Clean Energy Parties Presentation: Distribution Value Issues and Concepts

NY PSC Value Stack Working Group Meeting

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SEIA Solar Energy Industries Association®

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Context for Clean Energy Parties' Presentation

- Parties and associated member companies have been engaged from the beginning of the VDER process.
- Submitted comments on the VDER Phase 1 Order and Phase 1 Implementation Order with respect to Distribution Value, as well as other related REV proceedings.
- Some of the CEP concerns with DRV and LSRV were flagged in comments and left for future decision by the Commission.

Outline of Presentation

- Considerations for DER Financing
- Core Principles for VDER Distribution Value
- Key Distribution Value Issues

Considerations for DER Financing

Why Does Financeability Matter?

- A regulatory structure that ignores the business reality facing DER developers, customers, and financiers will not achieve the desired policy outcome.

- With few exceptions, DER today are not being deployed in response to the DRV/LSRV signals. The current mechanism is not providing the desired market response.

- DER can help achieve New York's vision for a dynamic, high-DER-penetration REV future, but regulators must provide a long-term, stable, financeable signal for DERs in order to achieve this goal.

- **VDER is still totally unproven from a financing perspective**
  - We are aware of only one rumored deal to finance a community solar portfolio under VDER Phase 1—to our knowledge, no one else has yet managed to secure private financing for DERs under VDER.

Key Considerations for Financeability

- **Because of their longevity (30+ years), DER projects must typically be financed based on contracted revenues (e.g., PPAs) of 20-30 years (shorter for small DER, longer for larger systems)**
  - Note: the residential and small commercial space is different—financing is typically based on expected 5-10 year energy savings proposition for a homeowner
  - Energy storage financing is rapidly evolving, but financing is also based on cash flows over 10+ years

- **For community solar projects, financing is based on individual subscriber agreements with hundreds of customers per project, each of which has a different credit score and customer profile**

Project Development and Ownership Risk is High

- **Developers typically take on all risk during the development process**
  - Developers take on all the risk that nobody will buy or finance the project at the end of the lengthy, costly development process (although typically, projects are sold or financed before mechanical completion)
  - This includes significant regulatory and market risk—e.g., changes in law or regulation or deteriorating market conditions

- **Customer and investor returns are never guaranteed**
  - Unlike many utility investments, our customers and investors cannot socialize unexpected changes in revenues or costs among other utility customers.
  - If market or regulatory structures change after an investment is made, customers and investors typically bear all of the risk
  - Key risks include:
    - Federal, state, and local regulatory changes (e.g., changes to moratoriums, federal tax laws, import tariffs, or net metering)
    - Changing technology or market conditions (e.g., fracking boom, new pipelines or transmission, capacity additions, changing load)

- **Energy Storage poses additional risks**
  - Energy storage is even more difficult to finance than solar: The technology—both hardware and software—is newer than solar technology, and is evolving along with regulatory policy at the local, state, and federal levels.
  - For these reasons, investors and customers typically require more revenue certainty or higher hurdle rates for storage than for solar.

Competition is Fierce, and Customers Are Not Wonks

- **DERs compete directly with utility offerings and with alternative retail supply offerings**
  - Solar offerings tend to require longer-term commitments than either utility rates (no commitment) or alternative retail supply contracts (1-5 year typical commitments).
  - To succeed, DERs needs to be either 1) significantly less expensive or 2) significantly less risky (preferably both).
    - Most PPAs and CDG subscriber agreements must provide a discount relative to the customer's current cost of power.
    - This means that project owners and investors typically sell "value stack" credits at a discount to their face value (and therefore receive less than 100% of the "value stack" in project revenue).

- **Our customers are not energy regulatory wonks**
  - Energy is a small part of most customers' typical expenses; customers devote an (appropriately) small amount of time to understanding utility rate structures and investment risks.
  - Difficult-to-quantify risks (such as a DRV value that could change dramatically every few years based on opaque utility and regulatory processes) significantly undermine customer interest.

Competition is Fierce, and Customers Are Not Wonks

- **Financiers are somewhat more sophisticated, but are also risk averse**
  - The more risk involved with a project’s revenue stream, the higher the investment hurdle will be, and the less financeable a DER project will be (higher risk = lower perceived value to owner).
  - Regulatory risk is particularly difficult to quantify or hedge–and, therefore, to finance. The more that revenues (or costs) are determined by unpredictable regulatory action or inaction, the more difficult it will be to attract financing.
  - DER competes with many other investment opportunities—if DERs become too risky or expensive relative to expected returns, the investment community will turn to other assets, and financing will dry up.

- **VDER Phase 1 is still totally unproven from a financing perspective**

Core Principles for VDER Distribution Value

Core Principles

- Principle 1: VDER Must Fully Value DERs
- Principle 2: VDER Must Provide a Level Playing Field with Utility Investment
- Principle 3: VDER Must Be Financeable
- Principle 4: VDER Must Be Delivered Through a Tariff
- Principle 5: VDER Must Address Information Asymmetries
- Principle 6: VDER Must Be Flexible

Principle 1: VDER must provide full distribution and transmission value to DERs

- DRV/LSRV (or whatever replaces these concepts) should fully value DER contributions to transmission and distribution grid and to reliability—either solely through the tariff or through a combination of tariff and other mechanisms (e.g., NWA solicitations).

- For Phase 2, previously unquantified values should not be ignored or treated as having no value—they should be estimated and included in the value stack.

- VDER must compensate DERs for value provided throughout the life of the DER asset. The ability of long-lived DERs to reduce loads in the future must be reflected in the value provided over the length of the VDER tariff.

Principle 2: VDER should level the playing field between DER and utility investments

- DERs must be put on a level playing field with utility infrastructure—the utilities should not have a greater incentive to invest in their own traditional infrastructure to support the deployment of DER alternatives, and the PSC should not prefer traditional investments above DERs.

- DERs should be compensated for the full cost of avoided infrastructure.
  - Just as utility investments are not required to provide customer “savings,” neither should VDER be designed to generate “savings” by making DER less competitive than utility infrastructure, or by providing lower valuation for a DER asset than for an equivalent utility asset.
  - From a systems perspective, a DER is still cost-effective when compensated at the avoided cost of the distribution system equipment because of the other values provided by the DER (e.g., resiliency, animating a more distributed market, environmental benefits, etc.) that distribution or transmission infrastructure cannot achieve.
  - Other utility programs (e.g., NWAs, demand response programs, efficiency programs) can be designed to provide ratepayer savings, but these programs should be separated conceptually from VDER.

Principle 3: The Value Stack "delivery mechanism" must be financeable to be effective

- Precision should not be the enemy of effectiveness: VDER Phase 2 risks placing an unrealistic (and likely unachievable) emphasis on "precision" in the tariff design that could make it impossible for DERs to actually respond to the signals sent by the tariff design (*see, e.g.,* Phase 1). To be effective in driving DER deployment as an alternative to utility infrastructure, the market signals established under VDER Phase 2 must be accurate but also sufficiently predictable and durable to allow for project financing.

- The design of the D-value delivery mechanism in the tariff should keep in mind that it must ultimately be understood by DER customers—individual companies and customers with little sophistication and many less complicated alternatives (including utility service).

- Stable, long-term pricing signals better reflect the long-lived nature of the infrastructure avoided and the long-lived nature of DERs.

Principle 4: VDER should be delivered through a tariff

- It has been suggested that DERs should seek compensation for different elements of the "value stack" through separate "markets." However, short run market signals and limited distribution infrastructure project solicitations (NWAs) are not sufficient to build a robust distribution grid with distributed energy resources.
    - Experience with short-run energy markets shows the challenge of supporting infrastructure investments.
    - For example, capacity markets and out-of-market actions (e.g., Reliability Must Run contracts) have been needed to ensure adequate capacity and meet other state goals where deregulated energy markets have failed to do so.

- A well-designed tariff is the optimal mechanism for attracting desired DER investment.
    - Solicitation-based and short-run market opportunities to encourage additional DERs or "stack values" can be effective if available above and beyond the tariff, but they should not replace the tariff.

Principle 5: Value Stack "delivery mechanism" must recognize inherent information asymmetry between DER and utilities

- There are unavoidable information asymmetries between the utilities and private DER providers. Utilities have far greater visibility into system operations, load, and future distribution needs than either DER providers or regulators.

- The VDER tariff structure for distribution value should recognize and be designed to ensure these asymmetries do not allow monopoly utilities to crowd out beneficial private investment.

Principle 6: VDER must be flexible enough for all technologies and customer types

- The design of the value stack must take into account the benefits and capabilities of different technologies.

- The needs of different market segments—e.g., residential, commercial, community solar—must be taken into account in tariff design.

- Optionality for DER providers and technologies should be a touchstone of any VDER reforms. Optionality means the ability to select from a menu of valid valuation approaches (e.g., ICAP alternatives 1, 2, and 3).

Key Distribution Value Issues

With Suggested Solutions

Issue #1: DRV "Delivery Mechanism" Is Unfinanceable

- **Frequent updating and lack of vintaging:**
  - Failure to vintage DRV value for longer than three years is the principal design flaw in DRV. Failure to vintage DRV results in DER "marginal value" being significantly reduced after three years (particularly in high-DER growth scenarios), because tariffed DER are included in new utility load forecasts that form the basis of the MCOS studies. Under current approach, existing DER are effectively given no DRV credit for the ongoing distribution cost deferment they provide after year 3.
  - Unbounded regulatory uncertainty with respect to how MCOS calculations will be conducted in the future is also a key challenge (staff has signaled that changes are coming to MCOS calculations).
  - The result of these two flaws is that the market/financiers/customers effectively assume that DRV will have near-zero value after year three under the current VDER tariff.
- **10-hour lookback does not match utility distribution planning and unduly concentrates risk:**
  - Utilities plan based on forward-looking deterministic load forecasts - not based on a single-year 10-hour lookback - and are developing new forward-looking probabilistic methods to address increasing uncertainty.
  - For DERs, changing annual peak hours concentrate risk that full-year DRV value will be lost due to one-time misalignment between peak hours and DER production.
- **Local outage risk:**
  - Unavoidable temporary outages (including many that are outside operator's control) mean that full-year DRV compensation could be compromised due to short-lived events.

Issue #1: DRV “Delivery Mechanism” Is Unfinanceable

- **Frequent updating:**
  - Solution: DRV value should be vintaged (set) for the full 25-year tariff term at the time of 25% payment (or equivalent)—similar to E-value under Phase 1.
    - DRV value would be updated periodically for new DERs (e.g., following revised MCOS study); New DER would be assigned the then-applicable DRV value at the time they make 25% payment (or equivalent for smaller systems).
    - This is analogous to the way utility distribution infrastructure is treated: utilities are allowed to recover distribution costs based on the need identified when they made the investment; they are not prevented from recovering costs on prudently deployed infrastructure, even if the forecasted need changes after 3 years.

Issue #1: DRV "Delivery Mechanism" Is Unfinanceable

- **10-hour lookback does not match utility distribution planning and unduly concentrates risk:**
  - <u>Solution</u>: DER compensated based on performance during subset of hours tied to expected distribution need.
    - Utility would identify and publish 200-300 "hours of concern"—hours during which distribution system is expected to be the most stressed - similar in concept to ICAP Alt. 2
    - DER compensation would be based on coincidence of generation with the hours of concern—encouraging DER that can match generation to hours of concern
      - Note: DER could be credited on a per-kWh basis (similar to TOU) or per-kW basis (similar to DRV)
    - Hours of concern could be updated periodically as system needs shift, <u>but DER would be vintaged into these hours of concern at time of 25% intx payment</u> (or equivalent)
      - As system needs shift, utility could update DRV value and hours of concern to send updated market signal for the deployment of *new* DERs with desired generation characteristics
  - <u>Optional Demand-Response program for dispatchable DER</u>:
      - Dispatchable DER could receive higher compensation in exchange for utility ability to call for dispatch during set periods

Issue #1: DRV "Delivery Mechanism" Is Unfinanceable

- **Local outage risk:**
  - Solutions:
    - Allow DER to be aggregated into risk pools to reduce local outage risk (opt-in basis)
      - E.g., Phase 1 Order required utilities to develop a utility-run "portfolio" service
      - Utility run program appears unnecessary and potentially costly—utility could simply establish risk pools by technology type and age (e.g., all solar DER installed over a 3-year period)—all DER that opt in would be compensated based on average performance of the risk pool
    - Base DRV compensation on a rolling 3-year average (to smooth out potentially precipitous 1-year drops in credit value that could harm customer value)

Issue #2: Incorporating all avoidable distribution costs

- **Transparency is lacking:** MCOS study methodology is opaque and inconsistent
- **Time horizon is problematic:** MCOS study timeframes are too short to accurately value long-lived DER benefits
  - A key benefit of deploying DERs is that distribution and transmission projects will never appear in distribution and transmission plans by avoiding peak loads
- **MCOS studies do not value full range of DER distribution benefits:** distribution system resiliency, reliability, extended equipment life, and other benefits that exist separate from incremental load relief are not quantified in MCOS
- **Including DER in load forecast baseline undervalues DER:** Updating DRV every three years based on marginal cost studies that effectively assume DER will remain online (and thus are not marginal) fails to value the avoided distribution costs that existing DER already provide. This is a key flaw in the Phase 1 tariff. MCOS studies also should not assume in load forecasts that new, incremental DER will come online in the future. This assumption results in effectively treating new DER as non-marginal and thus grossly undervaluing those DER as well.

Issue #2: Incorporating all avoidable distribution costs

- **Transparency is lacking:**
  - Solution: Detailed, DPS-led structured regulatory process for determining methods and assumptions used for conducting MCOS (or relevant DER distribution value study).
- **Time horizon is problematic:**
  - Solution: Extend distribution value study timeline to at least the term of the VDER tariff (25 yrs).
- **MCOS studies do not value full range of DER distribution benefits:**
  - Solution: Study and assign value to distribution system resiliency, reliability, extended equipment life, and other relevant benefits. For example:
    - Non-Capacity Reliability (ability to avoid customer outage costs due to DER presence on grid)
    - Reliability-Backtie (by reducing load on a feeder, utility can accommodate greater loads being shifted because of outages or in response to changing distribution system conditions)
    - Equipment life extension (by avoiding thermal stress on distribution equipment, the life of those assets can be extended)
- **Including DER in load forecast baseline undervalues DER:**
  - Solution: Exclude existing and projected DERs that would be subject to VDER from MCOS load forecasts.
    - For existing DER subject to VDER Phase 1, distribution value should be determined based on "but for" analysis.
    - Value of new DER can be determined on a forward-looking basis, based on traditional marginal avoided cost (including existing DER in baseline).

Issue #3: VDER does not value DERs' ability to defer or avoid transmission projects

- **Avoided Transmission Not Valued under VDER Phase 1:** Except for a small number of local projects included in MCOS, VDER does not currently value DER contributions to deferring new transmission to meet reliability (load growth), policy (transmission to deliver utility scale renewables), or economic needs
- **Distributed energy resources have significant value in avoiding expensive transmission projects:** E.g., California ISO has cancelled or deferred transmission projects in each of the past two transmission plans due to the growth of distributed solar and energy efficiency
  - California customer savings: 2015-2016: $192 million; 2017-2018: $2.6 billion
- **NY has approved billions of dollars of new transmission projects in the last few years**
  - Similar projects could be deferred or avoided if VDER tariff drives DER development in desired areas.

Issue #3: VDER does not value DERs’ ability to defer or avoid transmission projects

- **Avoided Transmission Not Valued under VDER Phase 1:**
  - Solution: VDER should compensate DER for marginal avoided transmission (T) value
    - E.g., value could be calculated using NERA’s regression methodology, which incorporates 10 years of historic investments, 5 years of forecasted investments, planned capacity in historical years, and forecasted load growth to develop initial system-level marginal transmission costs for each utility service territory.
    - Avoided T value would be credited through a mechanism similar to DRV (as revised per CEP recommendations)

Issue #4: Interaction between NWAs and LSRV

- **Current LSRV structure is difficult to finance (see issues with DRV, above)**:
  - 10-hour lookback and generation misalignment risk combined with unit-specific local outage risk mean that LSRV is not currently a useful signal to drive DER deployment in desired areas.
  - Uncertainty about LSRV following the initial 10-year value lock-in contributes to the weakness of the signal.
- **Solicitations are not a complete substitute for locational relief value:**
  - Solicitations can be valuable for addressing large, well-understood distribution issues, when sufficient time allows for development and auction participation.
  - Solicitations often provide a short-term signal (6-12 months) that is too immediate to allow for larger-scale DER planning and development (project development cycles can last 24 months or longer).
  - Administrative costs and risk associated with solicitations are also major impediments to smaller DER participation in solicitations.
  - For smaller-scale distribution issues, solicitations are likely too costly/cumbersome to achieve positive cost-benefit ratio.

Issue #4: Interaction between NWAs and LSRV

- **Proposed Solution: Hybrid LSRV + NWA Solicitations**
  - A. **3-5 years out from projected distribution need:** LSRV signal in VDER tariff based on expected per-kW cost "wired" alternative.
    - Compensation for intermittent DERs based on probabilistic assessment of their ability to meet LSRV need (similar to DRV).
    - Compensation for fully dispatchable DERs based on actual performance during utility-identified and dispatched "need hours"
  - B. **~18 months out from projected distribution need:** Utility runs NWA solicitation to address unmet needs.
    - If need remains unmet after the initial solicitation, solicitation would remain "open" to additional DERs willing to accept solicitation performance terms on a "first come" walk-up basis, with compensation fixed at the auction clearing price.
    - Projects with LSRV would not be eligible for NWA, and vice versa (unless they relinquish the award).
  - C. **~6-10 months out from projected distribution need:** NWA solicitation closed; utility procures wired infrastructure, if still needed.

- **Shared savings for the utility and ratepayers:** utility shareholders would be authorized to receive a share of the ratepayer savings realized through LSRV and NWA solicitations.
  - Savings = difference between the expected cost of the "wired" distribution solution and the actual installed cost of DER (including LSRV credits and NWA contract costs).
  - *Note: utility accountability mechanism may also be needed to ensure that initial LSRV signal is accurate (e.g., if utility procures a significantly more expensive solution than the "expected" solution, no cost recovery would be provided to the extent that the procured solution exceeds the cost of the "expected" solution identified in the NWA solicitation.*

Issue #5: VDER does not provide incentives to deploy certain high-value technology

- **DERs can provide services other than load relief that are currently not valued in the VDER framework.** Examples include:
  - **Absorbing or Injecting Reactive Power for Enhanced Voltage Regulation:** Ability for utilities to reduce voltage on a feeder can be enabled by smart-inverter voltage supply.
  - **Situational Awareness:** Technology can provide utilities granular, node-level data, to facilitate fault identification and a better understanding of net loads, including consumption data and much finer intervals than utility metering equipment and with lower latency.

- Solution: Quantify these benefits and provide optional compensation to DERs that provide them.

Thank You