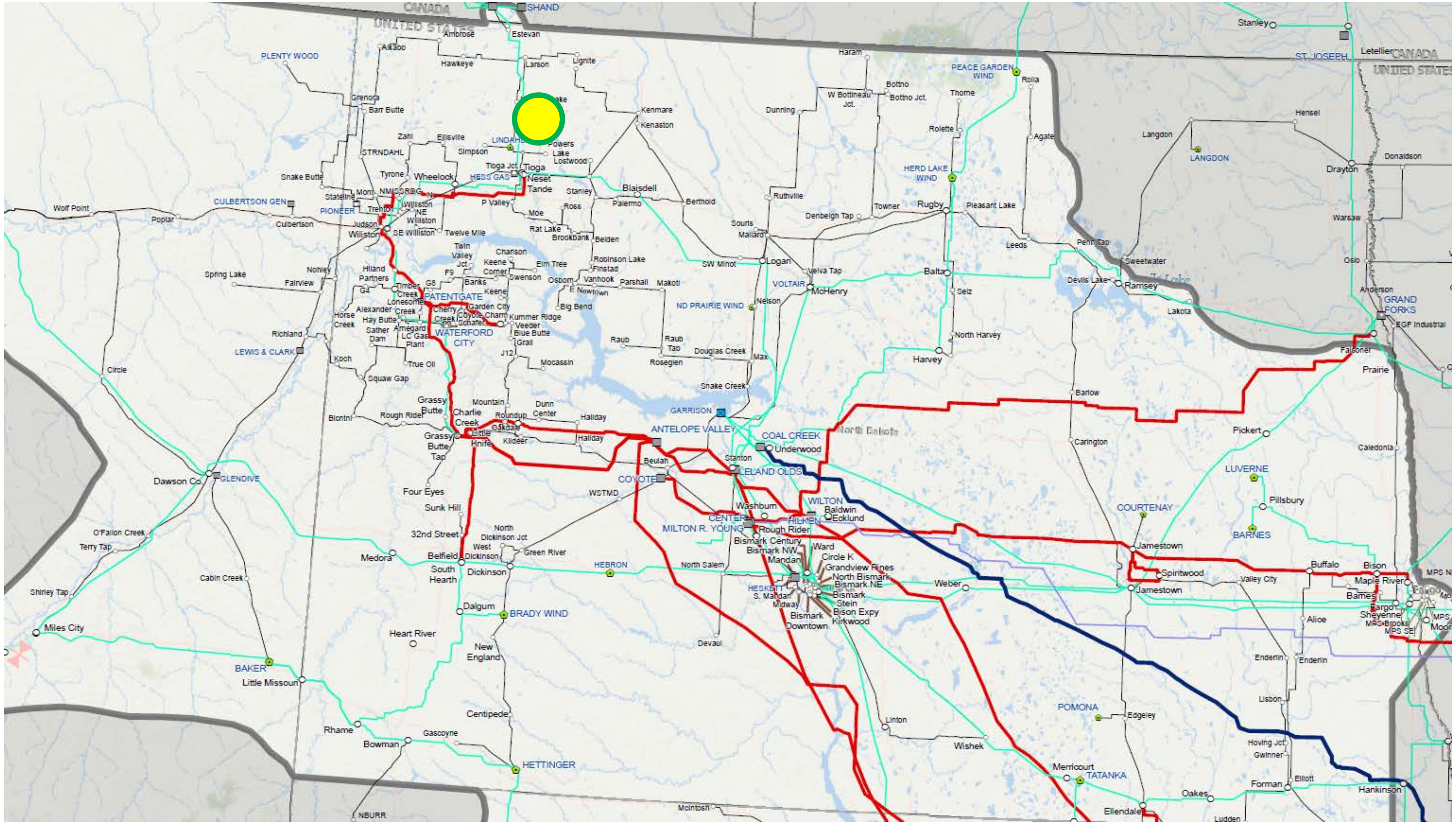
Project in relation to transmission



SPP GI Queue

Generation Interconnection Number	IFS Queue Number	Capacity (MW)	Substation or Line	Status
~~GEN-2014-004IS~~	~~IFS-2015-001-22~~	~~383.000~~	~~Charlie Creek 230kV~~	~~IA PENDING~~
GEN-2015-046	IFS-2015-002-46	300.000	Tande 345kV Substation (approximately 3.5 miles east of Tioga, ND)	FACILITY STUDY STAGE
GEN-2015-096	IFS-2015-002-43	150.000	Brady 230kV substation	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2015-098	IFS-2015-002-45	100.000	Proposed Mingusville 230kV Substation on the Dawson-Medora 230kV line	FACILITY STUDY STAGE
GEN-2016-004		202.000	Leland Olds 230 kV	FACILITY STUDY STAGE
GEN-2016-007		100.000	Valley City 115 kV	FACILITY STUDY STAGE
GEN-2016-108		200.000	Antelope Valley Substation (AVS)-Charlie Creek 345kV	DISIS STAGE
GEN-2016-130		202.000	Leland Olds 345 kV	DISIS STAGE
GEN-2016-151		202.000	Tande 345kV Sub	DISIS STAGE
GEN-2016-152		102.000	Tande 345kV Sub	DISIS STAGE
GEN-2017-010		200.100	Rhame 230 kV Sub	DISIS STAGE
GEN-2017-048		300.000	Tioga - Williston 230 kV	DISIS STAGE
GEN-2017-109		320.000	Dawson Co - Ft Peck 230 kV	FEASIBILITY STUDY STAGE

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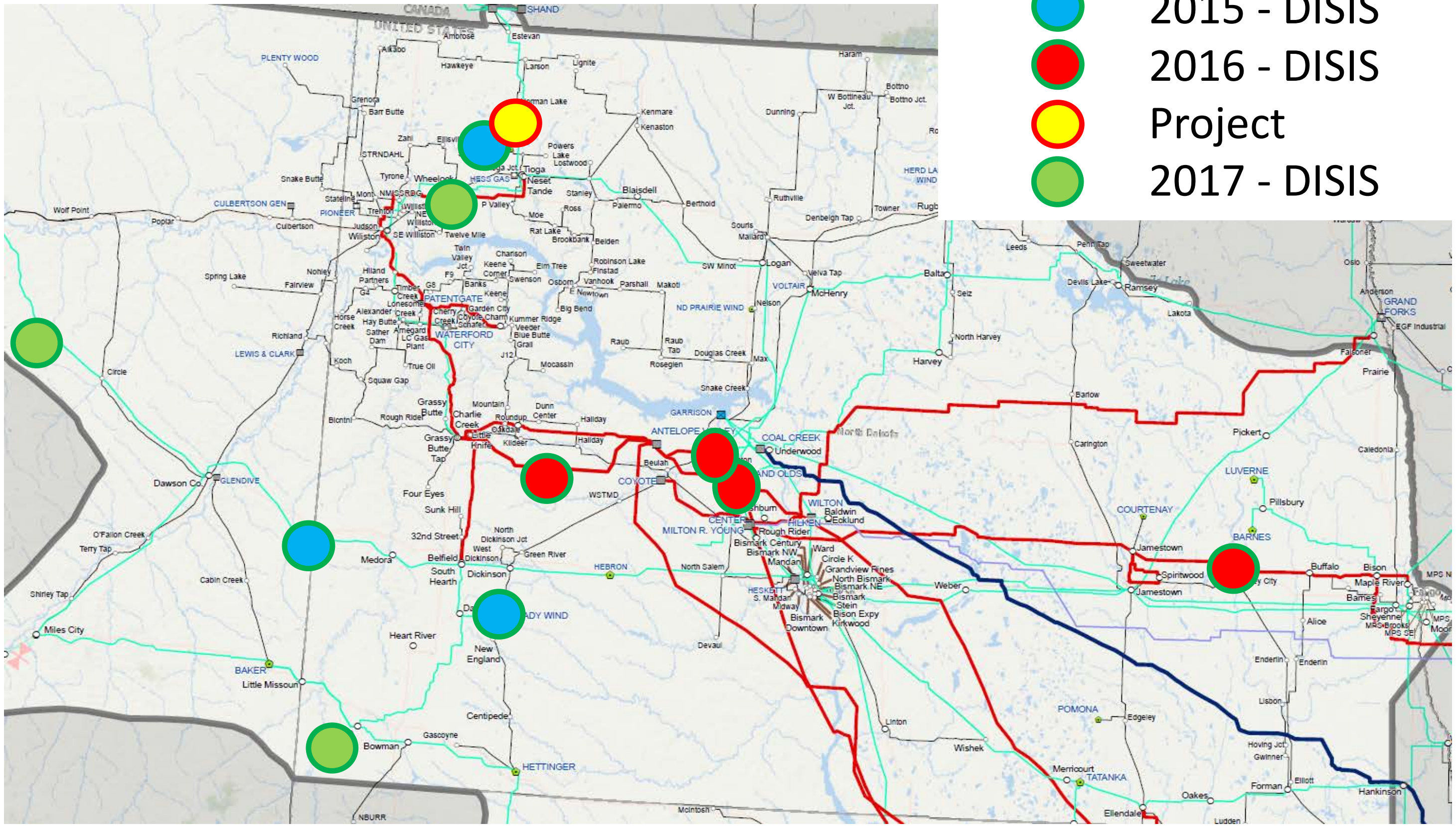
North Dakota Area

- 2015 - DISIS
- 2016 - DISIS
- Project
- 2017 - DISIS



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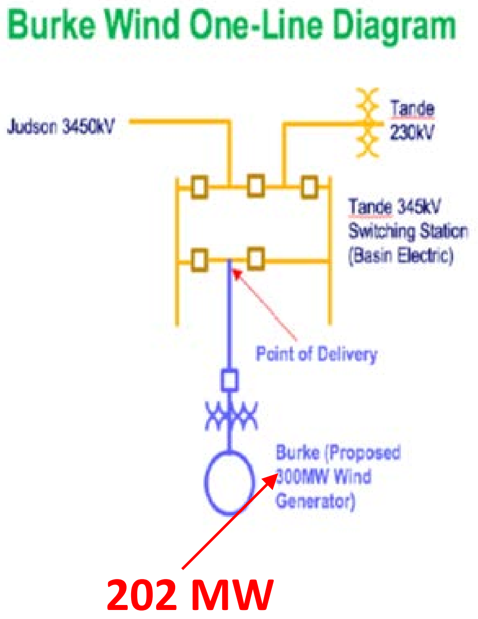
Burke Wind Info

- Gen Interconnection with SPP
  - GEN-2016-151 - 202 MW's
  - ~~GEN-2016-152 - 101 MW's~~
- Connect to Tande via radial 345 kV line
- Land
  - 100% of land leased for turbines
  - 100% of land leased for t-line - PSC application submitted for T-line in August 2018
- PSC application for wind farm submitted in Sept 2018
- NOTE: Not requesting waiver for GEN-2016-152



Gen Interconnect Issues

- Generation is part of the GEN-2016-002 study. Currently in restudy. Next report will be the 7^{th} revision.
  - There were issues identified in report for network upgrades, some projects have withdrawn and a restudy is underway

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Request

BEPC requests that the TWG and ESWG accept the resource addition request for the GEN-2016-151 (202 MW's) to be included in the 2020 ITP study.

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Westar
2020 ITP Resource Addition Request and Waiver Request for Soldier Creek Wind Farm

Economic Studies Working Group (ESWG) Meeting

December 3-4, 2018

evergy™

Public

Soldier Creek Wind Energy Center

Project Information

Project	Soldier Creek Wind Energy Center
Project Description	300 MW wind farm in Nemaha County in northeast Kansas owned by
Project Owner	Soldier Creek Wind, LLC, an affiliate of NextEra Energy Resources, LLC
Generation Type	Wind
GI Number	GEN 2016-149
Point of Interconnection	Stranger Creek Sub
In-Service Date:	EOY2020

Soldier Creek Wind Energy Center

Project Status

- In April 2018, after responding to a Westar Energy solicitation for renewable energy, NextEra Energy Resources executed a 20-year PPA with Westar Energy for Westar Energy to purchase the energy from the 300 MW Solider Creek Wind Energy Center.
- In August 2018, Westar publicly announced the agreement with NextEra.
  - Westar Energy has also publicly announced its intention to provide renewable energy from the Soldier Creek Energy Center to Kansas businesses and government agencies signing subscriptions for up to 200 megawatts under the Westar's new Renewables Direct green energy program.
- NextEra Energy Resources has acquired the funding for generating equipment in an amount constituting a majority of the queue position, has awarded procurement contracts, and has begun construction.
  - This generation resource has been entered into the DISIS process and the Facility Study process.

2020 INTEGRATED TRANSMISSION PLANNING ASSESSMENT SCOPE

Published on

By SPP Engineering

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
11/26/2018	SPP Staff	Initial Draft	

CONTENTS

SECTION 1: OVERVIEW

This document presents the scope and schedule of work for the 2020 Integrated Transmission Planning (ITP) Assessment. The Economic Studies Working Group (ESWG) and Transmission Working Group (TWG) are responsible for the creation and review of this document with approvals from the Market Operations and Policy Committee (MOPC) and the board of directors (Board).

OBJECTIVE

The objective of the 2020 ITP Assessment is to develop a regional transmission plan that provides reliable and economic delivery of energy and facilitates achievement of public policy objectives, while maximizing benefits to the end-use customer. This 2020 ITP Scope contains assumptions to be utilized in the 2020 ITP Assessment that are not standardized in the ITP Manual. These documents should be reviewed together for a comprehensive view of the 2020 ITP process and assumptions.

SECTION 2: MODELING DETAILS AND ASSUMPTIONS

This section details the additional assumptions for the development of the Market Economic models not already detailed in the ITP Manual.

MARKET ECONOMIC MODEL OVERVIEW

FUTURES

The ESWG developed two futures with input from the Strategic Planning Committee (SPC) and TWG. The MOPC approved both futures in October 2018.

Reference Case Future (Future 1)

The reference case future will reflect the continuation of current industry trends and environmental regulations. Coal generators over the age of 56, while gas fired and oil generators over the age of 50 years will be retired subject to review from generator owners. Long-term industry forecasts will be used for natural gas and coal prices. Solar and wind additions will exceed current renewable portfolio standards (RPS) due to economics, public appeal, and the anticipation of potential policy changes, as reflected in historical renewable installations. Battery energy storage resources will also be included relative to the approved solar amounts.

Emerging Technologies Future (Future 2)

The emerging technologies future will be driven primarily by the assumption that electrical vehicles, distributed generation, demand response, and energy efficiency will impact energy growth rates. Coal generators over the age of 56 will be retired, while gas-fired and oil generators over the age of 50 will be retired. Exceptions will be allowed for repowering (life extension) or emissions upgrades. As in the reference case future, current environmental regulations will be assumed and natural gas and coal prices will use long-term industry forecasts. This future assumes higher solar, wind, an energy storage resource additions than the reference case due to advances in technology that decrease capital costs and increase energy conversion efficiency.

	DRIVERS		
KEY ASSUMPTIONS	YEAR 2	REFERENCE CASE YEAR 5 YEAR 10	EMERGING TECHNOLOGIES YEAR 5 YEAR 10
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast	As submitted in load forecast
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast	Increase due to electric vehicle growth
Natural Gas Prices	Current industry forecast	Current industry forecast	Current industry forecast
Coal Prices	Current industry forecast	Current industry forecast	Current industry forecast
Emissions Prices	Current industry forecast	Current industry forecast	Current industry forecast
Fossil Fuel Retirements	Coal age-based 56+, Gas/Oil age-based 50+,	Coal age-based 56+, Gas/Oil age-based 50+, subject to generator owner review	Coal age-based 56+, Gas/Oil age-based 50+, subject to repowering or emissions upgrades
Environmental Regulations	Current regulations	Current regulations	Current regulations
Demand Response[1]	As submitted in load forecast	As submitted in load forecast	As submitted in load forecast
Distributed Generation (Solar) [2]	As submitted in load forecast	As submitted in load forecast	+300MW +500MW
Energy Efficiency[2]	As submitted in load forecast	As submitted in load forecast	As submitted in load forecast
Storage	None	20% of projected solar	35% of projected solar

	DRIVERS				
KEY ASSUMPTIONS	YEAR 2	REFERENCE CASE YEAR 5	REFERENCE CASE YEAR 10	EMERGING TECHNOLOGIES YEAR 5	EMERGING TECHNOLOGIES YEAR 10
Total Renewable Capacity					
Solar (GW)	Existing + RARs	4	7	5	9
Wind (GW)	Existing + RARs	26	28	30	33

Table 1: Future Drivers

EXTERNAL LOAD FORECASTS

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

External Entity	Load Data Source
AECI	2020 Base Reliability Model[2]
MISO	MTEP19
SaskPower	MTEP19
Manitoba Hydro	MTEP19
TVA	MTEP19
Other Regions	2020 Base Reliability Model[3]

Table 2: External Load Data Sources

MUST-RUN UNITS

Must-run designations will be assigned only to co-generation and nuclear units, unless an exception is requested during the generation review and approved by the ESWG. Must-run designation for hydroelectric generation will be allowed based upon ABB simulation ready data.

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

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

[3] Data for most regions external to SPP will be acquired from the 2017 series ERAG MMWG model set

RESOURCE PLAN

CONVENTIONAL GENERATOR PROTOTYPES

Placeholder

RENEWABLE ACCREDITATION

Placeholder

RESOURCE PLAN MODELING

As noted in the ITP Manual, the Market Powerflow models will contain system topology consistent with their respective market economic model. This topology consistency does not include the reactive power settings of the resource plans because they are not considered in the market economic models. The following parameters will guide how the resource plans, both internal and external, are modeled with regards to reactive settings such as: max/min VAR support, voltage schedule, and others. Stakeholders are given the opportunity to review certain reactive device settings during the market powerflow model review period described in Section 2.3.2 of the ITP Manual.

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

Conventional Generation

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

Solar, Wind, or Energy Storage Resources

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

SECTION 3: SOLUTION EVALUATION & PORTFOLIO DEVELOPMENT

PERSISTENT ECONOMIC OPERATIONAL SOLUTION EVALUATIONS

FLOWGATES

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

MANUAL COMMITMENT OF GENERATORS

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

CONSOLIDATION

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

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

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

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

Table 3: Consolidation Considerations Scoring Table

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

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

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

1. Test B/C threshold in opposite future
    - If project has less than 0.8 40-year B/C in opposite future, zero points will be awarded
    - If project has at least 1.0 40-year B/C in opposite future, 50 points will be awarded
    - If project meets 0.8 40-year B/C threshold in opposite future, but is less than 1.0, continue calculations
2. Calculate net APC benefits
    - $Net\ APC\ benefit_{P1,AVE}$
    - $Net\ APC\ benefit_{P1',AVE} = Net\ APC\ benefit_{P1,AVE}$ *with 1.0 40-year B/C in opposite future*
3. Calculate points awarded
    - $Points\ awarded_{P1,\%} = 50 \times \frac{Net\ APC\ benefit_{P1,AVE}}{Net\ APC\ benefit_{P1',AVE}}$

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

$$\begin{aligned} &Points\ awarded \\ &\quad = 10 \times \%\ Congestion\ relieved_{F1,addressed\ needs} \\ &\quad + 10 \times \%\ Congestion\ relieved_{F2,addressed\ needs} \end{aligned}$$

Points for consideration three will be calculated based on the severity of an operational issue that the project is expected to address, as a percentage of the operational needs criteria[4] multiplied by the points possible, up to 10.

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

OR

$$Points\ awarded = \left(\frac{Hours\ of\ system\ reconfiguration_{12\ months}}{X\%^{5} \times 8{,}760}\right) \times 10$$

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

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

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

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

5 X equals 25% for operational thermal issues. X equals 10% for operational voltage issues.

SECTION 4: FINAL ASSESSMENTS

SENSITIVITIES

Placeholder

VOLTAGE STABILITY ASSESSMENT

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

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

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

SECTION 5: SCHEDULE

The 2020 ITP assessment began in July 2018 and will be completed by October 2020. Figure 1 and Table 6 detail the study timeline.

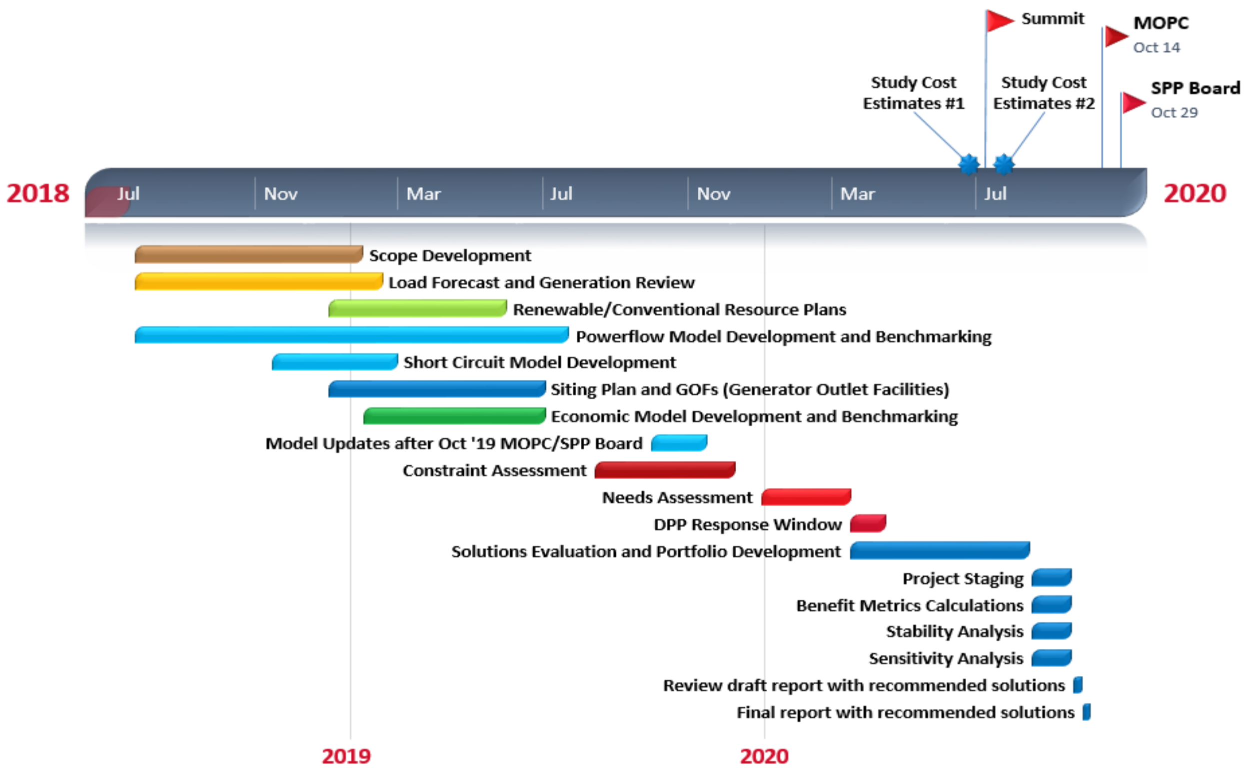

Figure 1: 2020 ITP Timeline

Milestone Name	Group(s) to Review/Endorse	Start Date	Completion Date
Scope Development	ESWG, TWG, MOPC, SPC	July 2018	January 2019
Load and Generation Review	ESWG, TWG, MDWG	July 2018	February 2019
Renewable Resource Plan	ESWG	January 2019	March 2019
Conventional Resource Plan	ESWG	February 2019	May 2019
Siting Plan & Generator Outlet Facilities (GOFs)	ESWG	April 2019	July 2019
Powerflow Model Development	TWG	July 2018	March 2019
Short Circuit Model Development	TWG	November 2018	March 2019
Economic Model Development	ESWG	July 2018	September 2019
Model Benchmarking	ESWG, TWG	December 2018	April 2019
Model Updates after October 2019 MOPC/Board (NTC/Re-evaluations)	TWG	October 2019	November 2019
Constraint Assessment	TWG	November 2019	December 2019
Needs Assessments	ESWG, TWG	January 2020	March 2020
Detailed Project Proposal (DPP) Window	ESWG, TWG	March 2020	April 2020
Solution Development	ESWG, TWG	March 2020	June 2020
Solution Evaluation	ESWG, TWG	March 2020	June 2020
Project Grouping	ESWG, TWG	April 2020	July 2020
Study Cost Estimates (Round 1)		June 2020	June 2020
Summit		July 2020	July 2020
Study Cost Estimates (Round 2)		July 2020	July 2020
Final Reliability Portfolios	TWG	June 2020	August 2020
Portfolio Optimization / Consolidation	ESWG, TWG	July 2020	August 2020
Project Staging	ESWG, TWG	August 2020	September 2020
Benefit Metrics Calculations	ESWG	August 2020	September 2020
Stability Analysis	TWG	August 2020	September 2020
Sensitivity Analysis	ESWG	August 2020	September 2020
Final Reliability Assessment	TWG	August 2020	September 2020
Review Draft Report with Recommended Solutions	ESWG, TWG	August 2020	September 2020
Final Report with Recommended Solutions	ESWG, TWG	September 2020	September 2020
	RSC, SPC, SSC	October 2020	
	MOPC, SPP Board		

Table 4: 2019 ITP Schedule

SECTION 6: CHANGES IN PROCESS AND ASSUMPTIONS

To protect against changes in process and assumptions that could present a significant risk to the completion of the 2020 ITP Assessment, any changes to this scope or assessment schedule must be appropriately vetted and follow the process outlined in the stakeholder accountability section of the ITP Manual.

2019 STEP

2019 SPP Transmission Expansion Plan Report

January XX, 2019

Engineering

Revision History

Date	Author	Description
11/05/2018	SPP	Initial Draft

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Section 1: Executive Summary

The 2019 SPP Transmission Expansion Plan (STEP) is a comprehensive listing of all transmission projects in SPP for the 20-year planning horizon. Projects included in the 2019 STEP are:

- Upgrades required to satisfy requests for Transmission Service;
- Upgrades required to satisfy requests for Generator Interconnection Service;
- Approved projects from the Integrated Transmission Planning (ITP) 20-Year,10-Year and Near-Term Assessments;
- Approved Balanced Portfolio Upgrades;
- Approved High Priority Upgrades;
- Endorsed Sponsored Upgrades; and
- Approved Interregional Projects.

The 2019 STEP consists of 376 upgrades with a total cost of $3.15 billion.

We invite stakeholders and all interested parties to submit any written comments on the projects included in the STEP via our Request Management System (RMS). SPP solicits feedback on proposed solutions to transmission needs through stakeholder working groups and planning summits as well as through meetings, teleconferences, web conferences, and via email or secure web-based workspace. These meetings provide an open forum where all stakeholders have an opportunity to provide advice and recommendations to SPP to aid in the development of the STEP. In addition to these opportunities, we also invite stakeholders to provide SPP with any transmission needs they deem to be beneficial to the transmission planning process through our website or RMS.

The chart below illustrates the cost distribution of the 2019 STEP based on project type. More detail on the total portfolio is listed in Section 10.

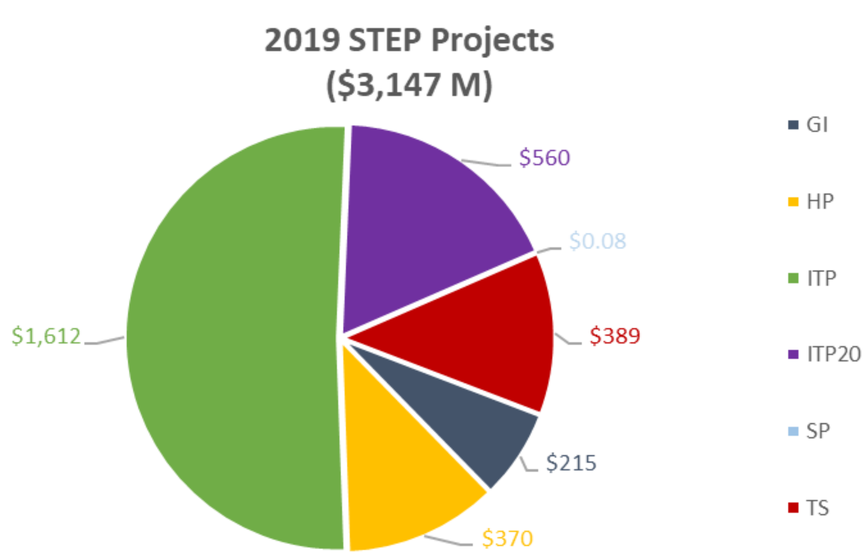


Figure 1-1: Cost by Project Type

After the SPP Board of Directors approves transmission expansion projects or once Service Agreements are executed, SPP issues Notifications to Construct (NTC) letters to appropriate Transmission Owners. A list of the NTCs issued in 2018 can be found in Section 11. A breakdown of the total list of NTCs issued in 2018 is shown below in Figure 1-2.

In 2018, SPP issued 18 NTC letters with estimated construction costs of $513 million for 24 upgrades to be constructed over the next five years through 2024. Of this $513 million, the upgrade cost breakdown is as follows:

- $39.4 million for Integrated Transmission Planning (ITP);
- $85 thousand for Sponsored Upgrades (SP);
- $474.5 million for Transmission Service (TS); and

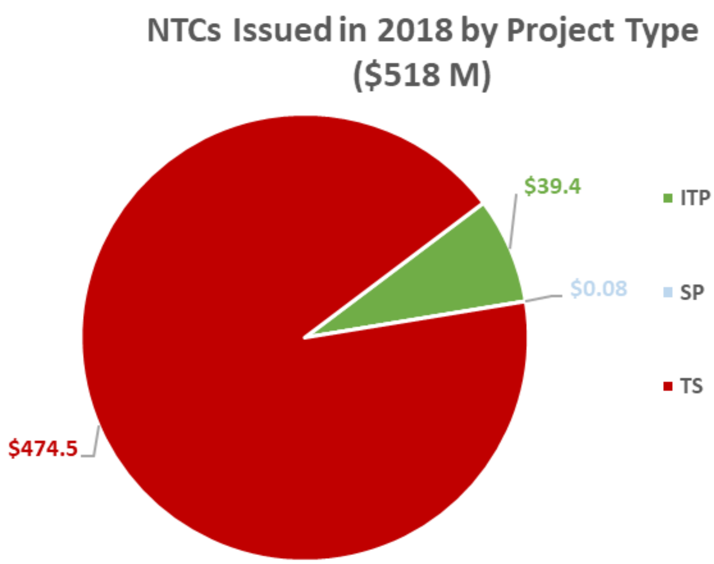


Figure 1-2: 2018 NTC Issuance

SPP actively monitors the progress of approved projects by soliciting feedback from project owners at least quarterly. As of November 6, 2018, upgrades totaling approximately $823.6 million were completed during the year. The breakdown includes:

- 11 GI - $37.1 million
- 17 HP - $202.8 million
- 61 ITP - $564.5 million
- 7 TS - $19.3 million

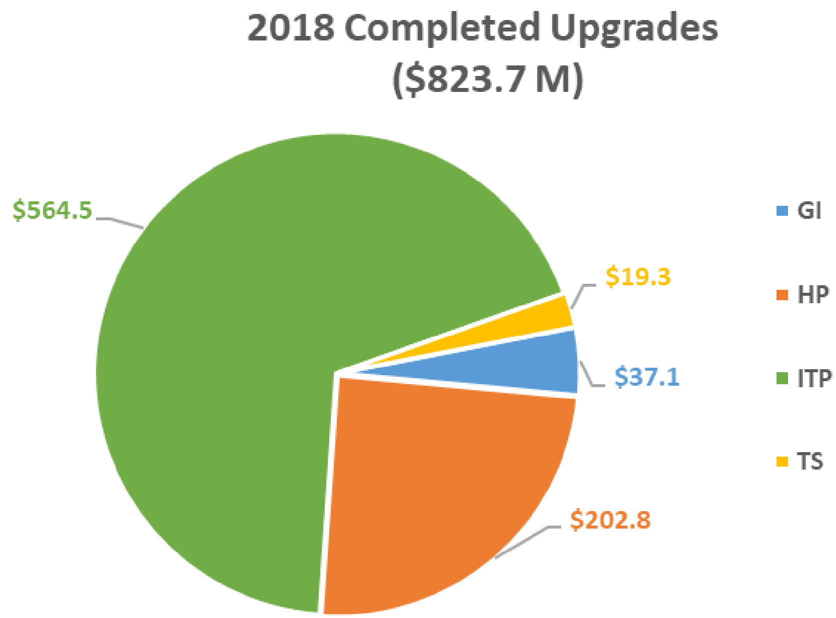


Figure 1-3: 2018 Completed Upgrades

Section 2: Transmission Services

2.1: Transmission Service 2018 Overview

SPP conducts the Aggregate Transmission Service Study (ATSS) process to determine if the SPP transmission system and neighboring Transmission Providers can accommodate requests for long-term firm Transmission Service. SPP combines all long-term point-to-point and long-term network integration transmission service requests received during a specified period of time into a single ATSS in order to develop a more efficient expansion of the transmission system that provides the necessary Available Transfer Capability (ATC) to accommodate all such requests at the minimum total cost.

During 2018, SPP completed two Aggregate Facilities Studies within the165-day study completion deadline in Attachment Z1 of the SPP Tariff. Service was granted for 42 requests with requested capacity totaling 2,078 MW. Below is a link to the Transmission Service Studies page where the studies can be further reviewed:

http://sppoasis.spp.org/documents/swpp/transmission/TRPAGE.cfm

The graph below shows the total estimated cost of Transmission Service projects included in the 2019 STEP as compared to previous STEP Reports. Fluctuations in the annual STEP estimates may be influenced by the number of new projects identified in completed Transmission Service Studies either having been issued NTCs or approved and awaiting the issuance of an NTC, the completion of Transmission Service related projects, and the increase and decrease of Transmission Owner submitted project cost estimates within the applicable STEP timeframe.

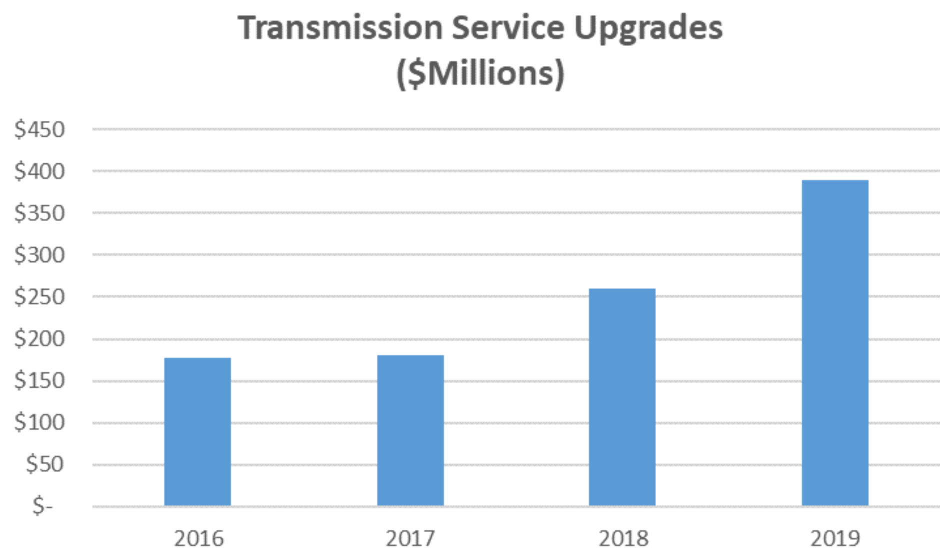


Figure 2-1: STEP Cost Estimate Comparison for Transmission Service Projects – 2016-2019

Transmission Service projects completed in 2018 can be found in the Completed Projects table in Section 12.

2.2: Tariff Attachments AQ and AR

Attachment AQ

SPP Tariff Attachment AQ defines a process through which delivery point additions, modifications, or abandonments can be studied without having to go through the Aggregate Study process. Delivery points submitted through the process are examined in an initial assessment to determine if a project is likely to have a significant effect on the transmission system. If necessary, a full study is then performed on the requested delivery points to determine any necessary upgrades. There were nine NTCs issued in 2018 as a result of the Attachment AQ study process.

The number of requests and required studies are summarized in Table 2-1 below.

Study Year	Delivery Point Requests	Full Studies Required	Load Increase
2013	87	25	1,179 MW
2014	102	27	2,502 MW
2015	94	18	1,767 MW
2016	137	21	2,025 MW
2017	104	26	2,354 MW
2018	113	33	24,490 MW

Table 2-1: AQ Study Summary – 2013-2018

Attachment AR

Attachment AR defines a screening process used to evaluate potential Long-Term Service Request (LTSR) options or proposed Delivery Point Transfers (DPT). The LTSR option provides customers with a tool to assess possible availability of transmission service. The DPT screening study option enables customers to implement a DPT via issuance of a Service Agreement, more expediently pending the results of the screening. Both of these screening tools allow for a more streamlined ATSS process by reducing the number of requests in the ATSS process.

During 2018, two DPT studies were posted and service was granted for both studies. There were no LTSR studies requested in 2018.

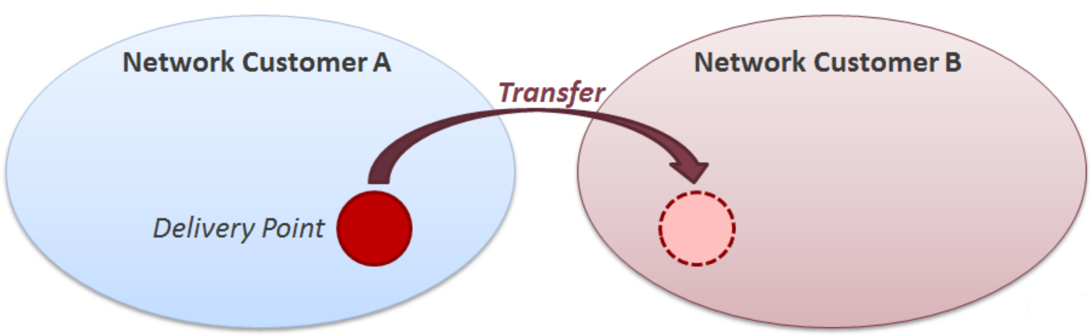


Figure 2-2 DPT Study Process

Section 3: Generator Interconnection

3.1: Generator Interconnection Overview

A GI study is conducted pursuant to Attachment V of the SPP Tariff whenever a request is made to connect new generation to the SPP transmission system. GI studies are conducted by SPP in collaboration with affected Transmission Owners and neighboring Transmission Providers to determine the required modifications to the transmission system, including cost and scheduled completion dates required to provide the service.

From January 1, 2018 to November 5, 2018 SPP received 74 GI requests and 17 (this includes both withdrawn and incomplete) affected system GI requests, compared to the 239 GI requests and 24 affected system study requests received through the same period in 2017. As of November 5, 2018, there were 434 active[1] GI queue requests under study for 77,826 MW, and 3 requests had been removed from "study" status either from being withdrawn by the Customer or SPP or by the Customer executing a Generator Interconnection Agreement (GIA). The affected system study requests were made by neighboring Transmission Providers requesting SPP's evaluation of the impact of the requests on SPP's transmission system.

The graph below shows the total estimated cost of GI projects included in the 2019 STEP as compared to previous STEP Reports. Fluctuations in the annual STEP estimates may be influenced by the number of new projects identified in completed Generator Interconnection Studies that have either been issued NTCs or are approved and are awaiting the issuance of an NTC, the completion of Generator Interconnection related projects, and the increase and decrease of Transmission Owner submitted project cost estimates within the applicable STEP timeframe.

[1] Active GI requests includes those with an OASIS status of: FEASIBILITY STUDY STAGE, PISIS STAGE, DISIS STAGE, FACILITY STUDY STAGE, or IA PENDING, and those that have been submitted but not yet validated.

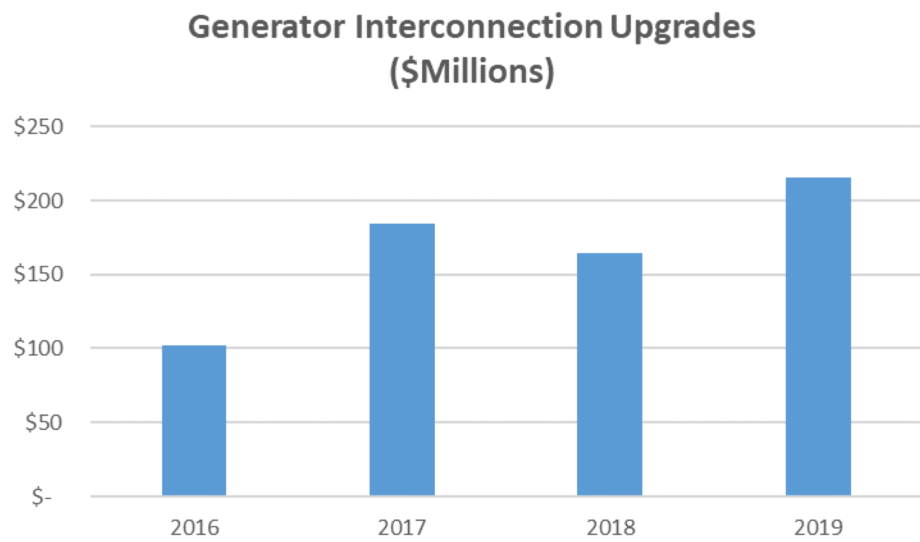


Figure 3-1: STEP Cost Estimate Comparison for Generator Interconnection Projects – 2016-2019

GI projects completed in 2018 can be found in the Completed Projects table in Section 12.

Section 4: Integrated Transmission Planning

4.1: 2018 ITP Near-Term (ITPNT)

During 2018, the 2018 ITPNT Assessment was completed and approved by the SPP Board of Directors in July. The 2018 ITPNT analyzed the SPP region's immediate transmission needs over the near-term planning horizon. The ITPNT assessed: a) regional upgrades required to maintain reliability in accordance with the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Reliability Standards and SPP Criteria in the near-term horizon; b) zonal upgrades required to maintain reliability in accordance with more stringent individual Transmission Owner planning criteria in the near-term horizon; and c) coordinated projects with neighboring Transmission Providers. ITPNT projects are reviewed by SPP's Transmission Working Group (TWG) and Markets and Operations Policy Committee (MOPC) and approved by the SPP Board of Directors. Following Board of Directors' approval, SPP issued NTC letters for upgrades that required a financial commitment within the next four-year timeframe.

SPP performed analyses identifying potential bulk power system reliability needs. These findings were presented to Transmission Owners and the TWG to solicit transmission solutions to the potential issues identified. Also considered were transmission solutions from other SPP studies, such as the Aggregate Transmission Service Study and Generator Interconnection processes. From the resulting list of potential solutions, SPP identified the cost effective regional solutions for potential reliability needs. Through this process, SPP developed a draft list of 69 kV and above solutions necessary to provide reliable service in the SPP region in the near-term planning horizon.

The 2018 ITPNT differed from previous ITPNT assessments in several specific areas. These areas include significant generation retirements [~1.7 gigawatts (GW)], implementation of the base reliability (BR) model methodology, addition of the Brookline high-voltage operational need, inclusion of DC-tie sensitivity cases modeling the northern DC ties with an opposite powerflowtrans bias, and additional scrutiny of scenario 5 summer needs.

For information on the 2018 ITPNT Assessment, see the full report (SPP.org > Engineering > Transmission Planning>2018 ITPNT Report).

The maps in Figures 4-1 and 4-2 show the draft ITPNT thermal and voltage solutions in correlation to the areas identified with reliability criteria violations.

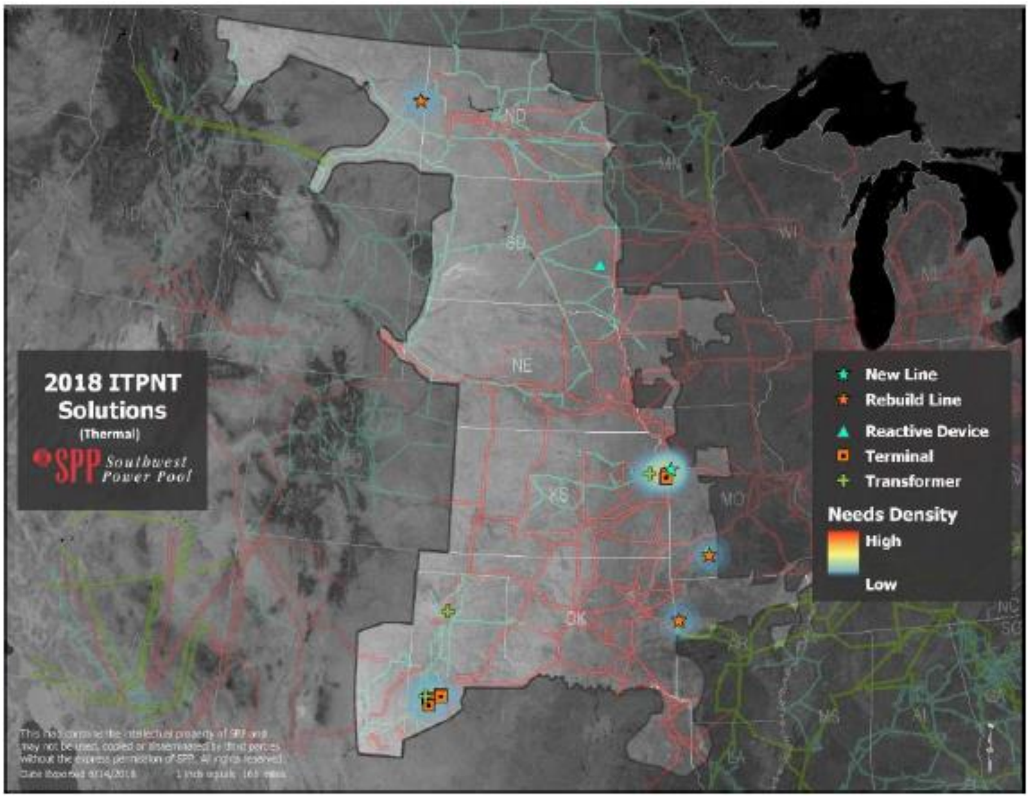


Figure 4-1: 2018 ITPNT Thermal Needs and Solutions

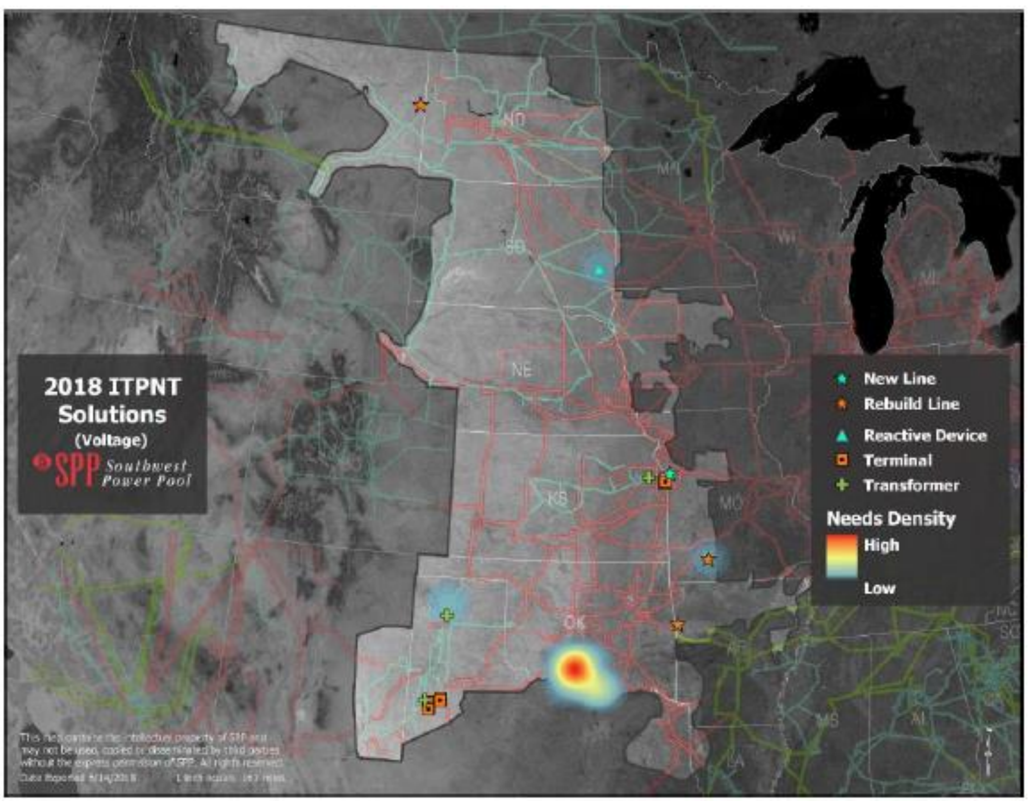


Figure 4-2: 2018 ITPNT Voltage Needs and Solutions

The net total study STEP impact of the 2018 ITPNT project plan is estimated to be ($55.3M). There are 18 proposed upgrades making up 14 projects in the project plan. Of the 14 proposed projects, all recommended for issuance of new NTCs. Net impact includes $394M for new projects and a reduction of $84.7M for withdrawn NTCs identified in the 2018 ITPNT Assessment. The 17 upgrades that received an NTC solved 47 thermal and 54 voltage needs on the SPP transmission system. Project plan mileage consists of 5.6 miles of new transmission line and 8.5 miles of rebuild/reconductor line.

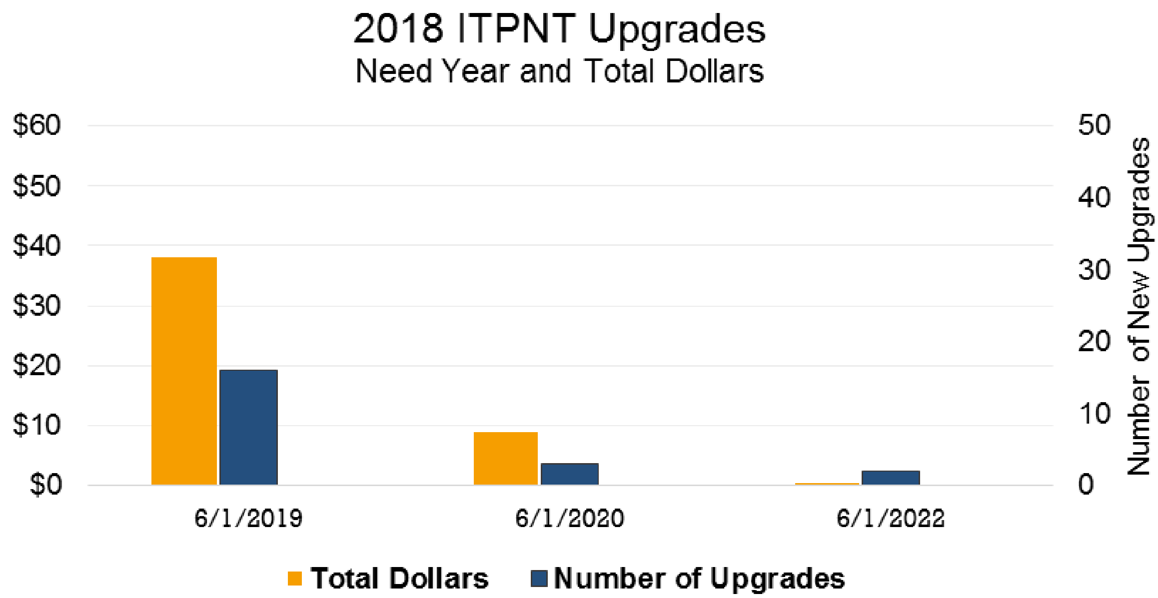


Figure 4-3: 2018 ITPNT Upgrades by Need Years and Dollars

Voltage Class	New Line (miles)	Rebuild/Reconductor (miles)
161 kV	5.6	0
115 kV	0	3
69 kV	0	5.5

Table 4-1: 2018 ITPNT Project Plan Mileages

The 2019 and 2020 ITP Assessments are currently in progress SPP intends to finalize the 2019 and 2020 Reports and Portfolios in October 2019 and October 2020, respectively.

Section 5: High Priority Studies

Figure 5-1 below is a comparison of the cost estimates for projects coming out of High Priority Studies. High Priority Studies upgrades completed in 2018 can be found in the Complete Upgrade table in Section 12. Study details follow in sections 5-1 and 5-2.

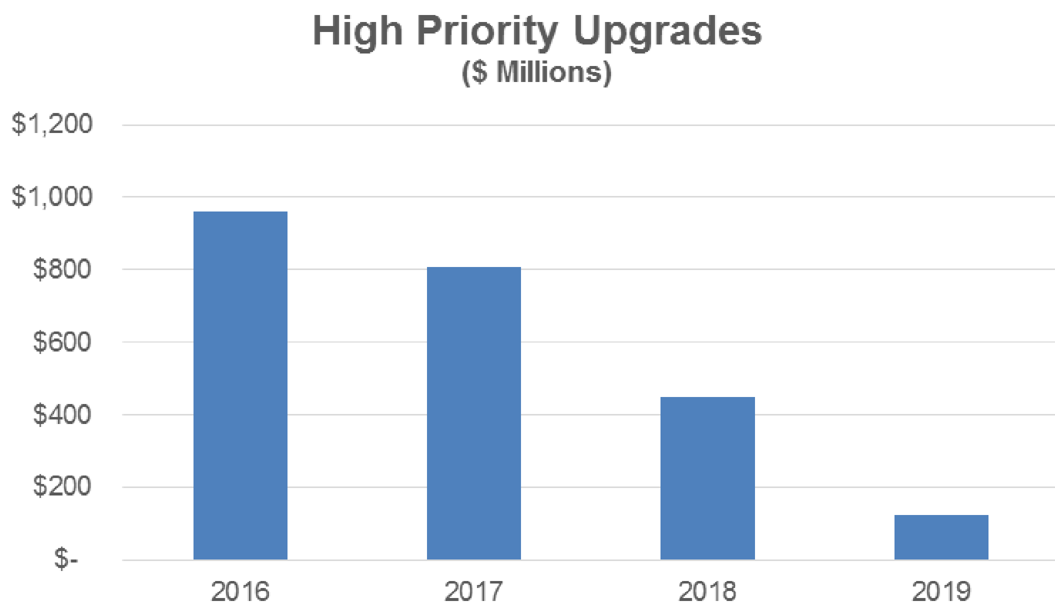


Figure 5-1: STEP Cost Estimate Comparison for High Priority Projects – 2016-2019

5.1: High Priority Incremental Load Study (HPILS)

HPILS upgrades included in the 2019 STEP List are listed in Table 5-2 below.

For information on the HPILS assessment, see the full report (SPP.org > Engineering > Transmission Planning>Local Area Planning and High Priority Studies).

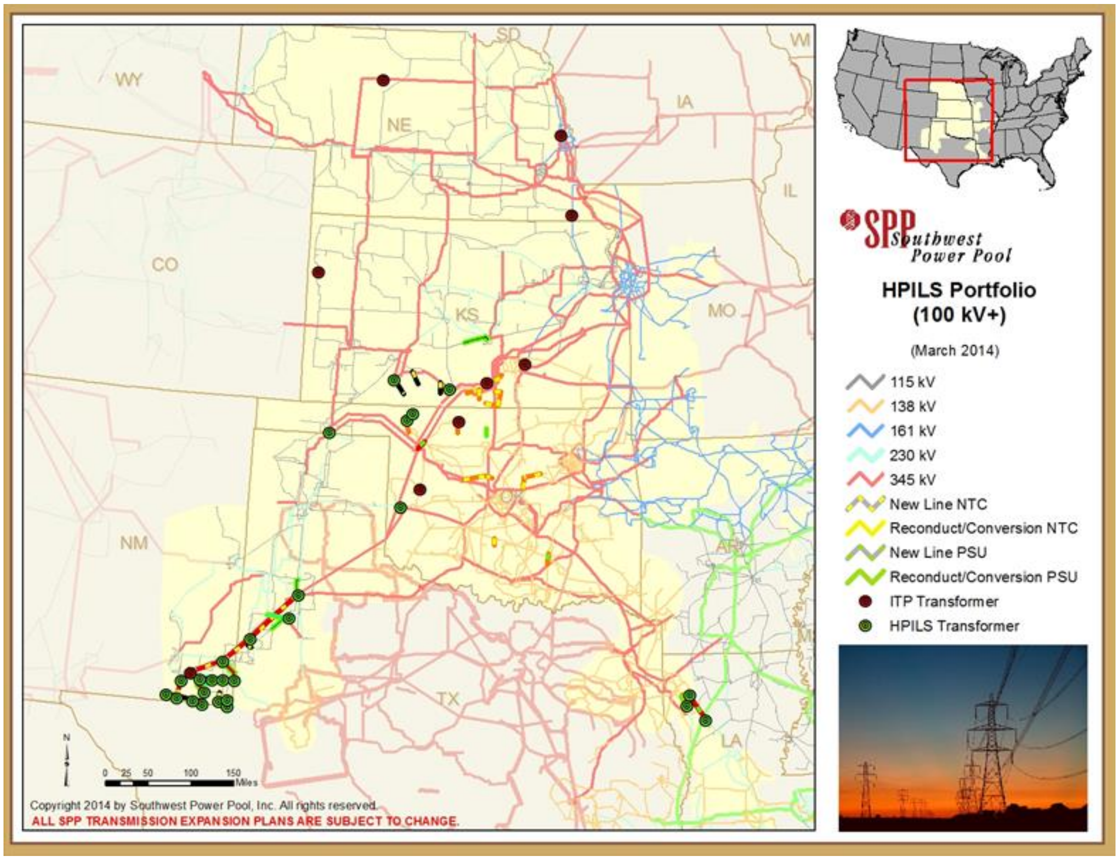


Figure 5-2: Finalized HPILS Portfolio (100 kV and above)

NTC ID	Project ID	Upgrade ID	Project Owner	Project Name	Current Cost Estimate
200282	30672	50874	MKEC	Line - Harper - Rago 138 kV Ckt 1	$12,625,134
200282	30675	50988	NPPD	XFR - Thedford 345/115 kV	$10,236,801
200282	30675	50869	SPS	Multi - China Draw - Yeso Hills 115 kV	$15,776,480
200277	30678	51002	SPS	Multi - Dollarhide - Toboso Flats 115 kV	$5,062,341
200277	30678	50889	SPS	Multi - Ponderosa - Ponderosa Tap 115 kV	$5,222,364
200309	30376	50457	SPS	Multi - Hobbs - Yoakum 345/230 kV Ckt 1	$104,655,870
210484	31068	50451	SPS	Multi - Kiowa - North Loving - China Draw 345/115 kV Ckt 1	$72,457,140

Table 5-1: HPILS Projects

Section 6: Sponsored Upgrades

From January 1, 2018 to November 5, 2018, nine Sponsored Upgrade study requests were submitted. Two NTCs for sponsored upgrades have been issued and are included in this Section 10 of this report.

NTC ID	Project ID	Upgrade ID	Project Owner	Project Name	Current Cost Estimate
210487	51278	72005	CPEC	North Bismarck 115 kV Terminal Upgrades	$0
210486	51278	72006	WAPA	Bismarck 115 kV Terminal Upgrades	$84,639

Section 7: Regional Cost Allocation Review (RCAR)

SPP filed Docket No. ER17-2229 with the Federal Energy Regulatory Commission (FERC) on August 2, 2017 requesting revision to Attachment J, Section III.D.1 of its OATT. SPP, with review and/or approval of the RARTF, RTWG, CAWG, MOPC and the RSC, requested the timeline for performing the RCAR analysis be revised from the current three-year mandatory requirement to six years. An effective date of October 1, 2017 was also requested. The FERC issued an Order[2] on September 29, 2017 accepting the tariff revision.

The RARTF is currently exploring options for the RCAR III and IV assessments. During the RARTF meeting on January 15, 2018, SPP staff presented details on four options for analysis methodology in the upcoming RCAR assessments:

1. Status Quo (Planning Based Approach) used in previous RCARs
2. Operations Based Approach utilizing the market engine to calculate a historical APC and forecasted future benefit based on historical data.
3. Historical Only Approach that would be similar to #2 above but without the forecasted future benefits.
4. Hybrid Approach that would include the historical Operations Based Approach in #2 for project that are in-service and a planning based approach described in #1 for those projects that have been approved but are not yet in-service.

SPP Staff has provided additional detail for all of these options emphasis on option 4. The RARTF is now focused on answering policy questions required to implement the selected methodology.

[2] https://www.ferc.gov/CalendarFiles/20170929091320-ER17-2229-000.pdf

Section 8: Interregional Coordination

8.1: Interregional Planning

Throughout 2017, SPP continued participation in joint planning and coordination processes with three different neighboring entities. SPP's respective Joint Operating Agreements (JOA) with Associated Electric Cooperative Inc. (AECI) and Midcontinent Independent System Operator (MISO) outline the requirements for joint and coordinated planning procedures, each of which result in the production of a Coordinated System Plan (CSP) which concluded in 2017. Addendum 4 to Attachment O of the Tariff outlines the requirements of the joint coordination procedures with the Southeastern Regional Planning Transmission group (SERTP).

2016 SPP-AECI JCSP

The SPP-AECI Joint Operating Agreement (JOA) requires a Joint Coordinated System Plan (JCSP) study be performed every other year to assure the reliable, efficient and effective operation of the transmission system along the SPP-AECI seam. SPP and AECI, along with SPP stakeholders, collaborated throughout 2016 on the performance of a JCSP to identify potential joint transmission projects that are mutually beneficial to both entities. The study concluded in January 2017 with the SPP-AECI Joint Planning Committee approving two projects.

Morgan Transformer Project

The project includes the addition of a new 345/161 kV transformer at AECI's existing Morgan substation in addition to an uprate of the 161 kV line between Morgan and Brookline. The analysis performed in the 2016 SPP-AECI JCSP showed significant benefit across multiple models used for the study. SPP and AECI utilized real-time Emergency Management System (EMS) modeling data to mimic the known and chronic operational issues in a planning model. These models allowed SPP to test potential transmission solutions to address the overloading issues at Brookline. An adjusted 2017 ITPNT model was also used to recreate the problem using a No Hydro Scenario. By turning off all of Southwestern Power Administration's (SPA) hydro generation and City Utilities of Springfield (CUS) JTEC units, SPP was able to recreate the overloading issues in a severe planning case. Table 8-1 illustrates the results of the Brookline overloading issues.

2016 SPP-AECI JCSP	Brookline Transformer %Overloaded (EMS Model)	Brookline Transformer %Overloaded (No Hydro Model)
Base case	102.8%	129.4%
Morgan Transformer	84.2%	99.5%

Table 8-1: Brookline Overloading Issues

In addition to the benefit shown in the joint study with AECI, this project also was recommended as an economic solution to address congestion in the 2017 SPP ITP10 study. The project's estimated engineering and construction costs is $13.75M. SPP and

AECI agreed to a cost share where SPP would be responsible for 89% of the project or $12.25M.

Brookline Reactor Project

The project includes the addition of a 50 MVAR reactor at SPP's existing Brookline 345 kV substation. The analysis performed in the 2016 SPP-AECI JCSP showed significant benefit for the project by reducing the voltage levels to be under SPP's criteria of 1.05 per unit (pu). The analysis also demonstrated that voltage levels would be lower on two AECI buses located at Huben and Morgan. SPP and AECI utilized real-time EMS modeling data to mimic the known and chronic operational high voltage issues in a planning model. These models allowed SPP to test potential transmission solutions to address the issue. Table 8-2 illustrates the results of the Brookline high voltage issues.

2016 SPP-AECI JCSP	Brookline High Voltages (pu)	Huben High Voltages (pu)	Morgan High Voltages (pu)
Base case	1.051	1.057	1.053
Brookline Reactor	1.039	1.054	1.046

Table 8-2: Brookline High Voltage Issues

In addition to the joint study with AECI, SPP also performed a regional review of this project in 2017. The project's estimated engineering and construction costs is $5M that would be allocated to SPP and AECI. SPP and AECI agreed to a cost share where SPP would be responsible for 97% of the project or $4.85M.

Regional Review of the 2016 SPP-AECI JCSP

SPP follows the stakeholder approved Regional Review Methodology to confirm the benefits to the SPP transmission system. The Morgan Transformer Project was not required to go through a regional review process because it was previously approved through an SPP regional planning process.

Regional Review of the Brookline Reactor Project

The TWG developed and approved the Brookline Reactor Regional Review Scope. The scope included evaluating the project in a planning model, reviewing the work done in the 2016 SPP-AECI JCSP, and confirming the project addressed a persistent operational need.

SPP utilized the 2017 ITP Near-Term supplemental model(s), which include the 2017 ITP10 approved projects, Generation Interconnection and Transmission Service approved projects and known model corrections, to evaluate the effectiveness of the project to provide voltage relief on the facilities in the area. As discussed in previous sections, no high voltage criteria violations in the area were identified in either the base or change case runs as this need is not typically identified in traditional planning studies.

SPP also presented an in-depth review of the analysis completed in the joint study with AECI to provide the benefits identified to SPP. The purpose of this was to provide stakeholders who had not been involved in the joint portion of the study with the study results and the benefit identified to SPP.

Lastly, SPP utilized the Persistent Operations Issues Criteria document that was approved within SPP's regional stakeholder groups to provide details highlighting the presence of the chronic operational issues the project is addresses. High voltage issues in the document are described below:

- High/Low Voltage issues (Reliability)
    - Transmission Operating Guides that require reconfiguration, documenting mitigations for high and low voltage issues, will be reviewed from the last cycle and related voltage issues will be added to the ITP needs list. The mitigation to avoid the high/low voltage issue must be implemented 10% of the time of the year due to non-outage issues. Transmission Operating Guides that will be considered will only include transmission reconfiguration or potential load shed events. Switched shunts and generator Mvar adjustments will be optimized prior to needs being identified.

SPP provided the data to show the high voltage needs this project addresses are indeed a persistent operational issue. The mitigation to relieve the high voltage needs was active 22.47% of the time in 2016.

The SPP SSC, TWG, MOPC, and Board of Directors all approved the Brookline Reactor Project out of the regional review process.

FERC Filings

On August 7, 2017, SPP submitted filings to FERC for i) approval of the joint SPP and AECI projects; ii) the cost sharing approach negotiated between SPP and AECI; and iii) the regional cost allocation of the SPP responsible costs. This filing also included the negotiated agreement between SPP and AECI. SPP had requested an October 6, 2017 effective date.

On October 6, 2017, FERC issued an order rejecting the cost allocation for proposed Morgan Transformer and Brookline Reactor transmission projects identified pursuant to the joint planning process contained in the Commission-approved Joint Operating Agreement between SPP and AECI, and in so doing rejecting the proposed projects.

In the Order, FERC stated that "SPP has not shown that the proposed cost allocation for these specific non-Order No. 1000 projects, and the allocation of SPP's share of the costs of these projects on a region-wide, load-ratio share basis, is roughly commensurate with the projects' benefits…" and continued "Our rejection of SPP's proposal in these dockets does not preclude SPP from making a filing with the Commission demonstrating that the Morgan Transformer Project and Brookline Reactor Project provide regional benefits or proposing an alternative allocation of its share of the costs of these transmission projects that is roughly commensurate with the benefits"

SPP staff is evaluating the Commission's order and developing next steps for cost allocation of the two joint projects.

2016 SPP-MISO CSP

SPP continued interregional planning activities with MISO in 2017. SPP and MISO continued the 2016 CSP study pursuant to the joint planning procedures contained in Article 9 of the SPP-MISO JOA. The CSP was formally initiated on May 31, 2016, when the SPP-MISO Joint Planning Commission (JPC) voted in favor of performing a 2016 CSP Study. The purpose of the 2016 CSP study was to jointly evaluate seams transmission issues and identify transmission solutions that efficiently address the identified issues to the benefit of both SPP and MISO. The study consisted of an economic evaluation of seams transmission issues previously identified in SPP and MISO regional planning processes. This was accomplished by leveraging transmission needs identified in the SPP Integrated Transmission Planning (ITP) studies (2017 ITP10) and the MISO Transmission Expansion Planning (MTEP) process (2016 MTEP). The goal of the approach was to determine if interregional transmission solutions exist that were more efficient and cost effective than what each Regional Transmission Organization (RTO) could do regionally to address these needs. The interregional portion of the study concluded in April of 2017 with one project being recommended by the SPP-MISO JPC.

Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls

The proposed Interregional Project, Loop One Split Rock to Lawrence 115 kV Ckt into Sioux Falls, was a proposed new transmission project located near Sioux Falls, South Dakota. This project had an estimated in-service date of 2021. This project is also referred to as “I-18”.

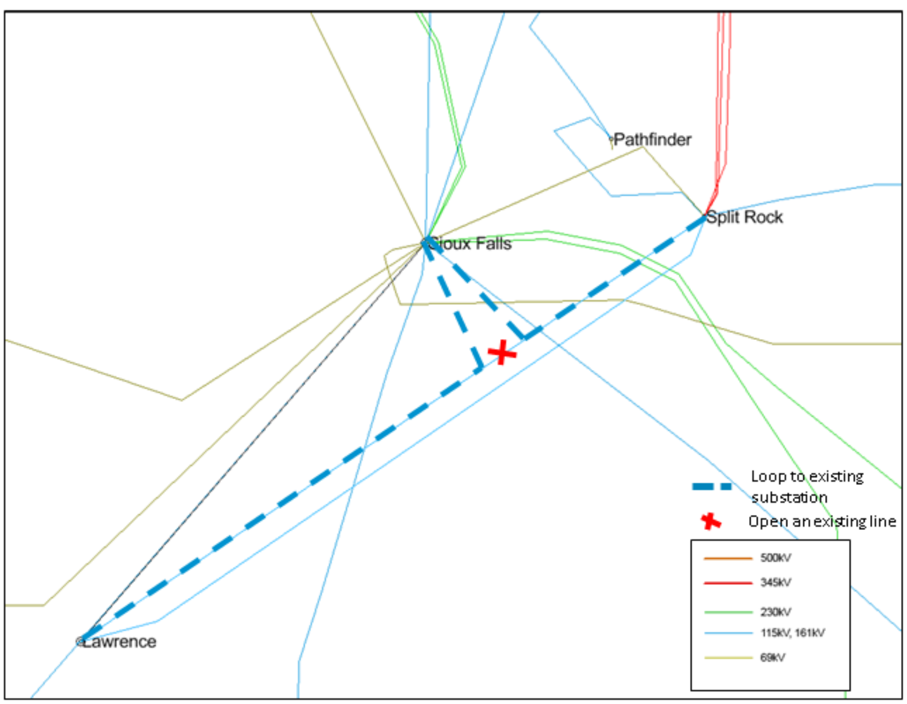


Figure 8-1: Loop One Split Rock to Lawrence 115 kV Ckt into Sioux Falls

The 2016 CSP study demonstrated this project provides APC benefits to both MISO and SPP that exceed the cost of the project over the initial 20 years of the project’s life. As a result the Loop One Split Rock to Lawrence 115kV circuit into Sioux Falls project was recommended by MISO and SPP to the Interregional Planning Stakeholder Advisory Committee (IPSAC) for endorsement to move from the interregional portion of the study into the regional review process of each respective region. Both the MISO and SPP portion of the IPSAC endorsed this recommendation with no opposition. Based on that recommendation, the MISO-SPP Joint Planning Committee (JPC) voted in favor of approving this project for review in both the MISO and SPP regional review processes.

This project was proposed to relieve congestion on the Sioux Falls to Lawrence 115 kV FTLO Sioux Falls to Split Rock 230 kV flowgate. MISO and SPP's analyses showed the project completely relieves the congestion on this flowgate and provides benefit to both parties.

The estimated a scoping level cost estimate was approximately $6.15 million for this project. Assuming the in-service date of 2021, the $6.15 million cost resulted in a 20-year present value cost of $7.51 million. MISO and SPP's 20-year present value benefit analysis showed that MISO and SPP are estimated to collectively receive $27.83 million in APC benefit over the first 20 years of the project's life, resulting in a B/C ratio of 3.71. Of the $27.83 million of APC benefit, SPP is estimated to receive $5.15 million with MISO receiving $22.68 million. Since the proportion of cost paid by MISO and SPP is based on the proportion of benefits, the individual B/C ratio for both MISO and SPP is 3.71. Both MISO and SPP supported the recommendation of this project into the regional review process.

Regional Review of the Loop One Split Rock to Lawrence 115 kV Circuit into Sioux Falls

SPP's regional review analyses evaluated the Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls project's benefit to the SPP transmission system. Similar to the results seen in the interregional portion of the CSP, the project was shown to be beneficial to SPP. In accordance with SPP's Regional Review Methodology, the SSC and the Economic Studies Working Group (ESWG) are the SPP stakeholder groups responsible for oversight of the regional review. The ESWG is responsible for developing and approving the study scope. The regional review scope approved by the ESWG included calculating 1 year APC benefits using the 2017 ITP10 Sidebar Models. The analyses included evaluating both Future 1 and Future 3 scenarios.

- Future 1: Regional Clean Power Plan Solution - This Future assumes that the EPA CPP will be implemented at the regional level by meeting emission targets within the SPP footprint and each of its neighboring regions. Future 1 includes all assumptions from Future 3 with an increase in large-scale solar development and minimal distributed solar development.
- Future 3: Reference Case - This Future assumes no major changes to policies that are currently in place. Future 3 will include all statutory/regulatory renewable mandates and goals as well as other energy or capacity as identified in the Renewable Policy Survey, load growth projected by load serving entities through the MDWG model development process, and the impacts of existing regulations. Additional significant features of this Future include competitive wind and high availability of natural gas.

In addition to evaluating I-18, SPP's regional review also evaluated the SPP benefits of operating the Sioux Falls to Lawrence 115 kV line as open. The ESWG approved the additional analyses as an amendment to the regional review scope. The results from the analyses are shown in the table below.

Project	Future	SPP 1-yr Nominal NPCC Cost	2025 Sidebar Model w/ 2017 ITP10 Portfolio	
			SPP 1-yr Benefit	SPP 1-yr B/C
I18	F1	$212,009.74	$3.5M	$16.49
I18	F3	$212,009.74	$0.17M	$0.80
Open Line	F1	$0.00	$3.73M	N/A
Open Line	F3	$0.00	($-0.24M)	N/A

Table 8-3: Analysis Results of Sioux Falls-Lawrence 115 kV Line

SPP's analyses determined both solutions evaluated were potentially beneficial to the SPP transmission system, but only I-18 would provide long-term benefit to SPP. While operating the Sioux Falls to Lawrence line as open does provide SPP benefit in Future 1, it does not provide SPP with positive benefit across all the sensitivities evaluated in the regional review. Additional analysis also showed opening the line has the potential of shifting congestion to other constraints in the area demonstrating operating the line as open is not a long-term solution for SPP. Loop One Split Rock to Lawrence 115 kV circuit into Sioux Falls was determined to fully relieve congestion on the study need across all sensitivities and provides positive benefit to SPP across all sensitivities as well. Additional analysis of I-18 demonstrated potential congestion relief under multiple different contingencies in the area, demonstrating the potential to provide a more robust solution to opening the line, which SPP views as a better long-term solution to address congestion.

The project was endorsed by SPP's Seams Steering Committee (SSC) as a result of the interregional process and the SPP MOPC endorsed the report given to them at their October 2017 meeting. The SSC and MOPC endorsements were a result of the projects inability to be an approved Interregional Project due to MISO's prior determination not to recommend the project move forward. MISO and SPP will continue to explore process improvements to the RTOs' joint planning processes with the goal of performing more meaningful and beneficial joint studies.

Section 9: Project Tracking

9.1: NTC Letters Issued in 2018

After the SPP Board of Directors approves transmission expansion projects or once Service Agreements are executed, SPP issues Notifications to Construct (NTC) letters to appropriate Transmission Owners.

In 2018, SPP issued 22 NTC letters with estimated new construction costs of $514 million for 87 upgrades to be constructed over the next five years through 2024. Of this $514 million, the upgrade cost breakdown is as follows:

- $474.5 million for Transmission Service (TS)
- $39.4 million for Integrated Transmission Planning (ITP) projects and
- $84.6 thousand for Sponsored Upgrades (SP)
- $30.1 million for projects with revised NTCs not included in Totals

9.2: Projects Completed in 2018

After the SPP Board of Directors approves transmission expansion projects, SPP issues NTC letters to appropriate Transmission Owners. SPP actively monitors the progress of approved projects by soliciting feedback from project owners at least quarterly. As of November 5, 2018, 96 upgrades totaling approximately $824.7 million were completed during the year. The breakdown includes:

- 11 GI - $37.1 million
- 17 HP - $202.8 million
- 61 ITP - $564.5 million
- 7 TS - $19.4 million

9.3: ITP20 Projects

ITP20 assessments were performed in 2010 and 2013. While the projects proposed by those studies are incorporated into the STEP Project List, they are not included in SPP's project tracking effort as part of the Quarterly Tracking Report. A list of active ITP20 projects will be maintained in the STEP Report and Project List. The current ITP20 projects are listed in the table below.

Project ID	Upgrade ID	Owner	Upgrade Name	RTO Determined Need Date	Latest Cost Estimate
30401	50492	TBD	Cass Co. - S.W. Omaha (aka S3454) 345 kV Ckt1	1/1/2033	$33,126,800
30402	50493	OPPD	S3459 345/161 kV Transformer Ckt 2	1/1/2033	$12,600,000

Project ID	Upgrade ID	Owner	Upgrade Name	RTO Determined Need Date	Latest Cost Estimate
30599	50769	AEP	South Fayetteville 345/161 kV Transformer Ckt1	1/1/2033	$12,600,000
30599	50770	TBD	Chamber Springs - South Fayetteville 345 kV Ckt1	1/1/2033	$21,295,800
30600	50771	GMO	Maryville 345/161 kV Transformer Ckt1	1/1/2033	$12,600,000
30601	50772	KCPL	Nashua 345/161 kV Transformer Upgrade Ckt11	1/1/2033	$12,600,000
30602	50773	TBD	Keystone - Red Willow 345 kV Ckt1	1/1/2033	$130,141,000
30603	50774	TBD	Tolk - Tuco 345 kV Ckt1	1/1/2033	$75,718,400
30604	50775	SEPC	Holcomb 345/115 kV Transformer Ckt2	1/1/2033	$12,600,000
30605	50776	TBD	Neosho - Wolf Creek 345 kV Ckt1	1/1/2033	$117,126,900
30606	50777	TBD	Clinton - Truman 161 kV Ckt1 Reconductor	1/1/2033	$15,701,325
30606	50778	TBD	North Warsaw - Truman 161 kV Ckt1 Reconductor	1/1/2033	$1,082,850
30608	50779	WR	Auburn 345/115 kV Transformer Ckt2	1/1/2033	$12,600,000
30608	50780	TBD	Auburn - Swissvale 345 kV Ckt1 Voltage Conversion	1/1/2033	$20,112,700
30608	50781	TBD	Auburn - Jeffrey EC 345 kV Ckt1 Voltage Conversion	1/1/2033	$35,493,000
30607	50782	OGE	Muskogee/Pecan Creek 345 kV Terminal Upgrades	1/1/2033	$34,605,675

Table 9-1: ITP20 Projects

Section 10: STEP Project List

The 2019 STEP Project List includes a comprehensive listing of transmission projects identified by the SPP RTO. All SPP BOD-approved projects are included in the 2019 STEP Project List. The list also includes SPP Tariff study projects, economic projects, and zonal projects.

Projects in the list are categorized in the column labeled "Project Type" by the following designations:

- Generator Interconnection – Projects associated with a FERC-filed Generator Interconnection Agreement
- High Priority – Projects identified in the high priority process
- ITP – Projects needed to meet regional reliability, economic, or policy needs in the ITP Near-Term and ITP 10 Year studies
- ITP 20 – Project identified in review of a twenty-year planning horizon and address, at a minimum, facilities 300 kV and above needed in year 20
- Transmission Service – Projects associated with a FERC-filed Service Agreement
- Interregional – Projected identified in SPP's joint planning and coordination processes
- Sponsored – Entity requested and funded project reviewed and approved by SPP

The complete Network Upgrade list includes two dates.

1. In-service: Date Transmission Owner has identified as the date the upgrade is planned to be in-service.
2. SPP Need Date: Date upgrade was identified as needed by SPP.

A copy of the *2019 SPP Transmission Expansion Plan Report Project List* can be found at the following location: spp.org>engineering>transmission-planning>documents

10.1: Facility owner abbreviations used in the STEP List

Abbreviation and Identification	
AECC	Arkansas Electric Cooperative Corporation
AEP	American Electric Power
BEPC	Basin Electric Power Cooperative
CBPC	Corn Belt Power Cooperative
CPEC	Central Power Electric Cooperative
CUS	City Utilities of Springfield
EDE	The Empire District Electric Company
EREC	East River Electric Cooperative
GHP	GridLiance High Plains LLC

Abbreviation and Identification	
GMO	KCP&L Greater Missouri Operations Company
GRDA	Grand River Dam Authority
ITCGP	ITC Great Plains
KCPL	Kansas City Power and Light Company
KPP	Kansas Power Pool
MIDW	Midwest Energy, Incorporated
NIPCO	Northwest Iowa Power Cooperative
NPPD	Nebraska Public Power District
OGE	Oklahoma Gas and Electric Company
OPPD	Omaha Public Power District
SEPC	Sunflower Electric Power Corporation
SPS	Southwestern Public Service Company
WAPA	Western Area Power Administration
WFEC	Western Farmers Electric Cooperative
WR	Westar Energy

10.2: Upgrades: Information breakdown

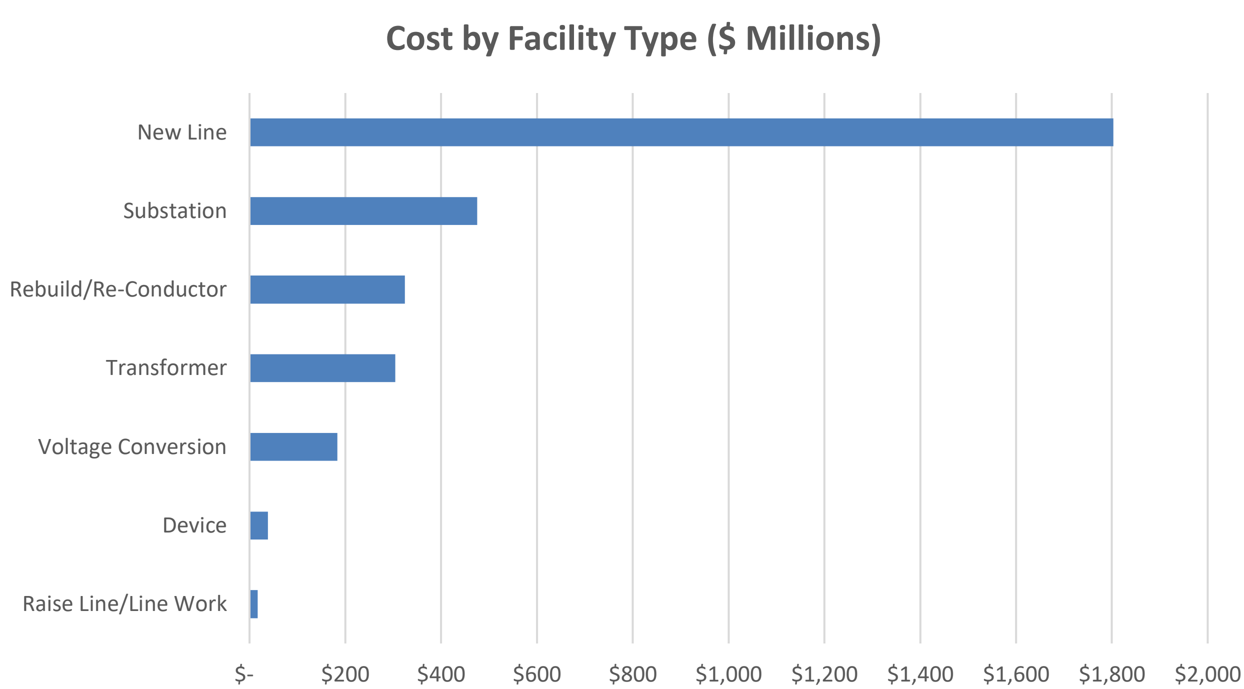


Figure 10-1: Total Cost by Facility Type

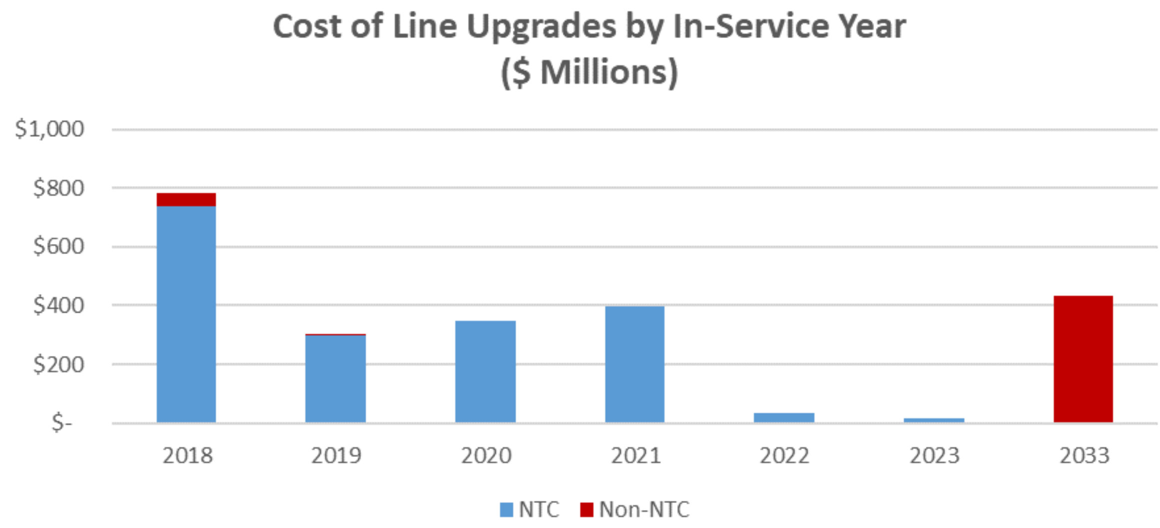


Figure 10-2: Total Cost of Line Upgrades

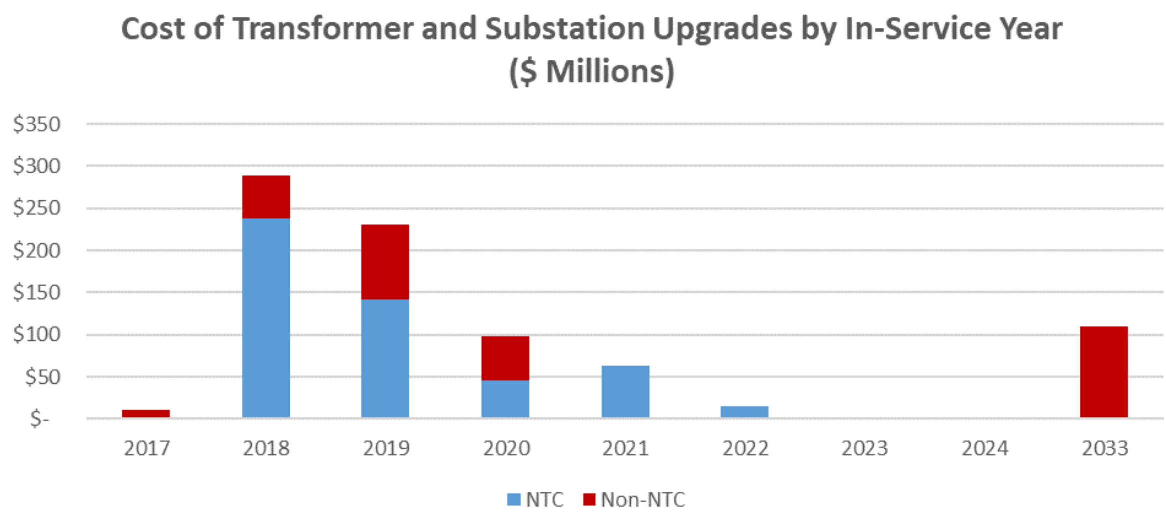


Figure 10-3: Total Cost of Transformer and Substation Upgrades

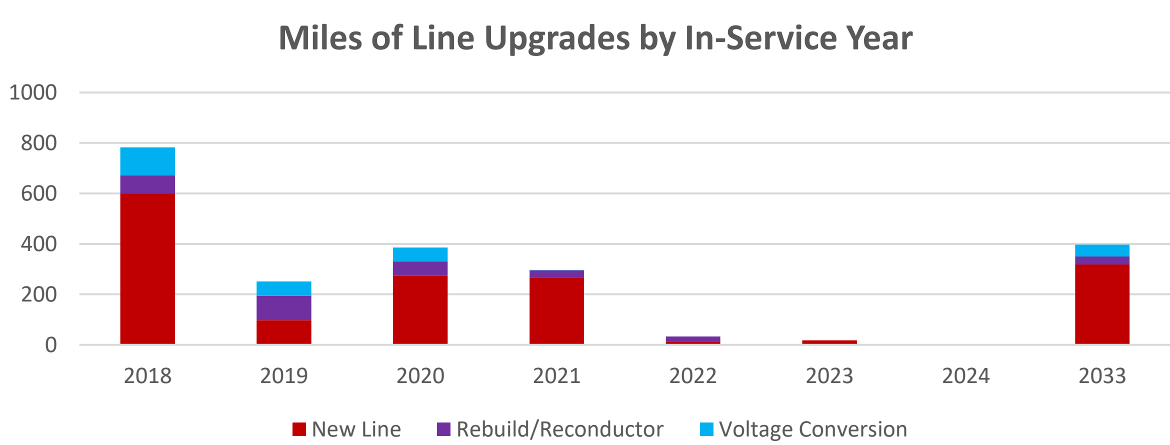


Figure 10-4: Total Miles of Line Upgrades

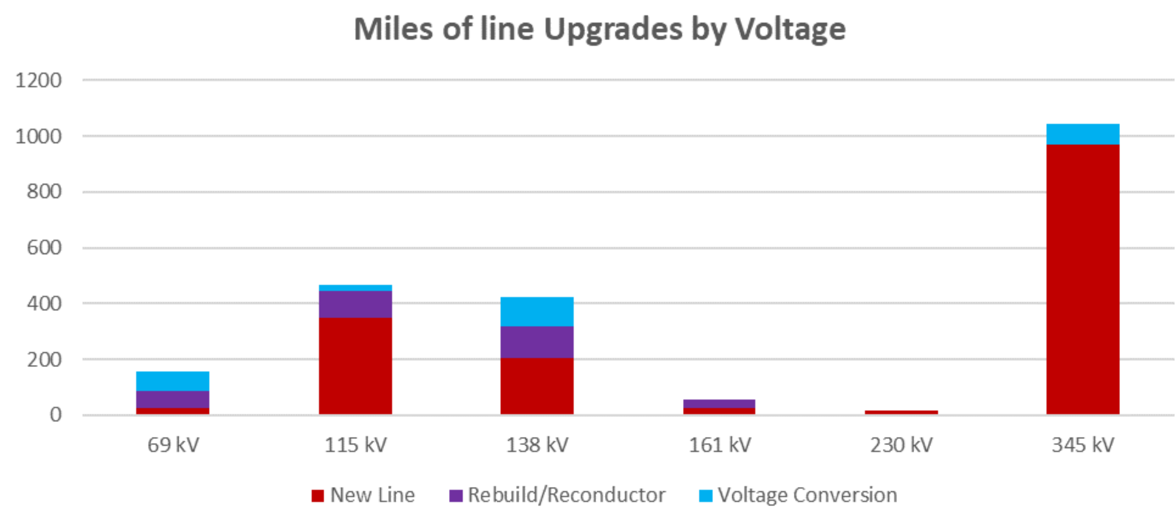


Figure 10-5: Total Line Mileage

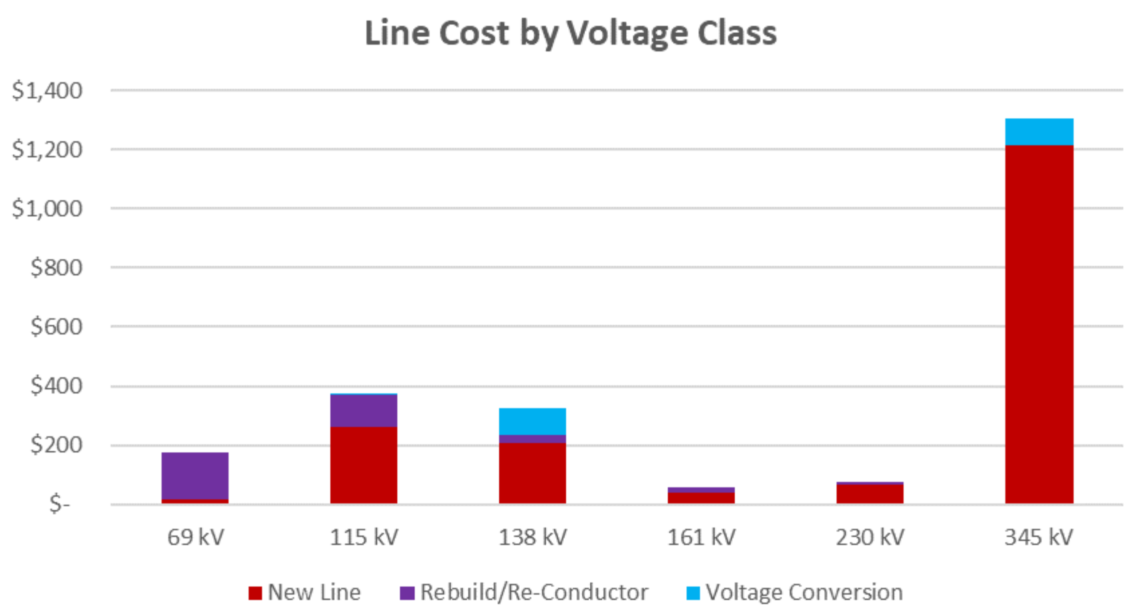


Figure 10-6: Total Line Cost by Voltage Class

Section 11: NTCs Issued in 2018

NTC ID	Project ID	Project Name	Facility Owner	Cost Estimate
200470	51260	Prestage Family 69 kV Cap Bank	CBPC	$ 1,256,000
200477	51254	Monolith 345 kV Substation	NPPD	$ 39,300,207
200479	51249	City of Winfield - Rainbow 69 kV Ckt 1	KPP	$ 1,467,084
200481	51282	Park Community 138 kV Substation	WFEC	$ 177,300,000
200482	51280	Dover SW 69 kV Cap Bank	WFEC	$ 500,000
	51281	Cherokee SW 69 kV Cap Bank	WFEC	$ 1,000,000
200483	51277	S1255 - S1260 161 kV Ckt 1 New Line	OPPD	$ 14,770,262
210484	31068	Yoakum 345/230 kV Ckt 1 Transformer	SPS	$ 5,047,344
210485	51327	Cogar - Cleveland Jct 138 kV Ckt 1 Voltage Conversion	WFEC	$ 76,444,565
210486	51278	Bismarck 115 kV Terminal Upgrades	WAPA	$ 84,639
210490	51300	Upgrade terminal Equipment at VBI North	AECC	$ 3,409,700
210492	51295	Lewis - Richland 115kV Ckt 1 (BEPC)	BEPC	$ 105,000
210493	51285	Brookline 345kV Reactor	CUS	$ 4,175,203
210494	51330	Lakeview 69 kV Substation #3	EREC	$ 5,617,000
210495	51292	Brookridge - Overland Park 161kV Terminal Upgrades	KCPL	$ 538,000
	51294	Olathe - Switzer 161kV Ckt1 Terminal Upgrades	KCPL	$ 1,088,000
210496	31007	Sundown 230/115 kV Transformer	SPS	$ 3,434,979
	41197	Terry County 115 kV Terminal Upgrades	SPS	$ 520,574
	51316	Carlisle 115 kV Terminal Upgrades	SPS	$ 319,760
	61346	McDowell Creek 230/115kV Substation	SPS	$ 13,204,182
210498	51305	Lawrence Hill 230/115kV Transformer	WR	$ 4,896,108
210499	51331	Nixa Downtown - Nixa Espy Ckt1	GHP	$ 1,108,561
210504	61347	Bopco - Road Runner 345 kV Ckt 1 New Line	SPS	$ 94,994,583
	71347	Eddy County - Kiowa 345 kV Ckt 1 New Line	SPS	$ 67,428,932
210484	31068	Multi - Tuco - Yoakum 345/230 kV Ckt 1	SPS	$ 5,047,344
18 NTCs Issued				**$ 518,010,683**

Section 12: Upgrades Completed in 2018

UID	Facility Owner	Upgrade Name	Upgrade Type	Cost Estimate
10646	AEP	Evenside - Northwest Henderson 69 kV Ckt 1	ITP	$ 11,980,465
11017	SPS	Carlisle Interchange - Wolfforth Interchange 230 kV Ckt 1	ITP	$ 29,400,000
11127	SPS	Centre St. - Hereford NE 115 kV Ckt 1	ITP	$ 10,000,000
11142	OPPD	Sub 917 - Sub 918 69 kV Ckt 1	ITP	$ 475,340
11509	SPS	Carlisle 230/115 kV Ckt 1 Transformer	TS	$ 3,000,000
50210	NPPD	ONEILL 115KV	ITP	$ 1,772,846
50419	OGE	Chisholm - Gracemont 345 kV Ckt 1 (OGE)	ITP	$ 37,541,440
50420	OGE	Tatonga - Woodward District EHV 345 kV Ckt 2	ITP	$ 50,594,040
50421	OGE	Matthewson - Tatonga 345 kV Ckt 2	ITP	$ 56,387,700
50425	ITCGP	Elm Creek - Summit 345 kV Ckt 1 (ITCGP)	ITP	$ 42,024,978
50441	NPPD	Neligh 345/115 kV Substation	ITP	$ 10,381,296
50452	SPS	Hobbs 345/230 kV Ckt 1 Transformer	HP	$ 13,685,569
50532	WR	Geary County 345/115 kV Substation	ITP	$ 22,470,822
50563	SPS	Kilgore Switch - South Portales 115 kV Ckt 1	ITP	$ 5,212,250
50564	SPS	Market St. - South Portales 115 kV Ckt 1	ITP	$ 5,400,000
50565	SPS	Market St. - Portales 115 kV Ckt 1	ITP	$ 14,000,000
50582	WR	Viola 345/138 kV Transformer Ckt 1	ITP	$ 10,376,149
50605	WR	Geary County 345 kV	ITP	$ 16,290,638
50612	WR	Viola 345 kV Terminal Equipment	ITP	$ 2,718,649
50720	AEP	Hallsville - Longview Heights 69 kV Ckt 1 Rebuild	ITP	$ 11,571,330
50722	SPS	Chaves - Price 115 kV Ckt 1 Rebuild	ITP	$ 5,961,279
50723	SPS	CV Pines - Price 115 kV Ckt 1 Rebuild	ITP	$ 4,319,668
50724	SPS	Capitan - CV Pines 115 kV Ckt 1 Rebuild	ITP	$ 4,343,227
50733	WR	Kenmar - Northeast 69 kV Ckt 1 Rebuild	ITP	$ 5,650,859
50748	OPPD	S906 - S924 69 kV Ckt 1 Rebuild	ITP	$ 1,360,327
50749	OPPD	S924 - S912 69 kV Ckt 1 Terminal Upgrades	ITP	$ 69,679
50757	NPPD	Broken Bow Wind - Ord 115 kV Ckt 1	ITP	$ 28,018,664
50760	NPPD	North Loup - Ord 115 kV Ckt 1	ITP	$ 516,009
50794	SPS	Curry County Interchange 115 kV	ITP	$ 2,965,311

UID	Facility Owner	Upgrade Name	Upgrade Type	Cost Estimate
50805	OGE	SW Station - Warwick Tap 138 kV Ckt 1	HP	$ 12,767,120
50806	OGE	Linwood - SW Station 138 kV Ckt 1	HP	$ 9,899,440
50807	OGE	Knipe - SW Station 138 kV Ckt 1	HP	$ 9,128,020
50819	SPS	China Draw - North Loving 345 kV Ckt 1	HP	$ 19,396,705
50820	SPS	Kiowa - North Loving 345 kV Ckt 1	HP	$ 23,082,520
50827	MKEC	Anthony - Harper 138 kV Ckt 1	HP	$ 11,563,708
50849	SPS	China Draw 345/115 kV Ckt 1 Transformer	HP	$ 5,234,609
50850	SPS	China Draw 345 kV Ckt 1 Terminal Upgrades	HP	$ 5,469,757
50851	SPS	Kiowa 345 kV Substation	HP	$ 11,734,613
50852	SPS	North Loving 345/115 kV Ckt 1 Transformer	HP	$ 6,698,432
50854	SPS	North Loving 345 kV Terminal Upgrades	HP	$ 5,345,796
50862	SPS	Road Runner 345/115 kV Ckt 1 Transformer	HP	$ 6,200,436
50863	SPS	Road Runner 345 kV Substation Conversion	HP	$ 6,308,675
50868	SPS	Kiowa 345/115 kV Ckt 1 Transformer	HP	$ 5,834,752
50871	SPS	Kiowa - Potash Junction 345/115 kV Ckt 1	HP	$ 2,945,348
50875	SPS	Hobbs - Kiowa 345 kV Ckt 1	HP	$ 47,464,598
50954	SPS	Ochoa - Ponderosa Tap 115 kV Ckt 1 Rebuild	TS	$ 4,200,000
50955	SPS	Ponderosa Tap - Whitten 115 kV Ckt 1 Rebuild	ITP	$ 2,280,000
50958	SPS	IMC #1 Tap - Intrepid West 115 kV Ckt 1 Rebuild	ITP	$ 3,121,473
50991	MKEC	Anthony - Bluff City 138 kV Ckt 1	ITP	$ 14,472,753
50992	SPS	Tuco 230/115 kV Ckt 1 Transformer	ITP	$ 200,000
50993	MKEC	Bluff City - Caldwell 138 kV Ckt 1	ITP	$ 10,401,473
50994	MKEC	Caldwell - Mayfield 138 kV Ckt 1	ITP	$ 7,311,543
50995	MKEC	Mayfield - Milan 138 kV Ckt 1	ITP	$ 5,658,800
51109	SPS	Canyon West - Dawn 115 kV Ckt 1 Rebuild	ITP	$ 5,873,947
51110	SPS	Dawn - Panda 115 kV Ckt 1 Rebuild	ITP	$ 3,715,155
51151	KCPL	Iatan 345 kV Voltage Conversion	ITP	$ 1,886,472
51163	SPS	Plains Interchange 115 kV Cap Bank	ITP	$ 1,630,000
51200	NPPD	Bassett 115 kV Substation	ITP	$ 5,163,000
51207	AEP	Linwood - South Shreveport 138 kV Ckt 1 Rebuild	ITP	$ 5,919,107
51235	SPS	Stevens Co. 345 kV Substation	ITP	$ 13,600,000

UID	Facility Owner	Upgrade Name	Upgrade Type	Cost Estimate
51240	SEPC	Walkemeyer - Stevens Co. 115 kV Ckt 1	ITP	$ 1,673,590
51241	SEPC	Walkemeyer 115 kV Terminal Upgrades	ITP	$ 7,246,297
51271	SEPC	Ellsworth 115 kV Cap Bank	ITP	$ 2,529,027
51277	NPPD	Bassett 115 kV Cap Bank	ITP	$ 902,000
51283	GMO	Iatan - Stranger Creek 345 kV Ckt 1 Voltage Conversion (GMO)	ITP	$ 7,685,983
51284	WR	Iatan - Stranger Creek 345 kV Ckt 1 Voltage Conversion (WR)	ITP	$ 23,000,000
51326	SEPC	Walkemeyer Tap 345 kV Substation (SEPC)	ITP	$ 3,686,933
51327	SEPC	Stevens Co. 345/115 kV Transformer	ITP	$ 8,305,939
51332	SEPC	Ingalls 115 kV Cap Bank	TS	$ 5,527,627
51356	OGE	Border 345kV Substation - GEN-2011-049 Addition	GI	$ 2,554,395
51394	MKEC	Viola 138 kV Line Tap (MKEC)	ITP	$ 3,836,068
51395	WR	Viola 138 kV Line Tap (WR)	ITP	$ 2,162,471
51409	SPS	Potash Junction 230 kV Terminal Upgrade	TS	$ 63,251
51448	AEP	Elk City 138 kV Move Load	ITP	$ 2,904,911
51454	AEP	Duncan - Tosco 69 kV Ckt 1 Rebuild	ITP	$ 5,974,766
51471	SPS	Plant X - Tolk 230kV rebuild circuit #1	GI	$ 5,100,000
51472	SPS	Plant X - Tolk 230kV rebuild circuit #2	GI	$ 5,100,000
51473	SPS	TUCO Interchange 345/230kV CKT 1 Replacement	GI	$ 3,347,036
51506	BEPC	Plaza 115 kV Substation	ITP	$ 3,918,000
51507	BEPC	Blaisdell - Plaza 115 kV New Line	ITP	$ 14,841,308
51508	BEPC	Plaza 115 kV Cap Bank	ITP	$ 283,000
51549	SPS	Terry Co. - Wolfforth 115 kV Terminal Upgrades	ITP	$ 1,461,643
51601	OGE	Border 345kV Substation - GEN-2011-049 Addition (TOIF)	GI	$ 1,099,958
51613	KCPL	Tap Centerville-Marmaton 161kV GEN-2015-016 Addition (TOIF)	GI	$ 581,433
51614	KCPL	Tap Centerville-Marmaton 161kV GEN-2015-016 Addition (NU)	GI	$ 7,978,000
51615	WR	Tap Centerville-Marmaton 161kV GEN-2015-016 Addition (WERE)	GI	$ 110,000
51626	WR	Butler - Altoona 138 kV Terminal Upgrades	ITP	$ 247,332
51630	KCPL	Northeast - Charlotte - Crosstown 161 kV Reactor	ITP	$ 204,681
51638	OGE	GEN-2015-063 Tap - Mathewson 345kV CKT 1	GI	$ 4,490,795
51766	SPS	Tap Tolk - Yoakum 230kV (Needmore) - GEN-2013-027 Addition (TOIF)	GI	$ 300,000

UID	Facility Owner	Upgrade Name	Upgrade Type	Cost Estimate
51767	SPS	Tap Tolk - Yoakum 230kV (Needmore) - GEN-2013-027 Addition (NU)	GI	$ 6,398,806
51826	OGE	Hancock - Muskogee 161 kV Ckt 1 Terminal Upgrades	TS	$ 37,638
61836	SPS	Martin - Pantex North 115 kV Terminal Upgrades	ITP	$ 324,392
61837	SPS	Pantex South - Highland Tap 115 kV Terminal Upgrades	ITP	$ 324,392
72013	WFEC	Park Community 138 kV Substation	TS	$ 2,000,000
72029	WFEC	Kingfisher SW - Park Community 138 kV Ckt 1 New Line	TS	$ 4,500,000

Section 13: Glossary of Terms

Abbreviation and Identification	
AECI	Associated Electric Cooperative Inc.
ATC	Available Transfer Capability
ATSS	Aggregate Transmission Service Study
B/C	Benefit-to-Cost
BOD	Board of Directors
CBA	Consolidated Balancing Authority
CPP	Clean Power Plan
CUS	City Utilities of Springfield
DPT	Delivery Point Transfers
EHV	Extra High Voltage
EMS	Emergency Management System
EPA	Environmental Protection Agency
ESWG	Economic Studies Working Group
FERC	Federal Energy Regulatory Committee
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
HP	High Priority
HPILS	High Priority Incremental Load Study
IPSAC	Interregional Planning Stakeholder Advisory Committee
ITP	Integrated Transmission Planning
ITP10	10-Year Integrated Transmission Planning Assessment
ITP20	20-Year Integrated Transmission Planning Assessment
ITPNT	Near-Term Integrated Transmission Planning Assessment
JCSP	Joint Coordinated System Plan
JOA	Joint Operating Agreement
LTSR	Long-Term Service Request
MDWG	Model Development Working Group
MISO	Midcontinent Independent System Operator
MOPC	Markets and Operations Policy Committee
MTEP	MISO Transmission Expansion Planning
NERC	North American Electric Reliability Corporation
NTC	Notifications to Construct

Abbreviation and Identification	
OATT	Open Access Transmission Tariff
RARTF	Regional Allocation Review Task Force
RCAR	Regional Cost Allocation Review
RMS	Request Management System
RSC	Regional State Committee
RTO	Regional Transmission Organization
RTWG	Regional Tariff Working Group
SERTP	Southeastern Regional Transmission Planning
SPA	Southwestern Power Administration
SPC	Strategic Planning Committee
STEP	SPP Transmission Expansion Plan
TPITF	Transmission Planning Improvement Task Force
TPL	Transmission Planning
TSS	Transmission Service
TWG	Transmission Working Group
WECC	Western Electricity Coordinating Council

STEP Report Improvements

Purpose

- Inform TWG & ESWG of STEP report format improvement
- Request endorsement from TWG & ESWG prior to January MOPC

Improvements

- New Formats
  - StoryMap backgrounds similar to ITP reports
  - Graphical representations for most sections rather than text and tables
- Locations of NTC Activity
  - Reflects Completed, Issued, and Withdrawn Upgrades
- Summary Metrics
  - Easy-to-read one page summaries
  - NTC Activity and Portfolio Status

NTC Reporting

Previous Format

Section 11: NTCs Issued in 2018

NTC ID	Project ID	Project Name	Facility Owner	Cost Estimate
200470	51260	Prestage Family 69 kV Cap Bank	CBPC	$ 1,256,000
200477	51254	Monolith 345 kV Substation	NPPD	$ 39,300,207
200479	51249	City of Winfield - Rainbow 69 kV Ckt 1	KPP	$ 1,467,084
200481	51282	Park Community 138 kV Substation	WFEC	$ 177,300,000
200482	51280	Dover SW 69 kV Cap Bank	WFEC	$ 500,000
	51281	Cherokee SW 69 kV Cap Bank	WFEC	$ 1,000,000
200483	51277	S1255 - S1260 161 kV Ckt 1 New Line	OPPD	$ 14,770,262
210484	31068	Yoakum 345/230 kV Ckt 1 Transformer	SPS	$ 5,047,344
210485	51327	Cogar - Cleveland Jct 138 kV Ckt 1 Voltage Conversion	WFEC	$ 76,444,565
210486	51278	Bismarck 115 kV Terminal Upgrades	WAPA	$ 84,639
210490	51300	Upgrade terminal Equipment at VBI North	AECC	$ 3,409,700
210492	51295	Lewis - Richland 115kV Ckt 1 (BEPC)	BEPC	$ 105,000
210493	51285	Brookline 345kV Reactor	CUS	$ 4,175,203
210494	51330	Lakeview 69 kV Substation #3	EREC	$ 5,617,000
210495	51292	Brookridge - Overland Park 161kV Terminal Upgrades	KCPL	$ 538,000
	51294	Olathe - Switzer 161kV Ckt1 Terminal Upgrades	KCPL	$ 1,088,000
210496	31007	Sundown 230/115 kV Transformer	SPS	$ 3,434,979
	41197	Terry County 115 kV Terminal Upgrades	SPS	$ 520,574
	51316	Carlisle 115 kV Terminal Upgrades	SPS	$ 319,760
	61346	McDowell Creek 230/115kV Substation	SPS	$ 13,204,182

NTC Reporting

New Format

New maps and updated tables for:

- Completed Upgrades
- NTC issuance
- NTC withdrawal

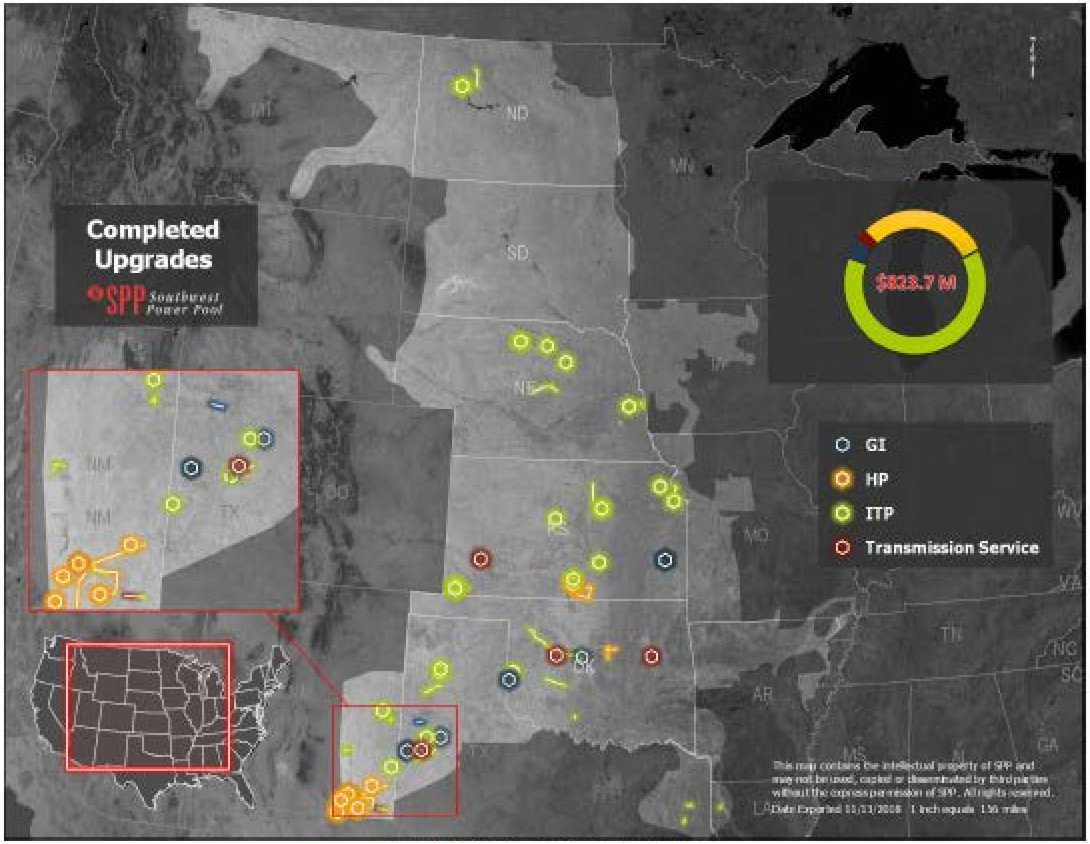


Figure 1: Completed Upgrades

Facility Owner	Upgrade Name	Upgrade Type	Cost Estimate
AEP	Evenside - Northwest Henderson 69 kV Ckt 1	ITP	$11,980,465
SPS	Carlisle Interchange - Wolfforth Interchange 230 kV Ckt 1	ITP	$29,400,000
SPS	Centre St. - Hereford NE 115 kV Ckt 1	ITP	$10,000,000
OPPD	Sub 917 - Sub 918 69 kV Ckt 1	ITP	$ 475,340

Portfolio Summary

Old Format

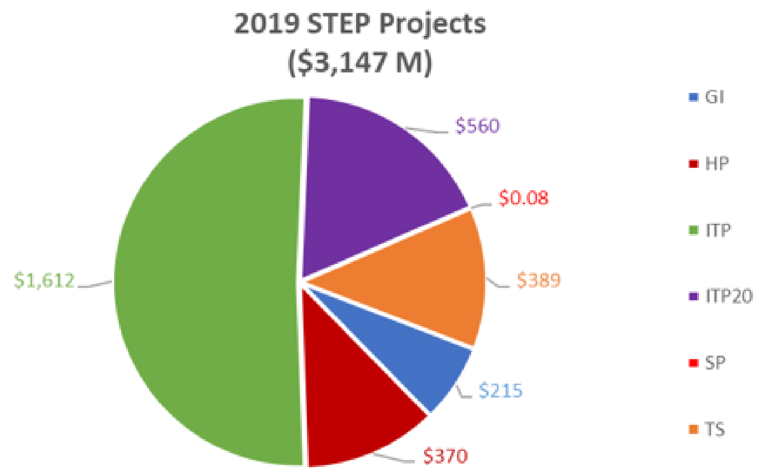


Figure 1-1: Cost by Project Type

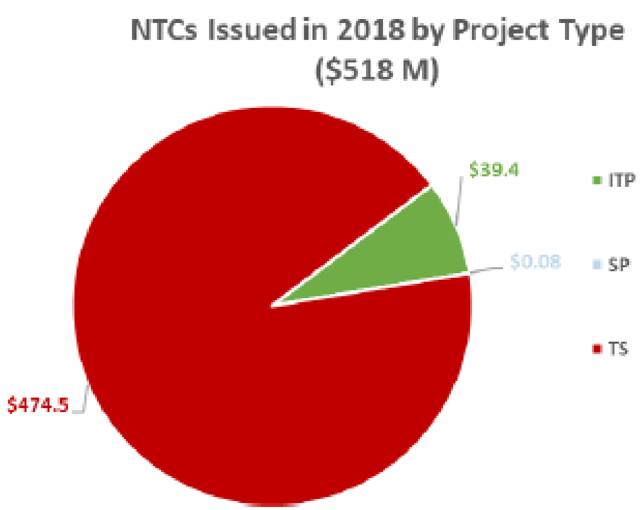


Figure 1-2: 2018 NTC Issuance

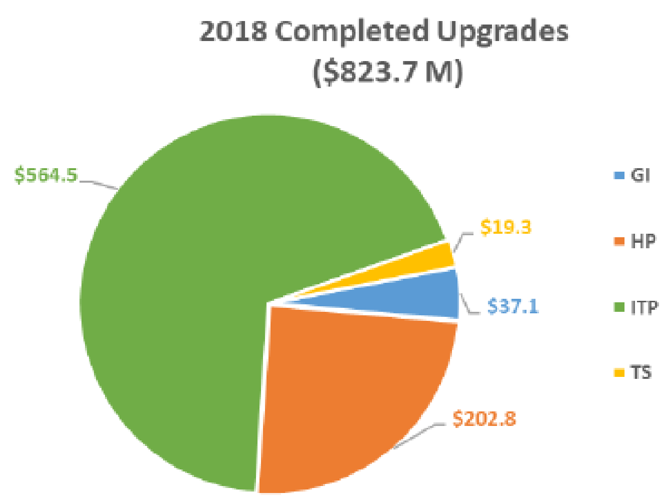


Figure 1-3: 2018 Completed Upgrades

Portfolio Summary

New Format

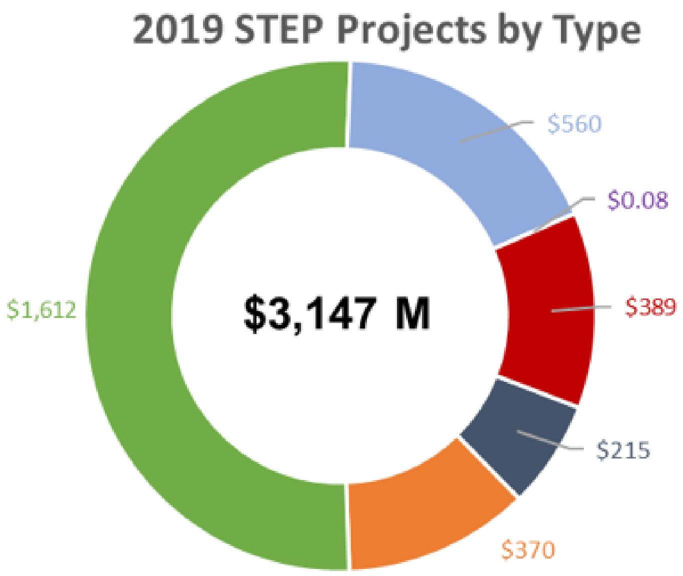
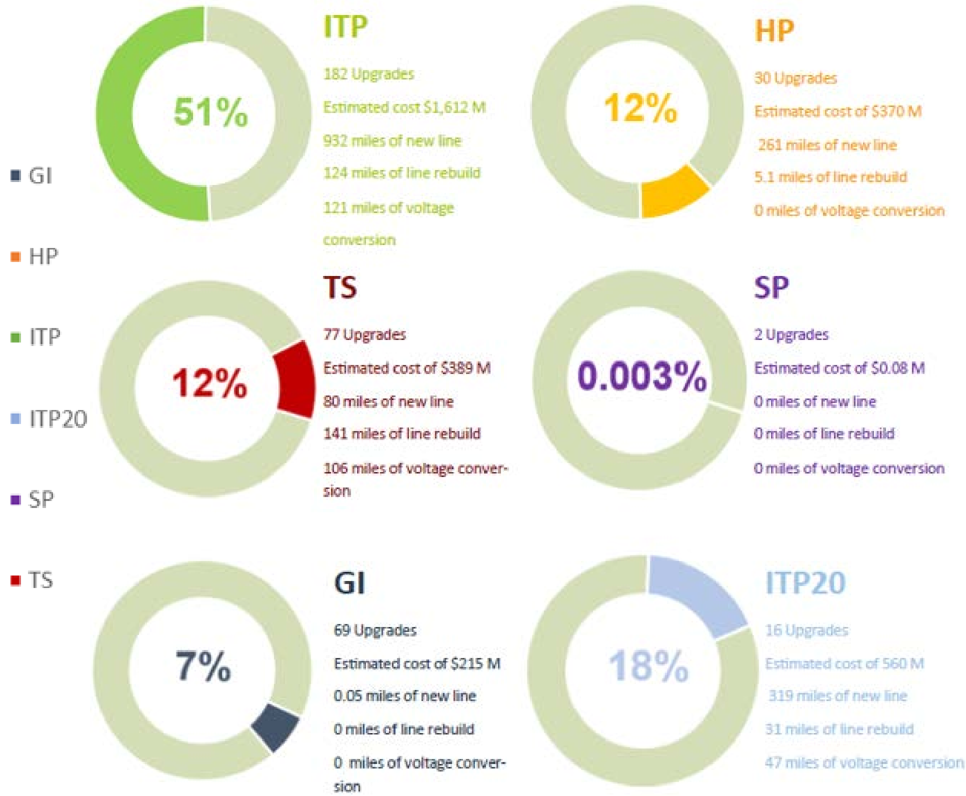


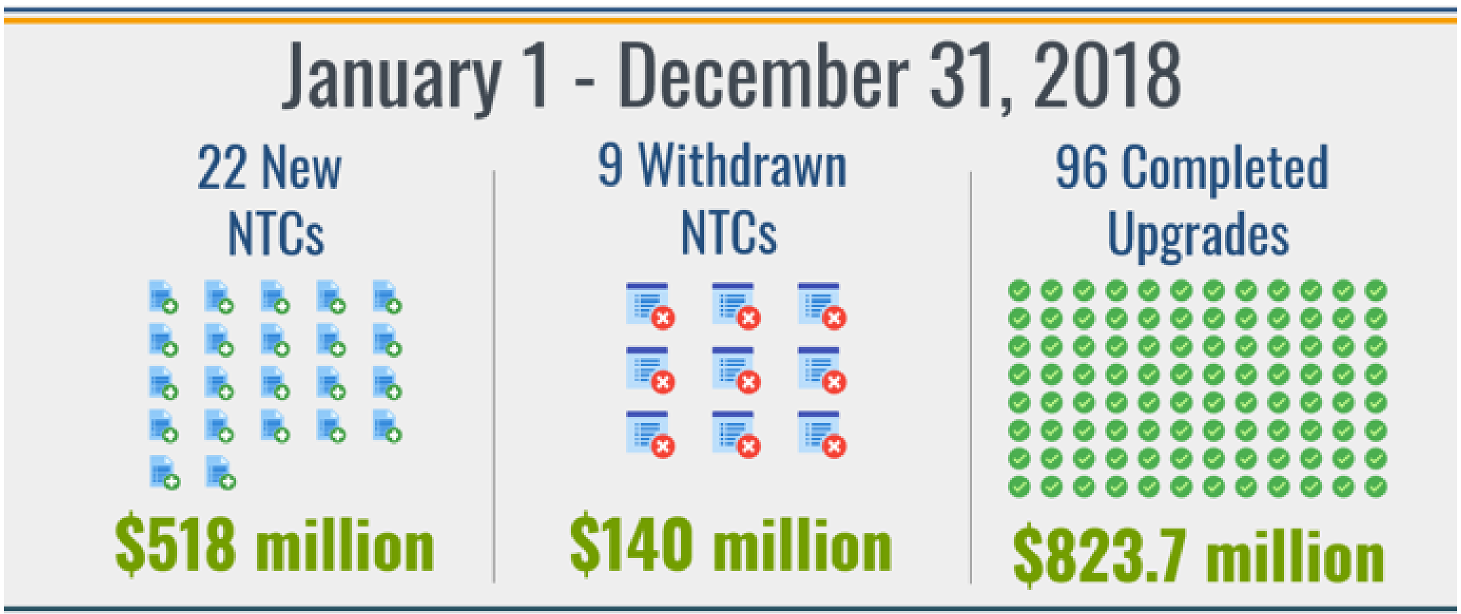
Figure 4: Total Portfolio



Executive Summary

SPP actively monitors and supports the progress of transmission expansion projects, emphasizing the importance of maintaining accountability for areas such as regional grid reliability standards, firm transmission commitments, and SPP Open Access Transmission Tariff (OATT) cost recovery.

SPP staff solicits quarterly feedback from the project owners to determine the progress of each approved transmission project. This quarterly report charts the progress of all SPP transmission projects approved by the SPP Board of Directors (Board) or through a FERC-filed service agreement under the OATT.



Projects in the current portfolio include all Network Upgrades for which construction activities are ongoing or those for which construction has completed but not all close-out requirements have been fulfilled in accordance with Section 13 in Business Practice 7060[1].

Recommendation

Staff is requesting a motion to recommend endorsement of the new STEP report format


SPP Southwest Power Pool
HELPING OUR MEMBERS WORK TOGETHER
TO KEEP THE LIGHTS ON... TODAY AND IN THE FUTURE.

2019 ITP Schedule

Juliano Freitas

December 3, 2018

Economic Model Building (Complete)

- Start: 7/3/2017
- End: 11/14/2018 (Member's Final Approval)
- Member Review Time:
  - Post 1: 2/12/2018 – 2/23/2018 (10 days)
  - Post 2: 5/8/2018 – 5/22/2018 (10 days)
  - Post 3: 6/6/2018 (informational only)
  - Post 4: 6/29/2018 – 7/16/2018 (10 days)
  - Post 5: 7/19/2018 – 7/26/2018 (5 days)
  - Final Post for Approval: 9/28/2018 – 10/09/2018 (7 days)
  - Initial Member Approval: 10/11/2018

  - Updated for Review/Approval – 11/7 - 14/2018 (5 days)
    - Including Lubbock Sensitivity Models
- Staff Leader: Clayton Mayfield (cmayfield@spp.org)
- Working Group Approval: ESWG

Economic Model Conversion to BA Powerflow (Market Powerflow Models) (Complete)

- Start: 8/2/2018
- End: 11/13/2018 (Member's Final Approval)
- LP&L End: 11/20/2018 (Member's Final Approval)
- Member Review Time:
  - Reactive Settings Review: 10/17/2018 – 10/24/2018 (5 days)
  - TWG Review/Approval: 11/07/2018 – 11/13/2018 (4 days)
  - LP&L – TWG Review/Approval: 11/14 – 20/2018 (4 days)
- Staff Leader: Kelsey Allen (kallen@spp.org)
- Working Group Approval: TWG

Base Reliability Needs Assessment

- Start: 8/2/2018
- End: 1/7/2019

- Staff Leader: Jason Speer (jspeer@spp.org)

BA Reliability (Market Powerflow) Needs Assessment

- Start: 11/13/2018
- End: 1/7/2019
- Staff Leader: Jason Speer (jspeer@spp.org)

Economic Needs Assessment

- Start: 11/07/2018
- End: 1/7/2019
- Staff Leader: Nikki Roberts (nroberts@spp.org)

Public Policy Needs Assessment

- Start: 11/13/2018
- End: 1/7/2019
- Staff Leader: Nikki Roberts (nroberts@spp.org)

Operational Needs Assessment

- Start: 11/1/2018
- End: 1/7/2019
- Staff Leader: Will Tootle (wtootle@spp.org)

Short Circuit Needs Assessment

- Start: 11/1/2018
- End: 1/7/2019
- Staff Leader: Jason Terhune (jterhune@spp.org)

DPP Window

- Start: 1/8/2019
- End: 2/6/2019
- Member Review Time:
  - Transmission-planning response window (30 calendar days)
- Staff Leader: Ellen Bailey (ebailey@spp.org)

Staff Solutions Development

- Start: 1/8/2019
- End: 3/20/2019
- Staff Leaders:
  - Reliability: Kelsey Allen (kallen@spp.org)
  - Economic: Nikki Roberts (nroberts@spp.org)
  - Policy: Nikki Roberts (nroberts@spp.org)
  - Operational: Will Tootle (wtootle@spp.org)
  - Short Circuit: Jason Terhune (jterhune@spp.org)

DPP/Solutions Evaluations

- Start: 1/8/2019
- End: 3/20/2019
- Staff Leaders:
  - Reliability: Kelsey Allen (kallen@spp.org)
  - Economic: Liz Gephardt (lgephardt@spp.org)
  - Policy: Nikki Roberts (nroberts@spp.org)
  - Operational: Will Tootle (wtootle@spp.org)
  - Short Circuit: Jason Terhune (jterhune@spp.org)

Initial Reliability Portfolio Development

- Start: 2/7/2019
- End: 3/20/2019
- Staff Leader: Kelsey Allen (kallen@spp.org)

Project Grouping – Phase 1
(Conceptual Cost Estimate)

- Start: 1/18/2019
- End: 4/23/2019
- Staff Leader: Clayton Mayfield (cmayfield@spp.org)

Study Cost Estimates – Round 1

- Start: 4/24/2019
- End: 5/16/2019
- Member Response Time:
  - 4/24/2019 – 5/16/2019 (16 days)
- Staff Leader: John O’Dell (jodell@spp.org)

Project Grouping – Phase 2
(Study Cost Estimate – Re-rank)

- Start: 5/15/2019
- End: 5/16/2019
- Staff Leader: Clayton Mayfield (cmayfield@spp.org)

Planning Summit

- Start: 5/17/2019
- End: 6/6/2019
- Member Review Time:
  - Summit Materials (7 days prior to meeting)
- Staff Leader: Ellen Bailey (ebailey@spp.org)

Project Grouping – Phase 3
(Conceptual + Study Cost Estimates using Summit Feedback)

- Start: 6/5/2019
- End: 6/19/2019
- Staff Leader: Clayton Mayfield (cmayfield@spp.org)

Study Cost Estimates – Round 2

- Start: 6/20/2019
- End: 6/26/2019
- Member Response Time:
  - 6/20/2019 – 6/26/2018 (5 days)
- Staff Leader: John O'Dell (jodell@spp.org)

Final Reliability Portfolios Development

- Start: 6/26/2019
- End: 8/5/2019
- Staff Leader: Kelsey Allen (kallen@spp.org)

Project Grouping – Phase 4
(Study Cost Estimate II – Final Re-rank)

- Start: 6/27/2019
- End: 7/8/2019
- Staff Leader: Clayton Mayfield (cmayfield@spp.org)

Project Grouping – Final Determination

- Start: 6/28/2019
- End: 7/8/2019
- Staff Leader: Clayton Mayfield (cmayfield@spp.org)

Optimization

- Start: 7/9/2019
- End: 7/17/2019
- Staff Leader: James Bailey (jbailey@spp.org)

Portfolio Consolidation

- Start: 7/18/2019
- End: 8/2/2019
- Staff Leader: Liz Gephardt (lgephardt@spp.org)

Project Staging

- Start: 8/5/2019
- End: 8/15/2019
- Staff Leader: Kirk Hall (khall@spp.org)

Benefit Metrics Calculation

- Start: 8/2/2019
- End: 8/26/2019
- Staff Leader: Antonio Barber (abarber@spp.org)

Stability Analysis

- Start: 8/5/2019
- End: 8/26/2019
- Staff Leader: Chris Jamieson (cjamieson@spp.org)

Sensitivity Analysis

- Start: 8/5/2019
- End: 8/26/2019
- Member Review Time:
  - 8/19/2019 – 8/23/2019 (5 days)
- Staff Leader: Clayton Mayfield (cmayfield@spp.org)

Final Reliability Assessment

- Start: 8/5/2019
- End: 8/27/2019
- Staff Leader: Dee Edmondson (dedmondson@spp.org)

Rate Impacts/ATRR

- Start: 8/15/2019
- End: 8/28/2019
- Staff Leader: Antonio Barber (abarber@spp.org)

Final Report

- Start: 8/1/2019
- End: 9/18/2019
- Staff Leader: Ellen Bailey (ebailey@spp.org)

TWG/ESWG Final Approvals

- Start: 9/26/2019
- End: 10/3/2019
- Member Review Time:
  - 9/26/2019 – 10/3/2019 (5 days)
- Staff Leaders:
  - TWG – Kirk Hall (khall@spp.org)
  - ESWG – Amber Greb (agreb@spp.org)

MOPC and SPP Board

- Start: 9/6/2019
- End: 10/29/2019
- Member Review Time:
  - MOPC: 10/7/2019 – 10/15/2019 (7 days)
  - SPP Board: 10/22/2019 – 10/29/2019 (5 days)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Policy Needs Assessment

Nikki Roberts

December 3, 2018

Objective

- Update on the current status of the Policy Needs Assessment

Milestone Update

- Policy Assessment work complete
- Shortfall identified for Western Farmers Coops in SPS in the Year 2 model
  - ITP Manual RR approved at July MOPC removes policy review requirements for year 2

Next Steps

- DPP Window Opens: 1/8/2019


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Economic Needs Assessment

Nikki Roberts

December 3, 2018

Objective

- Update on the current status of the Economic Needs Assessment

Milestone Update

- Evaluating drivers for top congested flowgates
- Determining binding constraint relationships as per the ITP Manual

Next Steps

- Finalize Economic Needs List
- Prepare narrative for Needs posting
- DPP Window Opens: 1/8/2019


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DPP Window

Ellen Bailey, Engineering Support

December 2018

SouthwestPowerPool SPPorg southwest-power-pool

Overview

- DPP Process Flow
- DPP Window
- Changes to DPP Submittal Form
- Best Practices

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DPP Process Flow

- SPP Business Practice 7650 provides overall DPP process
  - https://www.spp.org/spp-documents-filings/?id=18162
- Refer to DPP Submittal Form Instructions on SPP.org for step-by-step guide
  - Posted with DPP Submittal Form (zip file)
  - https://www.spp.org/engineering/transmission-planning/detailed-project-proposals/

DPP Window

- **Opens**: January 8, 2019, 12:00 a.m.
- **Closes**: February 6, 2019, 11:59 p.m.
- SPP will notify via [SPP.org](SPP.org) and email exploder when 2019 ITP needs assessment has been posted
  - https://www.spp.org/engineering/transmission-planning/detailed-project-proposals/
- All ITP Posting notifications are located on SPP.org
  - https://www.spp.org/spp-documents-filings/?id=31491

DPP Submittals

- DPP submittal requirements are contained in Section III.6.a of SPP Tariff Attachment O and SPP Business Practice 7650
- Submittals are accepted via SPP's Request Management System (RMS).
  - All communication will be through RMS ticket
- Utilize DPP Form and instructions found on spp.org*
  - https://www.spp.org/engineering/transmission-planning/detailed-project-proposals/

*Notification will be sent when updated form and instructions are posted for use in 2019 ITP DPP window

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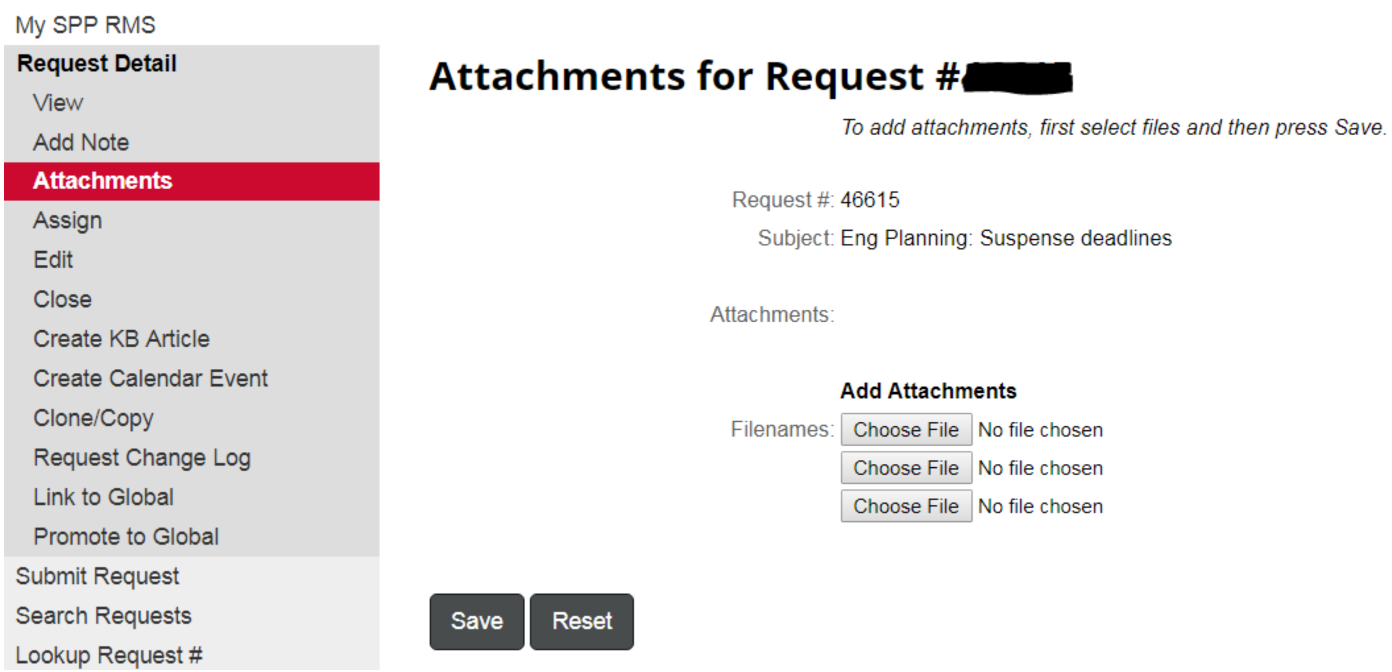
Changes to Submittal Form

- IDEVs should contain powerflow (positive) and zero sequence data
- PROMOD version updated (now 11.1.13)
- Years on Tab "Section 8" updated

RMS Attachments

- Attachments can be uploaded in increments of 3 at one time (50 MB total)
- Zip files may be added



Best Practices

- Always start on first tab for initial submitter and *continue* on "Multiple Submitters" tab if needed
- If legal disclaimer is needed, please include only once in the RMS description box (not in DPP submittal form)
- IDEV must match description in Section 1.a; if different, IDEV takes precedence
- All IDEVs must be tested before submission
- Only one IDEV per submittal

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Best Practices, continued

- If modeling correction is model-specific, please indicate which model in submittal
- Straight-line mileage is expected for line submittals; less than straight-line mileage will be returned to submitter for correction
- Submittals differing only by conductor rating will result in same conceptual cost during SPP analysis
- Solves should not be included in IDEVs


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2020 ITP Schedule

Juliano Freitas

December 3, 2018

Scope Development

- Start: 7/23/2018
- End: 1/16/2019 (Member's Final Approval)
  - MOPC Approval: 1/16/2019
- Member Review Time:
  - 12/15/2018 – 12/27/2018 (8 days)
- Staff Leader: Kirk Hall (khall@spp.org)
- Working Group Approvals: ESWG and TWG

Powerflow Model

- Start: 7/09/2018
- End: 2/15/2019 (Final Approval)
- Member Review Time:
  - *Pass 0 – Trial 1: 7/13/2018 – 7/20/2018 (5 days)*
  - *Pass 0 – Trial 2: 8/03/2018 – 8/24/2018 (15 days)*
  - *Pass 1: 9/14/2018 – 9/21/2018 (5 days)*
  - Pass 2: 10/05/2018 – 10/26/2018 (15 days)
  - Pass 3: 11/16/2018 – 12/07/2018 (15 days)
  - Pass 4: 12/21/2018 – 1/11/2019 (15 days)
  - **Final Data Submission Deadline: 1/11/2019**
  - Final Initial ITP: 2/02/2019 – 2/08/2019 (5 days)
  - **Final Initial ITP Approval: 2/15/2019**
  - **Final ITP Approval with Oct. 2019 Board approved projects in Nov. 2019**
- Staff Leader: David Duhart (dduhart@spp.org)
- Working Group Approval: TWG

Short Circuit Model

- Start: 11/14/2018
- End: 2/28/2019
- Member Review Time:
  - Pass 1: 12/14/2018 – 12/21/2018 (5 days)
  - Pass 2: 1/17/2019 – 2/01/2019 (10 days)
  - Pass 3: 2/21/2019 – 2/28/2019 (5 days) (MDWG Approval)
  - **Final ITP Approval with Oct. 2019 Board approved projects in Nov. 2019**
- Staff Leader: Theva Coleman (tcoleman@spp.org)
- Working Group Approval: TWG

Load Review

- Start: 7/23/2018
- End: 2/15/2019 (Member's Final Approval)
- Member Review Time:
  - *Load Pass 1: 9/17/2018 – 9/28/2018 (10 days)*
  - Load Pass 2: 10/15/2018 – 10/26/2018 (10 days)
  - Load Pass 2 Update*: 10/18/2018 – 10/31/2018 (10 days)
  - Load Pass 3: 11/26/2018 – 12/07/2018 (10 days)
  - **Final Data Submission Deadline: 1/11/2019**
  - Final Posting for Approval: 2/08/2019 (7 days)
- Staff Leader: Theva Coleman (tcoleman@spp.org)
- Working Group Approval: TWG and ESWG

* Posting based on approved ESWG items

Generation Review

- Start: 7/23/2018
- End: 2/15/2019 (Member's Final Approval)
- Member Review Time:
  - *Gen Pass 1: 9/17/2018 – 9/28/2018 (10 days)*
  - RAR & Waiver Request to Stakeholders: 9/21/2018 – 10/26/2018 (25 days)
  - Gen Pass 2: 10/15/2018 – 10/26/2018 (10 days)
  - Gen Pass 2 Update*: 10/18/2018 – 10/31/2018 (10 days)
  - Gen Pass 3: 11/26/2018 – 12/07/2018 (10 days)
  - **Final Data Submission Deadline: 1/11/2019**
  - Final Posting for Approval: 2/08/2019 (7 days)
- Staff Leader: Theva Coleman (tcoleman@spp.org)
- Working Group Approval: TWG and ESWG

* Posting based on approved ESWG items

Renewable Policy Review

- Start: 2/01/2019
- End: 2/22/2019 (Member's Final Approval)
- Member Review Time:
  - 2/08/2019 – 2/15/2018 (5 days)
  - 2/18/2019 – 2/22/19 (5 days)

- Staff Leader: Joshua Norton (jnorton@spp.org)
- Working Group Approval: ESWG

Policy Renewable Resource Plan – Phase 1

- Start: 2/22/2019
- End: 3/12/2019 (Member's Final Approval)
- Member Review Time:
  - 3/05/2019 – 3/12/2019 (5 days)

- Staff Leader: Joshua Norton (jnorton@spp.org)
- Working Group Approval: ESWG

Renewable & Conventional Resource Plan – Phase 2

- Start: 2/6/2018
- End: 5/23/2018 (Member's Final Approval)
- Member Review Time:
  - 5/15/2018 – 5/23/2018 (6 days)
- Staff Leader: Antonio Barber (abarber@spp.org)
- Working Group Approval: ESWG

Siting Plan & Generator Outlet Facilities (GOFs)

- Start: 2/01/2018
- End: 7/25/2019 (Member's Final Approval)
- Member Review Time:
  - Site Repository: 2/22/2018 – 3/8/2018 (5 days)
  - Site Prioritization: 4/9/2018 – 4/13/2018 (5 days)
  - Site Prioritization: 4/20/2018 – 4/27/2018 (6 days)
  - Site Assignment Renewable: 4/27/2018 – 5/4/2018 (5 days)
  - Site Assignment Renewable: 5/24/2018 – 5/31/2018 (5 days)
  - Site Assignment Conventional: 5/24/2018 – 6/1/2018 (6 days)
  - Site Assignment Conventional: 6/25/2018 – 7/2/2018 (6 days)
  - Siting Plan Approval: 6/14/2018 (early)
- Staff Leader: Joshua Norton (jnorton@spp.org)
- Working Group Approval: ESWG

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Market Economic Model Build

- Start: 2/01/2019
- End: 12/10/2019 (Member's Final Approval)

- Staff Leader: Clayton Mayfield (cmayfield@spp.org)
- Working Group Approval: ESWG

Economic Benchmarking

- Start: 4/30/2019
- End: 8/01/2019 (Member's Final Approval)

- Staff Leader: Clayton Mayfield (cmayfield@spp.org)
- Working Group Approval: ESWG

Model Updates

- Start: Pass 1 Powerflow Model (7/09/2018)
- Initial End: 2/15/2019
- Final End: 11/15/2019
  - (New NTCs and withdrawals approved by the Oct. 2019 MOPC/Board, and NTC re-evaluations)
- Staff Leader: David Duhart (dduhart@spp.org)
- Working Group Approval: TWG

Constraint Assessment

- Start: 8/2/2019
- End: 10/30/2019 (Member's Final Approval)

- Staff Leader: Kirk Hall (khall@spp.org)
- Working Group Approval: TWG

Market Powerflow Models (BA Reliability)

- Start: 11/15/2019
- End: 1/15/2020 (Member's Final Approval)

- Staff Leader: Hagen Boehmer (hboehmer@spp.org)
- Working Group Approval: TWG

Base Reliability Needs Assessment

- Start: 11/15/2019
- End: 3/14/2020

- Staff Leader: Jason Speer (jspeer@spp.org)

Market Powerflow Reliability Needs Assessment

- Start: 1/02/2020
- End: 3/14/2020

- Staff Leader: Jason Speer (jspeer@spp.org)

Economic Needs Assessment

- Start: 1/02/2020
- End: 3/14/2020

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

Public Policy Needs Assessment

- Start: 1/02/2020
- End: 3/14/2020

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

Operational Needs Assessment

- Start: 1/02/2020
- End: 3/14/2020

- Staff Leader: Will Tootle (wtootle@spp.org)

Short Circuit Needs Assessment

- Start: 1/02/2020
- End: 3/14/2020

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

DPP Window

- Start: 3/15/2020 12:00 a.m.
- End: 4/13/2020 11:59 p.m.
- Member Review Time:
  - Transmission-planning response window (30 calendar days)
- Staff Leader: Ellen Bailey (ebailey@spp.org)

Solutions Development

- Start: 3/15/2020
- End: 6/10/2020

- Staff Leaders:
  - Reliability: Kelsey Allen (kallen@spp.org)
  - Economic: Liz Gephardt(lgephardt@spp.org)
  - Policy: Liz Gephardt(lgephardt@spp.org)
  - Operational: Will Tootle (wtootle@spp.org)
  - Short Circuit: Jason Terhune (jterhune@spp.org)

DPP/Solutions Evaluations

- Start: 3/15/2020
- End: 6/10/2020

- Staff Leaders:
  - Reliability: Aaron Stewart (astewart@spp.org)
  - Economic: Amber Greb (agreb@spp.org)
  - Policy: Amber Greb (agreb@spp.org)
  - Operational: Will Tootle (wtootle@spp.org)
  - Short Circuit: Jason Terhune (jterhune@spp.org)

Initial Reliability Portfolio Development

- Start: 2/15/2020
- End: 6/10/2020

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

Project Grouping & Portfolio Development

- Start: 3/15/2020
- End: 8/14/2020

- Staff Leaders:
  - Nikki Roberts (nroberts@spp.org)
  - Liz Gephardt (lgephardt@spp.org)
  - Amber Greb (agreb@spp.org)

Study Cost Estimates – Round 1

- Start: 6/10/2020
- End: 6/25/2020

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

Planning Summit

- Start: 6/25/2020
- End: 7/10/2020
- Member Review Time:
  - Summit Materials (7 days prior to meeting)
- Staff Leader: Ellen Bailey (ebailey@spp.org)

Study Cost Estimates – Round 2

- Start: 7/10/2020
- End: 7/25/2020

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

Final Reliability Portfolios Development

- Start: 7/26/2020
- End: 8/14/2020

- Staff Leader: Aaron Stewart (astewart@spp.org)

Optimization & Portfolio Consolidation

- Start: 8/16/2020
- End: 9/18/2020

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

Project Staging

- Start: 8/14/2020
- End: 9/18/2020

- Staff Leader: Kirk Hall (khall@spp.org)

Benefit Metrics Calculation

- Start: 8/14/2020
- End: 9/18/2020

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

Stability Analysis

- Start: 8/14/2020
- End: 9/18/2020

- Staff Leader: Dee Edmondson (dedmondson@spp.org)

Sensitivity Analysis

- Start: 8/14/2020
- End: 9/18/2020

- Staff Leader: Kirk Hall (khall@spp.org)

Final Reliability Assessment

- Start: 8/14/2020
- End: 9/18/2020

- Staff Leader: Aaron Stewart (astewart@spp.org)

Rate Impacts/ATRR

- Start: 8/14/2020
- End: 9/18/2020

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

Final Report

- Start: 8/1/2020
- End: 9/18/2020

- Staff Leader: Ellen Bailey (ebailey@spp.org)

TWG/ESWG Final Approvals

- Start: 9/25/2020
- End: 10/2/2020

- Staff Leaders:
  - TWG – Aaron Stewart (astewart@spp.org)
  - ESWG – Amber Greb (agreb@spp.org)

MOPC and SPP Board

- Start: 9/6/2020
- End: 10/27/2020
- Member Review Time:
  - MOPC: 10/2/2020 – 10/13/2020 (7 days)
  - SPP Board: 10/20/2020 – 10/27/2020 (5 days)


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Conventional Generation Prototypes

EWSG

December 03, 2018

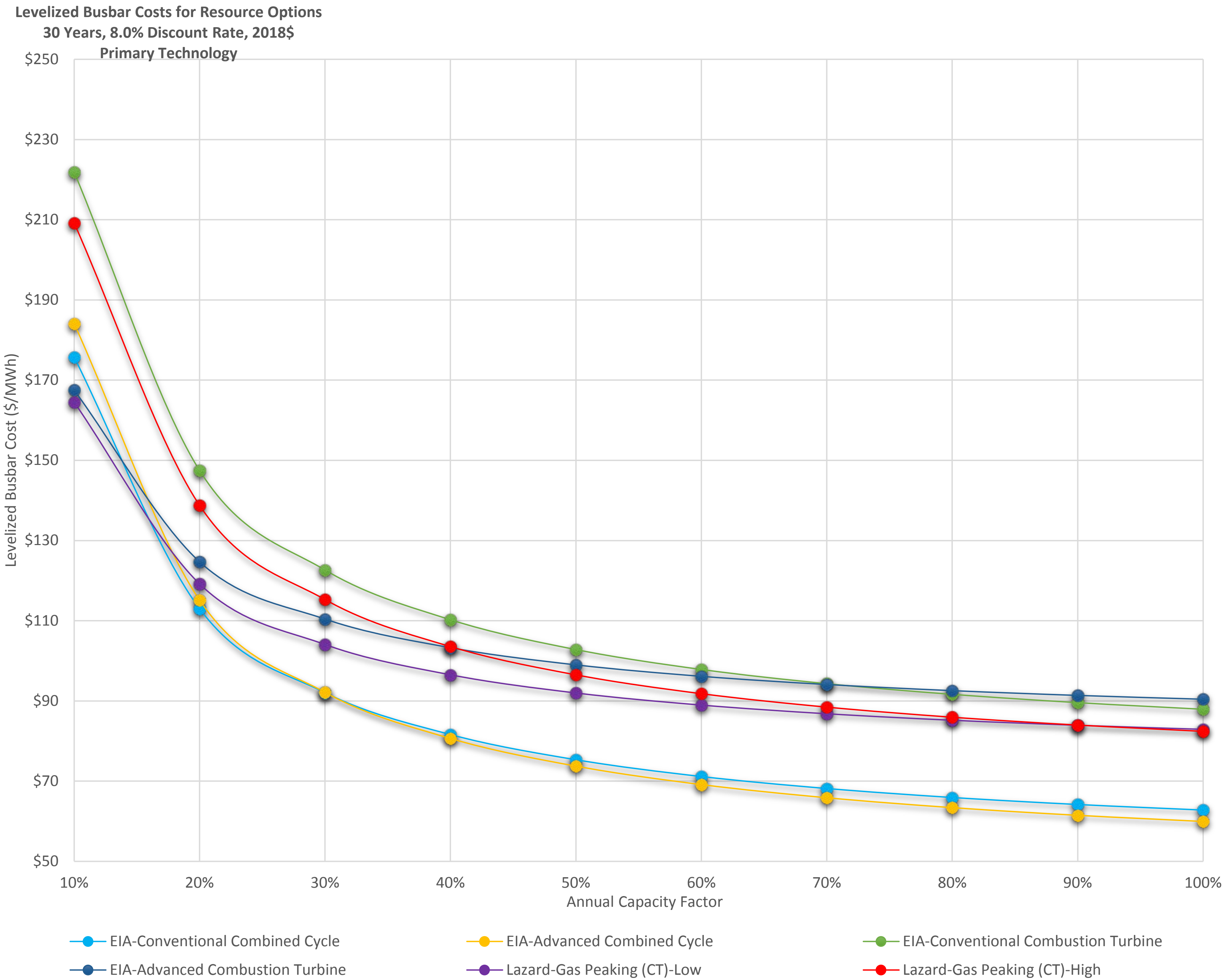
Antonio Barber

Objective

- Seek approval for Conventional Generation Prototypes for the 2020 ITP Scope.

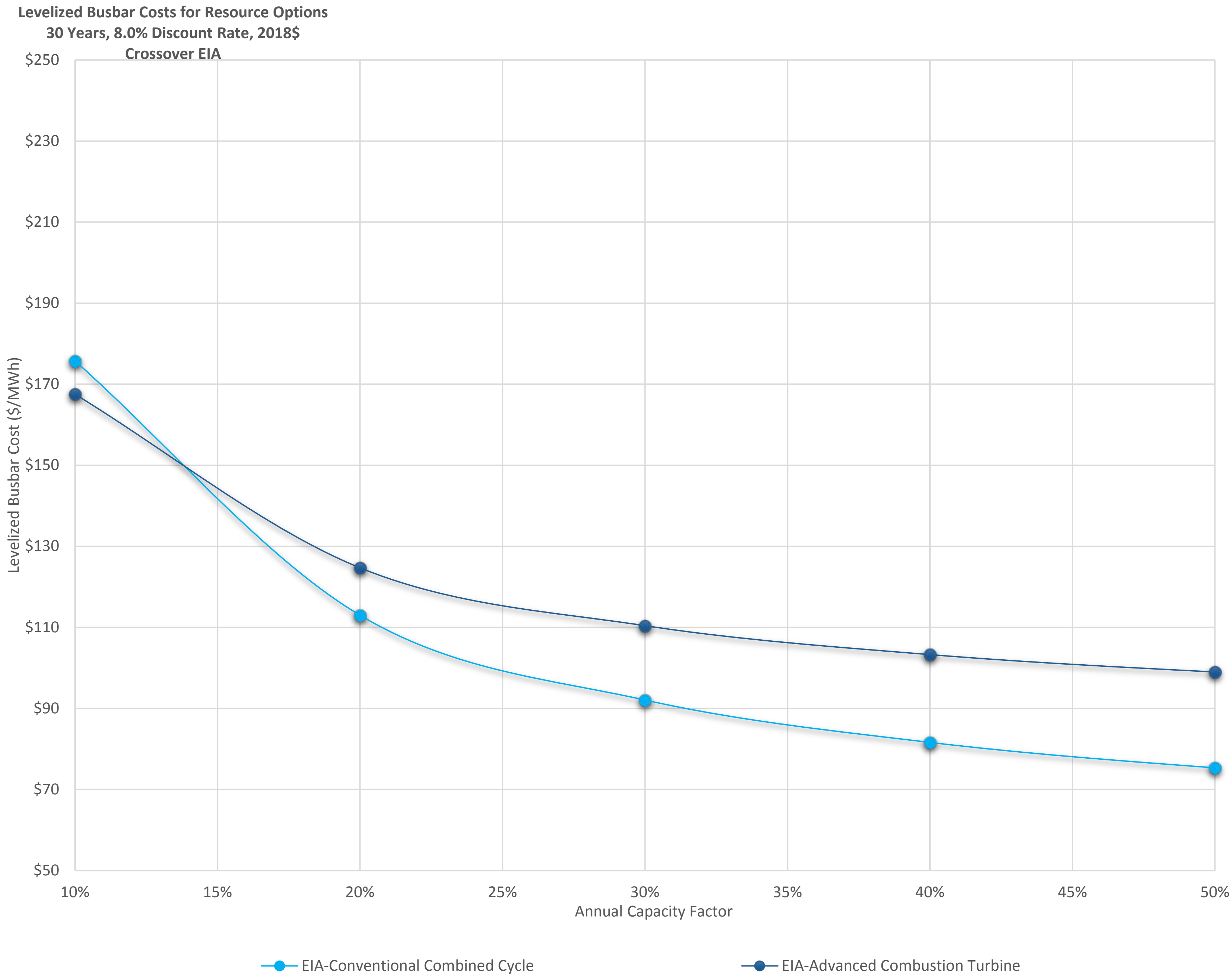
Prototype Data Source Options

- EIA Annual Energy Outlook (AEO) Report
  - Option in 2019 ITP: July 2017 Data
  - March 2018 Data
- Lazard Levelized Cost of Energy Analysis
  - Used in 2019 ITP10: December 2016 data (Version 10.0)
  - November 2017 (Version 11.0)



EIA / Lazard
30Yr

SPP


Levelized Busbar Costs for Resource Options
30 Years, 8.0% Discount Rate, 2018$
Crossover EIA
Levelized Busbar Cost ($/MWh)
$250
$230
$210
$190
$170
$150
$130
$110
$90
$70
$50
10%
15%
20%
25%
30%
35%
40%
45%
50%
Annual Capacity Factor
EIA-Conventional Combined Cycle
EIA-Advanced Combustion Turbine

Recommendation

SPP Staff recommends the ESWG approve using EIA Conventional Combined Cycle, EIA Advanced Combustion Turbine, prototypes and eliminating nuclear and coal as options.

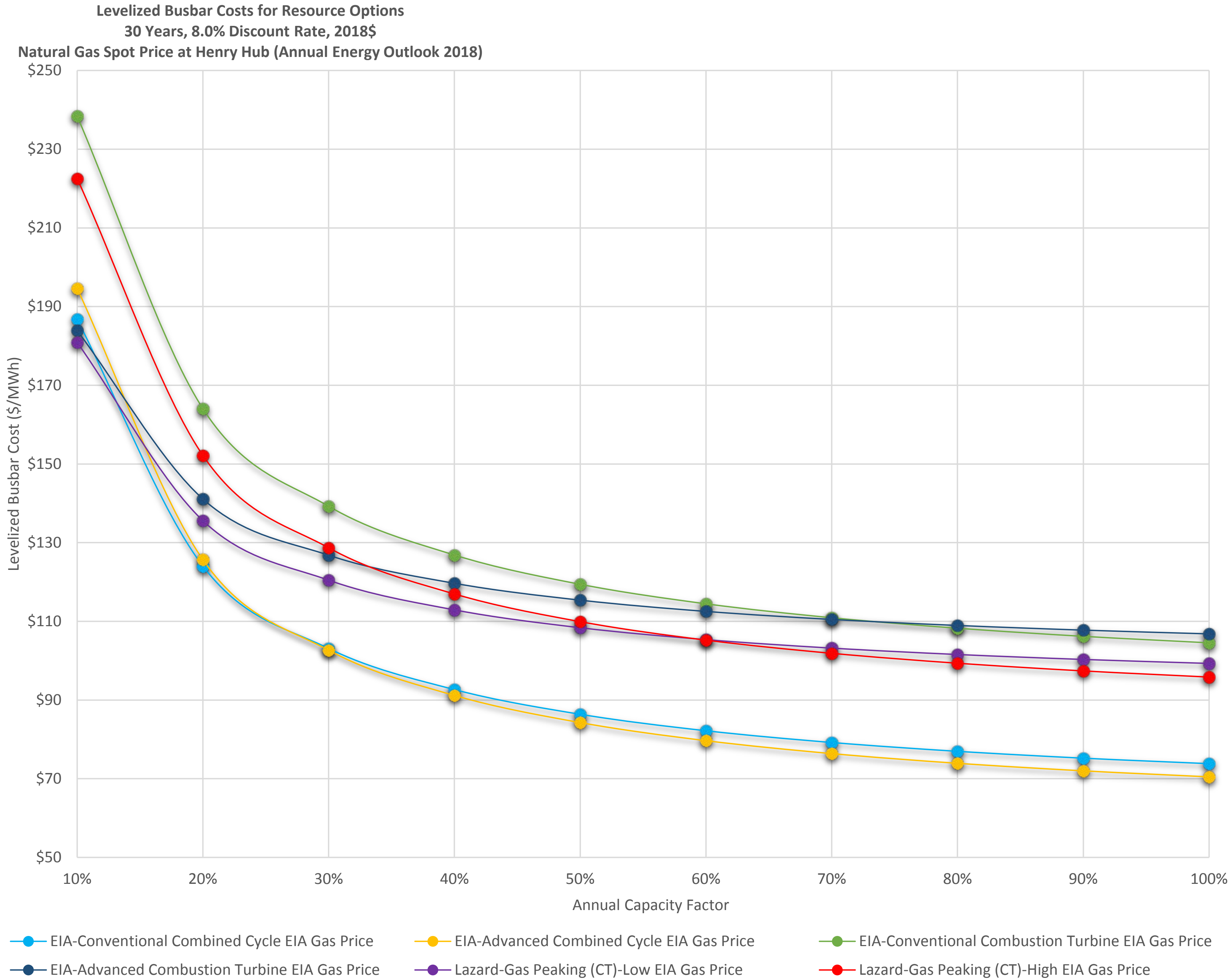
Generation Type	Data Source	Tech Type	Size (MW)	Total Capital Cost ($/kW)	V O&M ($/MWh)	F O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Combined Cycle (CC)	EIA AEO'18	Conv.	702	1,007	3.63	11.39	6,600
Combustion Turbine (CT)	EIA AEO'18	Adv.	237	697	11.08	7.04	9,800

Appendix

Capacity short fall after renewables

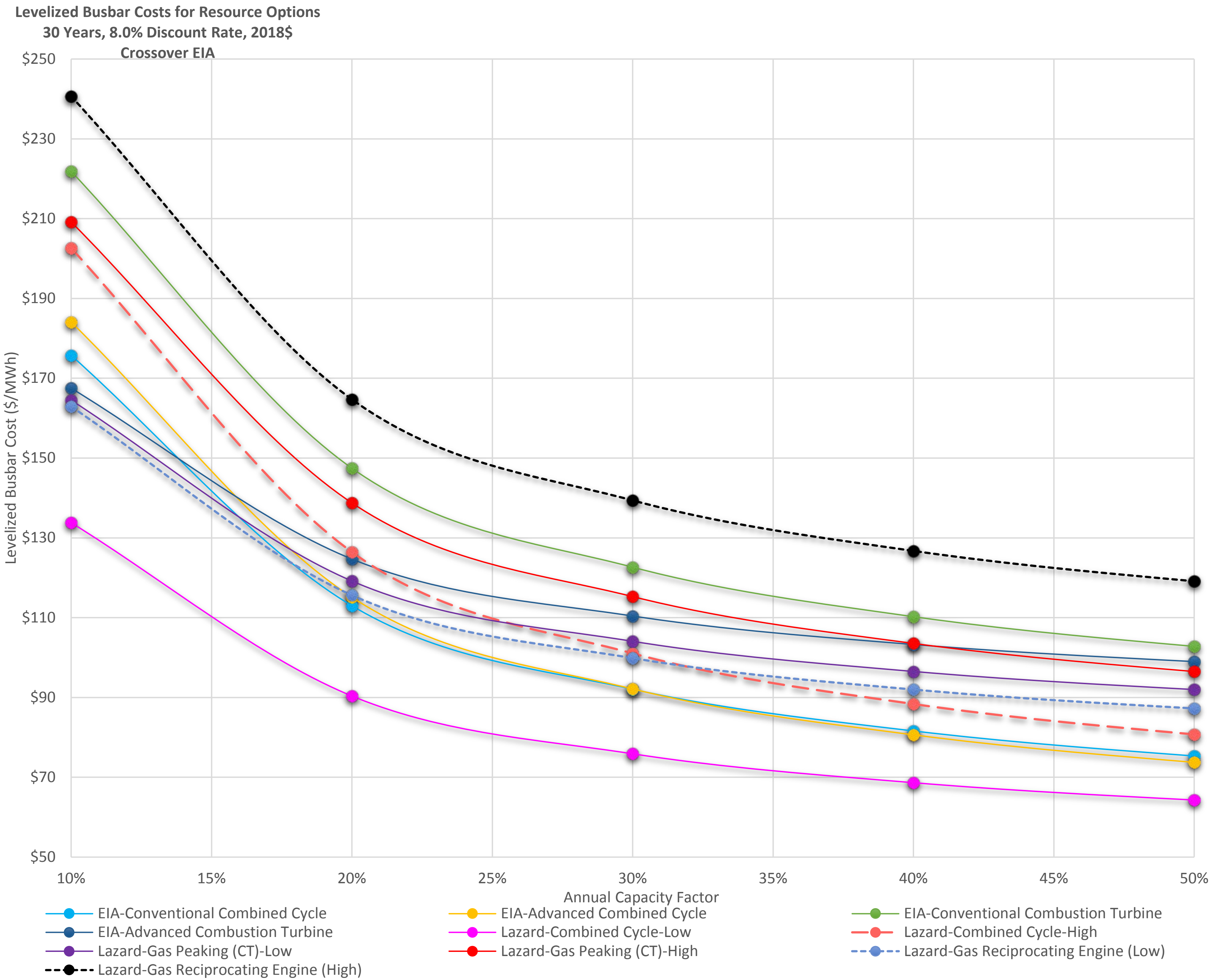
2019 ITP	F1 2025	F1 2030	F2 2025	F2 2030
Sub region (MW)	833	3,235	829	4,378

Natural Gas Spot Price at Henry Hub (Annual Energy Outlook 2018)



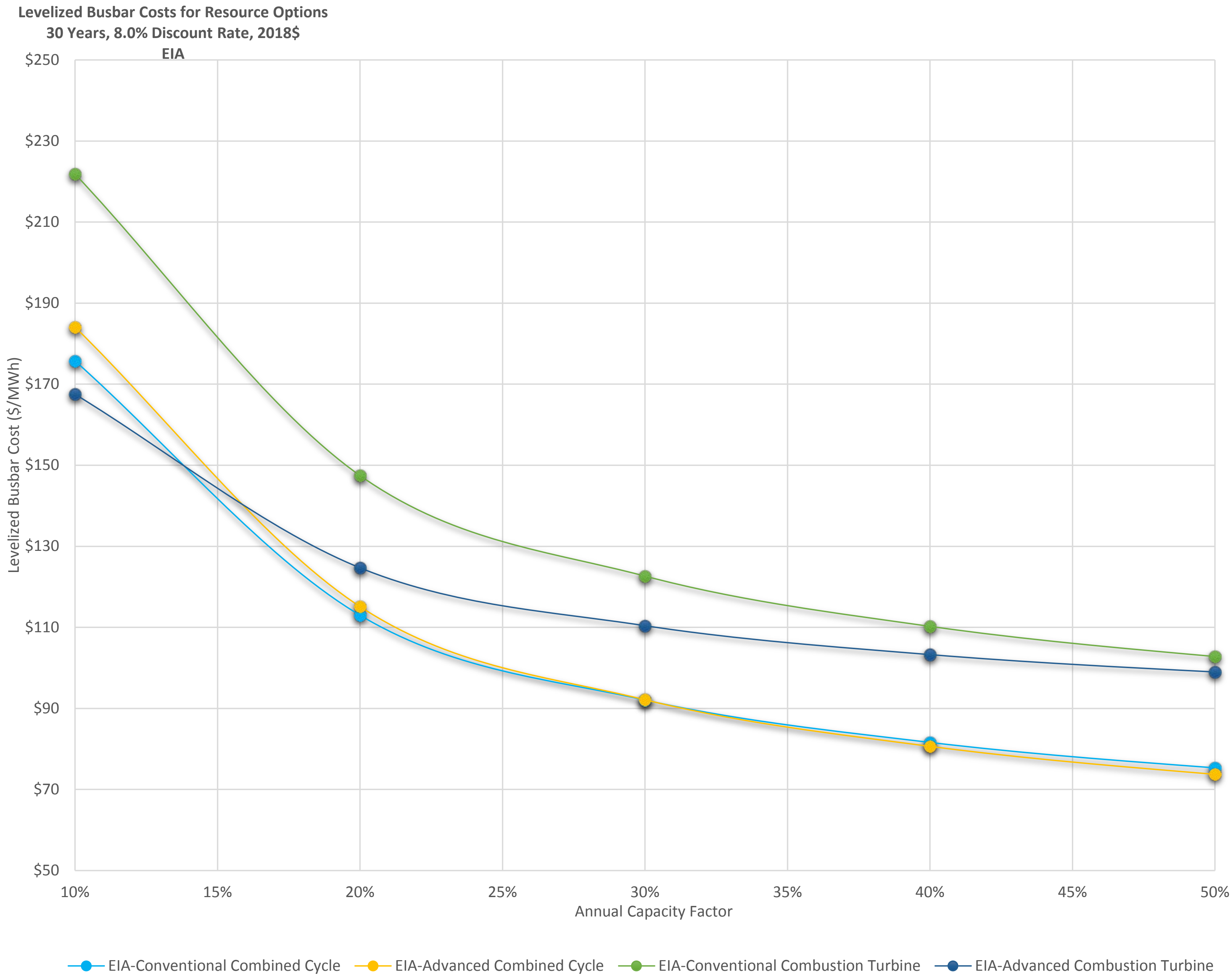
ITP 2020

Annual Capacity Factor 10%-50%

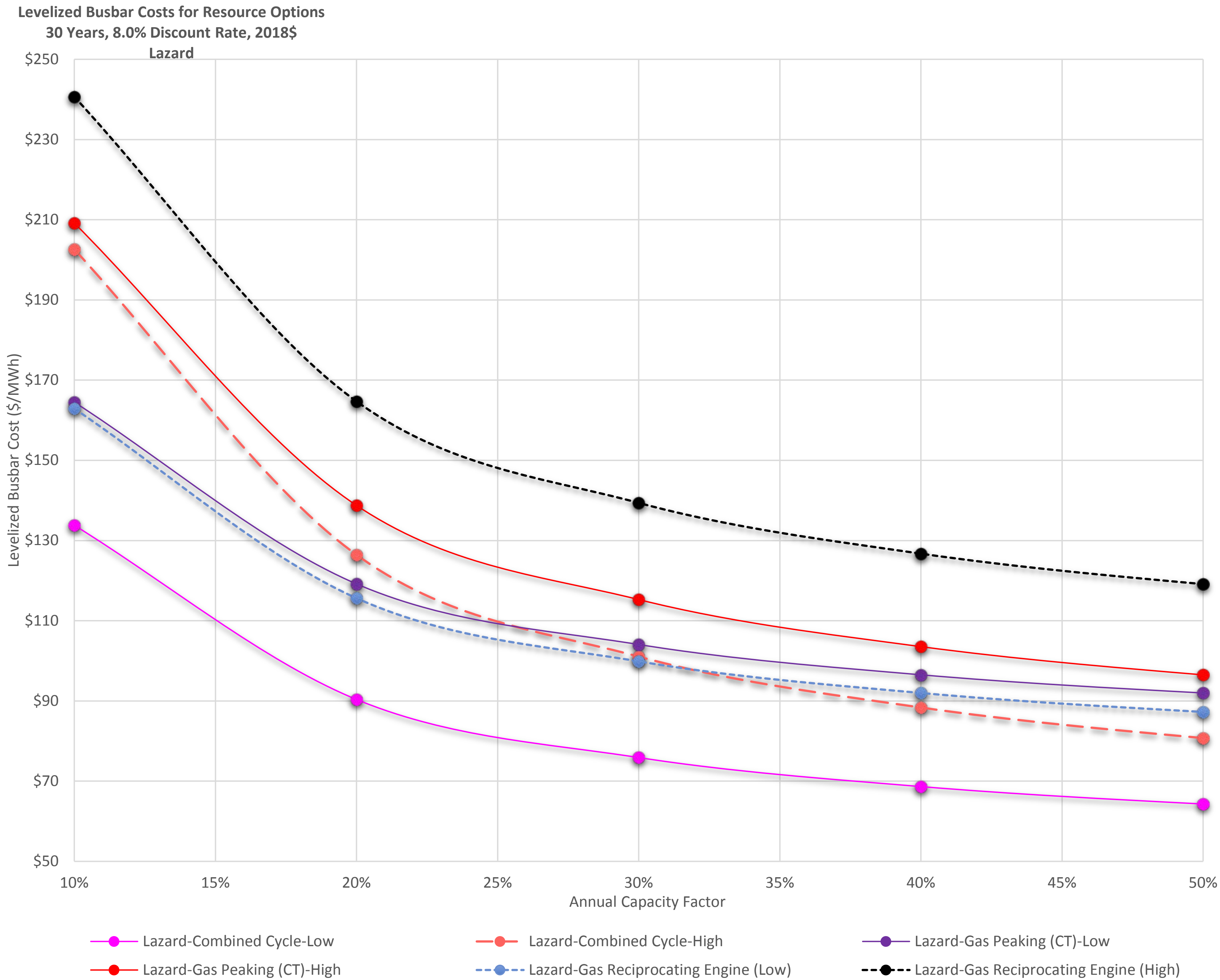


ITP 2020

Annual Capacity Factor 10%-50% EIA



Annual Capacity Factor 10%-50% Lazard



SPP

ITP 2020

EIA / Lazard / Staff

Generation Type	Data Source	Tech Type	Size (MW)	Total Capital Cost ($/kW)	V O&M ($/MWh)	F O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Combined Cycle (CC)	EIA AEO'18	Adv.	429	1,136	2.07	10.35	6,300
	EIA AEO'18	Conv.	702	1,007	3.63	11.39	6,600
	Lazard	High	550	1,333	2.05	5.64	6,900
	Lazard	Low	550	718	3.59	6.36	6,133
	Lazard 18	High	550	1,300	2.00	5.50	6,900
	Lazard 18	Low	550	700	3.50	6.00	6,133
	Tucson Electric Power	NGCC	550	1,128	34.82	2.09	7,400
	AEP System	1x1 J Class	540	1,000	10.81	1.97	6,300
	AEP System	2x1 J Class	1080	800	9.16	1.73	6,300
	AEP System	2x1 H Class	1150	700	8.65	1.63	6,300
	City of Dover (Tea The Energy Authority)	NGCC	200	2,050	17.94	2.01	7,400
	City of Dover (Tea The Energy Authority)	HGCC - LMS 100	106	1,538	17.94	2.01	8,600
	Tucson Electric Power	NGCC	550	1,128	34.82	2.09	7,400
Combustion Turbine (CT)	EIA AEO'18	Adv.	237	697	11.08	7.04	9,800
	EIA AEO'18	Conv.	100	1,135	3.57	17.82	9,920
	Lazard	High	50	1,025	10.25	20.50	8,000
	Lazard	Low	241	769	4.82	5.13	9,804
	Lazard 18	High	50	950	10.00	20.00	8,000
	Lazard 18	Low	241	700	4.70	5.00	9,804
	Tucson Electric Power	Small Frame Class	75	820	31.42	3.93	10,500
	Tucson Electric Power	Largae Frame Class	220	666	28.75	3.66	9,900
	AEP System	2 - "E" Class	180	1,200	17.60	3.94	11,700
	AEP System	2 - "F" Class w/ evap coolers	490	718	15.77	6.07	10,000
	City of Dover (Tea The Energy Authority)	NGCT/Frame	100	1,025	17.55	3.51	10,000
	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	1x1 501JAC	510	1,269	17.45	3.22	6,400
	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	501JAC	300	854	2.91	13.68	9,400
	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	2x1 501JAC	1020	1,117	11.40	3.23	6,400
Aero Derivative CT	AEP System	2 - Small Machines	120	1,400	18.93	2.44	9,900
	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	LMS 100PA	102	1,582	6.01	2.97	9,397
	City of Dover (Tea The Energy Authority)	NGCT	50	1,281	13.50	4.42	9,000
	Tucson Electric Power	Aeroderivative	45	1,333	30.64	3.66	9,800
	Lazard	High	0.25	1,128	15.38	20.50	10,000
Reciprocating Engines	Lazard	Low	1	666	10.25	15.38	8,000
	AEP System	Recip Engine Farm	220	1,300	6.32	2.61	8,300
	Tucson Electric Power	RICE	100	1,230	12.55	4.70	8,000
	City of Dover (Tea The Energy Authority)	RICE	10	1,128	20.40	6.97	8,200
	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	7x Wartsila 18V50SG	128	1,683	32.74	7.48	8,401

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Gen Type	Data Source	Tech Type	Size (MW)	Total Capital Cost ($/kW)	V O&M ($/MWh)	F O&M ($/kW-yr)	Heat Rate (Btu/kWh)
CC	EIA AEO'18	Adv.	429	1,136	2.07	10.35	6,300
	EIA AEO'18	Conv.	702	1,007	3.63	11.39	6,600
	Lazard	High	550	1,333	2.05	5.64	6,900
	Lazard	Low	550	718	3.59	6.36	6,133
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	Lazard 18	Low	550	700	3.50	6.00	6,133
	Tucson Electric Power	NGCC	550	1,128	34.82	2.09	7,400
	AEP System	1x1 J Class	540	1,000	10.81	1.97	6,300
	AEP System	2x1 J Class	1080	800	9.16	1.73	6,300
	AEP System	2x1 H Class	1150	700	8.65	1.63	6,300
	City of Dover (Tea The Energy Authority)	NGCC	200	2,050	17.94	2.01	7,400
	City of Dover (Tea The Energy Authority)	HGCC - LMS 100	106	1,538	17.94	2.01	8,600
	Tucson Electric Power	NGCC	550	1,128	34.82	2.09	7,400

Combustion Turbine / Aero Derivative

Gen Type	Data Source	Tech Type	Size (MW)	Total Capital Cost ($/kW)	V O&M ($/MWh)	F O&M ($/kW-yr)	Heat Rate (Btu/kWh)
CT	EIA AEO'18	Adv.	237	697	11.08	7.04	9,800
	EIA AEO'18	Conv.	100	1,135	3.57	17.82	9,920
	Lazard	High	50	1,025	10.25	20.50	8,000
	Lazard	Low	241	769	4.82	5.13	9,804
	Lazard 18	High	50	950	10.00	20.00	8,000
	Lazard 18	Low	241	700	4.70	5.00	9,804
	Tucson Electric Power	Small Frame Class	75	820	31.42	3.93	10,500
	Tucson Electric Power	Largae Frame Class	220	666	28.75	3.66	9,900
	AEP System	2 - "E" Class	180	1,200	17.60	3.94	11,700
	AEP System	2 - "F" Class w/ evap coolers	490	718	15.77	6.07	10,000
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	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	501JAC	300	854	2.91	13.68	9,400
	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	2x1 501JAC	1020	1,117	11.40	3.23	6,400
Aero	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	2x1 501JAC	1020	1,117	11.40	3.23	6,400
	AEP System	2 - Small Machines	120	1,400	18.93	2.44	9,900
	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	LMS 100PA	102	1,582	6.01	2.97	9,397
	City of Dover (Tea The Energy Authority)	NGCT	50	1,281	13.50	4.42	9,000
	Tucson Electric Power	Aeroderivative	45	1,333	30.64	3.66	9,800

Reciprocating Engines

Gen Type	Data Source	Tech Type	Size (MW)	Total Capital Cost ($/kW)	V O&M ($/MWh)	F O&M ($/kW-yr)	Heat Rate (Btu/kWh)
Recip. Engines	Lazard	High	0	1,128	15.38	20.50	10,000
	Lazard	Low	1	666	10.25	15.38	8,000
	AEP System	Recip Engine Farm	220	1,300	6.32	2.61	8,300
	Tucson Electric Power	RICE	100	1,230	12.55	4.70	8,000
	City of Dover (Tea The Energy Authority)	RICE	10	1,128	20.40	6.97	8,200
	Entergy Louisiana, Inc. 2019 Draft Integrated Resource Plan	7x Wartsila 18V50SG	128	1,683	32.74	7.48	8,401

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Battery Storage Accreditation

Joshua Norton

December 3-4th, 2018

Objective

- Approve accreditation for battery storage

Recap of Battery approvals

- Allocate by LRS
- Unassigned

Accreditation

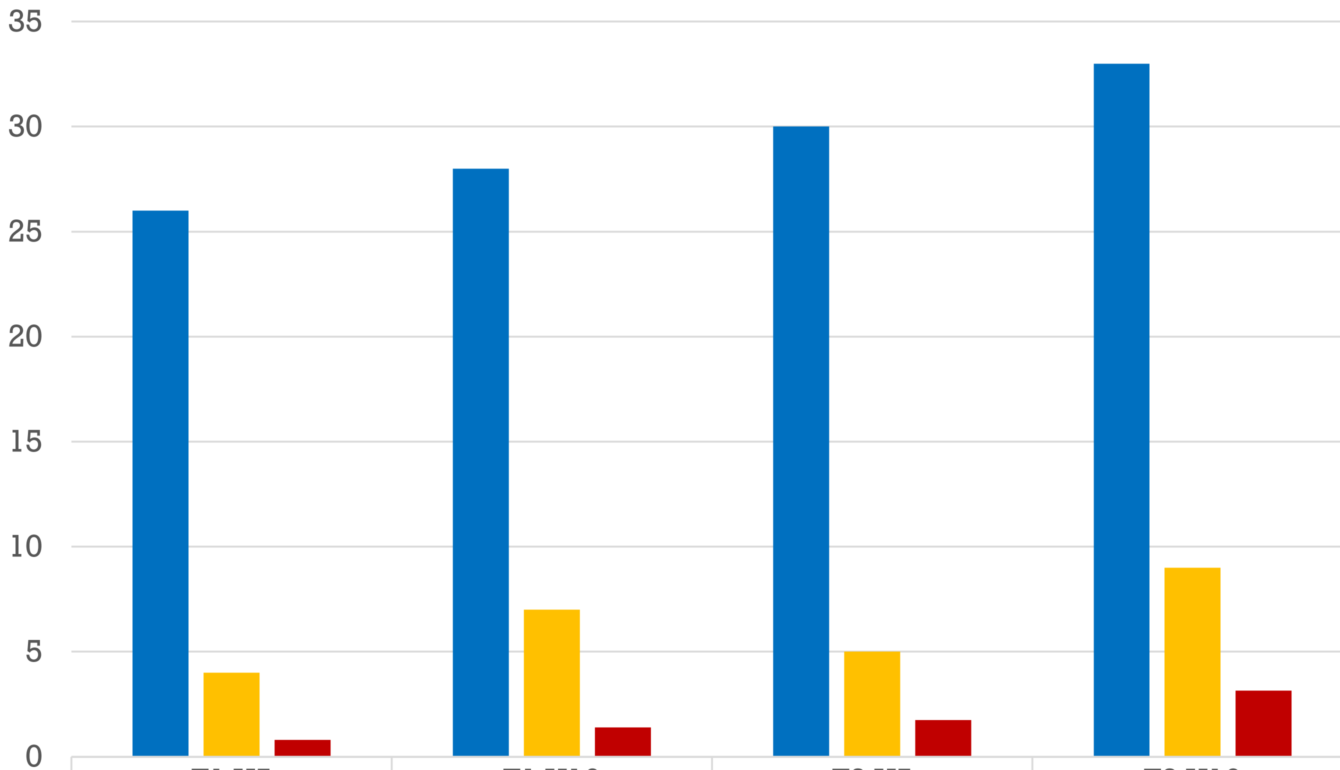
100%

- Operating flexible with contracts
- Market incentives

The 12% cap

- Deliverable Capacity process for RM
- Entities may not solely rely on the process
- Ensures reasonable mix of resources
- Uncertainty of proxy resources

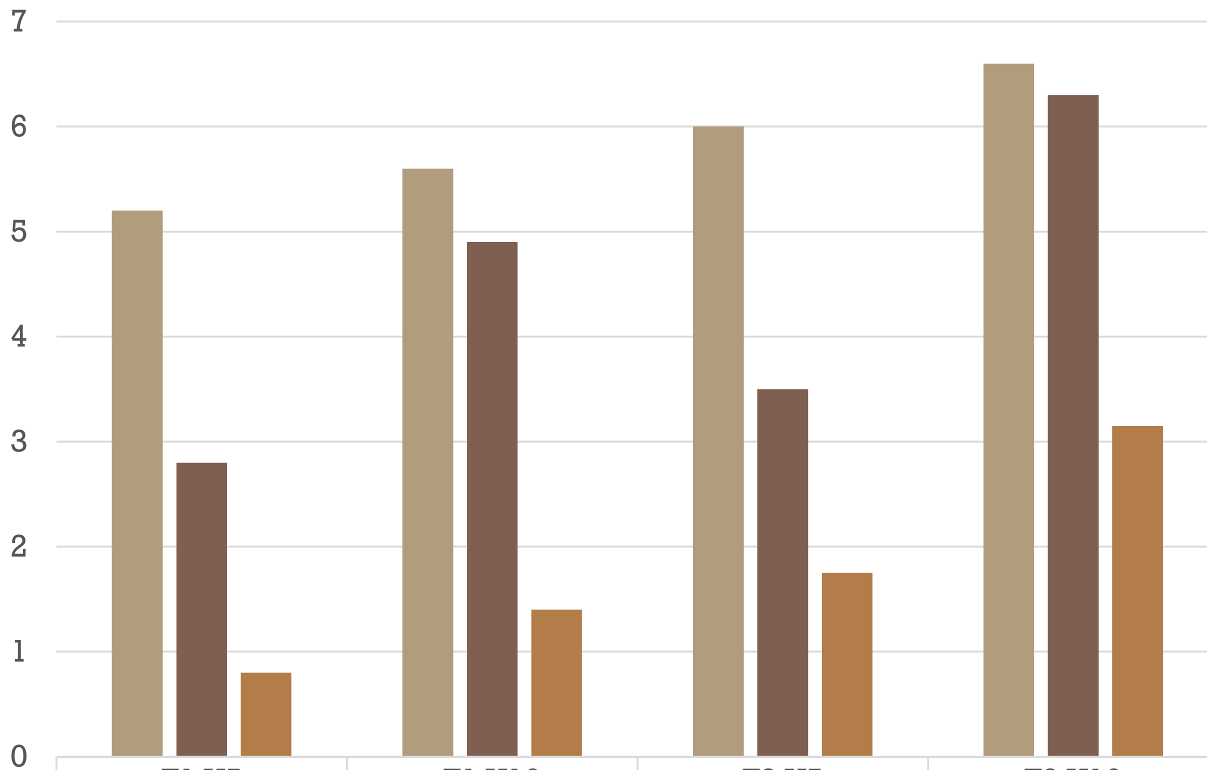
Approved Renewable and Battery Storage Amounts



	F1 Y5	F1 Y10	F2 Y5	F2 Y10
Wind	26	28	30	33
Solar	4	7	5	9
Batteries	0.8	1.4	1.75	3.15

Wind Solar Batteries

Renewable and Battery Storage Amounts - Accredited



	F1 Y5	F1 Y10	F2 Y5	F2 Y10
Wind Accred	5.2	5.6	6	6.6
Solar Accred	2.8	4.9	3.5	6.3
Batteries Accred	0.8	1.4	1.75	3.15

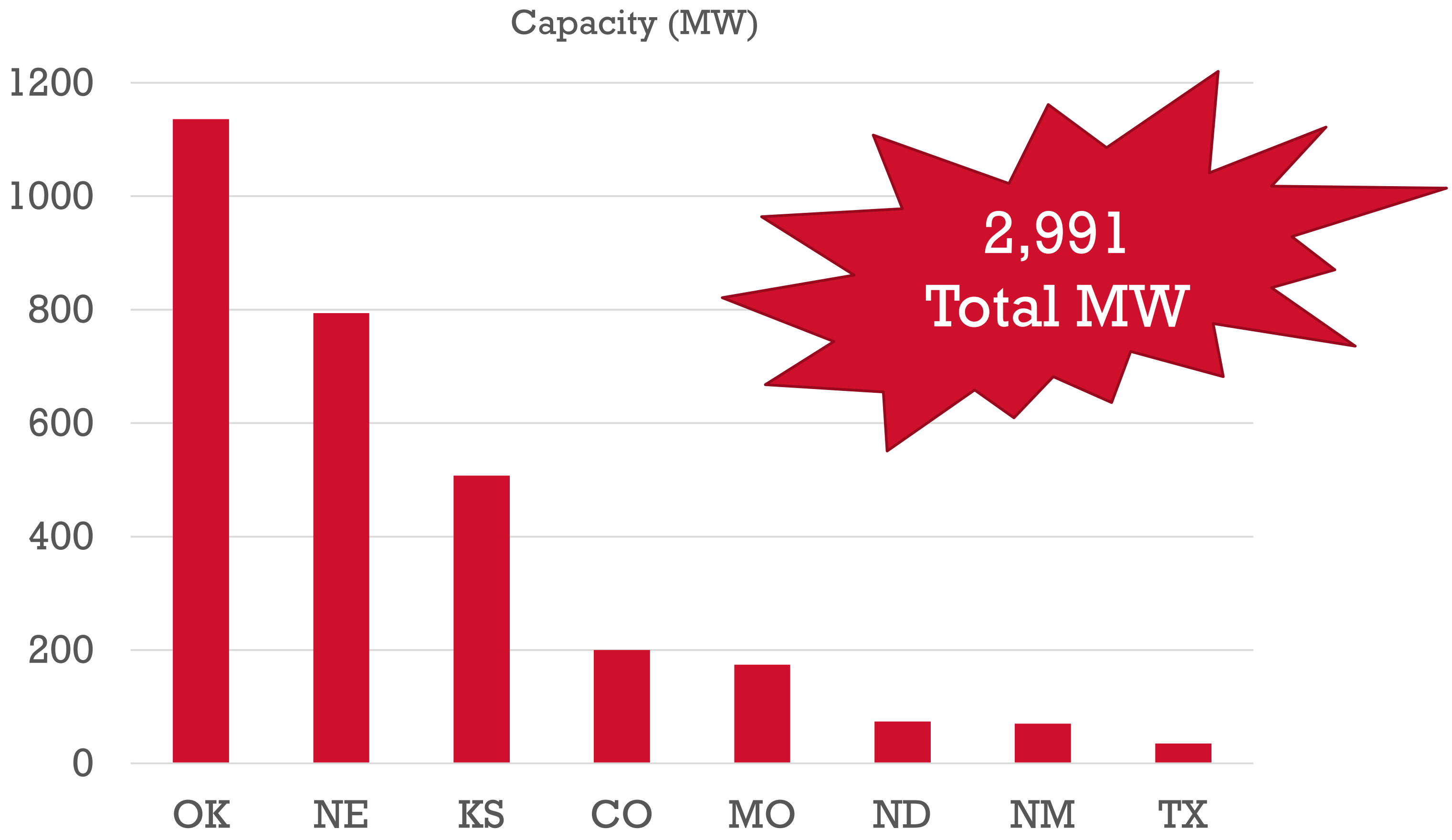
Wind Accred Solar Accred Batteries Accred

Recommendation

- Staff recommends battery accreditation at 100% and include in projected renewable 12% cap for the purposes of resource planning in the ITP Study.

Appendix

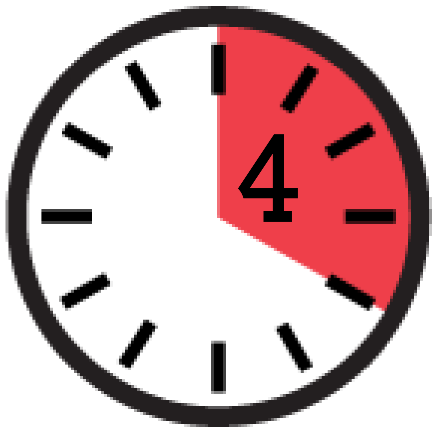
Batteries in GI Queue



General Resource Accreditation

- SPP Planning Criteria 7.1.5.2 (2):

  Shall be available for a minimum of four continuous hours

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2020 ITP Scope: Sensitivities

Kirk Hall

December 3-4, 2018

Objective

- Review ITP Manual Language
- Approve 2020 ITP Sensitivities (2020 ITP Scope Item)
- Approve Natural Gas price source (non-2020 ITP Scope item)

Fuel Prices (ITP Manual 2.2.1.7)

Fuel price forecasts for the reference case future, including natural gas, oil, uranium, coal, and associated transportation costs, will be based upon the latest vendor data set

Potential adjustments to the fuel prices for the non-reference case future(s)* will be determined by the ESWG to appropriately reflect each future and will be described in the ITP study scope document

*Note: Future 2 gas prices approved by ESWG and MOPC as current forecast

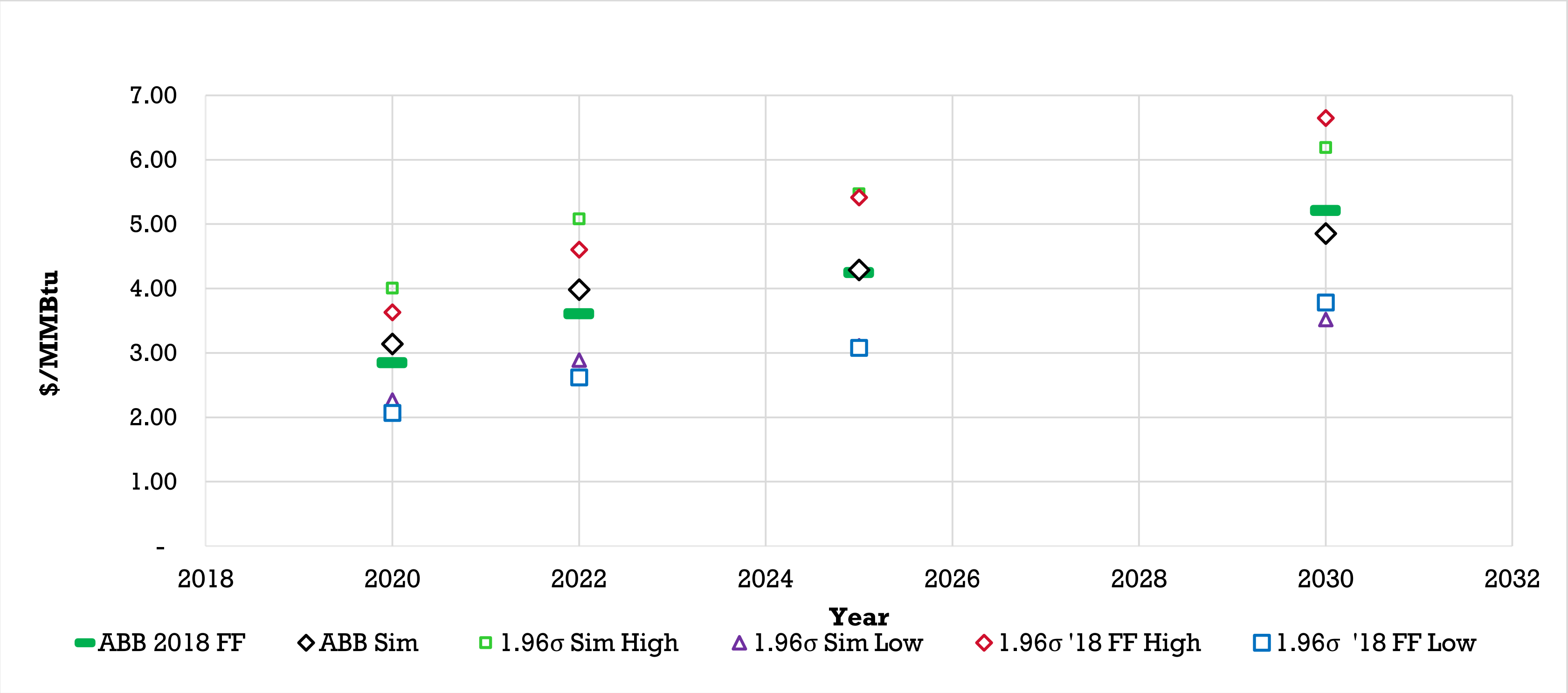
ITP Manual Language

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

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

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

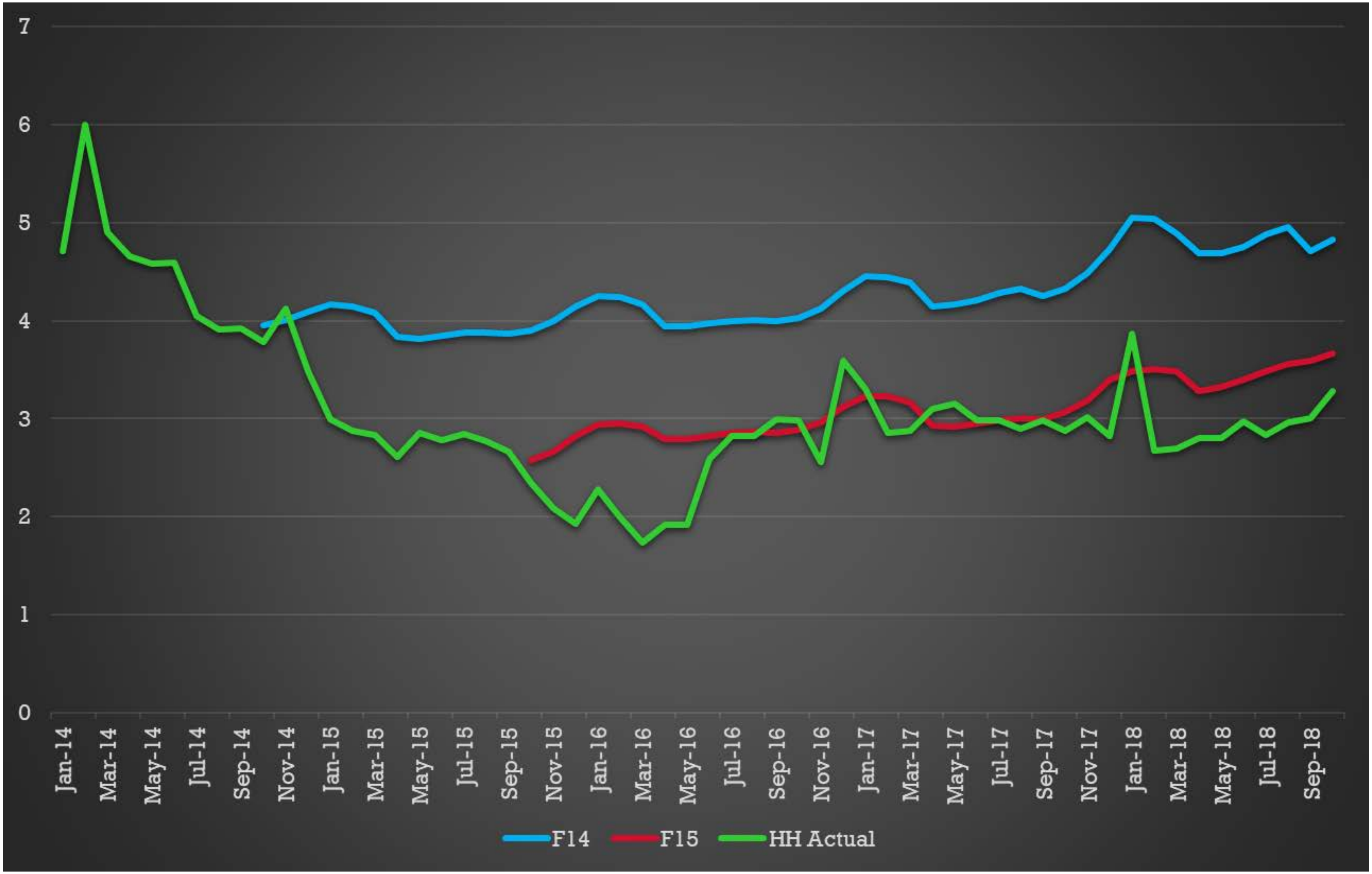
2018 FF vs 2018 Simulation Ready Data*



Year	ABB 2018 FF	ABB Sim	1.96σ Sim High	1.96σ Sim Low	1.96σ '18 FF High	1.96σ '18 FF Low
2020	2.85	3.14	4.01	2.27	3.63	2.07
2022	3.61	3.98	5.08	2.89	4.60	2.62
2025	4.25	4.29	5.47	3.11	5.41	3.08
2030	5.21	4.85	6.19	3.52	6.65	3.78

*NOTE: 2018 FF data considered preliminary

Forecast vs Actual HH Prices

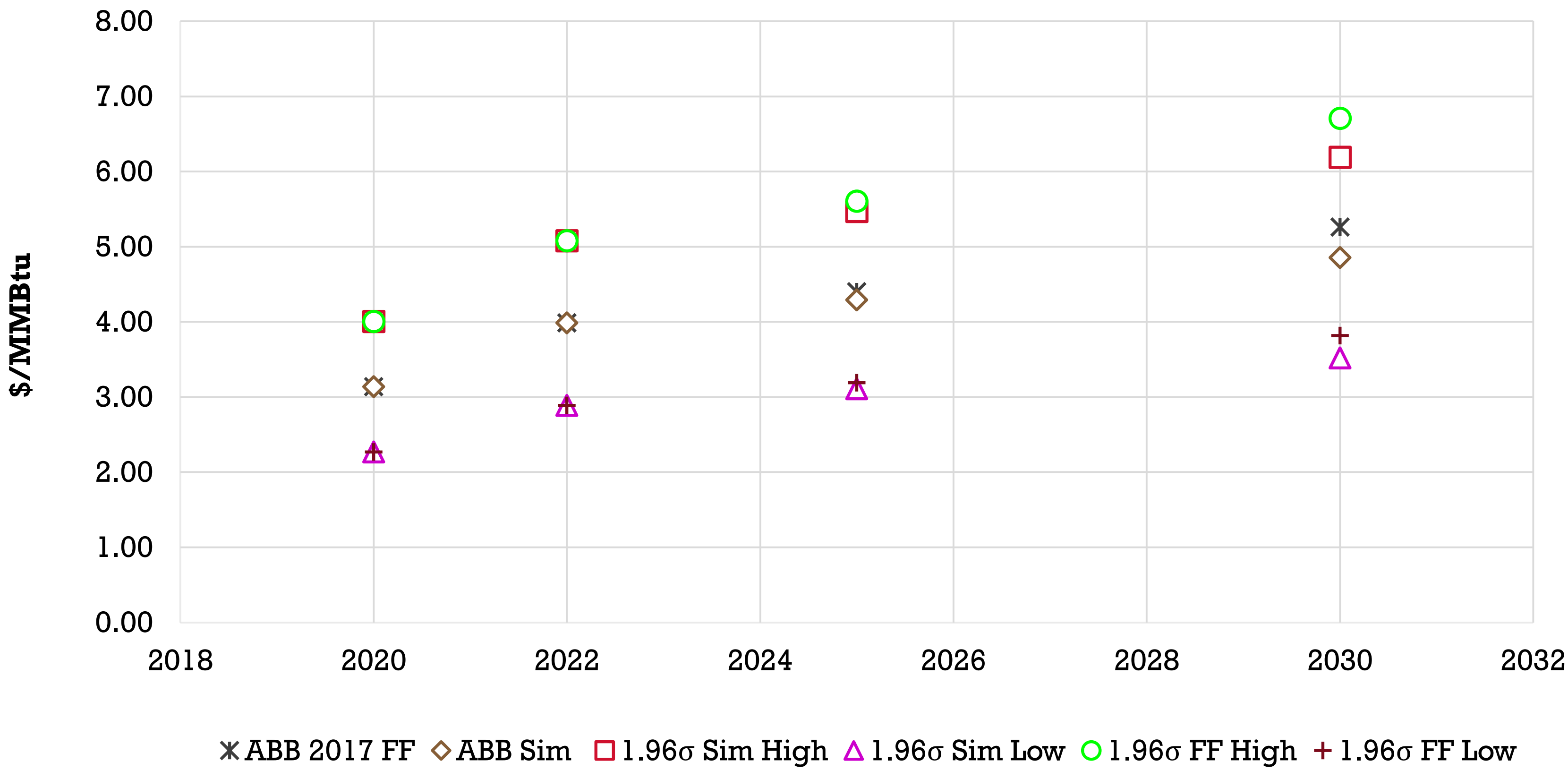


Recommendation

- Staff recommends the 2020 ITP study the sensitivities described in the ITP Manual
- Staff recommends using 2018 ABB fundamental forecast natural gas price data

Appendix

ABB 2018 Sim. Ready vs. 2017 ABB FF



Year	ABB 2017 FF	ABB Sim	1.96σ Sim High	1.96σ Sim Low	1.96σ FF High	1.96σ FF Low
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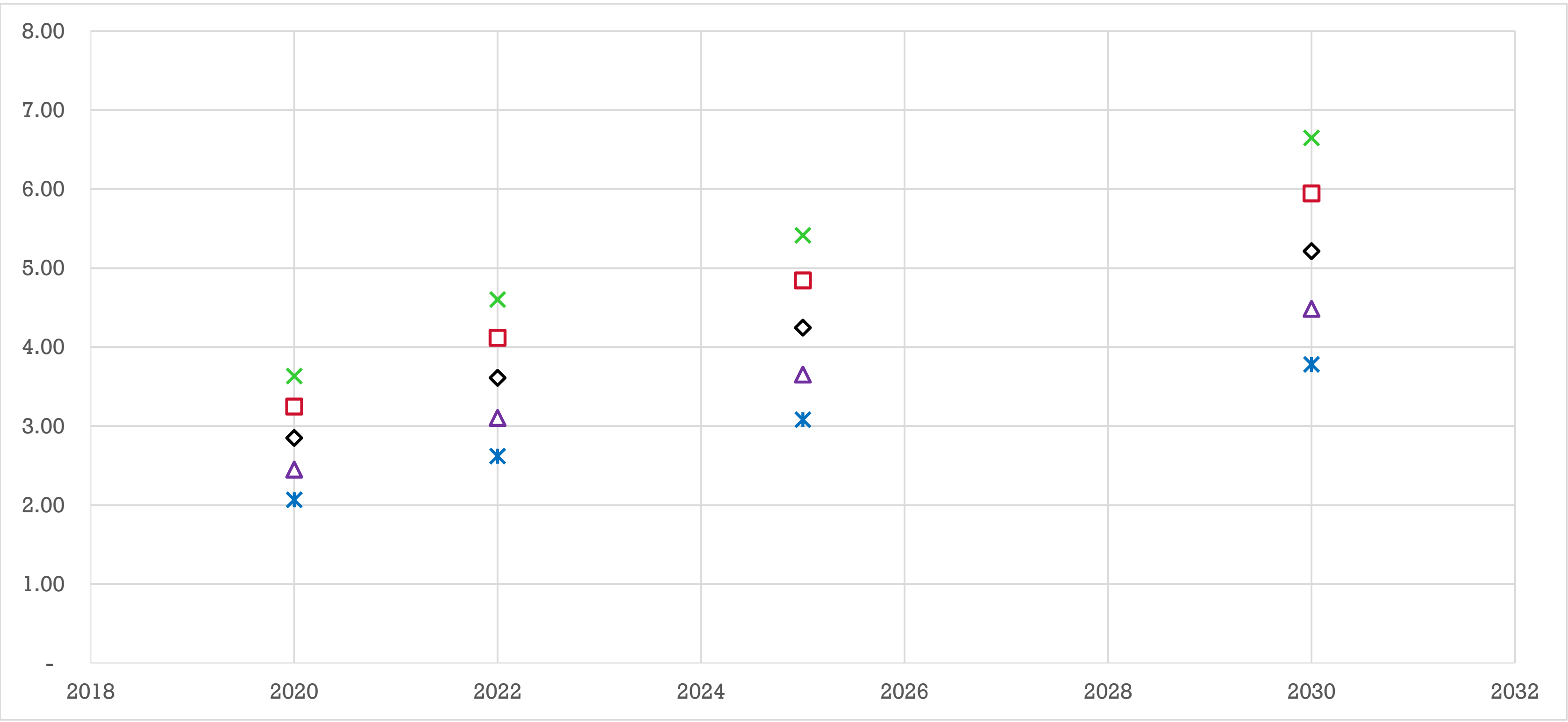
2025	4.40	4.29	5.47	3.11	5.61	3.19
2030	5.26	4.85	6.19	3.52	6.71	3.81

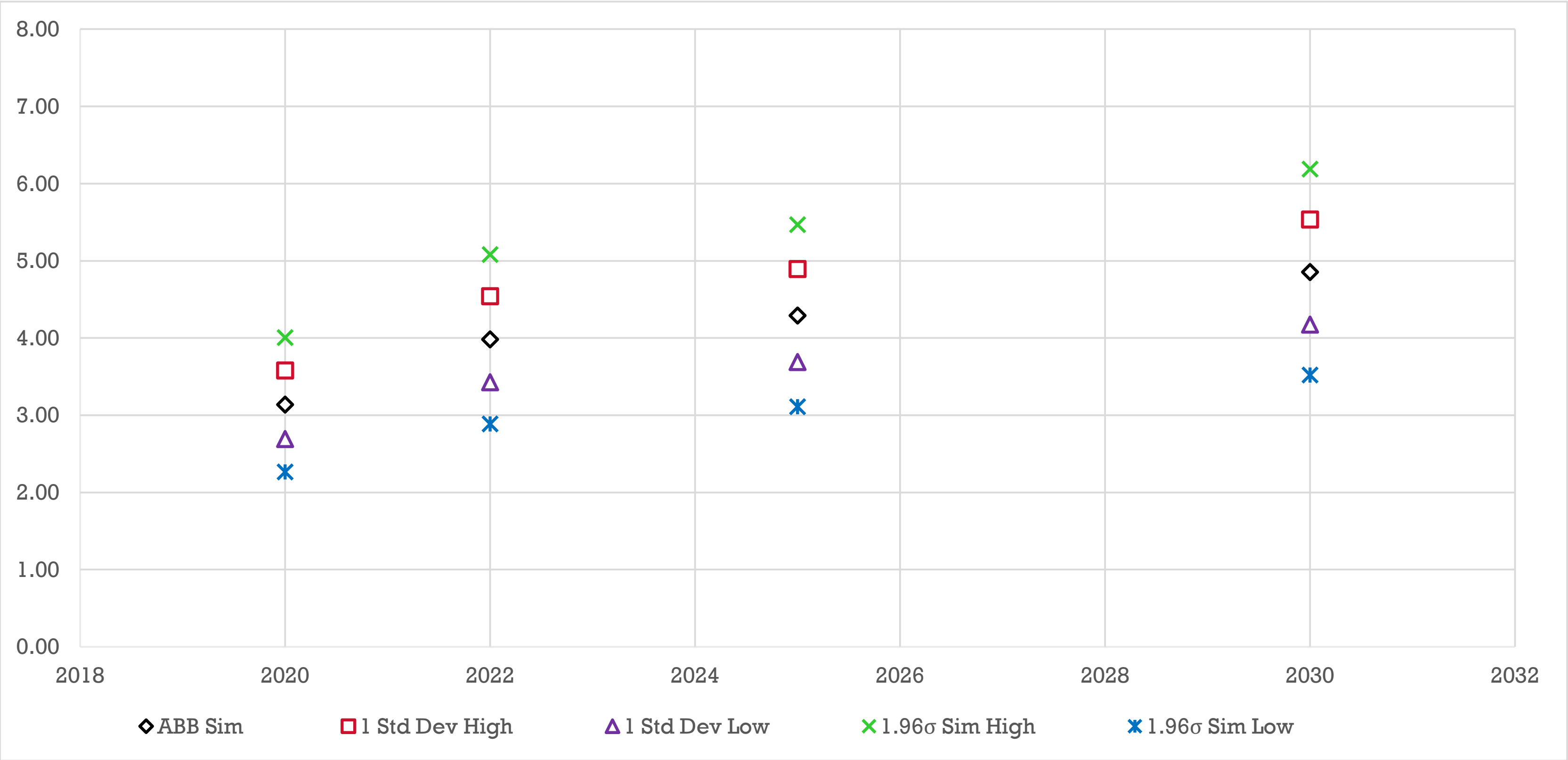
2018 Fundamental Forecast*



Year	ABB 2018 FF	1 Std Dev High	1 Std Dev Low	1.96σ '18 FF High	1.96σ '18 FF Low
2020	2.85	3.25	2.45	3.63	2.07
2022	3.61	4.12	3.10	4.60	2.62
2025	4.25	4.84	3.65	5.41	3.08
2030	5.21	5.94	4.48	6.65	3.78

*NOTE: 2018 FF data still considered preliminary

2018 Simulation Ready Data



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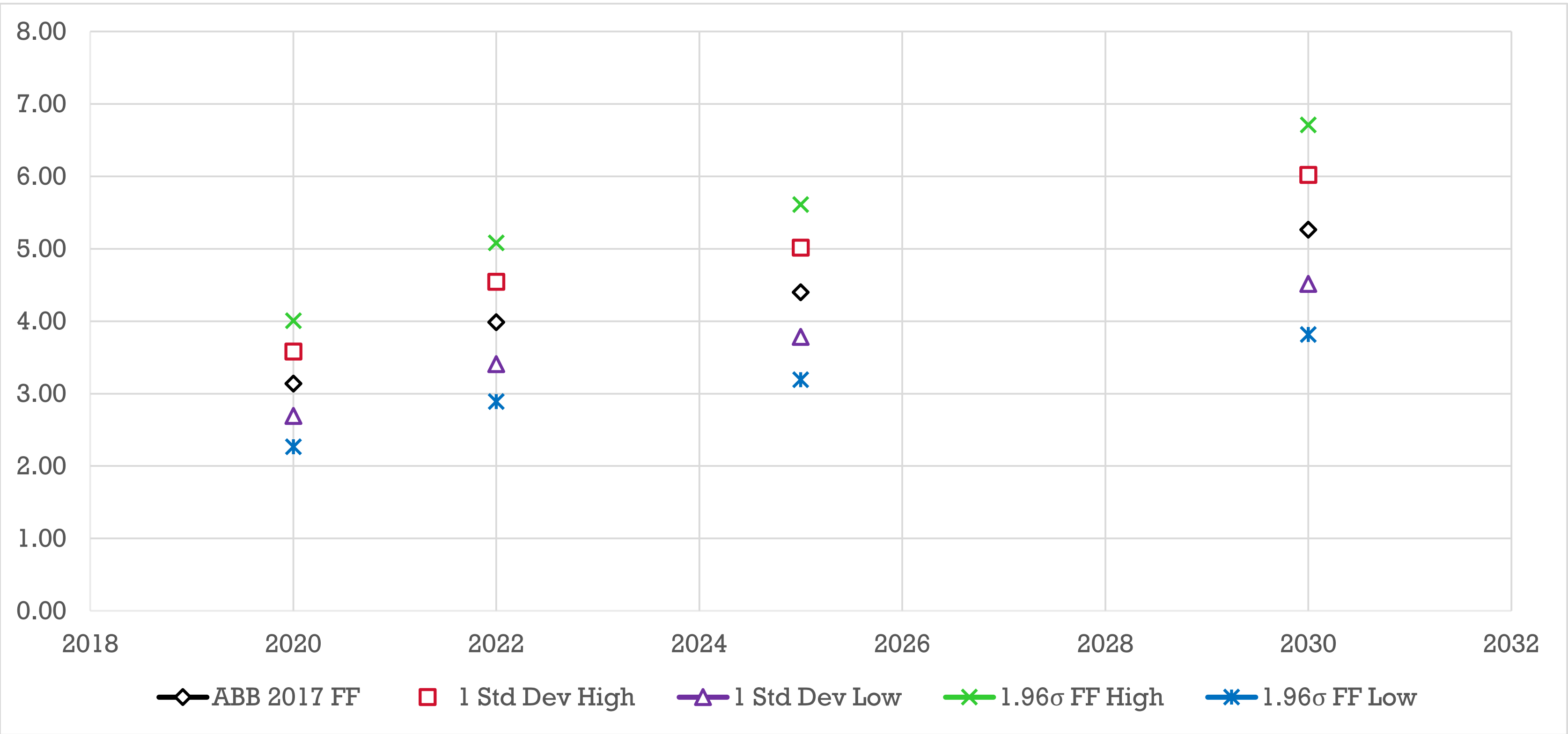
2022	3.98	4.54	3.42	5.08	2.89
2025	4.29	4.89	3.69	5.47	3.11
2030	4.85	5.53	4.17	6.19	3.52

2017 Fundamental Forecast



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2020 ITP Generation and Load Review Update

December 3, 2018

Theva Coleman

Objective

- Provide update on the current status of the Generation and Load review process

Gen and Load Review Update

- Pass 3 Stakeholder Review Period
  - Began – 11/26/2018
  - Deadline – 12/07/2018
- Review for Approval Period
  - Begins – 2/08/2019
  - SPP Request vote to approve (email) – 2/15/2018
- Final Generation and Load changes will include:
  - Pass 4 2020 ITP BR Powerflow updates:
    - Generation and Load lock down on 1/11/2019
    - Associated Powerflow topology lock down on 1/11/2019
  - 2020 ITP Generation and Load Review updates
    - Annual Capacity
    - Retirement Dates
    - Ownership Percentages
    - Demand Group Load Factor
    - Demand Group Loss Factor
  - RARs that meet ITP Manual inclusion criteria
  - Working group approved RARs
  - Staff additions