DER Task Force Meeting 2 Pre-read Materials

August 4, 2026

Goals for Meeting 2

Meeting 1: VA context setting, DER & VPP Policy Framework, topics and challenges to address in TF

Meeting 2 Goals

1. Align on shared vision for DERs/VPPs in Virginia and priority VPP types to focus on first
2. Understand what policies are needed to unlock those priority VPP types and where Virginia is today – which will inform interim draft report
3. Surface potential recommendations to include in interim draft report
4. Learn from other state experiences (New York)

Meeting 3: Discuss interim report findings, recommendations, and case studies; identify outstanding questions & gaps to close

Meeting 4: Review final report, finalize recommendations, and path forward

Agenda

Time	Topic	Speakers/Presenters
2:00 PM	Call to Order and Roll Call Vote to approve previous Meeting Minutes Vote on the participative planning report	Chair, Task Force Members
2:10 PM	Vision for DERs in Virginia	Chair
2:20 PM	Lessons Learned from Other States	NYSERDA
3:05 PM	Review DER / VPP Type Priorities	Ted Ko, EPDI
	FERC 2222 Primer & Implications for Virginia	David Kathan (former FERC)
3:35 PM	*5 MIN BREAK*	
3:40 PM	Policies & regulations needed to enable Priority VPP Types and where the Commonwealth is today	Ted Ko, David Kathan, Vaughan Woodruff (former IREC)
4:30 PM	DER Task Force Open Discussion	Task Force Members
4:45 PM	Wrap Up & Next Steps	Chair / Staff
4:50 PM	Public Comment	Chair

Long-term Vision for DERs in Virginia

Recap: Context

The Challenge

Virginia is experiencing rapid load growth, with electricity consumption projected to grow significantly over the next two decades. Peak demand is also predicted to grow at a similar rate, driving the need for **costly electric grid upgrades** and **putting upward pressure on electricity costs** for Virginians if not managed efficiently.

The Opportunity

Real-world experience from states and industry analysis have demonstrated that distributed energy resources (DERs) offer the ability to efficiently add GWs to the system through supply, time shifting, and flexibility, mostly **using the *existing* distribution system** and improving grid utilization. Aggregated DERs (or virtual power plants – "**VPPs**") offer these benefits at the utility scale, providing **capacity**, **peak reduction**, **peak shifting**, and **energy resilience** benefits that bring **grid-level efficiencies**.

The DER Task Force

Recognizing this opportunity, the Virginia General Assembly established the DER Task Force to "advance energy affordability and the Commonwealth's transition toward integrated DER markets and to support the Commonwealth's compliance with Federal Energy Regulatory Commission (FERC) Order No. 2222."

The goal of the Task Force is to **identify specific actions that support DER adoption and that unlock revenue streams for all types of dispatchable DERs to get paid to provide cost-effective services to meet Virginia's grid needs**---incentivizing adoption, cost-effectively adding more supply to the grid, and lowering energy costs for Virginians.

Vision for DERs in Virginia

A regulatory and market framework that builds upon Virginia's NEM foundation to ***enable all types of dispatchable DERs to get paid for providing cost-effective grid services*** *to meet Virginia's energy needs (affordable, reliable, clean, safe, and resilient power)*

Why this matters:

- **Helps Meet Virginia's Growing Demand:** Serves rapid demand growth by converting passive DERs into dispatchable Virtual Power Plants.
- **Improves Affordability**: Enables better use of existing grid infrastructure and defers costly traditional substations and wire buildouts, keeping electric bills lower for all Virginians.
- **Accelerates Clean Energy Goals**: Turns customer investments in batteries, EVs, and solar into active grid resources that maintain reliability while advancing clean energy deployment.

Discussion: Does this vision resonate? Any adjustments or additions?

Achieving this Vision

What this will look like:

- Consumers and communities are incentivized to invest in clean, distributed energy technologies because these resources are compensated for their contributions to the grid.
- Utilities and other market actors are incentivized to aggregate these DER resources (e.g., into Virtual Power Plants (VPPs)) to provide energy, capacity, and other services to meet Virginia's grid needs
- Utilities are incentivized to connect more DER capacity because these assets provide needed grid services

How Can We Achieve This Vision?

- **Market:** Align consumer and utilities' financial interests with DER deployment and aggregation.
- **Regulatory:** Updated/new laws, regulations, utility tariffs, or policies to support DER deployment and aggregation.
- **Technical:** Developed infrastructure, systems, standards, and operational capabilities to support DER aggregation and market participation.

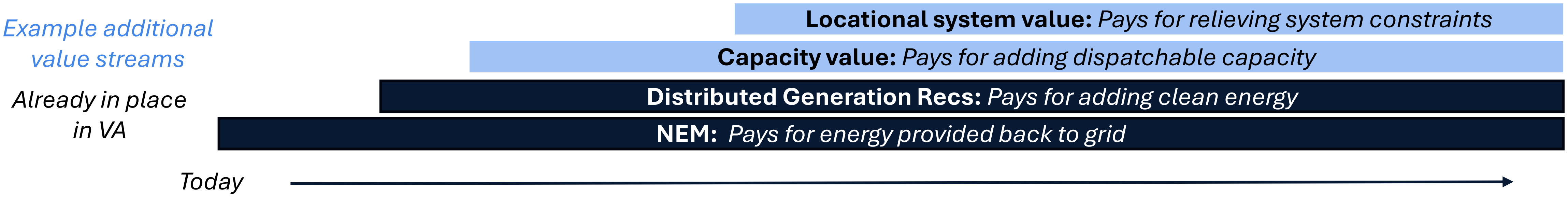
Implications for Virginia's compensation methods for DERs

Where we are today: NEM is providing the foundation for distributed solar growth across Virginia to date

Where we can go:

- Integrating **'value stacking' mechanisms allows dispatchable DERs to earn revenue across additional grid services** they provide (e.g., locational value to relieve system constraints, capacity value, etc.)
- Mechanisms can be designed—with clear accounting and to prevent double-counting—to **stack both retail tariffs and PJM wholesale markets** to maximize grid value
- This **improves project economics to support more DER deployments** (e.g., batteries, solar/storage, EVs)

Implementation lessons from other states (e.g., NY, MA, WA): Based on other state approaches, this expansion typically occurs as a phased transition—enabling customers to voluntarily opt in to value-stacking tariffs or alternative models alongside and/or in lieu of NEM



Discussion: Any feedback or additional input on this path forward? Does this resonate?

Priority VPP Types for Virginia based on Task Force input

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Reminder: VPP Type components and definitions (1/2)

There are different types of DER aggregations, or Virtual Power Plants (VPPs), that can be designed in different ways and provide different values (or "grid services") to the system

VPP Type = **combination** of i) grid services, ii) technologies and iii) business model(s)

i) Grid services - *benefits and services that dispatchable DERs can provide to help grid operators manage the grid reliably*

1. **PJM Capacity**: Support the regional PJM grid by providing additional regional capacity (kW) to lower wholesale capacity costs.
2. **PJM Energy:** Provide energy (kWh) to the PJM market to mitigate volatile energy price spikes
3. **PJM Ancillary Services**: Provide services like voltage regulation to the PJM market to mitigate wholesale energy balancing costs
4. **Transmission Capacity:** Provide additional capacity and services that ease transmission bottlenecks.
5. **System Distribution Capacity**: Support local Virginia utility grids by providing additional capacity on the distribution system
6. **Distribution NWAs/Non-Wires Alternatives:** Defer local distribution infrastructure capital expenditure
7. **Hosting Capacity**: Increase local hosting capacity on constrained circuits to enable more distributed generation interconnection.
8. **System Resilience:** Protect communities from outages.
9. **GHG Reduction**: Reduce emissions and pollutants.
10. **Contracted Capacity:** Large load customers pay to add VPPs/DERs

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Reminder: VPP Type components and definitions (2/2)

ii) DER technologies - *Types of distributed energy resources included as focus areas for VPPs analysis*

- **Residential BTM storage:** Behind-the-meter battery storage at homes, can be paired with solar.
- **C&I BTM distributed storage:** Behind-the-meter battery storage at commercial and industrial sites, can be paired with solar.
- **FTM distributed storage:** Front-of-the-meter battery storage connected on the utility side of the meter, can be paired with solar.
- **EV managed charging**: Controlled EV charging that shifts load to lower-cost or lower-stress grid hours.
- **EV V2G**: Electric vehicles that can send stored power back to the grid or a building.
- **On-site automated load control**: Automated control of equipment at a site to reduce or shift electricity use when needed.

Notes on technology scope:

- Focus of this VPP Type analysis is on **dispatchable DERs**—DERs that can be controlled when called on to provide a specific grid service—which includes solar+storage but not standalone solar. Standalone solar is not dispatchable unless paired with storage.
- Traditional demand response is not included as a priority areas because the market rules and process are already well established.

iii) Business models - *Ways DERs can be organized to provide grid services.*

- **Utility program:** Individual DERs provide services directly to a utility; simple customer entry point.
- **Utility-controlled DERs:** DERs owned or directly controlled by utilities to support reliability and grid operations.
- **Third-party aggregator (retail):** A third party combines many DERs to provide retail-facing energy services.
- **Wholesale market participant:** Aggregated DERs participate in ISO/RTO markets such as PJM as a single resource.

Homework #1 Outcomes: Top Priority VPP Type components

VPP Type = **combination** of grid services, technologies and business model(s)

Grid Services

- PJM Capacity
  - Not PJM Energy or Ancillary services
- Distribution Capacity
  - Non-wires alternatives to defer distribution upgrade costs was a close 2nd
- Contracted Capacity *(e.g., data center-funded VPPs)*

Technologies

- Tier 1: BTM Storage
- Tier 2:
  - FTM distributed storage
  - EV – managed charging, V1G
  - Automated load controls
- Tier 3:
  - EV – V2G
  - Traditional DR

Business Models

- PJM Wholesale Market – required but only for prioritized PJM capacity market
- Utility Program – easiest to implement in vertically integrated system
- 3rd party aggregator – important but longer to implement in Virginia
- Utility Control – lower priority

VPP = Virtual Power Plant, BTM = Behind-the-meter, FTM = Front-of-the-meter, V1G = unidirectional, charging (EV charging time/speed controlled), V2G = Vehicle-to-Grid (EV provides power back to grid)

Homework #1 Outcomes: Top VPP Types for Virginia

Specifying all three attributes of the VPP Type informs priority "policy topics"

(Policy topic = the individual policies, regulations, and program rules that regulators, utilities, and operators must establish for the VPP to work, e.g., interconnection rules, data access rules, etc.)

Top 3 VPP Types

- **PJM Capacity:** *Order 2222 VPPs bidding and exporting BTM storage in PJM capacity market*
  - Policy topics example: Need exporting storage interconnection rules, but not ancillary services telemetry requirements
- **Peak Shaving Utility Program:** *Peak shaving VPPs, with BTM storage, FTM distribution storage, managed EVs and automated load controls participating in utility programs*
  - Easier to extend existing demand response program constructs to other DERs
- **Data center-demand flexibility contract:** C) *Data center - VPP contracts to use demand flexibility within utility programs*
  - Data center funds utility program rather than contracting with VPP directly

***Discussion**:* Any feedback on these outcomes? Are we aligned on focusing on the specific enabling "policy topics" that are necessary to unlocking these VPP Types in Virginia?

Homework #1 Outcomes: Second Tier VPP Types

Valuable and important, just not top priority initially (can expand into these over time)

Sample of VPP Types to be considered next

- "Distributed Capacity Procurement of FTM storage for transmission capacity services"
  - Policy topic examples: Utility ownership of storage; EDC-PJM communications
- "*Local Non-wires Alternatives with 3rd party aggregators of solar+storage*"
  - Policy topics examples: Distribution Planning/Reliability value; 3rd party customer data access
- "*Data center – VPP contracts directly with 3rd party aggregator of storage and automated load controls*"
  - May require rules for data center – VPP operational coordination

DER challenges and opportunities identified by the Task Force

Challenges

While members highlighted diverse challenges, several common themes were surfaced in homework responses.

Challenges Facing DER deployment and Adoption: Identified Themes (1/2)

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Education & Feedback Channels

- Stakeholders across the power sector would benefit from **education on what DERs and VPPs are** to support informed investment decisions.
- **Awareness in Virginia remains limited;** implementers and local government decision-makers **do not yet have the expertise** to fully understand how these resources connect to their responsibilities.

Data Access & Transparency

- **Limited access to comprehensive customer and smart meter data is a major constraint on operationalizing DERs**, particularly for aggregators that need secure data access to understand market potential; **Green Button**'s data access model referenced as a useful tool.
- Need for greater transparency around **distribution infrastructure costs** to inform fair cost allocation.

Compensation, Incentives, & Valuation

- Current **compensation structures do not fully value DER capabilities**; for example, net metering rules limit payment for dispatchable DERs, and the ability to stack services for both local utilities and PJM market is limited.
- Service upgrade costs for DER owners can slow adoption, while utility valuations of DER benefits **understate the value these assets provide to local distribution systems**.

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Challenges Facing DER deployment and Adoption: Identified Themes (2/2)

Permitting & Coordination

- Permitting is a significant barrier to DER deployment **due to costly delays**; recommendation to consider **streamlined processes such as SolarAPP+**.
- Coordinating permitting alongside policy, market design, public concerns, workforce capacity, infrastructure, and cost is a major challenge. This reflects feedback to **move from a fragmented approach to systems approach** to address barriers comprehensively.

Regulatory Reform & Planning

- DERs are being **constrained by program caps** and because **DERs are not fully integrated into utility distribution planning and operations**, leaving potential value unrealized.
- **A clearer roadmap** with defined roles, responsibilities, deadlines, and success measures is needed.
- Utility **incentive structure may need to be updated** so that generation and transmission investments are not favored over third-party or customer-owned DERs.

Other Notable Challenges

- Safety and Security
- Aging infrastructure
- Equity
- Climate Change
- Workforce

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Challenges Facing DER deployment and Adoption: Illustrative Feedback

Education & Feedback Channels

"We are still a long way from widespread understanding of DERs in Virginia, let alone widespread acceptance."

Data Access & Transparency

"Aggregators need to have some level of secured customer data from smart meters to understand the full potential within Virginia's market."

Compensation, Incentives, & Valuation

"Net metering pays for energy. Disqualifying sites with net metering (because they have solar) that also have dispatchable sources of supply (demand response or batteries) from being able to provide and be paid for the full value of capacity from their dispatchable assets [is a challenge]."

Permitting & Coordination

"The greatest challenge is coordinating between policies, markets, public concerns, workforce, permitting, infrastructure, and costs."

Regulatory Reform & Planning

"Utility cost-of-service regulation incentivizes investments in generation and transmission and disincentivizes investment in third party/customer-owned DERs."

Opportunities for Virginia to Deploy DERs: Identified Themes (1/2)

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Education & Feedback Channels

- Educational tools like **case studies, public opinion surveys**, and **focus groups** can be leveraged to understand gaps and build public awareness of market benefits.

Tools & Technologies

- **Consider prioritizing larger scale commercial VPPs** (e.g., commercial & public buildings, parking lots) to capture economies of scale.
- Use a DER mapping tool such as [NLR's] dGen to **analyze where DERs are both quickest to build and most likely to be built**, helping better target resources to facilitate rapid deployment.
- Explore **extending the useful life of EV batteries** by repurposing them for BTM storage.

Compensation, Incentives, & Valuation

- Build on precedents from other states, **adjusting utility and customer incentives** through programs and regulatory changes to drive DER adoption.
- Ideas include **large load capacity procurement requirements**, a **winter demand response** program, and **expanding agricultural net metering** from 500 kW to 3 MW**.**

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Opportunities for Virginia to Deploy DERs: Identified Themes (2/2)

Programs

- Provide **state level insurance, procurement, and legal technical support** for solar PPAs for local governments and school boards.
- Include DERs and other VPP programming in **utility data center flexibility tariffs**.
- Develop **equitable programs for residents and small businesses** that lead to broad adoption of a variety of DERs (e.g., time of use, demand response, solar + battery, EV V2G, etc.).

Policy & Legislation

- **Identify and amend DER restrictive policies** at the state, county, and municipal levels, such as:
  - Using HB 434 / SB 621 as an opportunity to **provide distribution metrics** that evaluate DERs to avoid or defer distribution system upgrades.
  - Changing state legislation that **currently prohibits local utilities from exploring new technologies and renewables**.
  - Streamlining DER interconnection
  - **Removing solar from the 5-year lease limitations** of the Municipal Lease Act, which prevents cities from implementing PPAs at a higher rate.
  - **Loosen restrictions on city charters** which limit expansion of city energy portfolios.

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Opportunities for Virginia to Deploy DERs: Illustrative Feedback

Compensation, Incentives, & Valuation

“Create large load tariffs that require data centers to procure capacity from DERs to compensate for the grid constraints they will cause [...]. Create a mechanism for them to fund distribution services via a program or new marketplace.”

Education & Feedback Channels

“Clearly educate with specificity and good communication/story telling about how other markets are beginning to see clear wins in DER and VPP implementation, such that various players can see themselves operating in that framework.”

Programs

“Create a Winter demand response program in Dominion that can become a home for megawatts that are stranded by the PJM structure”

Policy & Legislation

“Richmond’s public utility is limited in expanding its energy portfolio because only the VA General Assembly has the authority to change a locality’s charter.”

Tools & Technologies

“dGen integrates hosting capacity analysis with variables such as demographics to analyze where DERs are both quickest to build and most likely to be built. This type of analysis can better help us understand where to target resources to rapidly deploy DERs.”

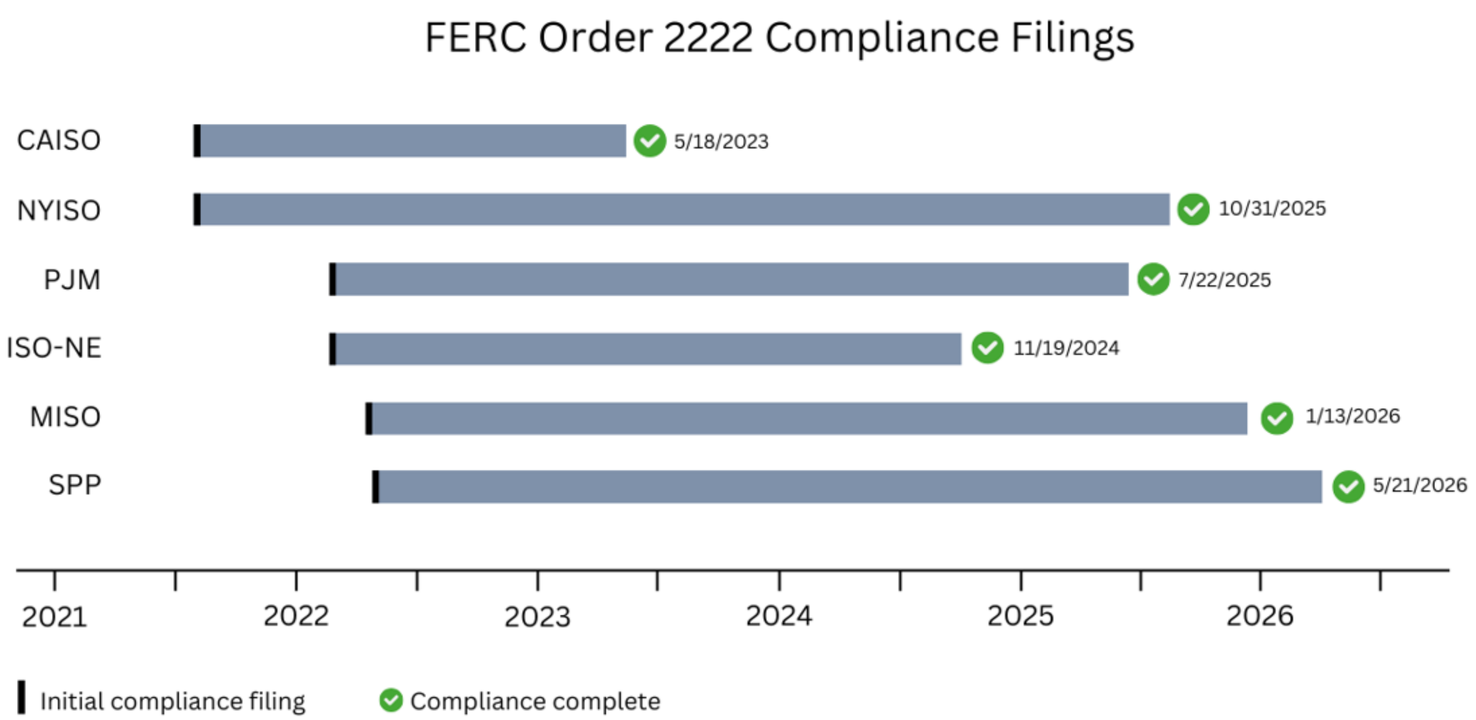
FERC Order 2222 Primer & Implications for Virginia

David Kathan

FERC Order 2222 Overview & Rationale

- **What Order 2222 is (Issued Sept 2020):** Federal mandate requiring RTOs (like PJM) to allow aggregated DERs to compete directly in wholesale power markets.
- **Rationale:** FERC found that existing RTO/ISO market rules are unjust and unreasonable in light of barriers that they present to the participation of DER aggregations in the RTO/ISO markets.
  - Such barriers can emerge when the rules governing participation in those markets are designed for traditional resources and in effect limit the services that emerging technologies can provide.
  - For example, DERs tend to be too small to meet the minimum size requirements to participate in the RTO/ISO markets on a stand-alone basis, and may be unable to meet certain qualification and performance requirements.
  - Existing participation models for aggregated resources, including DERs, often require those resources to participate in the RTO/ISO markets as demand response, which limits their operations and the services that they are eligible to provide (e.g., capacity, energy, ancillary services)
  - By removing barriers to the participation of DER aggregations in the RTO/ISO markets, FERC found that Order No. 2222 enhances competition and, in turn, helps to ensure that the RTO/ISO markets produce just and reasonable rates.
- **Timeline:** FERC approved PJM's FERC Order 2222 compliance in July 2025, and PJM will implement the order in February 2028

Status of 2222 Compliance across RTOs/ISOs



- All RTO/ISOs compliance filings have been approved by FERC
- Full FERC RTO/ISO approval took multiple filings, with FERC directing specific changes
  - PJM submitted three compliance filings

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Implementation of 2222 across RTOs/ISOs

RTO/ISO	Order 2222 Implementation Date
CAISO	November 1, 2024
NYISO	End of 2026
ISO-NE	**Energy & Ancillary Services:** November 1, 2026 **Capacity:** In place for Forward Capacity Auction 19
MISO	**Phase 1:** June 1, 2027 **Phase 2:** June 1, 2029
PJM	**Capacity:** February 1, 2027 (for 2028/29 Delivery Year) **Energy & Ancillary Services:** February 1, 2028
SPP	**Second Quarter 2030**

- Implementation date for the RTOs/ISOs varies
- CAISO implemented first in November 2024
- ISO-NE and NYISO will implement later this year
- PJM's full implementation will occur in February 2028

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PJM's Order 2222 Requirements (1/4)

- PJM has adopted market rules and requirements in response to FERC Order 2222
- Some of these rules (*see below*) are fairly restrictive and may need to be adjusted by PJM in the future to maximize DER participation
- Most are fairly standard and compliant and some are tailored specifically to PJM's unique market design *(see following slides)*

Most Restrictive PJM Requirements

Provision	RTO/ISO Requirements under Order 2222	PJM Market Rule
Locational Rules	Must set geographic boundaries for aggregations	**Restrictive, Varies by Market:** Single-node (PNode) for Energy; multi-node at state/EDC level for Ancillary; multi-node at zonal/sub-zonal delivery areas for Capacity
Metering & Settlement	Must set measurement rules without creating cost barriers	**Restrictive:** Revenue-level metering required for all component DERs at least an hourly level, and must be submitted within one business day
Dual Participation	DERs are able to participate simultaneously in retail/wholesale markets, but must not receive double compensation for providing the same service.	**Restrictive:** Single DER cannot be registered with multiple DER Aggregators or provide wholesale market services to PJM via more than one market model; NEM resources cannot provide energy to PJM, but can provide ancillary services
EDC Review	Must establish process for 60-day EDC review of DER participation	**Two-Level 60-Day EDC Review:** EDCs must assess capability of DERs to participate within 15 days, followed by 45-day reliability and safety review before PJM registration

DERA = DER Aggregator; EDC = Electric Distribution Company (i.e., utilities)

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PJM’s Order 2222 Requirements (2/4)

Detailed, PJM-Specific Requirements

Provision	RTO/ISO Requirements under Order 2222	PJM Market Rule
Dispatch Override	EDCs retain the ability to override an RTO/ISO dispatch instruction due to safety and reliability concerns; EDCs not liable for DERA performance penalties	**Detailed:** Developed detailed rules governing how dispatch overrides are coordinated, particularly during the operating day
Dispute Resolution	Include dispute resolution provisions as part of RTO/ISO implementation of the Order, and for the distribution utility review process.	**Dual PJM/State Role**: Disputes related to the PJM tariff resolved with PJM dispute resolution procedures, and disputes about EDC-specific issues resolved at the state-level. Disputes about EDC review can be taken to both PJM and states.
Telemetry	Must set measurement rules without creating cost barriers	**Varies by Market:** Telemetry required at the DERA level, but supportive data expected to be available at DER level; telemetry requirements vary by market, e.g., capacity market requires 1 minute, and regulation market requires 10 seconds
Utility Coordination	Must establish a framework for RTO, utility (EDC), and state (SCC) coordination	**Detailed:** PJM created structure for coordination between DERAs and PJM, and EDCs and PJM, especially during the operating day. States need to set DERA/EDC coordination framework.

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PJM's Order 2222 Requirements (3/4)

Standard & Compliant PJM Requirements

Provision	RTO/ISO Requirements under Order 2222	PJM Market Rule
Market Access	Must establish direct access for DER Aggregators (DERAs) as a distinct market participant	**Fully Compliant:** DERAs recognized in tariff; can bid in Capacity, Energy, & Ancillary markets
Participation Models	Must accommodate diverse asset mixes (solar, storage, EVs, demand response)	**Fully Compliant:** Supports heterogeneous VPPs
Minimum/Maximum Size	Max threshold of 100 kW minimum aggregation size	**Fully Compliant**: Sets minimum DERA size at 100 kW across all markets; no minimum size for individual assets , but sets maximum DER size as 5 MW; no limit on total aggregation size
Distribution Factors	Must mandate bidding parameters & location weighting	**Fully Compliant:** DERA must submit nodal weighting factors & standard operational dispatch parameters

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PJM’s Order 2222 Requirements (4/4)

<u>Standard & Compliant PJM Requirements (cont.)</u>

Provision	RTO/ISO Requirements under Order 2222	PJM Market Rule
Data & Registration	Must define required registration and asset-level data	**Fully Compliant:** DERA must register locations, ratings, and asset constraints before bidding . PJM still working on registration tool.
Interconnection	DERs must have completed interconnection agreements with EDCs	**Fully Compliant:** Valid State Interconnection Agreement will be needed for each underlying DER
Asset Modifications	Must establish a clear process for adding, removing, or replacing DER assets	**Streamlined:** Modifications trigger shortened EDC review before updated capacity clears
Participant Agreement	Must develop standardized participation contract for aggregators	**Standardized:** Tariff updated with binding DERA agreement on dispatch & penalties

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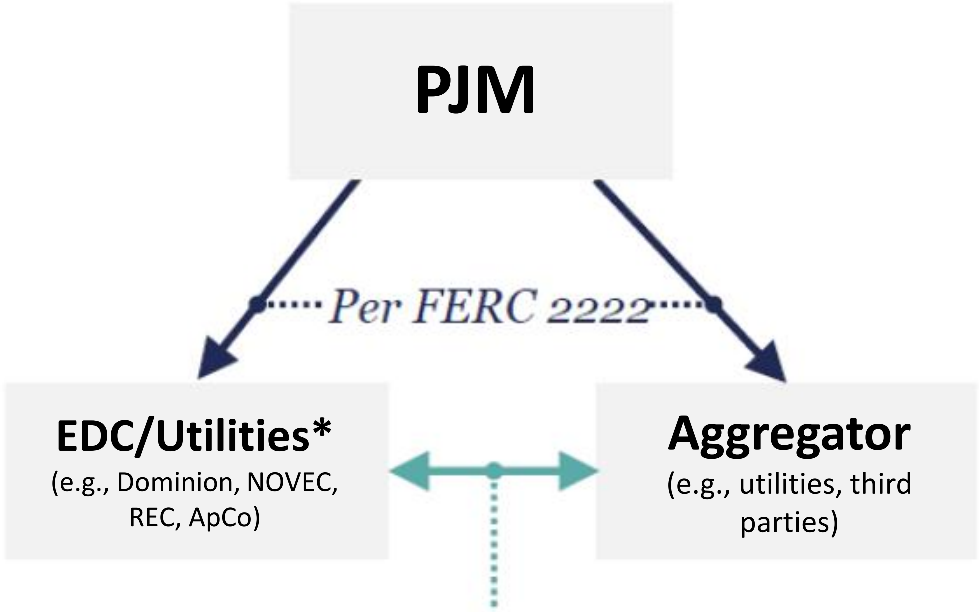
State/Federal Jurisdiction: Implications for Virginia



Rules between Utilities and Aggregators are determined by SCC/EDCs

**EDC = Electric Distribution Company; for simplicity, term "utilities" is used in this context to refer to EDCs. But not all utilities are EDCs – e.g., municipal & public power companies in VA are not EDCs.*

- **FERC has jurisdiction over PJM's wholesale markets**
  - Order 2222 requires changes to PJM tariffs and procedures to allow DER Aggregator participation
  - DER Aggregators are a wholesale market participant and guided by FERC rules
- **The SCC and EDCs (utilities) maintain jurisdiction over DER aggregations at the local retail grid level**
  - DER Review is the primary requirement placed on EDCs (utilities)
  - FERC explicitly leaves several DER aggregation rules to the SCC (e.g., interconnection, customer data access) *– will discuss these requirements in "current state" section later*

Key takeaway: Virginia policies and regulations plays an important role in enabling DER aggregations to participate in PJM wholesale markets under FERC Order 2222

Key takeaways

- **Without enabling rules at the state level, DER aggregators face many barriers to participate in PJM markets**
  - Consequently, DER aggregators will likely wait to participate in PJM markets until (a) PJM finalizes many of the system and manual changes that are upcoming, and (b) states implement supportive Order 2222 policies and regulations
  - In the meantime, given lack of supportive state policy, DER aggregations are choosing to do traditional demand response instead of bidding into PJM capacity auctions (as was seen in July 2026 PJM auction where DERs were allowed to participate for the first time and did not bid in)

- **Implication for Virginia:** Virginia (SCC, utilities) must establish supportive policies and programs in order to unlock one of Virginia's priority VPP types and to enable DERs to participate in PJM effectively under Order 2222 (providing services beyond traditional demand response)
  - *Additional discussion on which rules needs to be established to follow in the "Current State" section*

- *Note: Some of PJM's current rules still may present some challenges to full DER participation, but are outside of state control and will need to be addressed by PJM*

Policy Review – DER Interconnection Procedures

20VAC5-314 and 20VAC5-315

Vaughan Woodruff, Principal
EquinoxDG

August 4, 2026

Effective DER Interconnection Procedures Enable Markets

- DER interconnection procedures do not drive markets; they enable them
- States have broad authority over DER interconnection regulation and often underestimate the impact of interconnection on program delivery and success
- Effective interconnection procedures:
  - clarify party accountabilities in manner consistent with the public interest,
  - minimize the need for detailed engineering studies to assess the impacts of smaller energy generation and storage facilities, and
  - support effective regulatory enforcement
- The development of early model interconnection procedures were spurred by:
  - Public Utility Regulatory Policies Act (PURPA), which required utilities to buy power from qualifying small power production facilities and cogeneration facilities, and
  - introduction of net energy metering programs to simplify metering and participation for small generators

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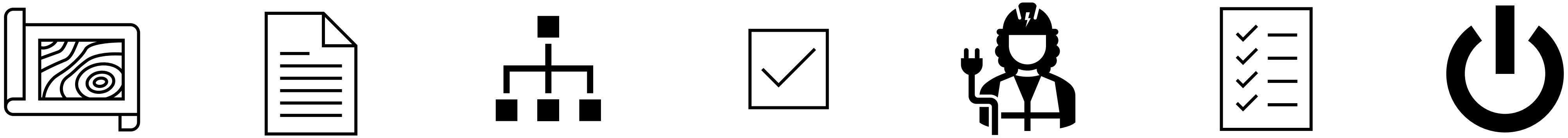
DER Interconnection Process



	Project Siting	Application	Utility Review	Utility Approval	Construction	Inspection	Permission to Operate
UTILITY	Siting tools; pre-application reports	Standard forms; application portal	Implementation of standard procedures	Provide Interconnection Agreement	Build upgrades (if required)	Verify operation	Provide notification and meter
CUSTOMER	Develop appropriate design	Provide design and project details	Track progress to defined timelines	Execute Interconnection Agreement	Build facility	Commission facility and verify code compliance	Ensure operation complies with IA

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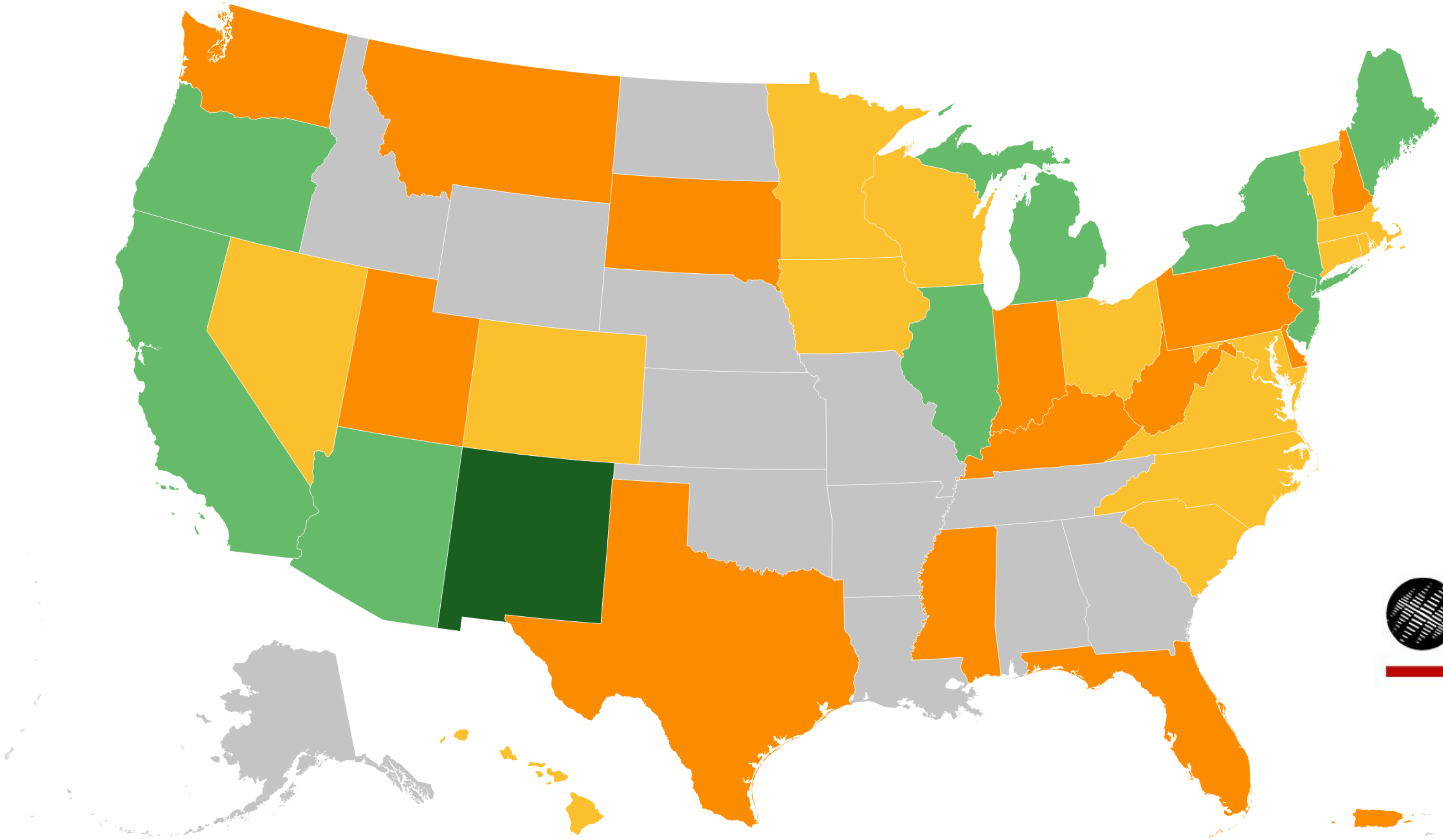
A Brief History of DER Interconnection Procedures

- In 2005, the U.S. Energy Act encouraged states to open proceedings to adopt interconnection procedures and to use model interconnection procedures from NARUC as a basis
- Today, 37 states have formal interconnection procedures; ~ 2/3 of those were established in 2005 or later
- In states where formal interconnection procedures have not been adopted, interconnection of DERs is left to the discretion of the utility
- The effectiveness of interconnection procedures typically depends upon having both a strong set of regulations, ongoing improvement as technologies evolve, and enforcement of existing regulations
- The strength of interconnection procedures is highly variable across the U.S.

Freeing the Grid Scores (2026)



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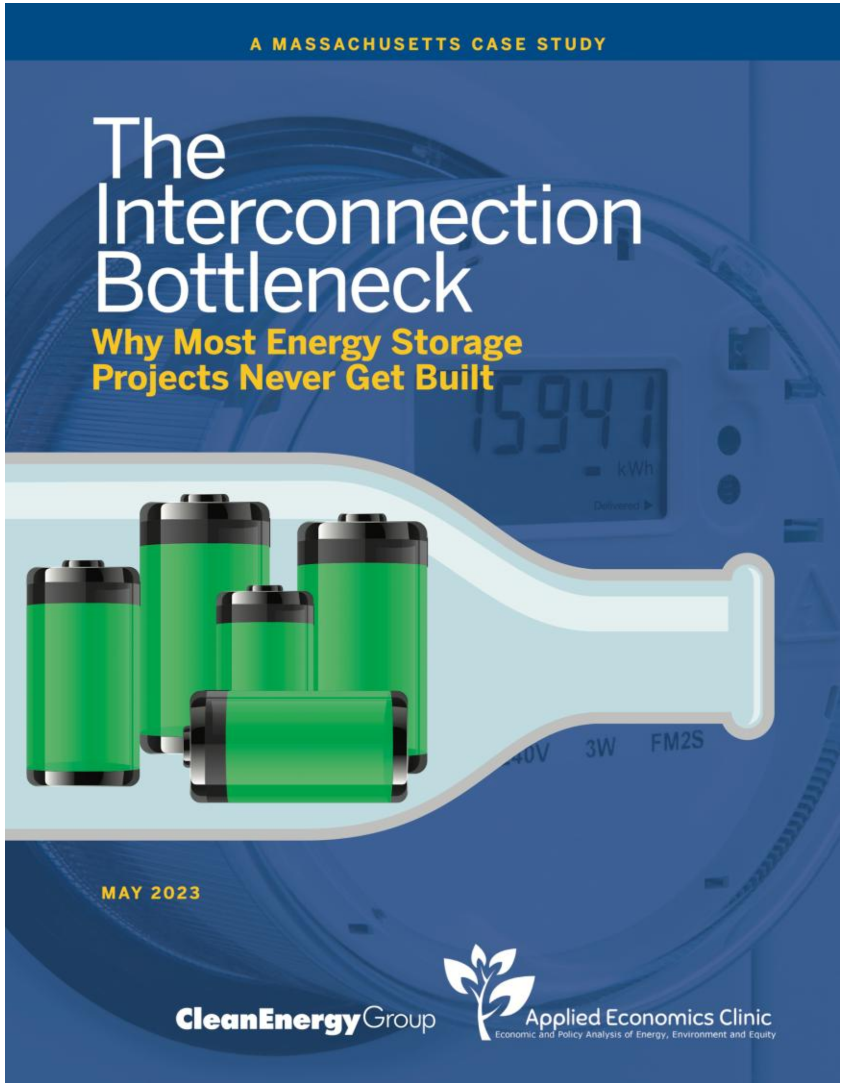
CASE STUDY: DELAWARE

- Delaware adopted interconnection standards in 2011 that were largely based on model interconnection procedures established in 2005
- State law required the development of interconnection standards in alignment with national best practices
- In 2021, legislation was passed to introduce a community solar program to serve customers of the state's investor-owned utility (Delmarva) and included a requirement to serve low income customers
- Delmarva began accepting interconnection applications in November 2021
- By 2024, more than 200 applications were submitted for projects with a capacity of 4 MW or less
- In September 2024, zero projects were online and the Delaware PSC opened a proceeding
- By the end of 2025, only one 4MW project was in operation
- The PSC could not hold Delmarva accountable because the state's interconnection standards did not require the utility to meet timelines for MW-scale projects

Pre-read only

CASE STUDY: MASSACHUSETTS

- Utilities initiated a demonstration period for the use of energy storage as part of their energy efficiency plans in 2016
- Demand increased and a formal program was launched in 2019
- By 2019, significant concerns arose regarding National Grid's interconnection practices and the DPU ordered a managerial audit that confirmed the utility's mismanagement
- After nearly 7 years of efforts by a working group, the state's interconnection procedures related to energy storage have not been adequately updated
- Energy storage interconnection issues persist



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Pre-read only

Code of Virginia – DER Interconnection

§ 56-578. Nondiscriminatory access to transmission and distribution system.

C. The Commission shall establish interconnection standards to ensure transmission and distribution safety and reliability, which standards shall not be inconsistent with nationally recognized standards acceptable to the Commission. In adopting standards pursuant to this subsection, the Commission shall seek to prevent barriers to new technology and shall not make compliance unduly burdensome and expensive. The Commission shall determine questions about the ability of specific equipment to meet interconnection standards."

Established by Virginia Electric Utility Restructuring Act, March 25, 1999

A Brief History of DER Interconnection Procedures in Virginia

- Virginia's original interconnection procedures were adopted in 2000 as part of Chapter 315 (net metering)
- The interconnection-related provisions in Chapter 315 have not fundamentally changed since 2000
- Chapter 314 was established in 2009; it is based on FERC's SGIPs
- The scope of Chapter 314 (20VAC5-314-10) explicitly excludes "customer generators operating pursuant to the Virginia State Corporation Commission's Regulations Governing Net Energy Metering"
- As a result, the interconnection requirements of Chapter 315 apply to DERs that participate in NEM and the requirements of Chapter 314 apply to those that do not
- As a result, the utilities have general discretion over the interconnection procedures for DERs that participate in NEM due to limited interconnection provisions in Chapter 315

Virginia's Interconnection Regulations

Chapter 314

Shared solar

FTM distributed storage

Chapter 315

Residential BTM solar

Residential BTM storage

C&I BTM solar

C&I BTM storage (NEM)

High-Level Assessment of Chapter 315 vs. Best Practices

Lagging

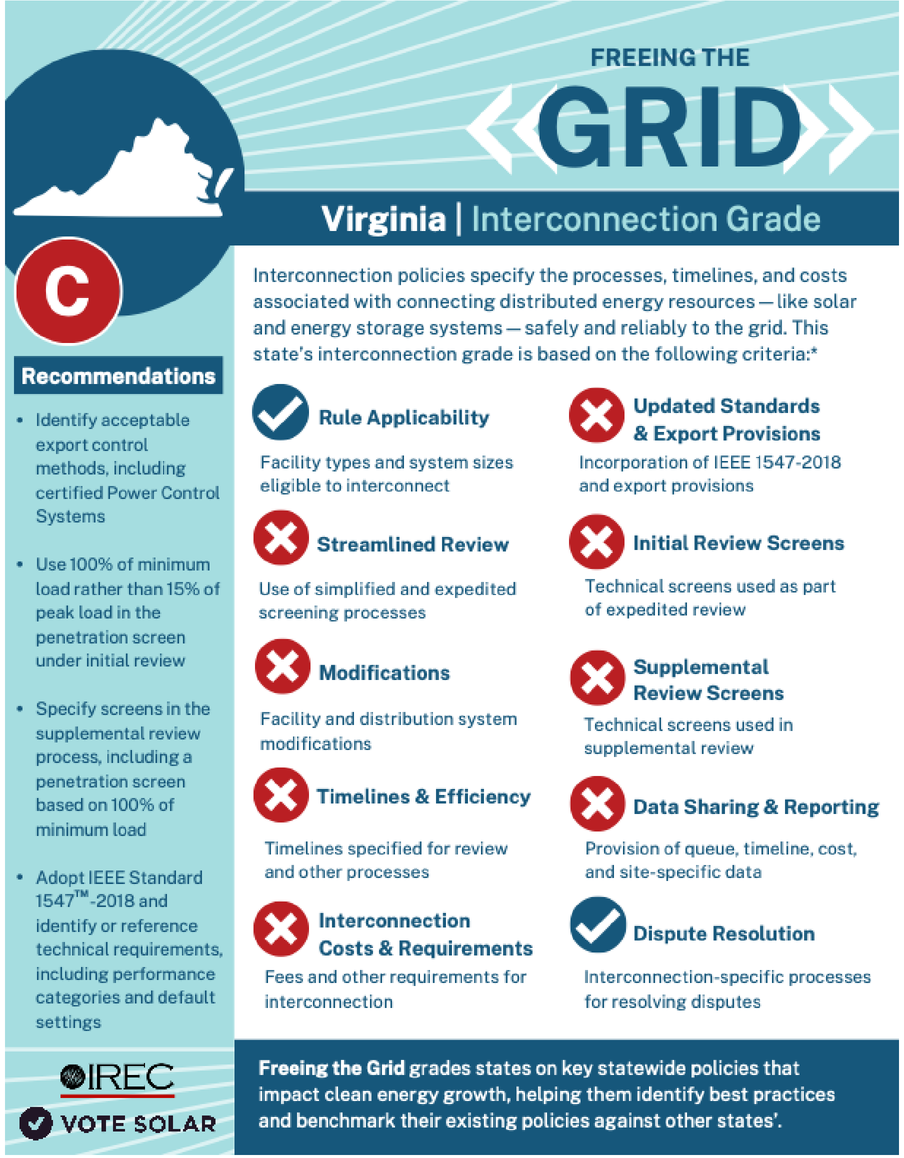
Aligned

Innovative

Unit cost guide

Cost sharing

High-Level Assessment of Chapter 314 vs. Best Practices



FREEING THE GRID

Virginia | Interconnection Grade

C

Interconnection policies specify the processes, timelines, and costs associated with connecting distributed energy resources — like solar and energy storage systems — safely and reliably to the grid. This state's interconnection grade is based on the following criteria:*

Recommendations

- Identify acceptable export control methods, including certified Power Control Systems
- Use 100% of minimum load rather than 15% of peak load in the penetration screen under initial review
- Specify screens in the supplemental review process, including a penetration screen based on 100% of minimum load
- Adopt IEEE Standard 1547™-2018 and identify or reference technical requirements, including performance categories and default settings

Rule Applicability
Facility types and system sizes eligible to interconnect

Updated Standards & Export Provisions
Incorporation of IEEE 1547-2018 and export provisions

Streamlined Review
Use of simplified and expedited screening processes

Initial Review Screens
Technical screens used as part of expedited review

Modifications
Facility and distribution system modifications

Supplemental Review Screens
Technical screens used in supplemental review

Timelines & Efficiency
Timelines specified for review and other processes

Data Sharing & Reporting
Provision of queue, timeline, cost, and site-specific data

Interconnection Costs & Requirements
Fees and other requirements for interconnection

Dispute Resolution
Interconnection-specific processes for resolving disputes

IREC

VOTE SOLAR

Freeing the Grid grades states on key statewide policies that impact clean energy growth, helping them identify best practices and benchmark their existing policies against other states'.

Innovative

Affected systems

Cybersecurity

equinoxDG

High-Level Assessment of Virginia's DER Interconnection Procedures as a Market Enabler

- Virginia is unique in having two separate sets of administrative rules for DER interconnection
- Virginia's Freeing the Grid (FTG) grade of a "C" for its interconnection rules is based on Chapter 314
    - Chapter 314 lacks the specificity needed to streamline interconnection for behind-the-meter DERs that do not participate in NEM and elect to participate in a VPP program
    - Recent changes to Chapter 314 (PUR-2023-00069) don't meaningfully impact FTG assessment
- If Chapter 315 alone was scored in Freeing the Grid, it would receive a "D" due to its lack of clear utility requirements to streamline review, define screening criteria, set timelines, clarify costs, and ensure predictable treatment of energy storage systems
- As a result, there are ample opportunities to improve Virginia's interconnection rules to reduce barriers for interconnecting DERs, generally, and for VPP participation, specifically

Key Takeaways from DSA White Paper for Task Force Consideration

Tony Smith

VIRGINIA DER TASK FORCE | JULY 2026

From Fragmented Policy to Integrated System Design

A systems framework for a fully utilized distributed grid — barriers, proven precedents, and the BIRDS principles that tie them together.

Prepared by the Virginia Distributed Solar Alliance (VA-DSA)

for the Virginia Distributed Energy Resources (DER) Task Force, established under HB 285

EXECUTIVE SUMMARY

Six Barriers, Six Proven Precedents

"Adopt, Don't Pilot": every barrier to a fully utilized distributed grid is paired with an operating model already demonstrated elsewhere.

Barrier	Adopt: Proven Precedent
1. Incentives (utility, customer, schools)	Enhanced ROE / PBR for utility grid-utilization metrics; NY-Sun declining-block model; VA Solar Schools & Communities (VSSC) program
2. Interconnection	New York's Standardized Interconnection Requirements; Delaware's HB 269 (IREC-based)
3. Commercial Rooftop Permitting	VEBC amendment proposed to DHCD to streamline permitting and reduce cost
4. Grid Integration / VPPs	Amend HB 895 for non-utility VPP aggregation; Maryland PSC's "Green Button" third-party directory
5. Workforce Development	Reinstate DOLI student solar apprenticeships (ages 16-18); fund community college training
6. Public Awareness & Engagement	Model solar PPA via VEPGA/VACO; statewide VA-DSA voter survey

SECTION 2.4

State DER Program Comparison

NY-Sun, Illinois Shines, and SMART show commercial-scale DER incentives are a proven operating category, not a novel undertaking.

Dimension	NY-Sun (New York)	Illinois Shines	SMART (Massachusetts)
Administering agency	NYSERDA; PSC oversight	Illinois Power Agency; ICC oversight	DOER; DPU tariff approval
Incentive structure	MW Block, declining, + Value Stack (VDER)	Utilities purchase RECs; prices decline as blocks fill	Fixed performance-based $/kWh, on top of net metering
Program capacity goal	10 GW distributed solar by 2030	Sized for 100% clean electricity by 2050	3,200 MW statewide solar target
Community solar	Major pillar — renters, schools, nonprofits	Core category with subscriber protections	Dedicated low-income shared-solar carve-out
Storage emphasis	Value Stack compensates storage + location	Minimal; handled separately	Strong dedicated storage adders
Low-income / equity	Income-qualified carve-outs	Equity Eligible Contractor provisions	Low-income adder, ~2x base rate
VPP readiness (mid-2026)	NYISO DER model live; FERC 2222 compliance due Dec. 2026	Clean & Reliable Grid Act requires utility VPPs; ICC program live	ConnectedSolutions pays ~$225/kW summer discharge

BIRDS: Five Principles for One Coherent System

A shared vocabulary for why the technical recommendations in this paper function as one system, not a list of separate fixes.

	PRINCIPLE	CORE QUESTION	VIRGINIA APPLICATION
B	**Balance**	*Dominion's capital plan: $824M. Its non-wires pilot: $50M. Same incentive for efficiency?*	Enhanced ROE for utilization, with automatic step-down once targets are met.
I	**Interdependence**	*Dominion: DTT above 250 kW. APCo: telemetry above 200 kW. No shared rule between them.*	Adopt NY's shared statewide standard — already used across multiple NY utilities.
R	**Regeneration**	*A battery's grid value: ~$800/MWh. PJM emergency power: $1,300+/MWh. Same net-metering rate either way?*	Layer NY's Value Stack (VDER) on net metering for larger projects.
D	**Diversity**	*One barrier, four use cases: homes, schools, hyperscalers, school buses. One pathway enough?*	Design VPP rules wide enough for VSSC, community solar, and hyperscaler models alike.
S	**Succession**	*Federal solar tax credits expire Dec. 2027 — built to outlast that, or not?*	NY-Sun's declining-block model: subsidy shrinks as adoption grows, no permanent dependency.

WHY VIRGINIA CAN LEAD

One System, Not a List of Fixes

- Every barrier in this paper — incentives, interconnection, permitting, VPP integration, workforce, public awareness — is paired with a precedent already operating at scale elsewhere: Adopt, Don't Pilot.
- BIRDS gives the Task Force a shared vocabulary — Balance, Interdependence, Regeneration, Diversity, Succession — for why these recommendations reinforce rather than compete with one another.
- These recommendations hold regardless of the Dominion-NextEra merger outcome, load-growth pace, or Order 2222 implementation timeline: they are no-regret strategies.

Sep 15, 2026	Oct 13, 2026	Oct 2026	2027
Interim Report	Final Report	Governor's Energy Plan	General Assembly Session

Path forward

Look ahead

Today

Mtg 1 (Jul 16)
Context setting, VPP types, early input on priorities

Mtg 2 (Aug 4)
Vision & priorities, current state of policies in VA, DER compensation models

Mtg 3 (Sept 15)
Review interim report findings, recs, & case studies, identify gaps to close

Mtg 4 (Oct 13)
Review Final Report, align on recommendations & path forward

Nov 1
Submit Report

	Phase 1: July 16 – Aug 4	Phase 2: Aug 4 – Sept 15	Phase 3: Sept 15 – Oct 13	Phase 4: Oct 13–Nov 1
Key Deliverable	• *Baselining research; participative report*	• *Draft Interim Report*	• *Draft Final Report*	• *Final Reviews*
Core Research & Analysis	• Prioritize VPP types • Identify minimum PRL requirement needed • Assess current state of Virginia across key policy dimensions • Refine research on current DER market state & barriers	• Refine assessment of current state of DERs and policies in VA • Draft VPP Regulatory Roadmap based on current vs. target state • Assess FERC 2222 compliance • Draft policy, regulatory, implementation recommendations	• Finalize & update research, regulatory roadmap, and recommendations • Address any outstanding research questions	• Final report adjustments, formatting & clean-ups • Final Admin reviews
Stakeholder Engagement	• Meeting with SCC staff • Meeting utility staff • *Ad hoc engagement*	• Public stakeholder listening session & soliciting written stakeholder input • 1-2 industry listening sessions • Engage with other VA Working Groups (EE/Weatherization, Balcony Solar)	• Public stakeholder listening session & solicit input • Meet with SCC staff • Meet with utility staff	

Next Steps: TF Member Homework

Will be asked to provide input on:

- What recommendations would you propose for inclusion in the report to enhance DER deployment and cost-effective market integration in Virginia?
- Are there additional topics or experts/perspectives you would recommend be covered in the last two Task Force meetings?
- Any initial feedback on report outline? Are there specific areas you would like to engage on (via support drafting, researching, providing focused input)?

Before next meeting, you can expect:

- Staff will reach out to set up **1x1 touchpoint** after synthesizing responses to refine input for draft report before next meeting
- **Draft interim report materials** will be shared for review and input

Wrap Up

- **Next meeting: Tuesday, September 15th, 2-5pm**
- **Recap of today**
- **Key questions**
  - Any input on key topics or questions for staff to look into before next meeting?
  - Any specific areas you would like to further engage on ahead of next meeting?
  - Other feedback or input?