FERC ORDER 2222 & DER POLICY AND IMPLEMENTATION REPORT

November 2025

CURRENT NEWS AND NEW DEVELOPMENTS

Summary of the latest developments in FERC Order 2222 and DER policy implementation

FERC and several states acted on distributed energy resource (DER) policy, the implementation of virtual power plants (VPPs), and FERC Order 2222 in the last several months. A summary of the actions is provided below.

RTO/ISO Order 2222 Implementation:

- On October 28, 2025, in Docket ER26-284, PJM filed a series of changes associated with FERC Order 2222 to its Tariff and Reliability Agreement. These changes are largely ministerial and reflect changes in the Reliability Agreement due to how the RTO calculates Electric Load Carrying Capacity (ELCC), and the timing of capacity auctions prior to the 2028 FERC Order 2222 implementation. [LINK]
- On September 19, 2025, FERC partially approved SPP's second compliance filing. SPP is directed to file another compliance filing on several aspects, including double counting restrictions, compensation requirements, distribution factors, and various operational coordination provisions. SPP is also directed to file a proposed effective date in the 2nd quarter of 2030 to implement FERC Order 2222. [LINK]

State FERC Order 2222 Implementation:

- Following its May 29, 2025, stakeholder meeting regarding rules that may be needed for a registration and study process of DER aggregations participating in wholesale markets via distribution systems in Indiana, URC staff invited comments to be filed by Oct. 20. Reply Comments were due Nov. 3. [LINK]
- On Oct. 11, 2025, utilities in Maryland filed their reports in response to Order No. 91603 related to implementation of FERC Order 2222 and deployment of cost-effective virtual power plants. Stakeholders were invited to file comments on the utilities' reports by Nov. 19, 2025, with a technical conference on Dec. 3. [LINK]

Other DER Policy Developments:

- On Oct. 21, 2025, the Maryland PSC issued an order addressing utilities' proposed TOU tariff offerings and pilot programs related to implementation of the DRIVE Act. The PSC accepted the utilities' TOU offerings, but is requiring that the utilities refile their VPP and V2G proposals to better align their programs with the legislative intent of the DRIVE Act. Utilities must re-file within 90 days of the Order. [LINK]
- The Iowa Utilities Commission opened a new rulemaking in October 2025 with the stated purpose of allowing participation in wholesale markets by demand response customers, which was previously prohibited. The proposed rule would require cooperation between utilities and ARCs regarding exchange of customer data to effectuate participation in wholesale markets by individual customers or aggregations with a load of 100kW or more. A public hearing was scheduled for Nov. 18, 2025, with parties filing comments on or before that date. [LINK]

KEY ISSUES ANALYSIS

Metering and Telemetry

Metering and Telemetry define the economic transaction points for the electric utility industry. As such, the specific requirements for metering and telemetry are tightly controlled and defined by industry standards based upon the type of economic transaction. Historically, metering could be collected monthly and even estimated for periods of time based upon historical trends. However, as the products and the markets have begun shortening their respective requirements, telemetry has begun to play a larger role in being able to provide metering information in shorter time periods. For example, if a product in the marketplace requires a fast response to market signals, i.e. frequency responsive products, fast (SCADA level 4 second communications) and secure (ICCP connections to the control center) telemetry could be required for the market and reliability coordinator to ensure the product is performing appropriately to be able to effectively maintain grid reliability.

Not all products require fast (4 second) communications and require their information to be transmitted to the control center. Some products may be able to utilize 15-minute, daily, or even monthly meter information and do not require direct control room links. Therefore, it is important that both the metering and telemetry requirements are defined based upon the utility program or market products being served with the resource. These rules need to be carefully specified to eliminate cost prohibitive requirements for DERs to effectively participate in utility programs or RTO/ISO market products.

Advancements in fully automated metering technologies are providing the ability for DERs to participate in virtually all utility programs or RTO/ISO market products without the need for incremental metering or telemetry if appropriate data sharing structures exist from the meter provider (typically the distribution utility) and Aggregators. Today, this issue is rapidly becoming the single biggest challenge to enabling DERs. Many utilities have balked at sharing this data based on technical and economic justifications that will be discussed in later sections. Resolving this conflict is paramount; metering and telemetry requirements must not economically prohibit DERs' ability to participate in markets and programs.

FERC Order 2222 Metering and Telemetry Requirements

FERC Order 2222 requires each RTO/ISO to revise its tariff to establish market rules that address metering and telemetry hardware and software requirements necessary for DERAs to participate in RTO/ISO markets.[1]

The Commission provided RTOs/ISOs with flexibility to establish necessary metering and telemetry requirements rather than prescribing specific or standard requirements. The Commission required each RTO/ISO to explain in its compliance filing why such requirements are just and reasonable and do not pose an unnecessary and undue barrier to individual distributed energy resources joining a distributed energy resource aggregation.

The Commission emphasized that RTOs/ISOs should base proposed metering and telemetry requirements on the information needed by the RTO/ISO while avoiding unnecessary requirements that may act as a barrier to individual distributed energy resources joining DER aggregations or to DER aggregations participating in the wholesale markets.

Because a DERA is the market participant and single point of contact, the Commission directed that the DERA is the entity that will be metered and will be responsible for providing any required metering and telemetry information to RTOs/ISOs. The Commission did not require that individual DERs must be separately metered. FERC further clarified this point in a CAISO compliance order. The Commission stated that FERC Order 2222 allows ISOs and RTOs to require telemetry from DERAs, but directs the

[1] Order 2222, P262

CAISO to "specify the methods available to an aggregator for providing telemetry to CAISO without requiring telemetry from all of the individual DERs in the aggregation."[2] The Commission also directed that each RTO's/ISO's proposed metering requirements should rely on meter data obtained through compliance with distribution utility or local regulatory authority metering system requirements whenever possible for settlement and auditing purposes.

All six RTOs/ISOs complied with these metering and telemetry requirements. There are several common aspects, such as only requiring telemetry from the DERA, but there are key differences, particularly with regard to telemetry and the ability to use submetering.

- **CAISO –** FERC found that CAISO's proposal generally complied with FERC Order 2222. Only the DERA itself is subject to CAISO's wholesale metering requirements and to provide settlement-quality data, and direct telemetry is not required on each individual DER if accurate aggregate data can be calculated and provided. Telemetry is required for DERAs providing ancillary services and DERAs 10 MW or greater. In response to direction to modify its Tariff to specify methods available to aggregators for providing telemetry without requiring telemetry from all individual DERs, CAISO stated that it will memorialize in its Tariff that DERAs can acquire the data from their DERs to provide the CAISO with accurate telemetry by any means, including calculation.[3]
- **ISONE –** ISONE's compliance filing tied metering and telemetry requirements for DERAs to the existing and new requirements for seven different participation models. Metering and telemetry are at the DERA level, and the initial proposal limited metering to metering equipment owned and operated by the host utilities. While the initial proposal indicated that the use of submetering to measure performance DER operation within a DERA would be allowed, ISONE specified that metering must be located at the retail delivery point. Through several compliance filings and orders, FERC directed and approved additional revisions and compliance to broaden the entities who can provide metering, establish protocols for sharing metering data, and to allow submetering.
- **MISO –** The Commission initially found that MISO partially complied with FERC Order 2222 metering requirements. MISO requires telemetry for each distributed energy aggregated resource (DEAR) through Inter Control Center Protocol (ICCP) via private Wide Area Network (WAN), and this data must be submitted every two seconds for all dispatchable DER aggregations, regardless of size or product. For non-dispatchable DER aggregations, telemetry is scaled to the product. In addition, MISO is flexible on the type of calculation or measurement made to develop a telemetry signal, as long as there is a common method used for a single DER group. Telemetry is not required at the individual DER level. For settlement, DERAs submit meter data for each DER Group comprising a DEAR.

[2] California Independent System Operator Corp., 179 FERC ¶ 61,197 (2022) (CAISO Compliance Order).
[3] CAISO August 2022 Compliance Filing Transmittal Letter, P 7.

- **NYISO –** NYISO's rules align metering and telemetry standards for DERAs with those used for generators and requires the provision of both real-time operational data and after-the-fact settlement data. DERAs are required to provide multiple streams of telemetry and revenue quality meter to NYISO at 6-second increments for automatic generator control (AGC) contexts, but telemetry of individual DERs is not required. NYISO's rules for small DERs under 100 kW are flexible, and NYISO allows alternative telemetry methods as long as they provide directly measured telemetry with periodicity of five minutes or less.
- **PJM –** PJM's proposal partially complied with the metering and telemetry system requirements. Like other RTOs/ISOs, PJM established the DER aggregator as the entity responsible for providing metering and telemetry information. DER Aggregation Resources under 10 MW participating only in energy markets are exempt from telemetry requirements. PJM did specify that meter data must be submitted within one business day, and that the metering equipment must meet electric distribution company accuracy requirements or have maximum error of two percent.
- **SPP –** SPP's proposal to comply with FERC Order 2222 requires real-time telemetry via ICCP at the DERA level. DERAs in SPP must designate a meter agent for revenue-quality metering requirements, and DERAs must make meter values available to the LSE and Distribution Utility at whatever granularity they require for reliability. In addition, if a DERA includes demand response, it must be separately telemetered, and metering must be submitted for the demand-response performance in addition to the aggregation total. After requiring more detail on data sharing and meter data deadlines, FERC approved most of SPP's proposal.

RTO/ISO compliance with FERC Order 2222's metering requirements identified two significant issues with profound implications for how DERs participate and how DERAs collect the granular data from individual DERs. While most of the RTOs and ISOs specified that the primary premise meter is the appropriate metering site, with prompting by FERC several of the RTOs and ISOs will accommodate submetering, particularly ISONE and PJM.

As discussed earlier, the issue of submetering and the need for reconstitution was a major source of controversy in the ISONE proposal. DER providers and clean energy advocates argued that submetering is essential for behind-the-meter (BTM) DERs to participate effectively in wholesale markets, and without submetering, many BTM devices, such as controllable thermostats, generators, energy storage devices, and electric vehicles, cannot participate under ISONE's participation models. In addition, many of these BTM devices incorporate onboard telemetry that meets the prescribed standards. Metering at the retail delivery point is not sufficiently precise to measure performance because other loads at the premise may mask operation. For example, if there are solar and battery resources behind the meter, their operation will mask demand response actions, and there is no way to determine solar performance, battery performance and demand response performance unless submetering is utilized. The utilities in New England, along with ISONE, argued that the use of submetering could result in double counting of energy services, and that customer load must be reconstituted to remove the submetered load from full premise load. Furthermore, the utilities maintained that their current metering configuration would not allow automatic reconstitution and would be burdensome and costly. Ultimately, ISONE adopted revisions that allowed submetering to be used by DERAs that participate as Alternative Technology Regulation Resources.

Goals must be clearly established to establish effective policy. Utility efforts to focus on reconstitution at one meter are attempting to mitigate double counting and to also address the technical reality that a demand response resource and a battery resource, if managed independently, could theoretically be operated in a way that would effectively cancel their value to the grid and the market while technically performing adequately in each of their respective categories. This is clearly not the goal, and appropriate policies must be put in place to ensure that different resources at a single premise, or behind a single meter, are collectively operated in a manner that supports the market or grid needs. In other words, all of the resources behind a single meter should be operated in a consistent manner, not in a manner that allows them to cancel out their effects or response to the grid and market needs with dis-similar operation.

State Action Needed

To support the implementation of FERC Order 2222, state and local regulators will need to examine their metering rules, particularly rules concerning who can provide metering service. A related issue, which was covered in an earlier tracking report, is how meter and other data can be shared and protected.

Key actions that state and local regulators should consider include:

- **Allow submetering.** If a state doesn't already allow submetering, utility codes and regulations may need to be revised to meet the defined goals for DER performance and market interaction. Many state codes do not allow non-utility metering and submetering (originally to prevent resale of electricity). State and local regulators will need to examine their metering rules and potentially carve out DER aggregation as a permitted submetering use under clear rules that meet the desired goals.
- **Develop submetering standards**. State and local regulators should establish or update submetering standards—defining accuracy, certification, and utility inspection requirements for DER devices or aggregations. In particular, regulators should approve configurations that allow parallel or sub-metering behind the main retail meter without violating anti-tampering or billing rules.
- **Telemetry infrastructure coordination**. State and local regulators should define acceptable communications pathways and technical standards (e.g., IEEE 2030.5, DNP3, etc.) for DER communication at the distribution level. Regulators should clearly define the requirements for

both Aggregations and individual DERS that appropriately recognize the FERC guidance for DERs. It is clear that smaller resources (under some threshold – i.e., 1MW) cannot economically install ICCP links and four second telemetry. However, the Aggregator may be required to have ICCP links and telemetry requirements to present the Aggregation to the market. Finally, regulators should clearly define the requirements for utilities and aggregators to interoperate effectively rather than blocking participation or duplicating technology costs.

- **Data Access**. State and local regulators should define requirements for fair and effective access to necessary data to enable DERs.

Submetering of DERs is a relatively new topic. At this point, California is the primary state that allows submetering of DERs, but other states like Maryland are considering regulations that would allow submetering and device-level measurement. With CPUC Decision 22-08-024, the California PUC adopted rules and submetering protocols for plug-in electric vehicles, making it the first state to allow separate metering of EVs without installing a separate utility meter. This action sets an important precedent for allowing submetering behind the main meter, defining accuracy and communications/data protocols, and aligning utility billing/validation systems accordingly.[4] The Interconnection Work Group of the Maryland PSC is drafting regulations to implement VPP rules and FERC Order 2222. The draft rules under consideration accommodate the use of non-utility device-level meters as long as they meet appropriate standards such as the American National Standard for Electric Meters C12.1 Code for Electricity Metering (ANSI C12.1).

Future Model for Success

Today, technology provides an opportunity for more effective collaboration and enablement of DERs while also lowering the overall cost burden of metering and telemetry industry wide. There are two specific examples that illustrate efforts in this area.

First, in ERCOT, a common meter authority (Smart Meter Texas) was created to allow consumers, Aggregators and Retail Electric Suppliers access to meter data. This has allowed an effective method for these third-party providers to provide services in addition to retail electric service without the burden of fully redundant solutions. However, in this example, Smart Meter Texas was developed such that the data it received was a copy, or mirror, of the utility meter data. They effectively doubled the cost of the data systems by creating a requirement to collect and maintain two data sets – one set for Smart Meter Texas, and the other set at utilities/ERCOT to enable settlement of the retail market. This structure initially created significant issues like the Evaluation, Measurement and Verification (EM&V) process for the data was not consistent between the systems and created data disparities between the raw data and post-processed data between the systems. While this has been resolved, the reality of doubling the cost

[4] CPUC, Decision Adopting Plug-In Electric Vehicle Submetering Protocol and Electric Vehicle Supply Equipment Communication Protocols, 2022, Decision 22-08-024.

for redundant systems with the potential for inconsistent data still exists and ultimately is a burden on consumers, especially when limitations in functionality, such as the frequency of access to real-time data, have remained an impediment.

Second, in Ontario, a common meter authority was established with only one head end system that is utilized by utilities, the ISO and third-party providers. This has significantly reduced costs for metering as utilities no longer need their own independent head-end system. A single system used by all parties eliminates any discrepancies and ensures the lowest possible cost to collect and share this data appropriately with each required stakeholder. Ontario is an example that shows the opportunity that could exist for state sponsored common meter authorities that would allow for significant cost reduction for all utilities in the state and provide a more effective and efficient method to ensure third-parties and the ISO have appropriate access to this data for settlement and operational needs going forward.

Ultimately, a unified, shared structure like this will need to be adopted to control ever-escalating IT and system costs in the industry. And perhaps more importantly, it will eliminate the ability of meter providers to limit access to the data required for DERs to be effectively enabled and settled in the market.

Summary

Metering and telemetry decisions in each state will likely define the success or failure of DER enablement. Policies that limit access to DER and meter data for third parties or RTOs/ISOs, or create cost prohibitive technology requirements for telemetry will slow, or even cause complete failure, for the effective enablement of DERs to the grid and market. It will be important that regulators have the ability to decipher and define appropriate technology requirements while also ensuring fair access to the required data. This area represents a significant opportunity for the electric industry to collaborate more effectively and move away from historical norms. Simply examining the very successful example of Ontario's common metering authority shows that it is not only possible to save millions of dollars in costs through this collaboration, but it will also enable DERs and eliminate many of the current issues being faced in the U.S. for fair and cost-effective access to required data.

TRACKER TIPS AND HIGHLIGHTS

The Policy Tracker is available to the public at FERC2222.org. [LINK] If you would like to recommend content for the Tracker or provide feedback, please contact us.

The Policy Tracker allows users to filter and search for content within a database of content pertaining to DER Policy, with emphasis on the implementation of FERC Order 2222. The keyword search functionality includes review of the source documents within the database, while the filters allow users to narrow their searches based on issue topic, organization, and state.

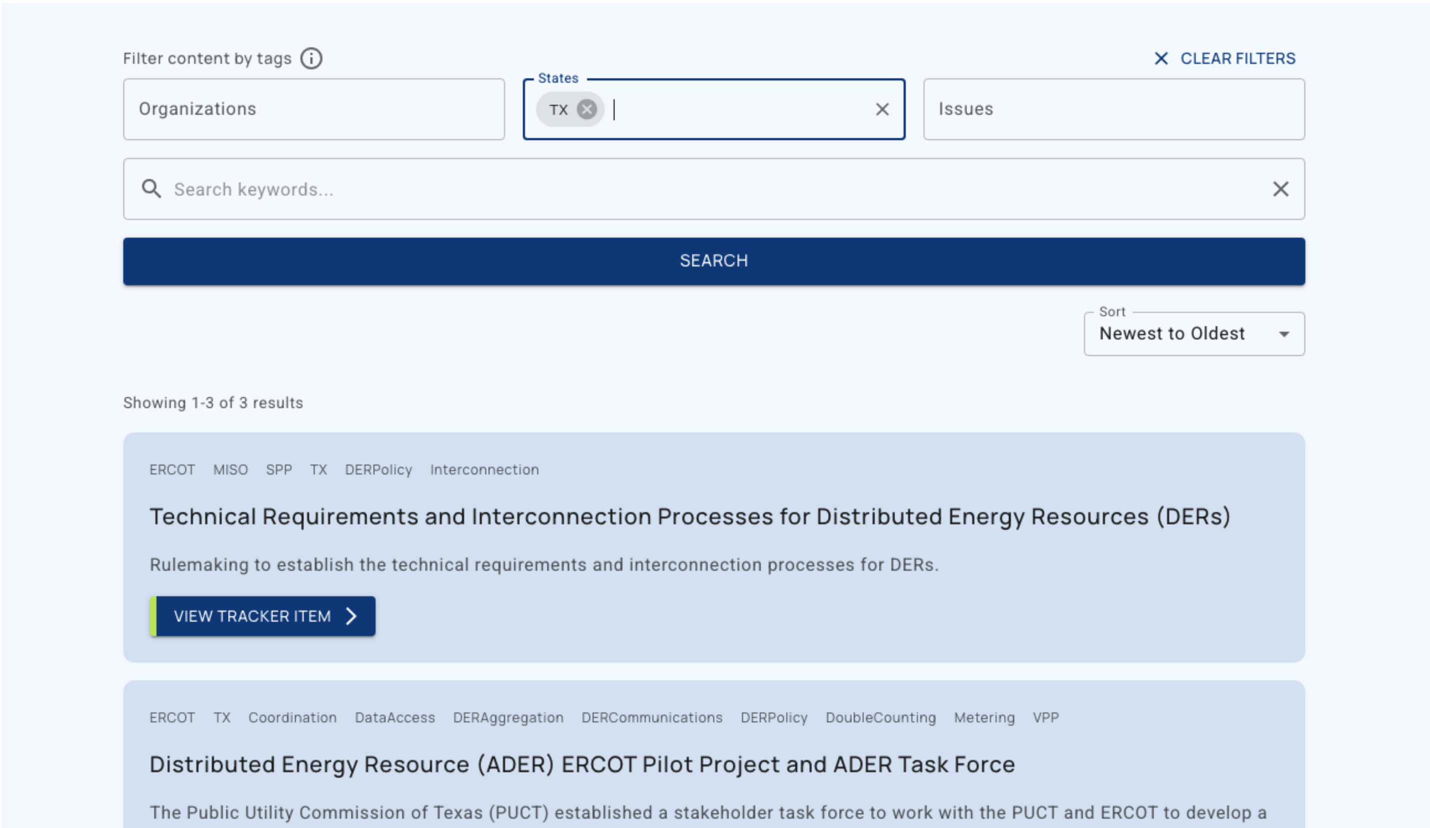

Figure 1: Screen capture of filter results (TX) from the FERC2222.org Policy Tracker.

The search function searches all tracker items by keywords in tags, titles, descriptions, and content. The filter function filters by tag (Organization, State, Issue). For Issues definitions click on the information icon above the filter fields.

In Figure 1, we demonstrate the most basic use case of the filter feature. Adding "TX" to the State filter results in all tracker items with "TX" in their list of tags. In Figure 2, below, we demonstrate the and/or logic utilized in our filter feature. By filtering for "TX" in the State filter and "Interconnection" in the Issues filter we will see fewer results than the first query because by selecting both tags we are filtering for items with *both* "TX" *and* "Interconnection."

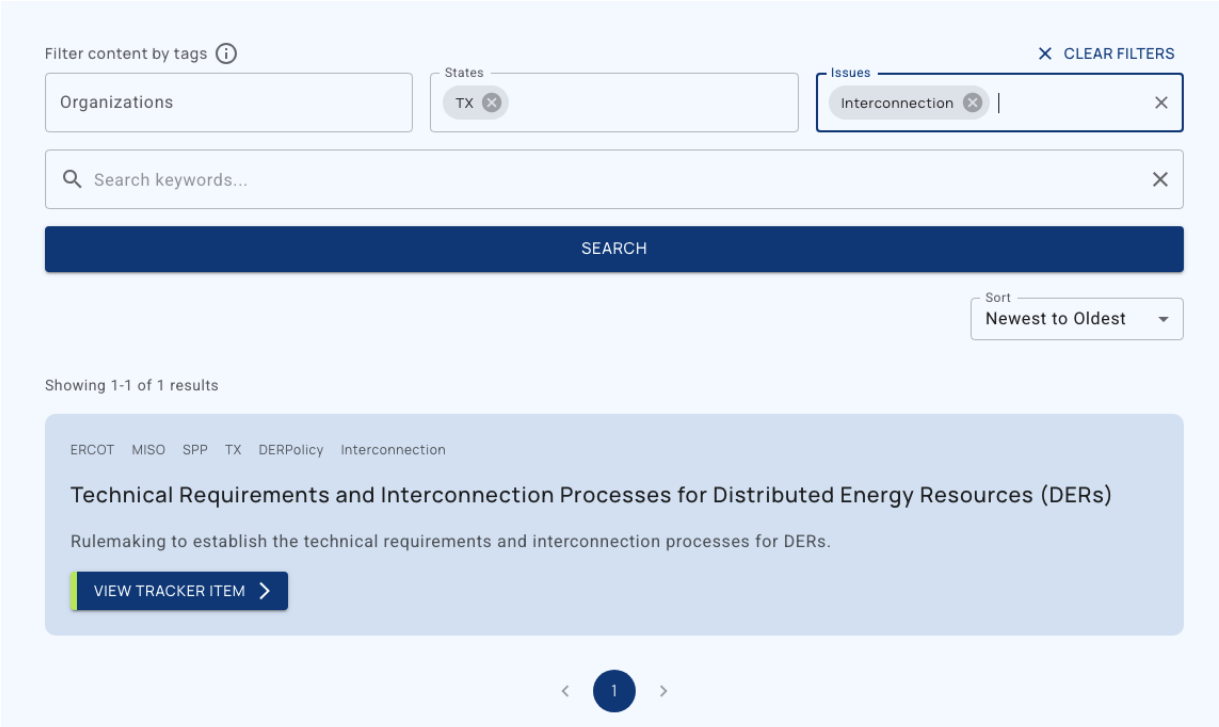

Figure 2: Screen capture of filter results (TX and Interconnection) from the FERC2222.org Policy Tracker.

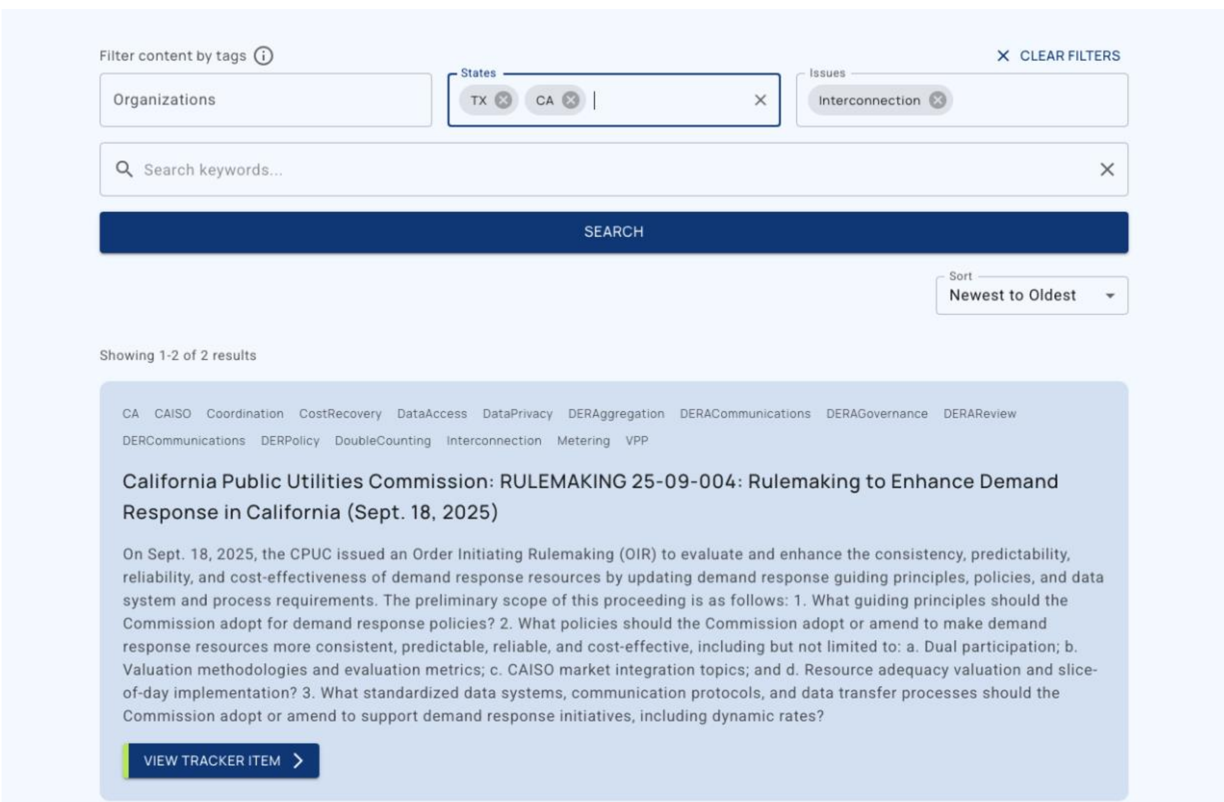

Figure 3: Screen capture of filter results (TX, CA and Interconnection) from the FERC2222.org Policy Tracker.

In Figure 3, we demonstrate the logic implemented for more complex filtering. When a user adds "CA" and "TX" to the State filter and "Interconnection" to the Issues filter, the results will show tracker items that are tagged with both "CA" *and* "Interconnection" *as well* as items tagged with both "TX" *and* "Interconnection".

In summary, the tag filter feature uses OR logic for multiple tags *within* a category, and AND logic for tags across multiple categories.

Previous bi-monthly reports, webinar recordings, registration links for upcoming events, and FERC Order 2222 related resources can also be found on ferc2222.org.

Discussion Groups are currently unavailable as we make some improvements to this feature.

Figure 4: Screen capture of Reports page (ferc2222.org/reports)

Upcoming Webinar

Join our upcoming webinar on Thursday, January 8th [LINK] . We'll dive into the Key Issues Analysis from this report, focusing on **Metering and Telemetry**. Have questions or insights on this topic – or on broader developments related to FERC Order 2222? We'd love for you to join the discussion and share your perspective!

DISCLAIMER