

ENERGY BAR ASSOCIATION

ANNUAL MEETING & CONFERENCE

2026

Transmission Planning in Transition: Implementing Order No. 1920 in a Shifting Landscape

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Transmission Planning in Transition: Implementing Order No. 1920 in a Shifting Landscape

Order 1920: NARUC and State Perspectives

- **Kimberly Duffley**, *Sr. Director of Energy Policy and Legal Counsel*,
NARUC

Overview of state roles in transmission:

- Siting and permitting
- State transmission authority
- State transmission investments
- Utility cost recovery and consideration of lower-cost alternatives
- Participate in regional transmission operator (RTO) and independent system operator (ISO) planning and cost allocation processes
- Integrated Resource Planning (IRP)

What is an IRP and where does it happen?

Utility IRPs seek an optimal combination of demand- and supply-side options—including transmission—to satisfy future energy service demands in an economic and reliable manner

Primarily in vertically integrated states, where utilities are responsible for meeting customers' energy and capacity needs

Some states with electric industry restructuring require some type of long-term BPS plan

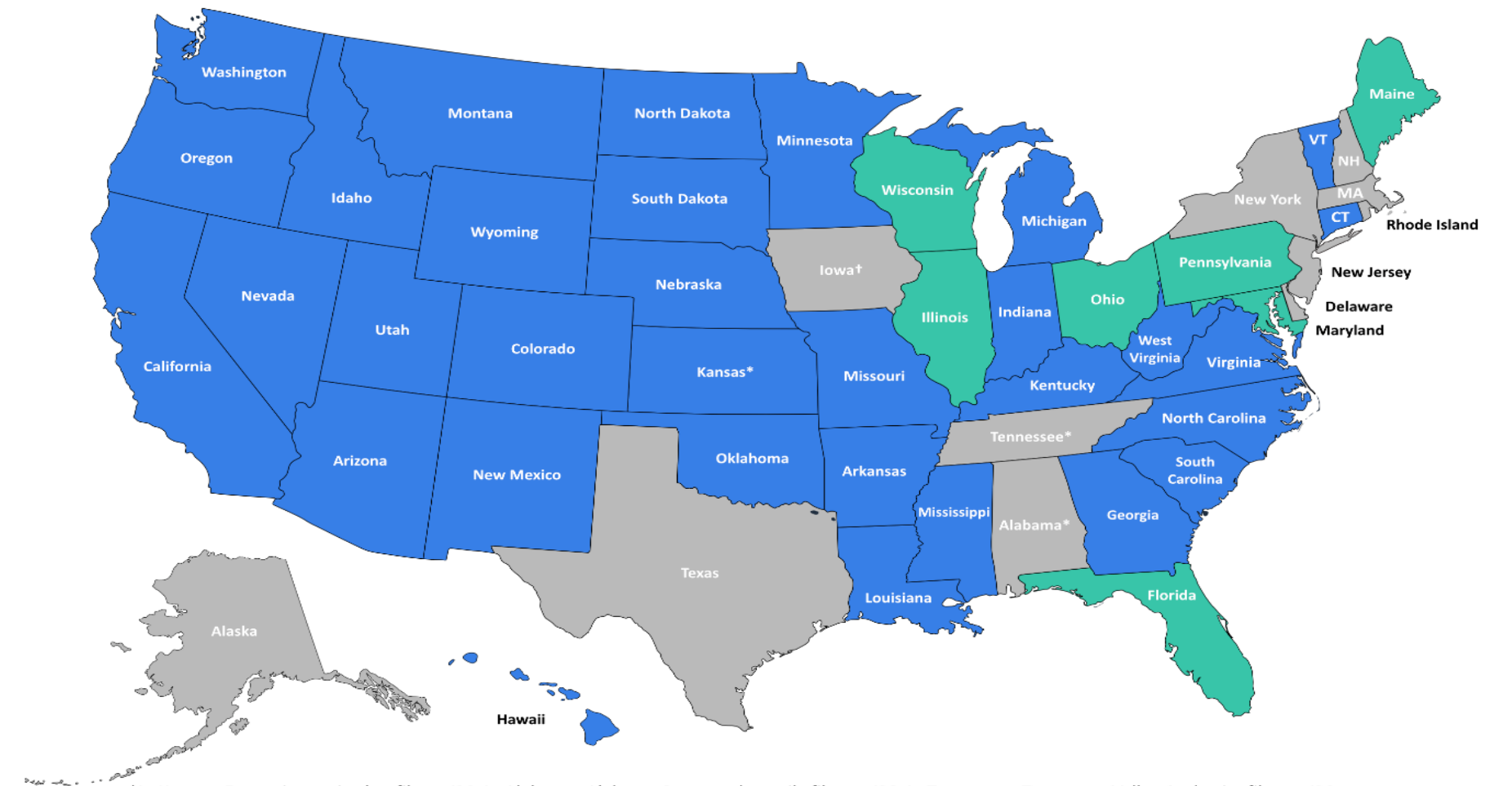
Provides for stakeholder engagement

Properly executed process results in transparent report and clear short-term action plan

Regulatory approval varies

Litigated docket that may result in plan approval

Informal process—formal acknowledgment of action plan or only accepting that plan met filing requirements



*In Kansas, Eversource is required to file an IRP. In Alabama, Alabama Power voluntarily files an IRP. In Tennessee, Tennessee Valley Authority files an IRP.
†In Iowa, no IRP is required, but the major public utilities have agreed to one-off planning exercises as a condition of several settlement agreements.

State has an IRP and filing requirement

State does not have a filing requirement for long-term plans

State has a filing requirement for long-term plans

[Biewald et al. 2024](#)

*Some states and utilities are taking steps to include distribution planning elements. See [slides](#) on forthcoming LBNL report.

FERC History on Transmission Planning

1996	Order No. 888	Established Open Access, Cannot Discriminate	Required a transmission provider to account for the needs of its network customers in transmission planning activities on the same basis as it provides for its own needs; encouraged regional transmission planning; as part of providing open access transmission service to their transmission customers that is comparable to the service they provide themselves; universal access to the transmission grid for all qualified users on a non-discriminatory, open access basis.
2007	Order No. 890	Transparency and Coordination	Required transmission owners and operators to provide a more open, transparent inclusive transmission planning process not covered by the OATT regime and to develop their own cost allocation method for new projects considering cost causation and beneficiaries.
2011	Order No. 1000	Plan Regionally with Cost Allocation	Required planning processes at the regional level and produce a regional transmission plan; and ensure that the costs are allocated fairly to those who benefit, or costs must be roughly commensurate with the benefits. Required ex ante cost allocation methodology.
2024	Order No. 1920	Plan For Future Needs	Required transmission providers to conduct Long-Term Regional Transmission Planning

The Role for States Provided in Order No. 1920

What is a Relevant State Entity? Any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state. e.g. State Commissions, State Siting Boards, Transmission Authorities

FERC states that Order No. 1920 established a role for Relevant State Entities to inform the planning, evaluation and selection, and cost allocation methods adopted by Transmission Providers.

Planning Stage: TPs must provide Relevant State Entities a meaningful opportunity to engage in planning scenarios and inputs.

Evaluation & Selection Stage: TPs must make a good faith effort to consult with and seek support from Relevant State Entities for evaluation and selection of projects.

Cost Allocation Stage: TPs must provide a 6-month period for states to agree on cost allocation before compliance, and **must file** any state-agreed upon *ex ante* method(s) and State Agreement Process.

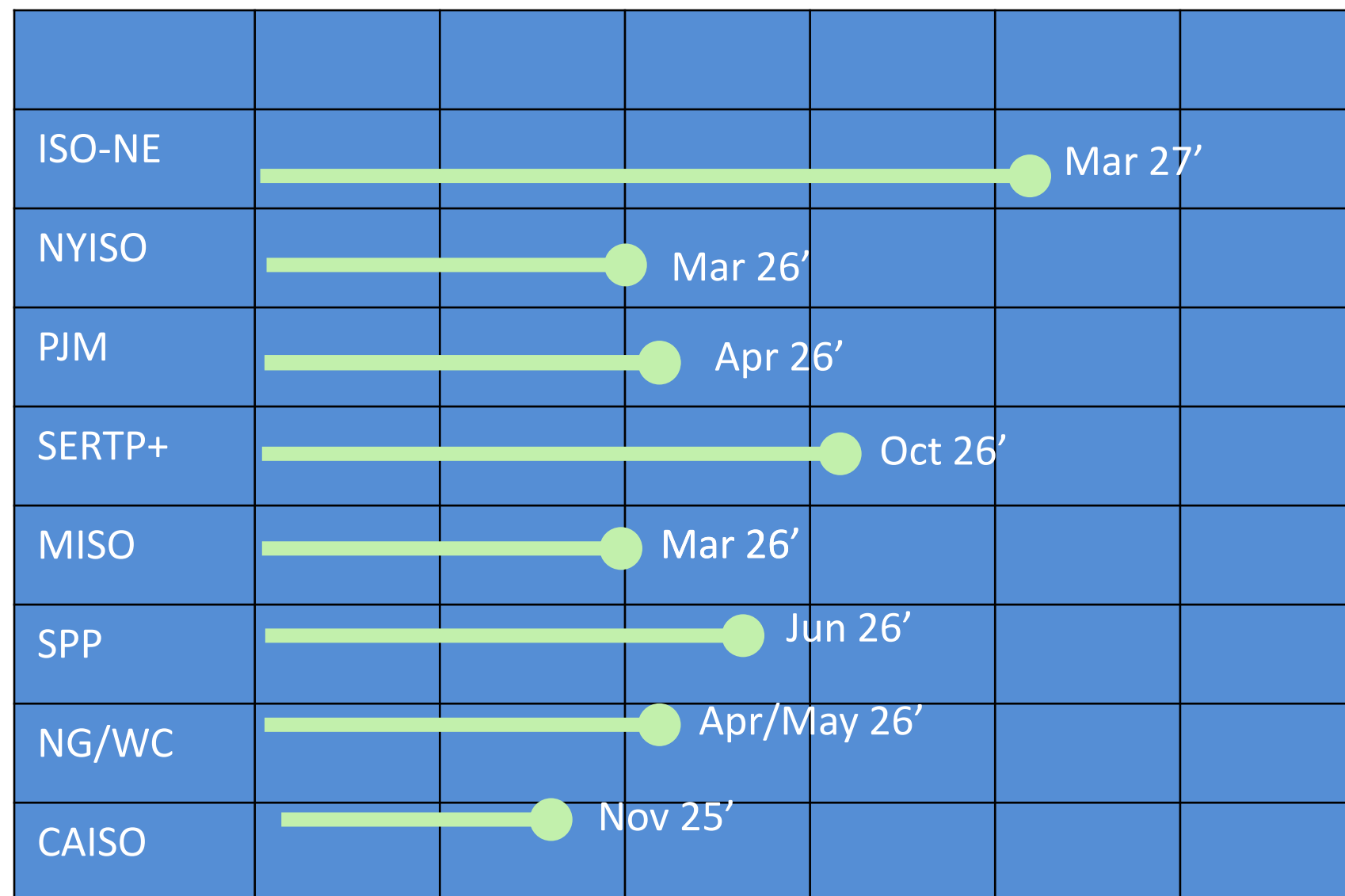
Cost Allocation Requirements

Order No. 1920 Requirements Cost Allocation:

Transmission providers must file an ex ante cost allocation method for selected facilities and may file a State Agreement Process. Transmission providers must:

- Establish at least a 6-month period for states to agree on ex ante cost allocation method and/or a voluntarily State Agreement Process and provide a forum for negotiation (State Engagement Period)
- File any ex ante cost allocation method agreed to by the states, alongside or instead of a their own.
- If they file a voluntary State Agreement Process, it must be agreed to by the states.

State Engagement Periods



*//Each State Engagement Period started on a different date

Order No. 1920 Cost Allocation

Required: *Ex-ante* cost allocation method(s)

Transmission providers must file *ex ante* cost allocation method or methods Can be multiple *ex ante* methods.

Allowed to have different *ex ante* methods for based on facility size or sub-regions.

Meet cost causation, costs must be allocated roughly commensurate with estimated benefits

State entities can develop preferred *ex ante* cost allocation method or methods

Transmission providers must file any method that states agree upon and FERC makes the decision between the two provided (1920-A)

State Agreement Process (SAP)

Transmission providers may also file a State Agreement Process but it must be agreed to by the states to be considered compliant.

State Agreement Process can be for initial cost allocation as well as it gives states a “second bite” to re-do cost allocation after a facility is selected, effectively custom cost allocation

States have 6 months after a project is selected to agree on alternative/custom cost allocation method.

If future negotiations fail, the applicable *ex ante* method serves as a backstop.

Order No. 1920 B Additional Points

The states in a region can ask the TP to run *additional* long-term planning scenarios beyond the three required in Order Nos. 1920-A and 1920-B.

Importantly, the states can ask the TP to run a baseline scenario that excludes project costs driven by state laws and policies. This will enable states to see the cost difference between that baseline scenario and the larger costs of the scenarios that include projects driven by an individual state's policies.

Under this option, TPs *must* identify the state policy causers of the added costs above the baseline scenario cost and then *must* allocate those added costs solely to the states that are the causers of the policy-driven costs. Benefits are re-defined in Order Nos. 1920-A and 1920-B to include public policy benefits, to match costs with the policy benefits of policy-caused projects and allocate those costs directly to the state drivers of policy-driven projects.

Order No. 1920 B Additional Points

If a multi-state TP already has in place a state agreement approach for cost allocation of regional transmission projects, such as PJM's State Agreement Approach, that cost allocation formula does *not* require re-approval from FERC. It is explicitly allowed to remain in effect and can be used as a voluntary future option, on a case-by-case basis. For example, it can be used for state-driven public policy projects, such as offshore wind projects driven by state policies, in which all the costs are allocated to the state or states sponsoring the public policy projects.

In the future, if the TP wants to change the cost allocation formula, the TP *must* consult with the states in the region in advance of any such proposed change and its subsequent Federal Power Act Section 205 filing.

STATE VIEWS ON ORDER NO. 1920

19 states joined together and filed a Request for Rehearing at FERC contending:

- The Rule **intrudes upon the primary jurisdiction** of the states over the selection and approval of generation resources.
- The Rule **violates the major questions doctrine** that reserves major changes in public policy to Congressional action and does not allow administrative agencies, like FERC, to make by a rulemaking a major change as to the generation types that should be favored over others in transmission decision making.
- The Rule exceeds the Commission's authority under the FPA. **FERC has not identified sufficient evidence to demonstrate** that the current long term and other transmission planning processes for all RTOs/ISOs and other transmission providers are **unjust and unreasonable**.
- The Rule erroneously and unlawfully **mandates transmission planning criteria** that marginalize the input from Relevant Electric Retail Regulatory Authority ("RERRA" or "RERRAs") in transmission planning, instead favoring selected generation.
- The Rule will result in **unjust and unreasonable rates by adopting seven required factors** and seven benefit metrics to evaluate the proposed long-term transmission facilities.
- The Rule erroneously and **unlawfully adopts a cost allocation process** that is unjust, unreasonable, and arbitrary and capricious.

STATE VIEWS ON ORDER NO. 1920

On Appeal to the 4th Circuit the 8 states or PUCs (TX, GA, AZ, KY, MS, UT, OH, LA) argued:

1. Order 1920 exceeds FERC's statutory authority and intrudes into States' authority over generation under the FPA.
2. The major questions doctrine, non-delegation doctrine, and the equal sovereignty doctrine bar Order 1920.
3. Order 1920 fails under both prongs of the FPA Section 206.
4. Order 1920 violates the APAs notice and comment requirement.

Michigan PSC and Pennsylvania PUC Argument:

1. The state role in transmission planning and cost allocation under Order No. 1920 is essential to timely, efficient development and for just and reasonable rates.
2. The Inclusion Requirement does not unlawfully encumber public utility FPA Section 205 filing rights.
3. FERC possesses statutory authority to adopt the Consultation Requirement.
4. The Inclusion and Consultation requirements do not violate the first amendment rights of transmission owners.

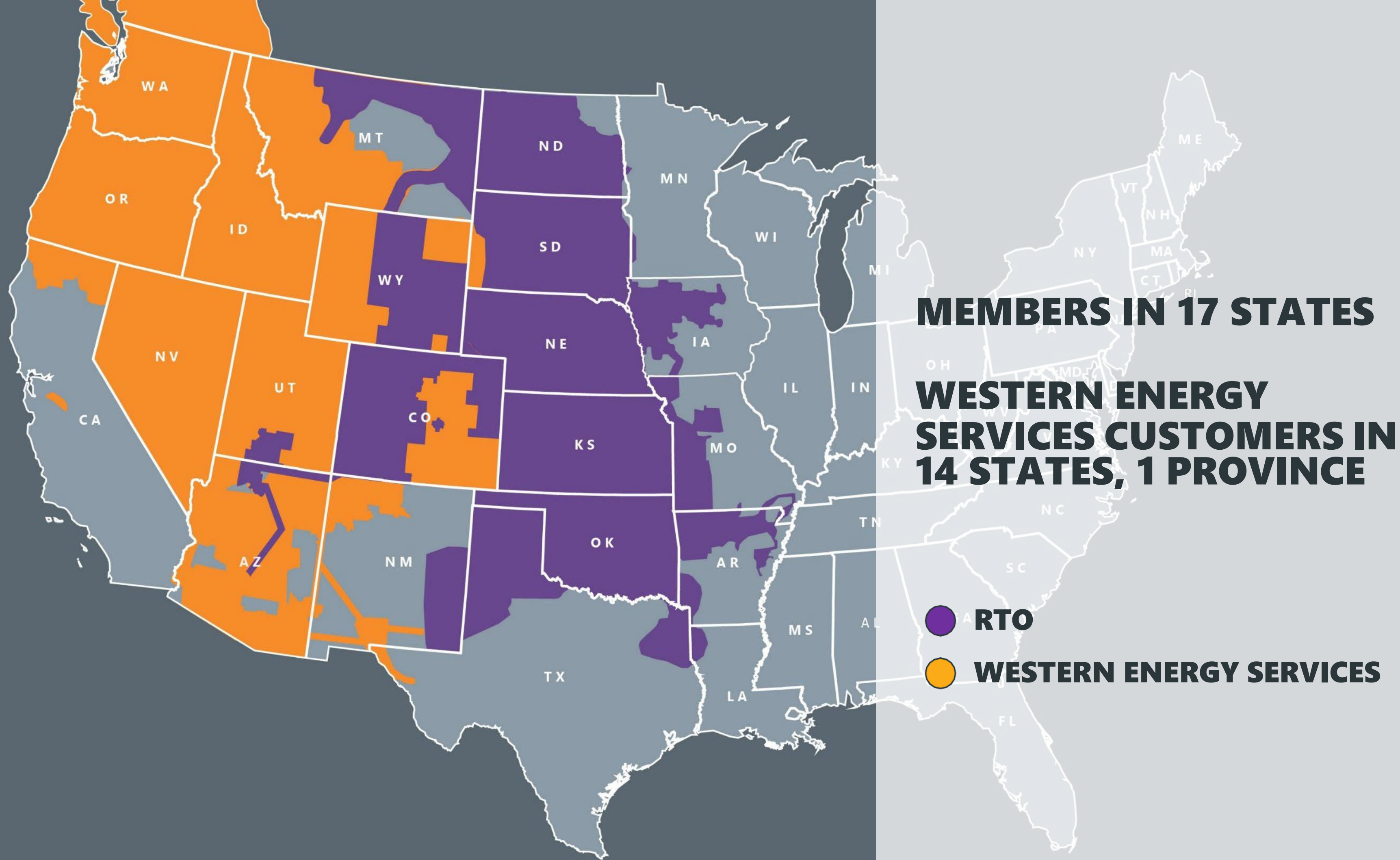
Contact: Kim Duffley kduffley@naruc.org

Special thank you to NARUC's Office of Professional Development and to Liz Salerno and Lisa Schwartz for the use of some of their slides created for the NARUC Transmission training as modified for this presentation.

Transmission Planning in Transition: Implementing Order No. 1920 in a Shifting Landscape

SPP's Consolidated Planning Process (CPP) and Order 1920 Compliance

- *Kimberly O'Guinn, Senior Director Regulatory Policy, SPP*



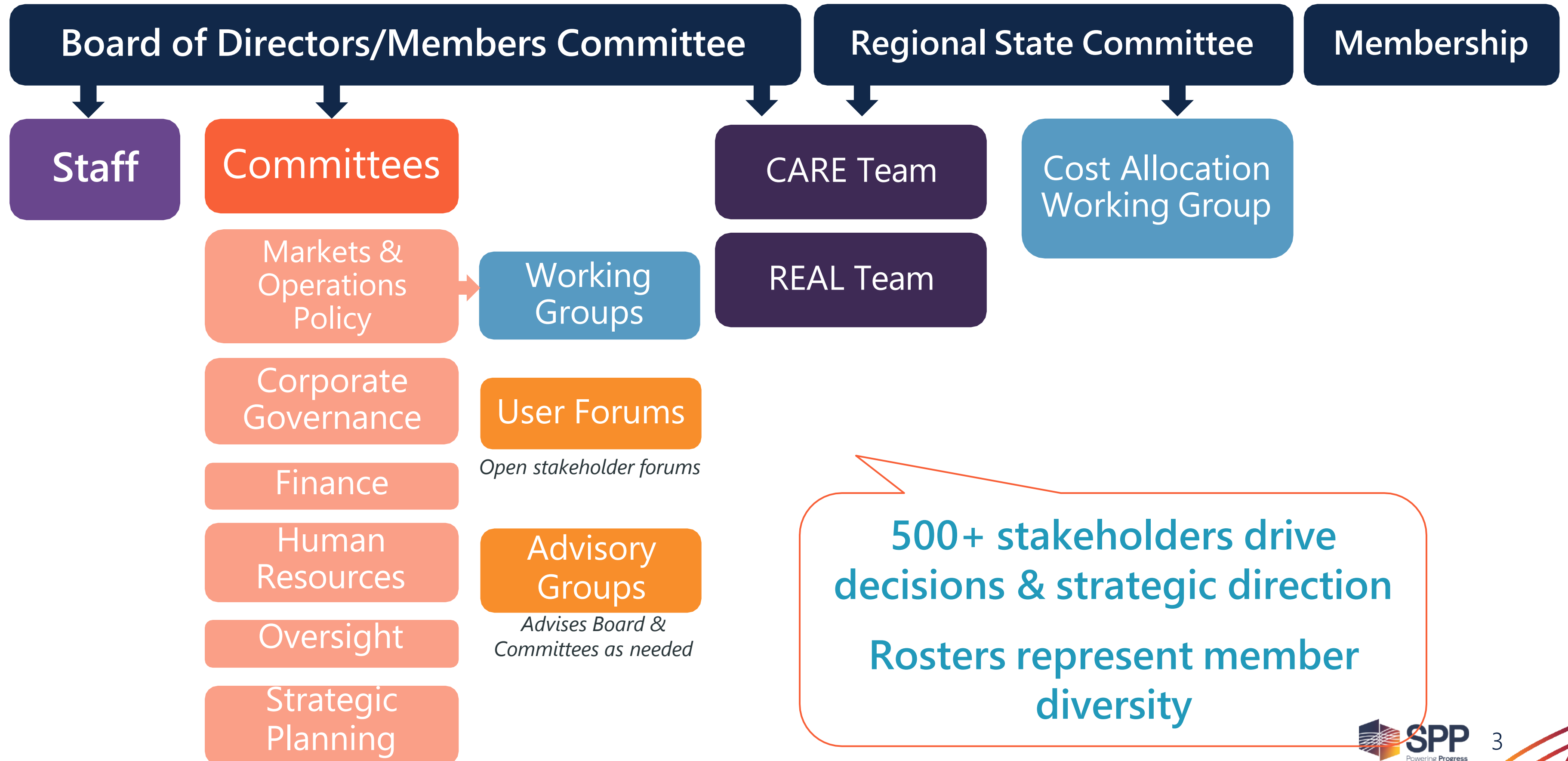
MEMBERS IN 17 STATES

WESTERN ENERGY SERVICES CUSTOMERS IN 14 STATES, 1 PROVINCE

RTO

WESTERN ENERGY SERVICES

COLLABORATIVE STAKEHOLDER PROCESS





ORDER 1920 AND CURRENT SPP 20 YEAR ALIGNMENT

The Order 1920 Big Picture

- Long-Term Regional Transmission Planning (20-year horizon).
- *Ex ante* cost allocation methodology for Long-Term Regional Transmission Facilities.
- Six-month engagement period with Relevant State Entities.
- Reforms to enhance transparency and support selection of cost-effective transmission projects.

SPP COMPLIANCE TIMELINE

Requirement	Current Status of Compliance
Overview of Four Major Requirement Categories	
Long Term Planning (20 year-horizon)	SPP complies generally.
Cost Allocation	SPP complies.
Local Planning	Overall, SPP complies generally, with areas of improvements.
Interregional Transmission Coordination	SPP complies generally.



CPP FILING IMPACTS

WHAT IS THE CPP?

The **Consolidated Planning Process** (CPP) is a revolutionary integrated planning process that aligns regional transmission planning with the generator interconnection process.

It will address reliability, public policy, operational, and economic needs while meeting compliance requirements.

Result: the CPP will produce **reliable, holistic, cost-effective** transmission portfolios with **equitably allocated costs** and will provide **cost certainty** to interconnection customers.


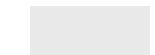


CPP FILING

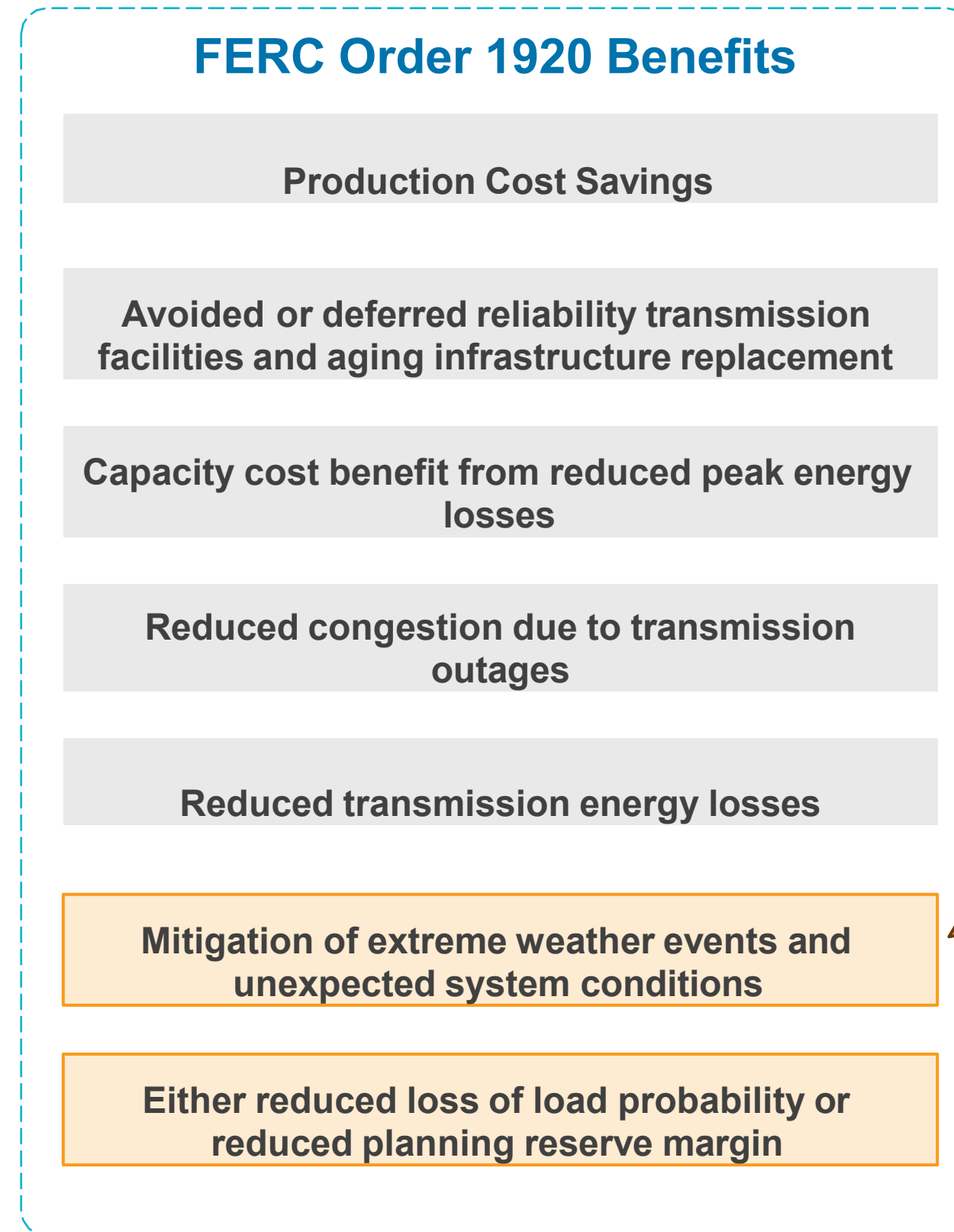
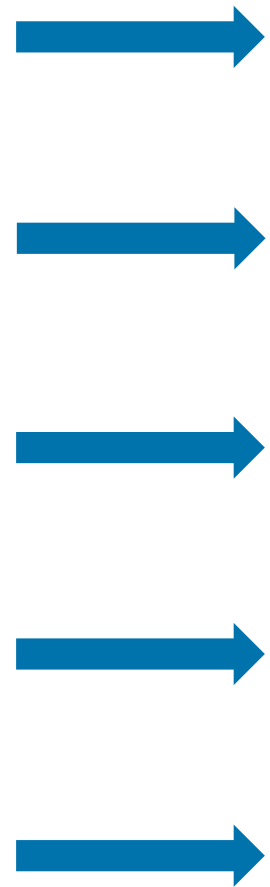
CLOSING THE O1920 AND SPP 20 YEAR GAP

Category	Order 1920	SPP CPP
Planning Horizon	20-year minimum	20-year embedded annually
Scenarios	≥3 required	Multiple + stress-tested
Solutions	Regional projects	Optimized regional portfolios for load and gen
Cost Allocation	Required, benefits identified	Forward-looking, granular (GRID-C)
Stakeholder Role	Required participation with states and developers	Mature governance + state authority + GI developers
GI Integration	Consideration of needs required	Fully integrated
Transparency	Required	Required

Comparison

Order 1920 vs Current SPP Benefits

-  - SPP Benefit
-  - Corresponding Order 1920 Benefit
-  - SPP Unique Benefit
-  - Order 1920 Unique Benefit



Evaluation occurring in 2025 ITP

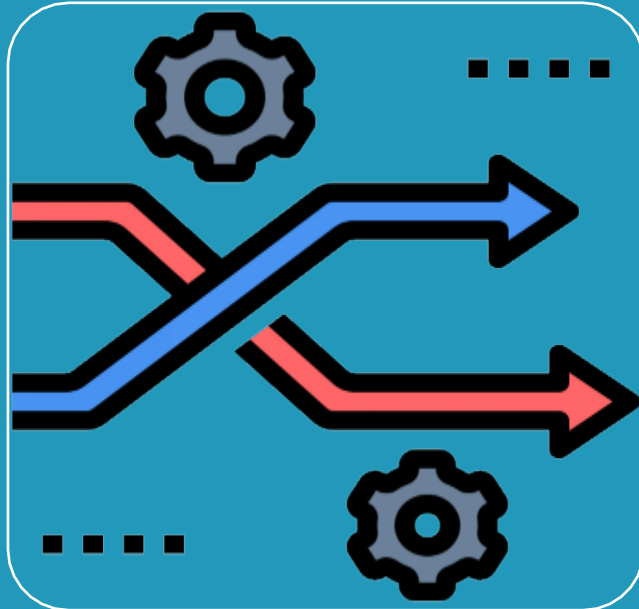
Current evaluating calculation options



APPENDIX

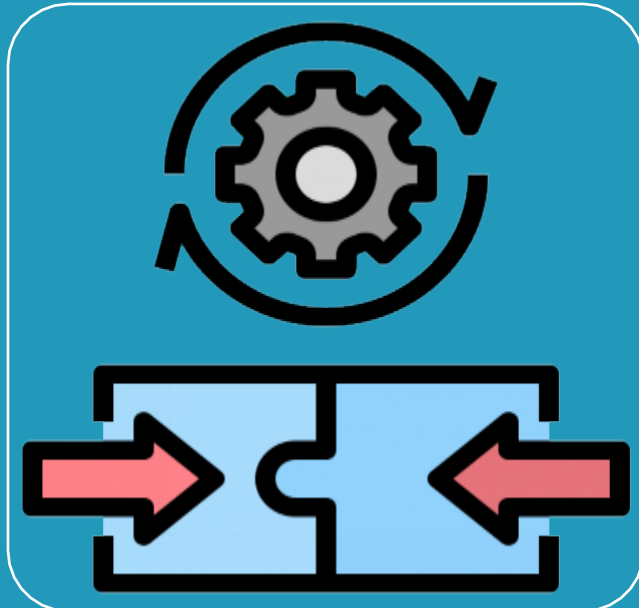


CPP: OVERVIEW



Previously, **generation interconnection (GI)** and regional **integrated transmission planning (ITP)** were handled in separate processes.

This disjointed approach led to **delays, redundancies, and missed opportunities** for synergistic solutions.



CPP brings GI and ITP together—helping ensure the right transmission upgrades are built at the right time and costs are shared using a beneficiary based approach.

SPP COMPLIANCE TIMELINE

Task	Date
<u>Kick-Off</u> of Six-Month Engagement Period	October 28, 2024
<u>Current</u> Compliance Deadline (FERC approved extensions)	June 12, 2026 (regional) December 12, 2026 (interregional)
<u>Close of Six-Month Engagement Period</u> (FERC approved an extension)	November 3, 2025 (to align with RSC meeting schedule)

CPP FILING

CLOSING THE O1920 AND SPP 20 YEAR GAP

1. Big Picture Alignment

- **Order 1920 intent:**
 - Move from reactive, short-term planning → **proactive, long-term, regional portfolio planning**
 - Improve **cost allocation, transparency, and state involvement**
- **SPP CPP:**
 - Designed *from the ground up* as a **long-term, portfolio-based planning + cost allocation framework**
 - Integrates **planning + interconnection + cost causation** in one process

CPP FILING

CLOSING THE O1920 AND SPP 20 YEAR GAP

2. Long-Term Planning Horizon (20+ Years)

- **Order 1920 Requirement**
 - Minimum **20-year regional transmission planning horizon**
 - Updated at least every **5 years**

SPP CPP

- CPP anchored on:
 - **20-year (CPP-20) planning horizon**
 - Integrated with **ITP (Integrated Transmission Planning) cycles**
- Uses **forward-looking portfolios (e.g., EHV/UHV overlay, long-term needs)**

CPP FILING

CLOSING THE O1920 AND SPP 20 YEAR GAP

3. Scenario-Based Planning (≥ 3 Futures)

- **Order 1920 Requirement**

- At least **3 long-term scenarios**
- Reflect uncertainty (load growth, generation mix, policy)

SPP CPP

- Already uses:
 - **Multiple futures (economic, policy, load-driven)**
 - **Resiliency / extreme condition modeling (TGEM/BGEM concepts)**
- **Expanding to include:**
 - High load growth (e.g., large load, data centers)
 - Delayed generation / GI constraints via proactive planning
 - Fuel price variability

CPP FILING

CLOSING THE O1920 AND SPP 20 YEAR GAP

4. Portfolio-Based Solutions (Not Project-by-Project)

- **Order 1920 Requirement**
 - Identify **efficient regional solutions**
 - Evaluate using **multiple benefit metrics**
- **SPP CPP**
 - Core design principle:
 - **Portfolio optimization (not single projects)**
 - Co-optimization of:
 - Reliability
 - Economics (APC)
 - Policy drivers
 - Interconnection needs

CPP FILING

CLOSING THE O1920 AND SPP 20 YEAR GAP

5. Cost Allocation (Core of Order 1920)

- **Order 1920 Requirement**
 - Must have **ex ante cost allocation**
 - Must align with **cost causation principles**
- **Strong state involvement**

SPP CPP

- SPP has an existing ex ante cost allocation for 10 year solutions and is working with regional state committee on the 20 year applications
- Phase 1:
 - **GRID-C (generation contribution)**

CPP FILING

CLOSING THE O1920 AND SPP 20 YEAR GAP

6. State & Stakeholder Engagement

- **Order 1920 Requirement**

- Formal stakeholder process:
 - Assumptions, Needs, Solutions meetings
- Stronger **state role in scenarios + cost allocation**

SPP CPP

- Mature stakeholder model:
 - TWG, ESWG, CAWG, CPPTF, MOPC, RSC
- States (RSC) already:
 - Directly decides transmission cost allocation decisions
- Continuous engagement—not just 3 meetings

CPP FILING

CLOSING THE O1920 AND SPP 20 YEAR GAP

7. Integration of Interconnection Needs

- **Order 1920 Requirement**
 - Must consider:
 - **Repeated interconnection-driven needs not built**
- **SPP CPP**
 - Directly integrates:
 - **Generator interconnection (GI)**
 - **Transmission planning (ITP)**
 - CPP goal:
 - Eliminate large volume of **restudies**
 - Pre-identified **network upgrades**

CPP FILING

CLOSING THE O1920 AND SPP 20 YEAR GAP

8. Transparency & Data Sharing

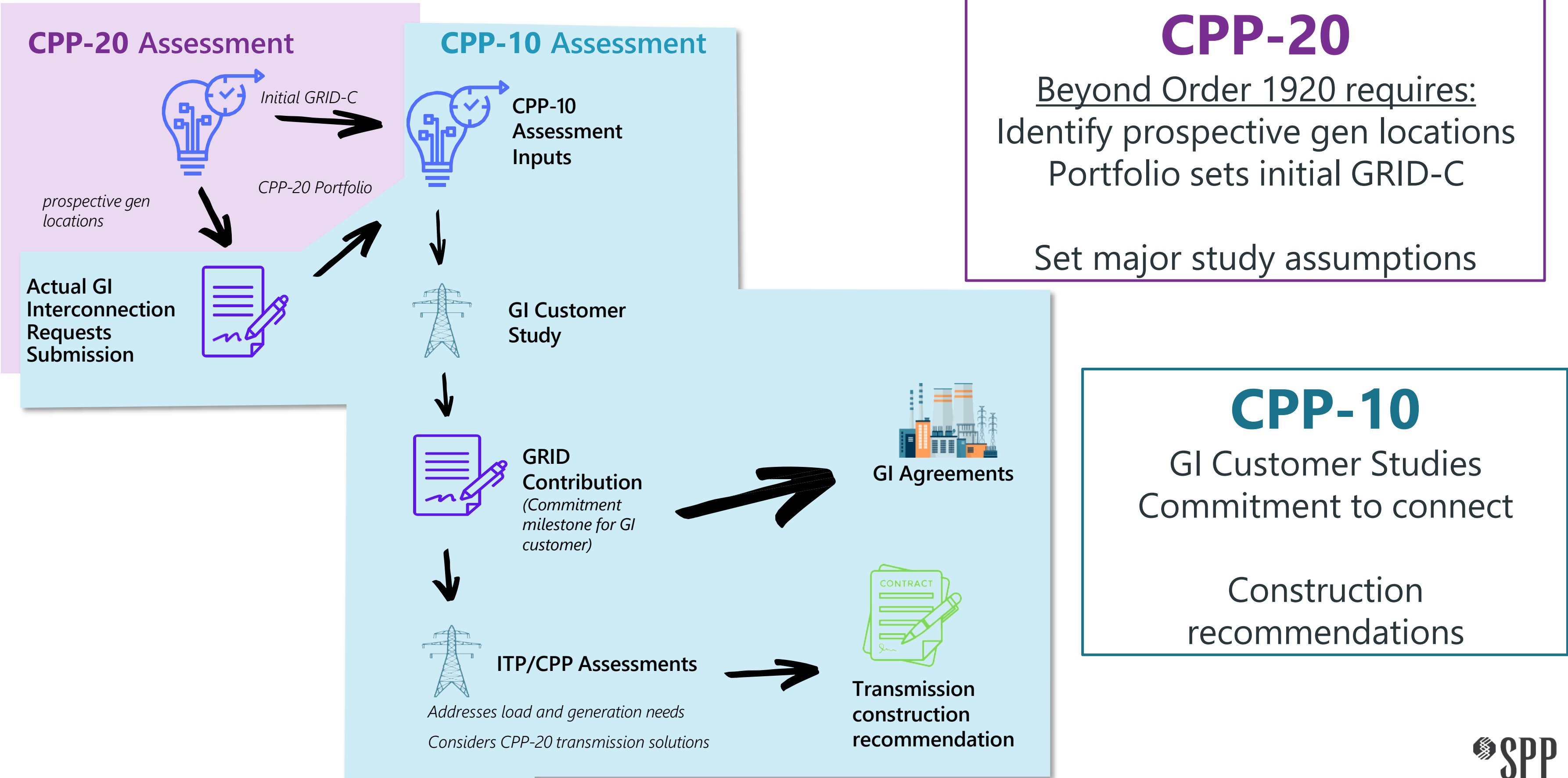
Order 1920 Requirement

- Public posting of:
 - Costs
 - Benefits
 - Allocation by zone
- **SPP CPP**
 - Already provides:
 - Detailed ITP reports, RSC updates, open stakeholder meetings for all key milestones
 - Stakeholder approved assessment and modeling inputs

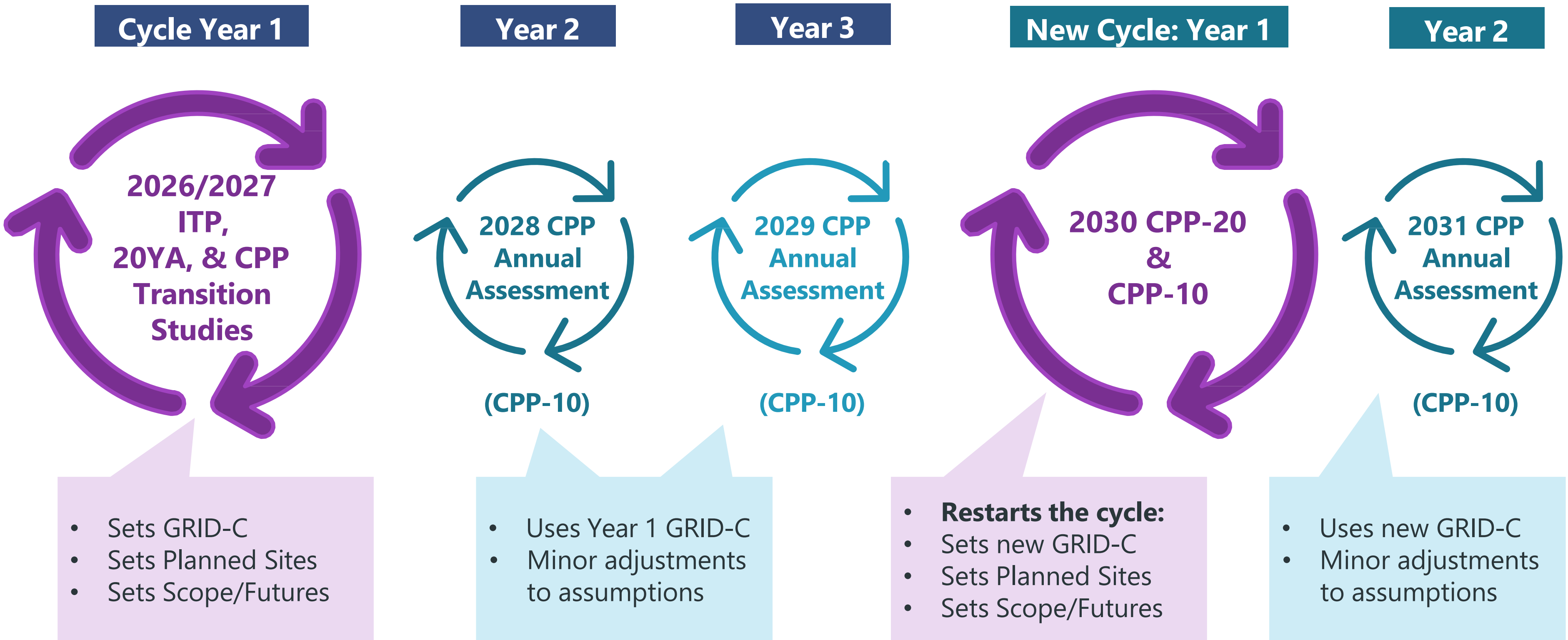


CPP OVERVIEW

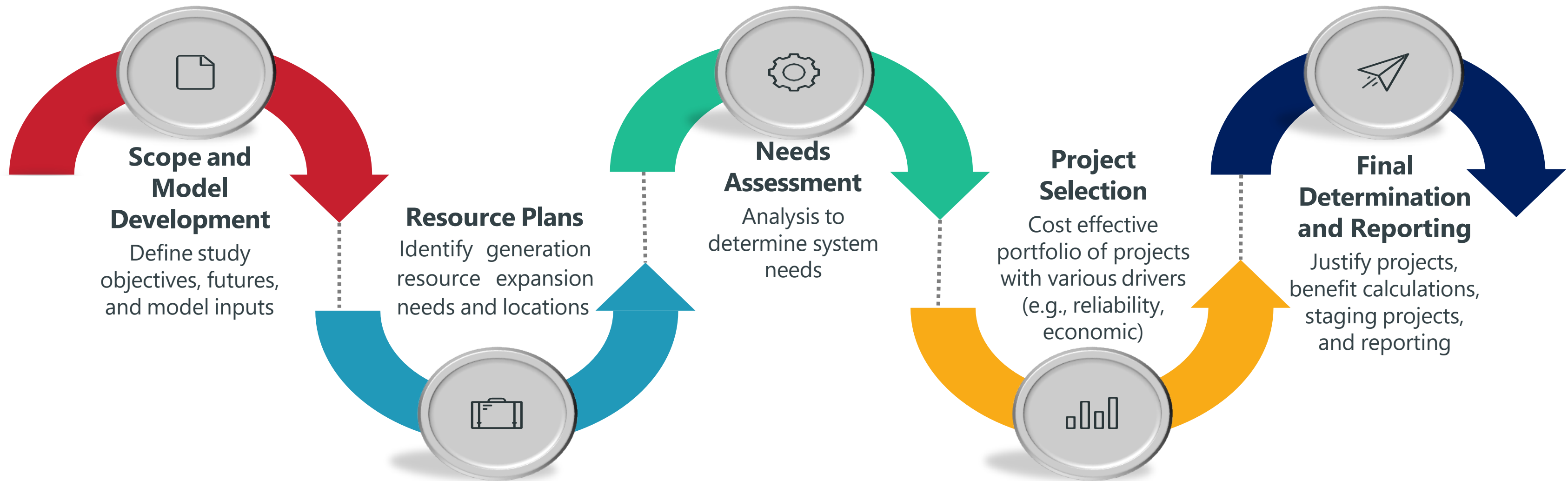
GRID-C: PROCESS FLOW



CPP CYCLE

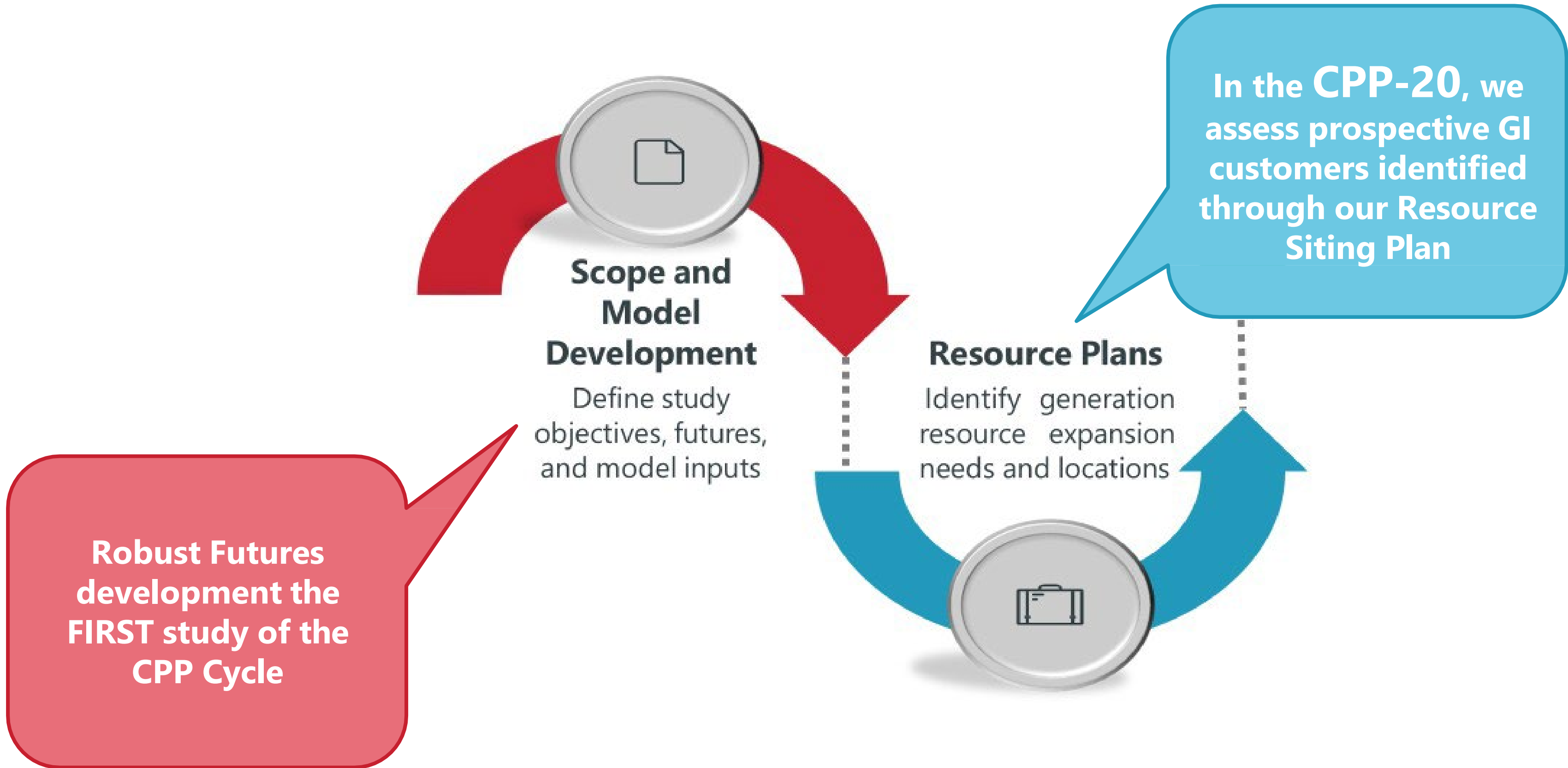


ITP/CPP PROCESS: OVERVIEW

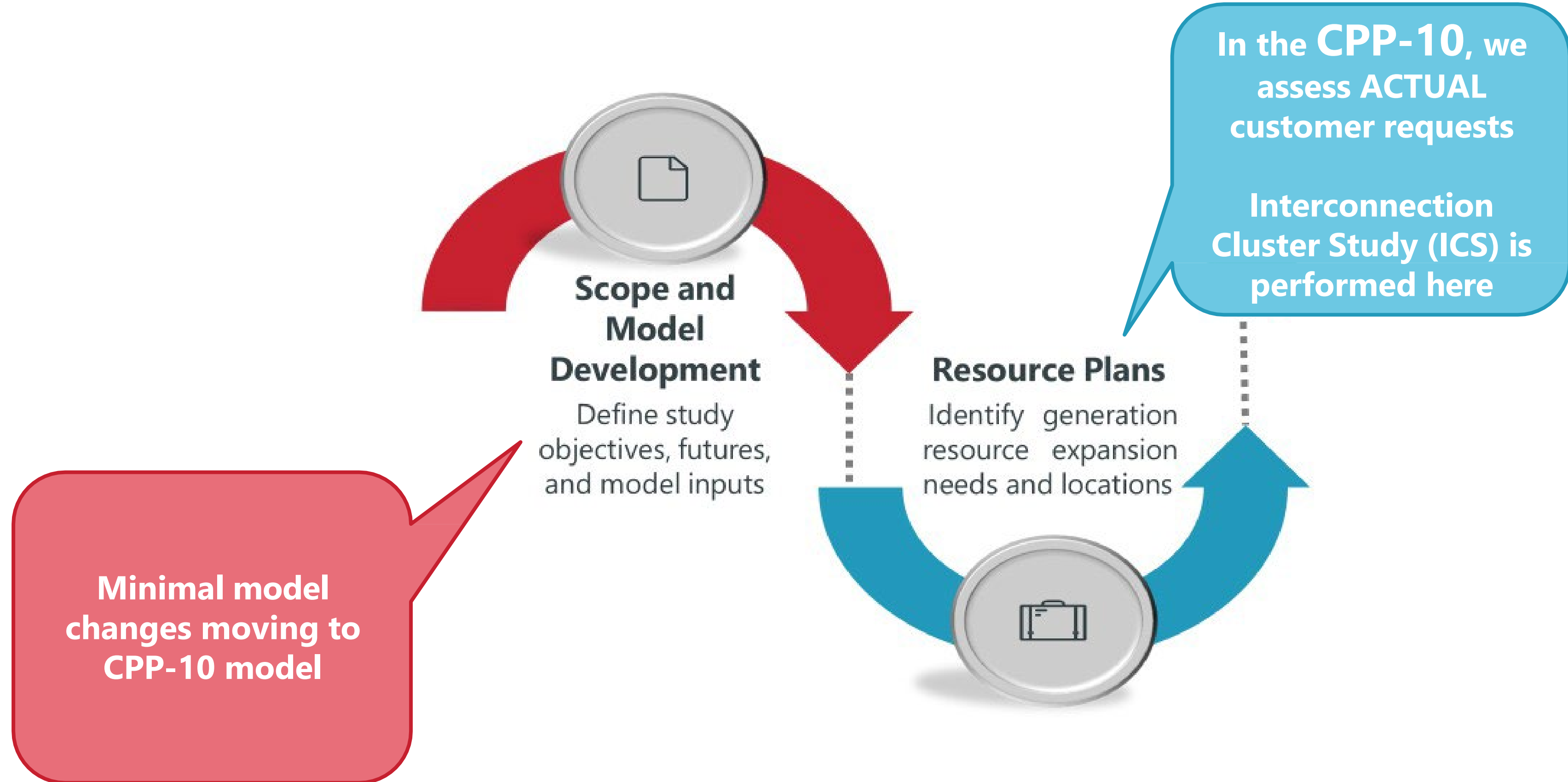


Overall study process for the ITP/CPP is unchanged

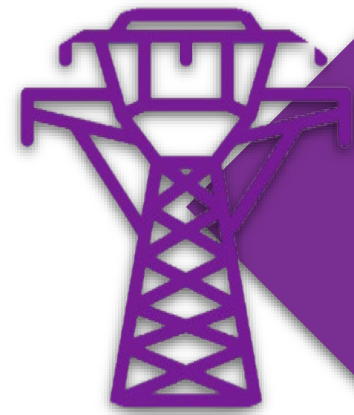
CONSOLIDATED PLANNING PROCESS (CPP-20)



CONSOLIDATED PLANNING PROCESS (CPP-10)

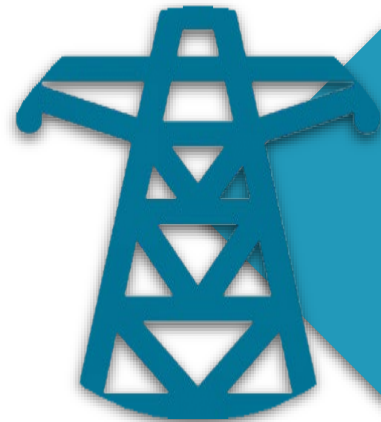


CPP CYCLE STRUCTURE



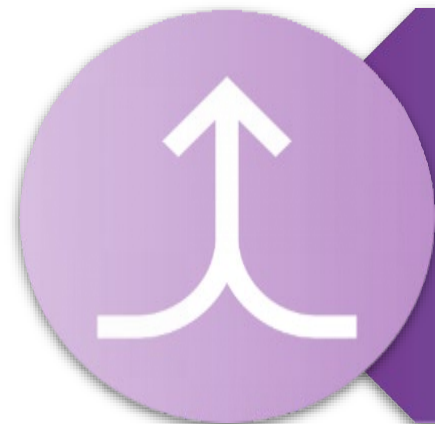
CPP-20

- EHV Contribution
- HV Contribution



CPP-10

- Point of Interconnection Costs
- System upgrade costs from unplanned locations



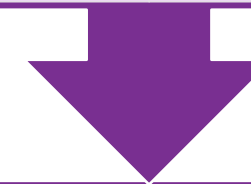
CPP-20 & CPP-10

- Deliverability costs (NRIS+ Adder)

Inputs: CPP-20 (20-year assessment, every three year)

LRE Loads and Resources, **Order 1920**
(post effective date)

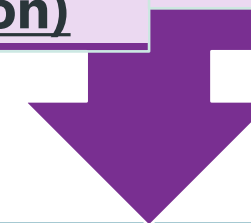
Scope/Futures, Generation Expansion and
GI Stakeholder Input



Outputs: CPP-20

ITP and **GI transmission needs**
(Excluding Point of Interconnection)

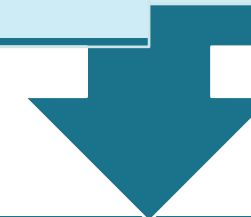
Initial Grid-C



Inputs: CPP-10 (Annual 10-year assessment, three times)

GI Requests (including GRID-C
financial commitment)

Scope, minor Futures' adjustments



Outputs: CPP-10

Transmission Plan for **GI**
and ITP needs

GIAs within one year for
planned locations

Additional costs: NRIS
adder, POI costs and
unplanned location

WHAT IS THE GRID-C?

GRID-C What is it?

Name: Generalized Rates for Interconnection Development (GRID) Contribution

Purpose: Create cost certainty for interconnection customers through a generalized rate used to contribute to the network upgrade costs of the system.

GRID-C: FRAMEWORK

The **GRID Contribution Framework** provides transmission solutions for load and generation requirements.

- Transforms the generator cost assignment from project-centric to support (general contribution) for regional transmission portfolios.

The **GRID Contribution** serves as an upfront and certain cost commitment for network improvements required due to expected load and generation demands identified through the CPP.

- All generator interconnection customers are subject to GRID-C.
- Provides a high degree of cost certainty known upfront, in return, requires a high degree of commitment from GI customers.

GRID-C: OVERVIEW

The initial GRID-C is

- Based on the **CPP-20**
 - Transmission portfolio costs
 - Future generator expectations

GRID-C cost is

- **\$/MW** assigned to **GI customers** in the **CPP-10**
- **A credit to transmission customers**

GRID-C is used to

- Fund more **holistic network transmission** solutions
 - Network upgrades now part of the base plan that have historically been directly assigned

GRID-C: WHY ARE PLANNED SITES IMPORTANT?



If you're a generator wanting to interconnect to SPP and you select a "**Planned Interconnection Location**" (PIL), you pay the **GRID-C*** rates to cover Network Upgrade costs

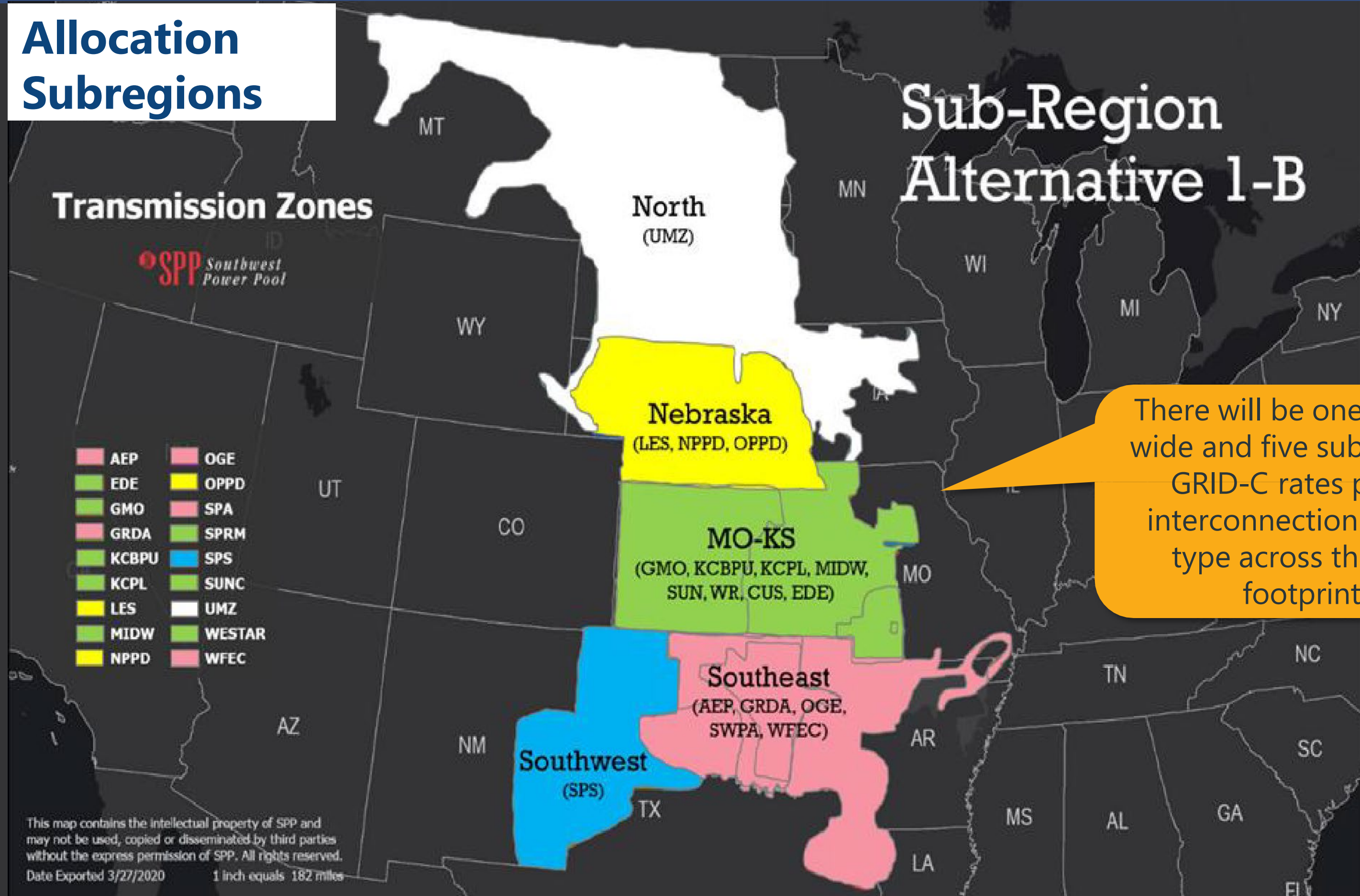


If you're a generator and you interconnect to an "**Unplanned Interconnection Location**" you pay the **GRID-C*** rates + **all additional required Network Upgrade costs**

*Plus, directly assigned Interconnection Facility, POI and sub-100 Network Upgrade, and Affected System costs

GRID-C AND SUBREGIONAL COST ALIGNMENT

Allocation Subregions



GRID-C AND SUBREGIONAL COST ALIGNMENT

GRID-C Credits Region-Wide or Subregional Charges

GRID-C regional revenues are credited against regional charges and GRID-C subregional revenues are credited against subregional charges
(Details in slide 22)

GRID-C

ERIS GRID-C
(regional and subregional)

NRIS GRID-C
(regional and subregional)

EHV Contribution

HV Contribution

EHV Contribution

HV Contribution

EHV (300kV+)
All generators will pay a portion of EHV upgrades through GRID-C rates.

CPP EHV upgrade costs are allocated: 100% region-wide

HV (100-300kV)
HV upgrades located in each subregion will be the basis for GRID-C charges to generators located in the subregion.

CPP HV upgrade costs are allocated: 33% region-wide, 67% subregional

GRID-C: SERVICE TYPES

A GI Generator can take *either* ERIS or NRIS+ transmission service

ERIS

Energy Resource Interconnection Service
Evaluates a generator's impact to the grid on **as-available** (energy) basis but does not guarantee firm transmission service.

NRIS+

Network Resource Interconnection Service
Evaluates a generator's impact to the grid under a more rigorous **deliverability** (capacity) analysis.

TUF = Transmission Utilization Factor
EF = Energy Factor

The service chosen by the generator determines the **GRID-C** calculation

$$\text{ERIS Charge (Energy Benefit Calculation*)} = \frac{\text{CPP20 Portfolio Costs} \times \text{ERIS TUF} \times \text{EF}}{\text{Incremental Nameplate MW from Future Gens}}$$

$$\text{NRIS+ Charge (Capacity Benefit Calculation)} = \frac{\text{CPP20 NRIS Portfolio Costs}}{\text{Incremental Accrediation MW from Future Gens}}$$

NRIS+ customers pay the NRIS+ charge plus the ERIS charge

Transmission Planning in Transition: Implementing Order No. 1920 in a Shifting Landscape

Interregional and Merchant Transmission Under Order 1920

Jeb Stenhouse, *Director of Regulatory Affairs*, Invenergy

Order 1920 and Interregional Transmission

- **Does not include interregional transmission planning or cost allocation requirements**
- **Tweaks Order 1000 interregional transmission “coordination” requirement to:**
 - include long-term regional transmission plans; and
 - identify and jointly evaluate IR Tx facilities “that may be more efficient or cost-effective” for long-term needs
- **Standardized benefits framework expected to improve comparability of plans across regions**
 - Benefit 6 includes consideration of increased interregional transfer capability
- **FERC declined to require inclusion of advanced-stage merchant HVDC transmission (the majority of interregional transmission projects under development) in Long-Term Scenarios**
 - Failure to account for interregional transmission flows – including over advanced-stage merchant lines – risks selection of conflicting transmission investments in regional planning
 - While FERC granted Invenergy’s complaint regarding MISO’s exclusion of Grain Belt Express in their LRTP, MISO’s “compliant” use of executed Transmission Connection Agreement (TCA) fails to capture all MHVDC
- **To leverage MHVDC developed outside of planning processes, RTOs also need to unlock the ability for ratepayers to access the reliability services and resource adequacy value of interregional transmission**

Report tackles...

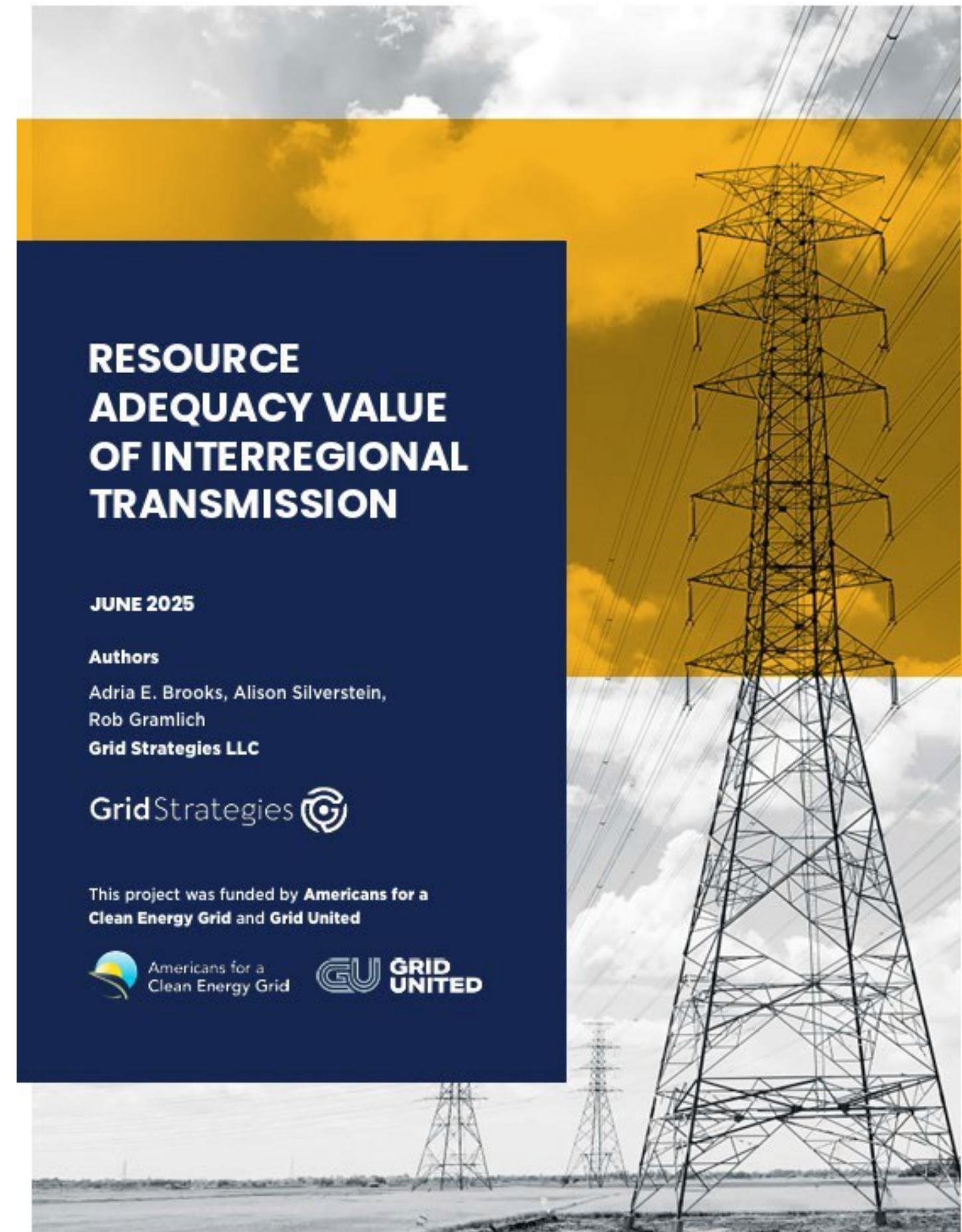
Part I | The role of transmission in supporting resource adequacy

Part II | Capturing the value of interregional transmission for resource adequacy

Part III | Recommendations

Appendix | Current resource adequacy and transmission accreditation practices

<https://gridstrategiesllc.com/reports/>



System planners incorporate some capacity value of interregional transmission into RA assessments

Capacity value and associated RA contributions of firm and non-firm imports used in regional planners' RA assessments

Region	Import type	Nameplate capacity (MW)	Accredited capacity (MW)	Reported reduction in RA metric	Reduction in reserve margin	Equiv. capacity value (accredited / nameplate)
Tennessee Valley Authority	Non-firm		4,750		8%	
Southern Company	Non-firm		2,714		1.75%	
Desert Southwest (APS, AEPCO, EPE, PNM, SRP, TEP)	Non-firm		1,379	LOLE: 0.04 day/yr NEUE: 0.34 ppm		
Public Service Colorado	Non-firm		390		4.70%	
Idaho Power	Non-firm	100	14			14%
MISO	Firm	1,986	1,935		1.60%	97%
	Non-firm	12,000	4,351		3.50%	36%
SPP	Firm	2,255	2,255		3.60%	100%
CAISO	Firm		1,700		3.80%	
PJM	Firm	1,485	1,269		1.10%	85%
	Non-firm		2,937		1.50%	
NYISO	Firm		1,600		5.1%	
	Non-firm		3,500 (max)	LOLE: 0.42 day/yr		
ISO-NE	Firm	1,936	1,870		6.0%	97%
	Non-firm	3,980	2,175	LOLE: 0.724 day/yr	7.0%	55%

Many system planners have calculated the reduction in LOLE or planning reserve margin (PRM) associated with the *fleet of interregional ties* that currently exist between regions.

↳ However, not many system planners have calculated the LOLE / PRM reduction from an *individual transmission facility*.

↳ Nor have they converted that LOLE / PRM reduction *into a capacity value*.

Notes | Unless otherwise stated, all capacity value calculations are estimated by the authors using industry reported information. Blank cells indicate the calculation was not performed, not reported, or cannot be estimated from reported information.

Capacity value and associated RA contribution of interregional transmission facilities

Emerging methods to calculate the capacity value of interregional transmission

There is no consistent method to accredit interregional transmission for their RA value...

- Planners need a capacity value method that they can easily integrate into their RA assessments.
- Otherwise, they will likely fail to attract/retain this capacity, missing reliability/economic benefits.

...but proven methods have emerged, such as effective load carrying capability (ELCC)

- ELCC quantifies the capacity value based on changes in RA metrics (e.g., LOLE).
- This method has been successfully applied in several recent facility and/or RA studies to derive the capacity value of interregional transmission.

Transmission Facilities	Accrediting region	Number of associated facilities	Nameplate capacity (MW)	Accredited capacity (MW)	Reported reduction in LOLE (day/yr)	Capacity Value (accredited / nameplate)
North Plains Connector	WECC			1,800	0.088	60%
	SPP	1	3,000	1,350	0.087	45%
	MISO			400	0.070	13%
Three Corners Connector	PSCo	1	1,800	715	0.09	40%
	SPP			1,362	0.054	76%
Grain Belt Express Phase 1	MISO	1	2,500	2,116	0.06	85%
	SPP			450		18%
Boardman to Hemingway	Idaho Power	1	750	700	0.006	93%
CAISO Interties	CAISO	45	39,923	16,148		40%
NS-NB Reliability Intertie Project	Nova Scotia	1	300 (est.)	200		67%
North Sea Link	NESO	1	1,400	1,316		94%
NESO - Ireland Interties	NESO	3	1,500	1,050		70%
NESO - France Interties	NESO	3	4,000	2,680		67%
Nemo Link	NESO	1	1,000	800		80%
Viking Link	NESO	1	1,400	1,204		86%
BritNed	NESO	1	1,000	840		84%
ISONE - Maritimes	ISONE	2	980	770	0.469	78%
ISONE - HQ Phase II	ISONE	1	1,400	1,060	0.556	76%
ISONE - HQ Highgate	ISONE	1	200	160	0.137	80%
ISONE - NYISO Ties	ISONE	8	1,400	730	0.454	52%
Soo Green	ComEd	1	2,100	2,016	0.1	96%
Champlain Hudson Power Express	NYISO	1	1,250	1,250	0.008	100%

Notes | Because transmission lines can be accredited differently in multiple directions, the importing capacity is listed for the named entity in the Accrediting region column. Blank cells indicate the calculation was not performed, not reported, or cannot be estimated from reported information.

Options for valuing interregional transmission capacity in resource adequacy: from recognition to compensation

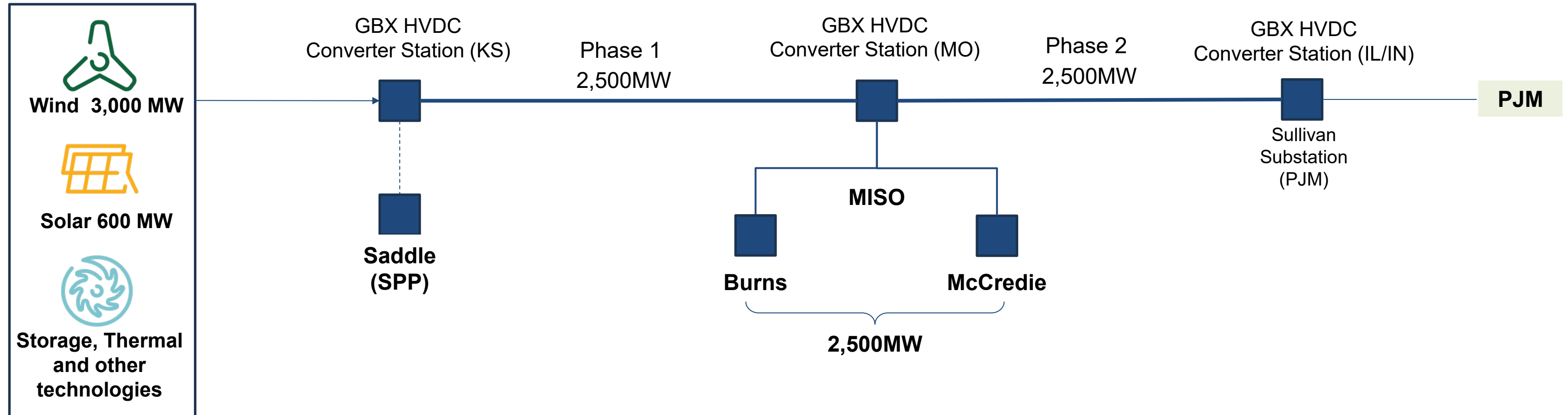
System planners could account for the capacity contribution of interregional transmission by...

- A** Planning for a lower reserve margin
 - B** Converting LOLE, etc. reductions to ELCC values
 - C** Assigning capacity value directly to the asset
- These RA accreditation methods are based in current industry practice, and are similar to the benefits that FERC requires transmission planning regions to consider as part of long-term regional planning under Order No. 1920 in the form of either reduced loss of load probability or planning reserve margin...
 - ...but in the interregional case, this method enables market sales of that transmission capacity as a capacity resource in an RA regime.

Accrediting capacity value enables investment and development. Without (1) a benefit to LSEs associated with their RA obligations or (2) direct compensation to developers, there is less incentive to build these resources. Valuation and compensation methodologies can apply to both regulated assets and merchant interregional transmission, or hybrids of the two.

Interregional Bi-directional HVDC Transmission Lines Like Grain Belt Express (GBX) Improve Reliability by Connecting Grid Regions

Fuel Diverse Generation Portfolio



Interregional HVDC lines enhance grid reliability and resilience during extreme weather events by enabling grid operators to access geographically diverse resources and utilize bi-directional capabilities to mitigate system emergencies.

*"[Winter Storm Elliot is] one of those examples of how you need to build a grid that's bigger than the weather."
- a former senior official at PJM Interconnection **

GBX Reduces Resource Adequacy Requirements by Over 1 GW

- Invenergy retained PowerGEM to assess the resource adequacy value provided by GBX.
- PowerGEM modeled GBX without any associated generation portfolio, but with the ability to transmit bidirectionally between MISO and SPP
- The table shows the approximate resource adequacy value for MISO and SPP. These UCAP values represent the accredited generation capacity that MISO/SPP can avoid building locally.

Estimated Planning Reserve Margin Reductions (Accredited Capacity MW)		
	MISO	SPP
Summer	750	400
Fall	1,250	-
Winter	750	500
Spring	1,000	-

Building on and moving beyond Order 1920:

Recommendations for system planners and regulators to unlock IR Tx RA

1 Account for transmission-enabled imports in resource adequacy assessments

- Include the RA contribution of transmission-enabled imports using LOLE or reserve margin reductions.
- Use neighbor-specific, stress-period data and probabilistic methods for imports.

2 Quantify transmission capacity value of major interregional facilities

- Use LOLE or expected unserved energy to calculate the capacity value of major interregional lines.
- Apply seasonal and neighbor-specific accreditation.
- FERC could expand the NERC *Interregional Transfer Capability Study* to support this effort.

3 Enable procurement and development of interregional lines that support RA

- Support regulated or merchant transmission with RA value via rate-base recovery, load serving entity obligation reduction, or direct compensation.
- Regulatory oversight may be needed to ensure procurement decisions benefit ratepayers.

Questions? Ideas?
Don't hesitate to reach out!



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Transmission Planning in Transition: Implementing Order No. 1920 in a Shifting Landscape

Opportunities for Improved Planning under Order 1920

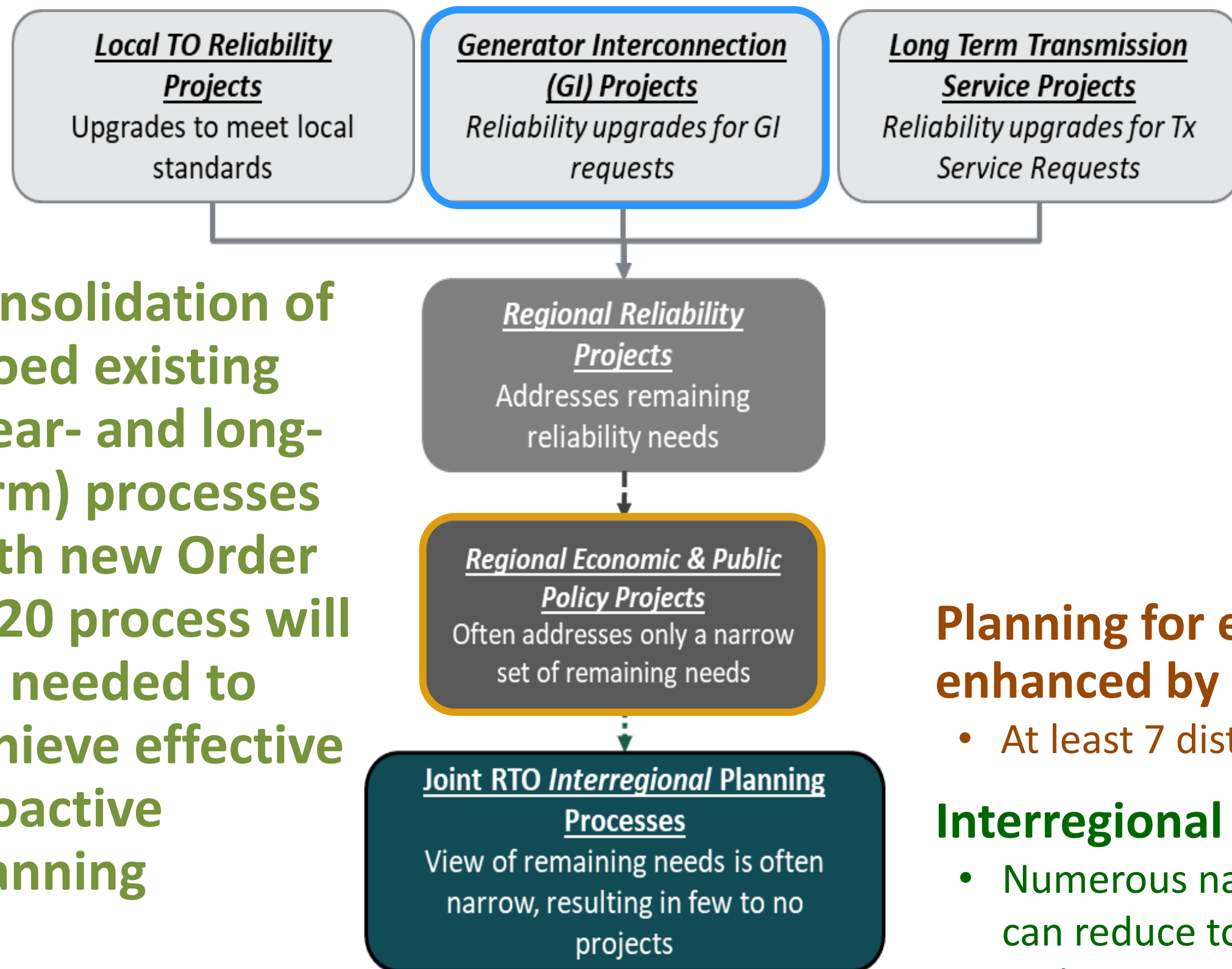
Johannes P. Pfeifenberger, *Principal*, The Brattle Group

FERC's Order 1920 leaves room for improvements

Order 1920 compliance offers opportunities to improve transmission planning processes beyond the Order's mandated minimum requirements:

1. **Consolidate** siloed (near- and long-term) planning processes
2. Use best-practice experience for comprehensive benefit quantification (**beyond 7 benefits** and understated quantification)
3. Directly address long-term uncertainties through proactive, **scenario-based planning**
4. Employ **least-regrets** planning criteria to minimize the risk of both over-building and under-sizing
5. Develop more **flexible** solutions
6. **Get more out of the existing grid**, focus on cost effectiveness, and include cost-control incentives
7. Explicitly consider **interregional solutions** to regional needs

Order 1920 does not address the inefficiencies of siloed planning



Consolidation of siloed existing (near- and long-term) processes with new Order 1920 process will be needed to achieve effective proactive planning

These solely reliability-driven processes account for > 90% of all US transmission investments

- None involve any assessments of economic benefits (i.e., cost savings offered by the new transmission)

Incremental generation interconnection has become the primary tool (and efficiency barrier) to support public policy goals

Planning for economic & public-policy needs will be enhanced by Order 1920 minimum requirements

- At least 7 distinct benefits (cost savings and reliability) considered

Interregional planning processes are large ineffective

- Numerous national studies show more interregional transmission can reduce total system costs
- Order 1920 only addresses interregional coordination

Potentially missing and understated transmission benefits

The 7 benefits required in Order 1920 is not a complete list of benefits:

- For example, FERC's ANOPR also considered: (8) diversification of weather and load uncertainty; (9) deferred generation capacity investments; **(10) access to lower-cost generation**; (11) increased competition; and (12) increased market liquidity

Any framework for benefit-cost analysis needs to be flexible enough (not overly prescriptive) to explicitly allow for:

- Learning from the experience with quantifying transmission-related benefits (i.e., cost savings or reliability improvements) over time
- Consideration of all transmission-related benefits that can reasonably be documented and quantified (even if beyond those required in Order 1920 or pre-specified in tariffs and business practices)

While double counting needs to be avoided, many quantified benefits are understated:

- Example: **production cost savings** typically understated by 50+% because simulations that do not capture realistic congestion due to weather-normalized data, no transmission outages, and perfect foresight (i.e., no unexpected challenges during real-time market operations)
- Example: **extreme weather metrics** quantify only benefit avoiding loss of load events, but do not capture the high costs incurred during such events even when no load is shed

See also discussion in [Proposal to Develop Optimal Transmission Planning in Alberta](#) (2025).

Better planning for an uncertain future

Order 1920 compliance offers opportunities to improve transmission planning processes beyond the Order's mandated minimum requirements:

1. **Consolidate** siloed (near- and long-term) planning processes
2. Use best-practice experience for comprehensive benefit quantification (**beyond 7 benefits** and understated quantification)
3. Better deal with long-term uncertainties through proactive, **scenario-based planning**
4. Employ **least-regrets** planning criteria to minimize the risk of both over-building and under-sizing
5. Develop more **flexible** solutions
6. **Get more out of the existing grid**, focus on cost effectiveness, and include cost-control incentives
7. Explicitly consider **interregional solutions** to regional needs

Key planning tools for an uncertain future

(beyond transmission):

- Scenario based
- Flexible, least-regrets solutions

For more detail, see [Integrated System Planning under Uncertainty](#), September 23, 2025.

Scenario planning to explicitly recognize an uncertain future

Scenario-based planning is a process first developed in the 1940s and 1950s as a tool for integrating uncertainties into long-term strategic planning:

- Used by Shell with great success since the 1970s for long-term planning under large uncertainties
- **Allows planners to think, in advance, about the many ways the future may unfold and how to respond effectively and flexibly as uncertain future outcomes become reality**
- Ranks among the top-ten management tools in the world today*
- Scenario = one fully-defined, plausible view of what the future may look like

This type of scenario-based planning is a multi-step process:

1. Define scenarios of plausible futures by scanning the current reality, trends and forecasts, uncertainties, and important internal and external drivers
2. Develop a series of plans (initiatives, projects, policies, tactics) that work well across multiple scenarios (e.g., by developing **solutions that are flexible and robust across all plausible futures**)
3. Implement preferred plan and define indicators to alert planners that a certain future is likely to occur, so they can take action (e.g., exercise options to address the new developments)

*See [Living in the Futures \(hbr.org\)](https://hbr.org) and [Using Scenario Planning to Reshape Strategy](#) (MIT Sloan Management Review).

Least-regrets planning: how can risks be mitigated?

The concept of “least-regrets” planning is widely popular but poorly understood.
What is it?

Should least-regrets planning identify resource and grid plans that offer:

1. The lowest transmission cost for the chosen “reference/base-case” scenario (least-cost planning)?
2. The lowest total system costs (G+T+reliability costs) for the reference/base-case scenario?
3. Investments needed only for the least challenging scenario (to avoid building too much)?
4. Sufficient capacity to handle even the most challenging scenario (to avoid being “caught short”)?
5. The lowest average cost (highest average benefits) across all scenarios (i.e., best probability-weighted outcome)?
6. The lowest “cost of being wrong” across all scenarios (i.e., minimize risk)?
7. The best combination of (5) and (6)?



This is what least-regrets planning should focus on!

Example: AEMO [least-regrets framework](#) used in its Integrated System Plan (ISP)

We need to double or triple US transmission capability ... and can do at least some of it quickly and cost-effectively!

1. Advanced, grid enhancing technologies

- Dynamic line ratings
- Flow control devices
- Topology optimization
- Grid-optimized DER/storage
- Remedial action schemes
- Grid-forming inverters

2. Upgrades of existing lines

- Advanced conductors
- Rebuild aging lines at higher voltage
- Conversions to HVDC

3. New transmission

- Highway/railroad corridors
- ROW-efficient AC designs
- HVDC transmission
- Submarine/underground
- New greenfield overhead

Examples:

[Priority order](#) required by the German “[NOVA Principle](#)”

MA [CETWG Report](#): “Loading Order” and ATT/GETs recommendations

Thank You!

(additional slides)

“Transmission Benefits” – what are they?

Multi-value transmission planning allows the selection of transmission solutions that offer the greatest net benefits:

- But what are these (often abstract) “transmission benefits”?

Transmission benefits = Cost savings (or better reliability) offered by the upgrade

Examples of savings from right-sized, multi-value transmission investments:

- Enable lower-cost generation to displace higher-cost generation = production cost savings
- Reduce need for reserve capacity through geographic diversification = investment cost savings
- Avoid costs of other transmission upgrades or refurbishments = investment cost savings
- Allow generation construction in lower-cost areas/regions = investment cost savings
(Note: this benefit is not in Order 1920’s list of seven required benefit metrics)

Studies show: if planned well, every \$1 billion spent on transmission saves \$2-3 billion

Bottom line: sometimes you must spend money to save money!

Well-documented: proven practices for quantifying a broad set of transmission benefits

Take advantage of proven practices (as referenced in Order 1920):

- See our [report](#) with Grid Strategies for a summary of quantification practices, incl. benefits beyond Order 1920's mandated ones

Most recent developments:

- Use [weather-reflective](#) (rather than weather-normalized) production cost and long-term expansion planning simulations (e.g., for 20-30 weather years)
- Production cost simulations with both [day-ahead and real-time](#) cycles to capture unpredictable real-time challenges and associated transmission value

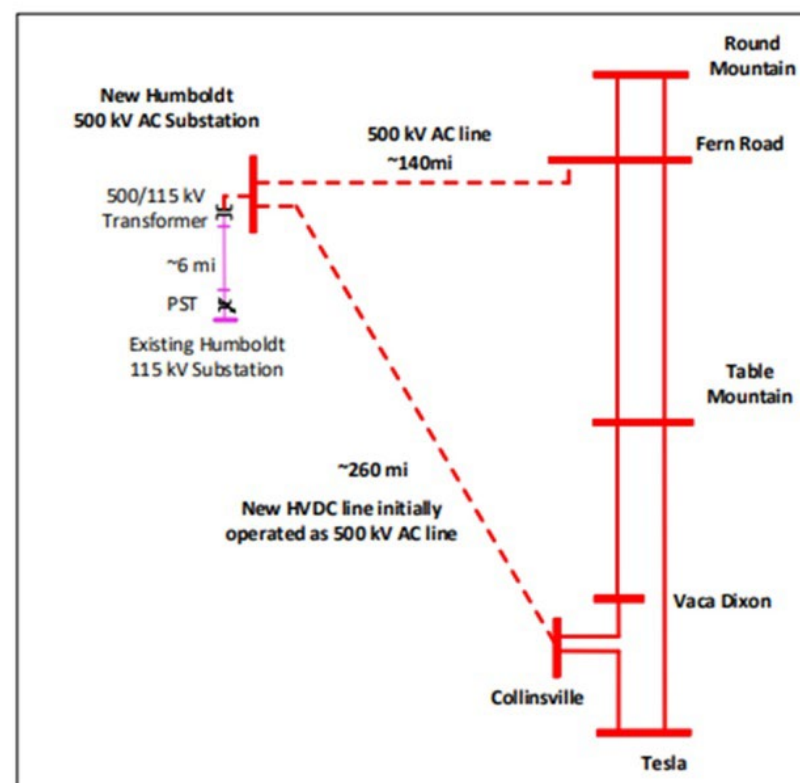
Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs , increased wheeling revenues, HVDC operational benefits

Examples: flexible solutions to reduce costs and minimize regrets

Planning processes need to develop more flexible (lower-regret) generation and grid solutions that create valuable options, given high long-term uncertainties:

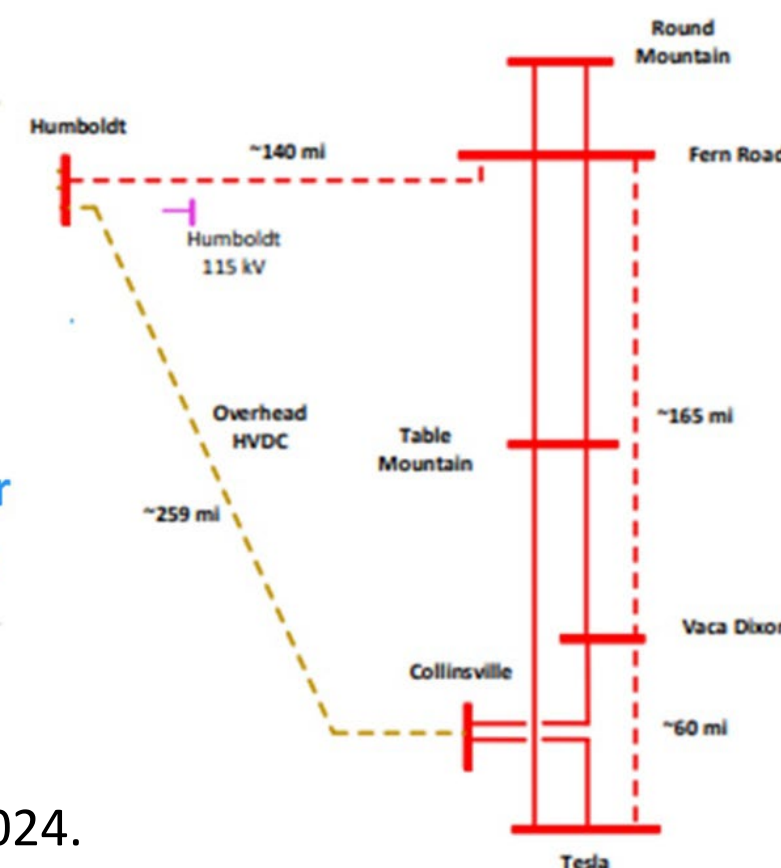
- Example 1 – rebuild aging single-circuit 230kV line as 345kV-ready with double-circuit towers to create option to: (1) initially operate circuit at 230kV, (2) later add 1 GW of transfer capability by stepping it up to 345kV (with transformation), and (3) if needed, expand the capacity by adding a second circuit
- Example 2 – CAISO’s expandable offshore-wind integration solution with HVDC-ready 500kV line:

Phase 1: Base Case Plan
(1,607 MW)



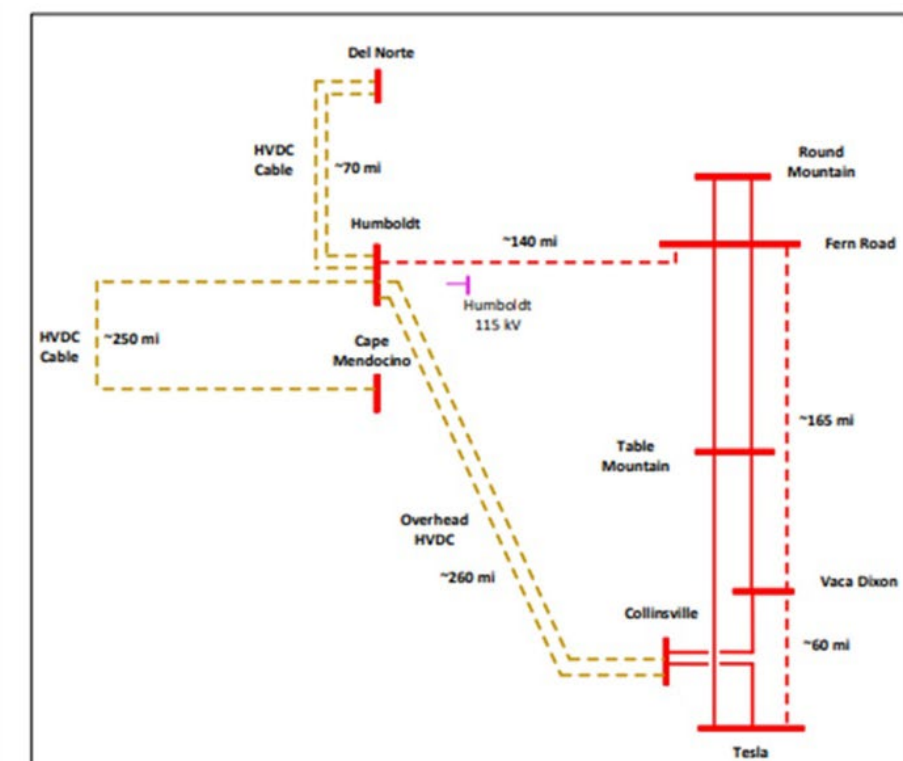
Source: [CAISO-2023-2024-transmission-plan](#), May 23, 2024.

Phase 2: DC Conversion
(3,100 – 3,300 MW?)



➡
Add DC converter stations to each end of the line

Phase 3: Expanded Plan (Option B)
(8,045 MW)



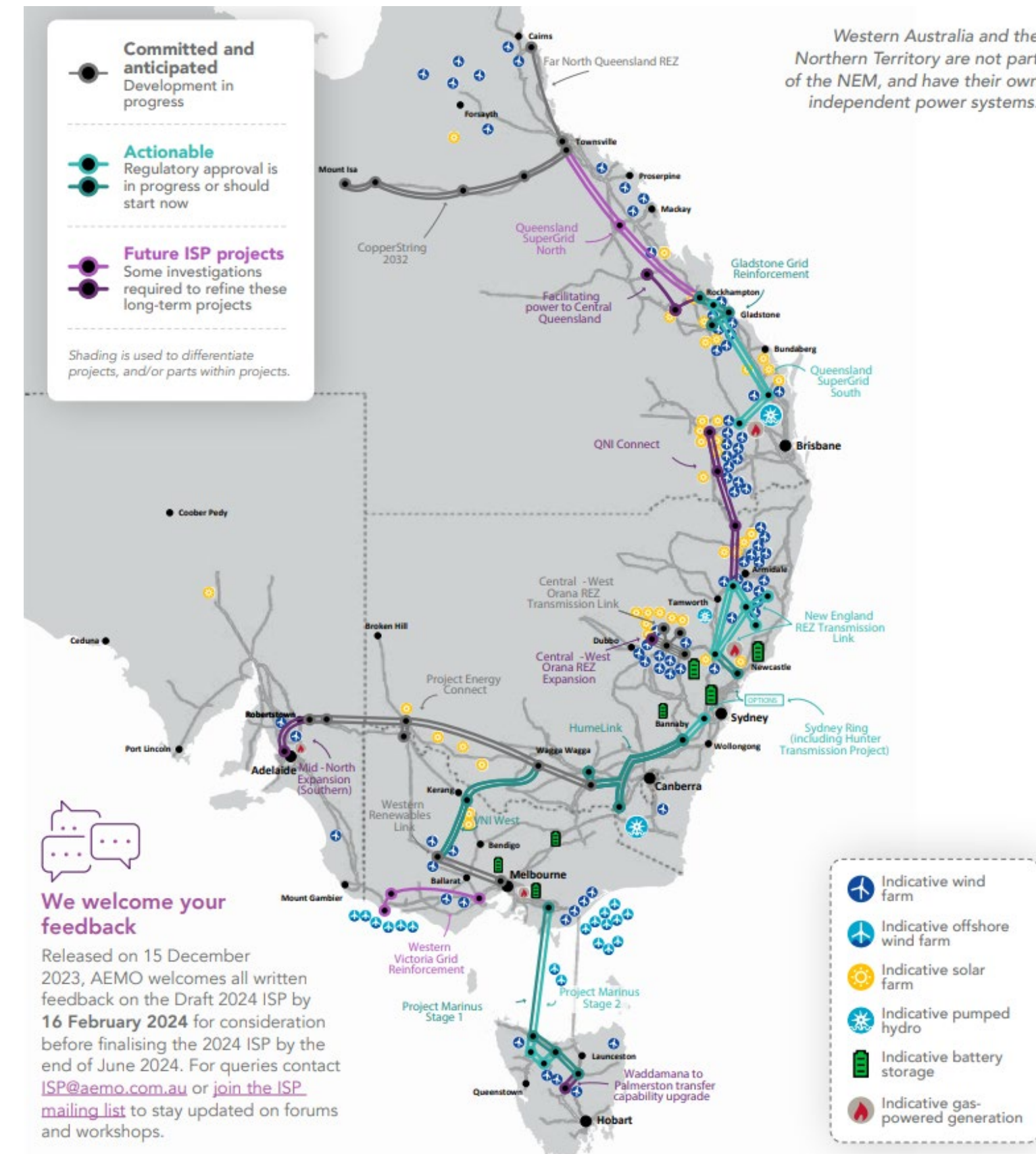
➡
Add a second HVDC line

Two new 500kV lines, of which one is “HVDC-ready”

Example: Australian Integrated System Plan (ISP)

The Australian Energy Market Operator (AEMO) integrated planning process is “best in class” for proactive, scenario-based, least-regrets planning:

- **Clearly-specified but flexible** methodology ([link](#)) produces updated plans every two years with extensive stakeholder consultations (see [Draft 2024 ISP](#))
 - **Scenario-based** analysis explicitly considers long-term uncertainties and risk mitigation over next 30 years ([link](#))
 - **Least regrets** planning values optionality that can be exercised if/when needed (e.g., projects that can be built/expanded in stages; or undertaking “early works” to develop shovel-ready projects that can be constructed quickly in the future)
 - **Both near- and longer-term needs:** (1) actionable projects for which the need is certain enough now to move forward; and (2) future projects that are likely needed at some point
- **Guidelines** for cost-benefit framework, forecasting, and “investment tests” from the Australian Energy Regulator (AER) make AEMO plans actionable ([link](#))



Transmission options for more cost-effective, affordable outcomes

Achieving cost-effective transmission-planning outcomes requires a multi-faceted approach:

1. More **proactive and comprehensive transmission planning** (as mandated by Order 1920)
 - Multi-driver/value planning (incl. for generator interconnection) to find lowest-total-cost solutions
 - Least regrets planning to mitigate risk and costs of both overbuilding and under-sizing
2. **“Loading order”** for transmission planning that prioritizes lower cost/impact options
 - Optimize existing grid → upsize existing lines → add new lines
3. **Cost control incentives**
 - Soft/hard cost caps, broad-based PBR, or targeted incentives (such as shared savings/overruns)
4. **Competitive solicitations**
 - Where possible and practical; with added cost-control incentives
5. **End-use efficiency and demand flexibility**
 - To reduce transmission, distribution, generation, and resource-adequacy costs

See [Ensuring Cost Effective Transmission to Support Affordable State Electricity Policies](#), NARUC Annual Meeting, Nov 13, 2024.

Order 1920's "Interregional Transmission Coordination" requirements

As FERC's [Explainer](#) states: "Order No. 1920 requires transmission providers in neighboring transmission planning regions to modify their existing interregional transmission coordination procedures to align with long-term regional transmission planning reforms. Order No. 1920 established the following requirements to adapt existing procedures with this requirement.

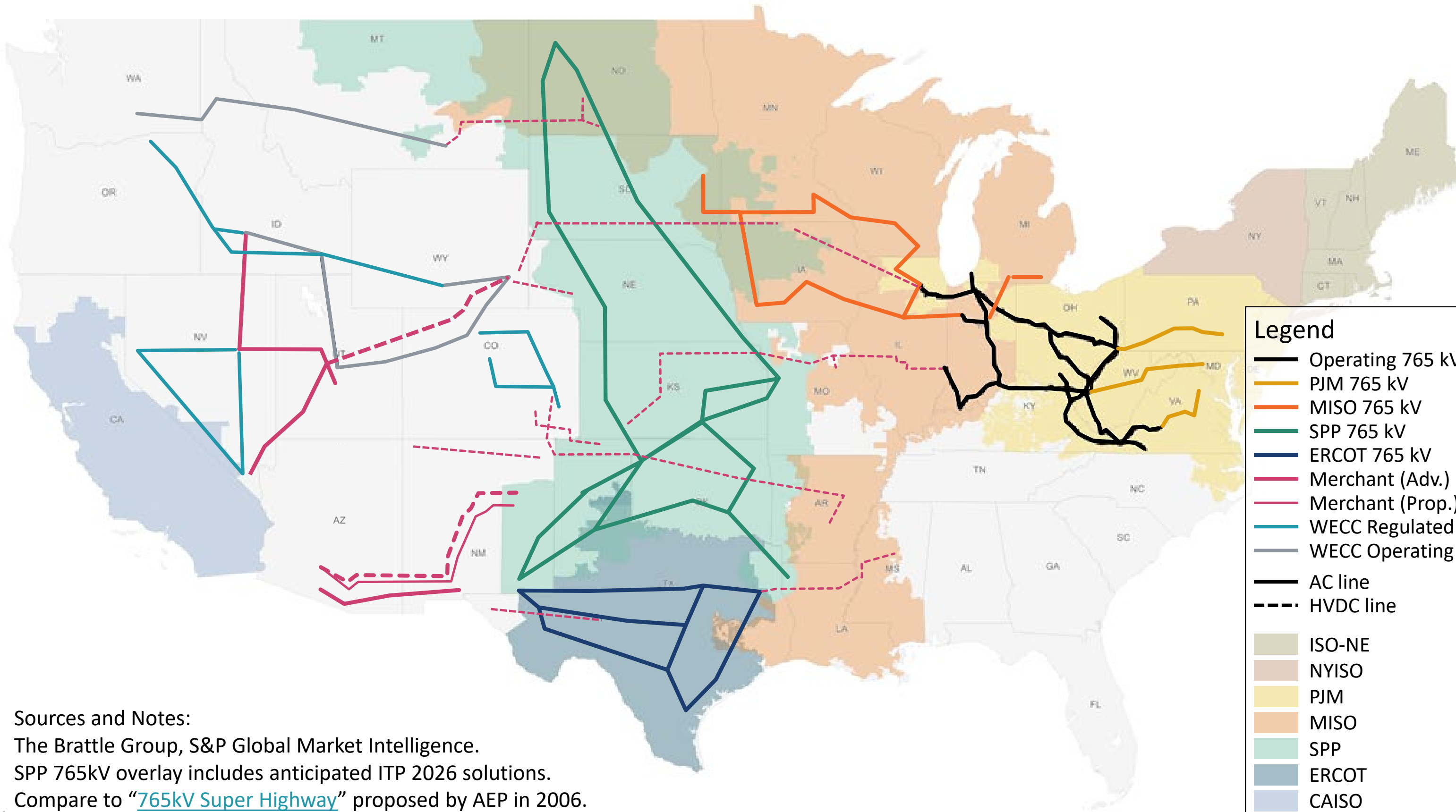
1. Require transmission providers to share information regarding long-term transmission needs and identify and jointly evaluate interregional transmission facilities to address those needs
2. Allow entities to propose interregional transmission facilities as more efficient or cost-effective solutions to long-term transmission needs

Transmission providers are mandated to make the following information publicly available through their website or e-mail list to enhance transparency and information sharing.

1. Long-term transmission needs discussed in interregional transmission coordination meetings
2. Interregional transmission facilities proposed or identified as part of long-term regional transmission planning
3. Details such as voltage level, estimated cost, and estimated in-service date of proposed interregional transmission facilities
4. Results of cost-benefit evaluations for such interregional transmission facilities, including overall benefits and region-specific benefits
5. Selection of interregional transmission facilities to meet long-term transmission needs, if any

These reforms aim to ensure that identified long-term transmission needs are considered in interregional coordination and cost allocation processes, thereby promoting fair rates."

Can Order 1920 help “connect” regional transmission overlays?



The 765 kV systems planned by PJM, MISO, SPP, and ERCOT are adjacent to each other!

- They could (should?) be planned to be connected, which would create an interregional Macro Grid
- Then should also be integrated with HVDC lines, including into ERCOT and WECC

Sources and Notes:

The Brattle Group, S&P Global Market Intelligence.

SPP 765kV overlay includes anticipated ITP 2026 solutions.

Compare to [“765kV Super Highway”](#) proposed by AEP in 2006.

About the Speaker



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[\(webbio and publications\)](#)

Johannes (Hannes) Pfeifenberger, a Principal at The Brattle Group, is an economist with a background in electrical engineering and over twenty-five years of experience in wholesale power market design, renewable energy, electricity storage, and transmission. He also is a Visiting Scholar at MIT's Center for Energy and Environmental Policy Research (CEEPR), a former Senior Fellow at Boston University's Institute of Sustainable Energy (BU-ISE), a IEEE Senior Member, and currently serves as an advisor to research initiatives by the U.S. Department of Energy, the National Labs, and the Energy Systems Integration Group (ESIG).

Hannes specializes in wholesale power markets and transmission. He has analyzed transmission needs, transmission benefits and costs, transmission cost allocations, and renewable generation interconnection challenges for independent system operators, transmission companies, generation developers, public power companies, industry groups, and regulatory agencies across North America. He has worked on transmission matters in SPP, MISO, PJM, New York, New England, ERCOT, CAISO, WECC, and Canada and has analyzed offshore-wind transmission challenges in New York, New England, and New Jersey.

He received an M.A. in Economics and Finance from Brandeis University's International Business School and an M.S. and B.S. ("Diplom Ingenieur") in Power Engineering and Energy Economics from the University of Technology in Vienna, Austria.

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