Understanding FERC's Order 1920

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On May 13, 2024, FERC issued Order 1920, a landmark rulemaking requiring transmission planners in the US to conduct long-term, scenario-based regional transmission planning to prepare for the future. FERC subsequently issued Order 1920-A on November 21, 2024, updating some key provisions of Order 1920. This fact sheet summarizes key provisions within Orders 1920 and 1920-A to help stakeholders better understand how to best engage in regional long-term planning processes.

Order 1920 Summary

With Order 1920, FERC requires each transmission planning region to initiate long-term, scenario-based regional transmission planning. Order 1920 specifies the duration and frequency of long-term transmission planning cycles, the number of scenarios planners must incorporate, a set of seven minimum factors to be used in developing scenarios, and a set of seven minimum benefits that need to be quantified as part of planning. It also requires regions to establish a mandatory default cost allocation methodology that is consistent with Order 1000 while allowing for states to provide input on an alternative cost allocation methodology. Planners are also required to consider Alternative Transmission Technologies (ATTs) and right-sizing of lines as part of long-term planning and make updates to their interregional coordination processes that include results of long-term planning cycles. In addition to long-term planning reforms, Order 1920 also requires new transparency protocols in local transmission planning and creates opportunities to streamline interconnection with regional planning.

Order 1920 Implications

Order 1920 aims to ensure each transmission planning region does long-term regional planning using a common baseline set of standards. Because most regions are not doing comprehensive, long-term transmission planning, FERC's Order 1920 mandates a major change from the status quo. The Order 1920 regional planning changes could also make interregional planning and coordination easier by standardizing long-term regional planning requirements – though FERC has yet to mandate interregional planning.

While Order 1920 standardizes study requirements, the order does not require planning regions to select projects resulting from the long-term studies – it only requires that the studies take place. For the planning to translate into beneficial grid projects, states and stakeholders will need to continue to participate in planning processes and push for actual project selection and construction.

Content of the Rule

RMI interpretation provided in blue

Long-Term Transmission Planning Duration and Scenario Design

- Transmission planners must initiate a new long-term planning process looking 20 years into the future and include at least three scenarios. The scenarios must be plausible and diverse, capturing a set of "reasonably probable" futures. Planners must also include at least one sensitivity, applied to each scenario, which is a variation on a scenario that captures "uncertain operational outcomes" such as extreme weather events.
- Transmission providers may run additional scenarios to provide Relevant State Entities with information to help them on cost allocation discussions. These additional scenarios are optional and do not need to comply with all of the Order 1920 requirements for the three mandatory scenarios (e.g., seven factors listed below).
- Transmission planners must conduct long-term transmission planning at least every 5 years, with projects selected by year 3 in each cycle.
- Transmission providers are required to solicit state input in designing scenarios.
- In defining scenarios, planners must include seven factors. Scenarios must assume that the first three factors occur but can probabilistically discount the last four inputs. The factors are:
    - Federal, state, Tribal, and local laws and regulations affecting the resource mix and demand. *For example, a state Clean Energy Standard mandating 100% clean energy by 2050.*
    - Federal, state, Tribal, and local laws and regulations affecting decarbonization and electrification. *For example, a state law banning new gas car sales by 2035.*
    - State-approved Integrated Resource Plans (IRPs) and expected supply obligations for Load-Serving Entities (LSEs)
    - Trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies. *For example, the Inflation Reduction Act's impact on clean energy costs, higher natural gas prices, etc.*
    - Resource retirements such as legislatively mandated closures or economic retirements driven by regulations. *FERC allows each region to decide how to treat retirements.*
    - Generator interconnection requests and withdrawals.
    - Utility commitments and federal, state, Tribal, and local policy goals. *Note that policy goals differ from "laws and regulations" in that they are non-binding. Also note that this factor in Order 1920 included corporate commitments, but this requirement was struck in Order 1920-A.*
- Transmission providers must identify needs for planning using economic and reliability drivers.

Long-Term Transmission Planning Benefits

Plans must quantify at least seven benefits for any transmission projects identified by planning. Selection of projects must seek to "maximize benefits," although FERC leaves it up to each region on how to do that (e.g., net benefits, minimum benefit-to-cost ratio no lower than 1.25 to 1). This list represents a policy-agnostic set of benefits, meaning that states will pay only in proportion to the benefits received and independent of any other state's policies.

Long-Term Transmission Planning Benefits (continued)

The seven benefits are:

- Avoided or deferred reliability transmission facilities and aging infrastructure replacement. *Planning transmission infrastructure comprehensively can reduce the need for more piecemeal investments, such as replacements of aging poles and wires.*
- Either reduced loss of load probability (LOLP) or reduced planning reserve margin (PRM). *Comprehensive long-term planning increases access to a diverse resource mix, enhancing reliability by reducing the chance of outages (LOLP quantifies the risk of outages while PRM quantifies the amount of generation that the grid must have on hand to manage outages—either metric can work here to quantify the enhanced reliability benefits that transmission confers.)*
- Production cost savings. *Comprehensive long-term planning can enhance efficient operational use of the grid by reducing congestion. Production cost modeling captures these efficiency improvements in the form of financial savings for consumers. It also captures the cost savings from using lower cost generation (e.g., running expensive peaker plants less).*
- Reduced transmission energy losses. *More efficient usage of the grid can reduce power losses from an overly congested grid. This can be incorporated into production cost modeling in addition to benefit #3.*
- Reduced congestion due to transmission outages. *A more efficiently planned grid faces fewer transmission outages, resulting in less congestion from fewer lines being down. This can be incorporated into production cost modeling in addition to benefit #3.*
- Mitigation of extreme weather events and unexpected system conditions. *This benefit explicitly captures the savings from proactive planning during extreme weather events using tools such as production cost modeling (different from benefit #3, which considers only normal system conditions).*
- Capacity cost benefits from reduced peak energy losses. *A more efficiently planned grid reduces losses of energy from line congestion during times of peak consumption. This means that the grid operator does not need to procure as many generation resources. This benefit is in addition to #3, production cost savings, as it considers the cost of investing in new capacity whereas #3 considers operational savings.*

Cost Allocation

- Transmission providers must file a default ex ante cost allocation methodology that explains how lines planned as part of long-term planning are paid for. This methodology must be consistent with several principles from FERC's Order 1000, issued in 2011, which mandates that costs be assigned commensurate with benefits and that no entity can be forced to pay more than the benefits they receive. The list of seven benefits above can be used as a starting point for determining a cost allocation methodology consistent with Order 1000.
- Transmission providers must engage states on designing the default methodology during an initial 6-month State Engagement Period before complying with the rule. States may request an additional 6-month extension on this period if desired, which would extend the deadline for the entire compliance filing.
- Transmission providers are required to file any methodology that states agree to during the State Engagement Period as part of their compliance filing at FERC, in addition to the default methodology that transmission providers agree to (if such methodologies differ). FERC will make the ultimate decision in each compliance filing which cost allocation methodology will be accepted as final for planning purposes.
- During the State Engagement Period and each subsequent planning cycle, states have the option to create a State Agreement Process (SAP) cost allocation methodology as an alternative to the default ex ante methodology. Transmission providers are required to file any SAP during the initial compliance filing and must consult states before updating cost allocation processes in future planning cycles. The results of such consultations must be posted publicly.

Right-Sizing and Alternative Transmission Technologies

- Transmission providers must consider right-sizing options as part of long-term planning. Right-sizing usually means increasing the carrying capacity of a line by increasing its voltage or adding circuits. Transmission providers must submit a minimum voltage threshold for consideration (no higher than 200 kV) and then must regularly post, "sufficiently early" in the planning process, a list of projects set to be replaced in the next 10 years that would be eligible for right-sizing. Right-sized projects are eligible for a Right of First Refusal (ROFR).
- Transmission providers are required to consider Alternative Transmission Technologies (ATTs), including Grid-Enhancing Technologies (GETs), such as dynamic line ratings and advanced power flow controls; advanced conductors; and transmission switching. *ATTs are often lower cost than traditional transmission infrastructure solutions but their adoption thus far lags behind their technical potential. RMI analysis has shown that GETs can be cost-effective solutions to resolve transmission system planning issues.*

Consideration of Interconnection Network Upgrades in Planning

Order 1920 requires that planners modify their Order 1000 regional planning processes (not the new long-term planning processes) to consider the inclusion of network upgrades that have been identified in at least two previous interconnection study cycles occurring in the past five years. Upgrades must be 200 kilovolts or higher and at least $30 million to be considered. They must have not been selected for development as part of the interconnection process. *This is meant to solve reoccurring interconnection bottlenecks repeatedly identified, but not resolved, as part of the interconnection process. The voltage and cost thresholds are meant to focus on solutions that would benefit from regional planning review and cost allocation.*

Local Transmission Planning Transparency

Order 1920 mandates that transmission improve transparency by adopting PJM's Attachment M-3 process, which requires each local transmission project be reviewed in three meetings tackling Assumptions, Needs, and Solutions. Each of these meetings must be separated by at least 25 calendar days, with meeting materials posted at least five calendar days in advance. This process applies only to projects within the scope of FERC Order 890, so it does not apply to asset management projects (i.e., infrastructure replacements).

Interregional Transmission Coordination

In Order 1920, FERC requires that the Order 1000 interregional transmission coordination include inputs from the new long-term planning processes. Each region must share long-term planning assumptions, needs, and proposed solutions with their neighbors. They must then identify and jointly evaluate potential interregional facilities. Any entity can propose an interregional project as a solution to meet joint long-term regional needs.

Right Of First Refusal and Construction Works In Progress

In Order 1920, FERC declined to reinstate the federal ROFR or remove the CWIP incentive. These were both part of the NOPR (Notice of Proposed Rulemaking) for Order 1920 but were not included in the final rule.

Compliance

Compliance filings on all matters except interregional coordination are due 10 months after posting in the Federal Register. Compliance filings on interregional coordination are due 12 months after posting. The compliance filing deadline for all materials will be extended if states take advantage of the optional 6-month extension for the State Engagement Period on cost allocation. Transmission providers must also indicate in their compliance filings a date no later than two years in the future from the compliance filing deadline when the first long-term planning cycle will commence (initially this had been one year in Order 1920 but was amended to two years in Order 1920-A).

Order 1920-A Summary

Order 1920-A keeps most parts of Order 1920 intact but makes key changes to enable a greater role for states as part of the planning process. These changes are reflected in the rest of this fact sheet but are summarized here.

- Requiring transmission providers to file as part of their compliance filing any cost allocation methodology agreed to by Relevant State Entities during the State Engagement Period. Transmission providers were previously not required to file states' cost allocation methodology. Now, transmission providers must file it, including if it differs from the default *ex ante* methodology that transmission providers define, with the final decision on which cost allocation methodology will be utilized up to FERC. Transmission providers must also participate in the State Engagement Period upon request (they previously were not required to do so).
- Requiring transmission providers to consult states when amending cost allocation methodologies during planning cycles following compliance filing approvals.
- Requiring transmission providers to solicit state input when designing planning scenarios.
- Allowing transmission providers to run additional, optional scenarios beyond the three required by Order 1920. These optional scenarios are meant to help states navigate cost allocation discussions and are not required to incorporate all seven factors to the extent that the three mandatory scenarios must.
- Allowing states to request a 6-month extension to the 6-month State Engagement Period on cost allocation (bringing total duration to 12 months maximum).
- Removing the requirement for long-term transmission needs to be identified using the seven benefits. This was originally required in Order 1920, but certain regions appealed to FERC about how this requirement would be too onerous to implement as part of their existing planning processes, which utilize a model (the sponsorship model) that identifies needs at a less granular level to encourage more innovation during the competitive bidding window mandated under Order 1000, making benefits determination challenging. The identification of needs must still rely on "economic and reliability drivers."
- Removing the corporate commitments component of Factor Category 7 for scenario development (see p. 2).
- Extending the timeline for the first planning cycle to commence from one to two years after compliance filings are due.

For more information on the rest of RMI's transmission work, please visit https://rmi.org/our-work/electricity/building-clean-competitive-grids/