Understanding FERC's Order 1920

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Order 1920 Overview

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

Itallics indicate RMI interpretation

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 planners must conduct long-term transmission planning at least every five years, with projects selected by year three in each cycle.
- 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:
    1. 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.*
    2. Federal, state, Tribal, and local laws and regulations affecting decarbonization and electrification. For example, a state law banning new gas car sales by 2035.
    3. State-approved Integrated Resource Plans (IRPs) and expected supply obligations for Load-Serving Entities (LSEs)
    4. 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.*
    5. Resource retirements such as legislatively mandated closures or economic retirements driven by regulations. FERC allows each region to decide how to treat retirements.
    5. Generator interconnection requests and withdrawals.
    7. Utility and corporate commitments and federal, state, Tribal, and local policy goals. *Note that policy goals differ from "laws and regulations" in that they are non-binding.*

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.*

1. 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.*
2. 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).*

3. 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).*
4. 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.*
5. 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.*
6. 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).*
7. 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 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.
- On cost allocation, during each planning cycle, states have the option to create a State Agreement Process (SAP) alternative cost allocation methodology, but the default methodology must be used if states either do not elect the SAP option or fail to reach consensus. Transmission providers must engage states on designing the default methodology during an initial six-month Engagement Period before complying with the rule.

Long-Term Transmission Planning Right-Sizing and ATTs

- 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 kilovolts) 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 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 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 (a key omission).

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 Work in Progress

In Order 1920, FERC declined to reinstate the federal ROFR or remove the construction work in progress (CWIP) incentive.

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.