



Distribution System Evolution

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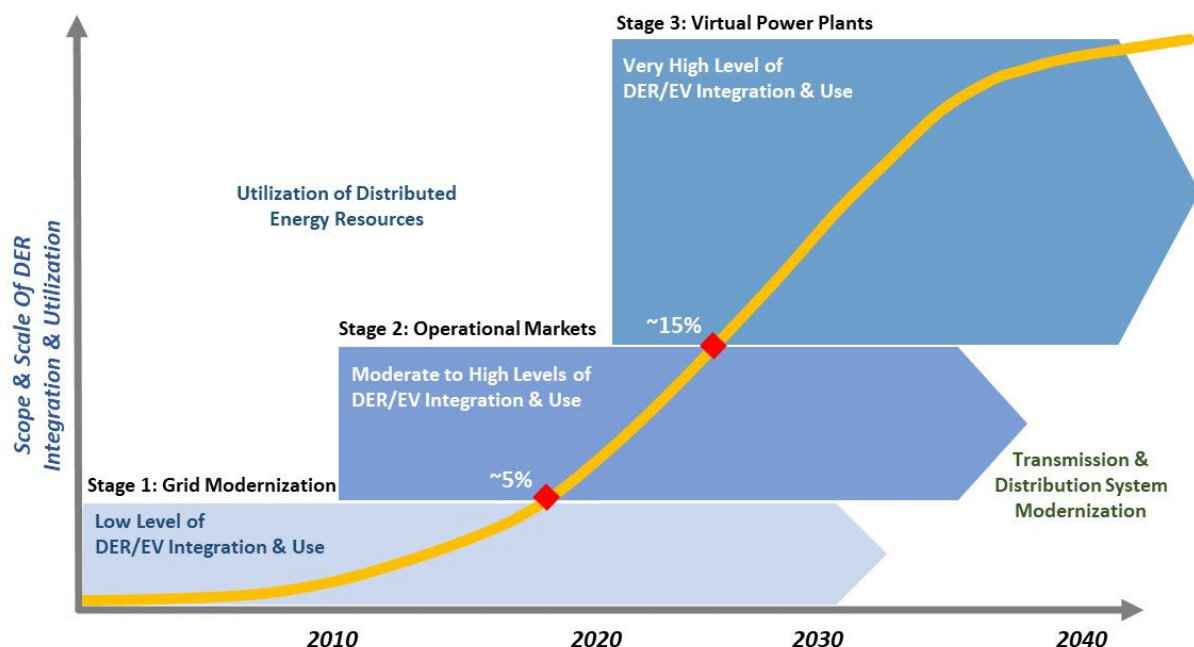
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Evolving Electricity System

The U.S. electric system is undergoing significant change due to a range of drivers, including an evolution of federal, state, and local policies addressing climate mitigation and adaptation, as well as an increasingly diverse and distributed set of electricity resources. Today, the adoption of distributed energy resources (DERs) in the United States is uneven; certain areas have significant adoption, whereas others have a very low percentage. This is true even within a state or utility service area. This patchwork of adoption is currently driven by technological cost-effectiveness, local economic factors, consumer interest, and grid integration considerations. The adoption patterns observed in several states and countries over the past decade, along with the related impacts to distribution system planning and operation, can help identify the key issues and decisions.

There are a number of factors driving the scale and makeup of the future U.S. energy marketplace: DER adoption pace and scale, number of DER providers and aggregators, and growth of electrification, for example. In addition, there are several potential considerations for DER utilization (e.g., size threshold for wholesale market participation, wholesale and distribution rules for DER aggregation, scope of DER services eligible, how system and distribution planning incorporates DER services). These integration and participation factors, as well as future issues, will inform how the system will need to evolve from its current state. The prospective impact of higher levels of consumer and independently aggregated DERs on markets, planning, and operations will increase commensurate with their share of the resource mix. In particular, higher levels of DERs provide an opportunity to leverage these resources to optimize grid investments and improve overall power system performance, economic efficiency, and reliability.

This paper describes an evolutionary framework for U.S. electric distribution systems to enable DERs and their evolving use as virtual power plants (VPPs) for a broad range of grid services while also offering grid planning considerations for state regulators, utilities, and stakeholders. VPPs can help address a broad range of challenges to modern grid operations by providing clean energy and demand flexibility to help minimize costs for a decarbonized future, improve resilience, and provide other consumer and grid benefits.



Source: P. De Martini

Figure 1. Distribution System Evolution

Figure 1 illustrates a three-stage evolutionary framework for the distribution system. This framework is based on the assumption that the distribution system will evolve in response to both top-down (public policy) and bottom-up (customer choice) drivers. The yellow line represents a classic technology S-curve as applied to DER integration and utilization. Each level builds upon the previous one. Due to higher levels of DER penetration and more ambitious policy goals, each subsequent level requires additional market and regulatory requirements as well as distribution system functionalities that create an increasingly complex system.

Stage 1 – Grid Modernization: Low DER adoption (<5% of distribution system peak). DER levels can be accommodated within existing distribution systems without material changes to infrastructure, planning, and operations. Grid modernization¹ is undertaken to address reliability, resilience, safety, and operational efficiency and to enable forecasted requirements for DER integration and utilization.

Stage 2 – Operational Markets: Wider scale (e.g., 5% – <15% of distribution system peak) customer adoption of onsite DER/electric vehicle (EV) technologies for their energy management and resilience. DERs—individually and in aggregations—are increasingly used as load-modifying resources for both distribution non-wires alternatives (NWAs) and wholesale capacity and ancillary services. Integrated distribution system planning and grid modernization are needed to enable real-time observability and operational use of DERs.

Stage 3 – Virtual Power Plants: Large scale (e.g., ≥15% of distribution system peak) adoption of DER/EV technologies and utilization for wholesale and distribution services, plus community microgrids. Individual DERs and DER aggregations are optimized and orchestrated to support grid service requirements for distribution and transmission systems. Multi-use/community microgrids help support local energy supply and resilience. Ultimately, distribution system-level energy transactions are enabled. This third stage of DER utilization requires coordination across jurisdictions (e.g., Federal Energy Regulatory Commission [FERC] Order 2222²) and infrastructure to support both grid and market operations.

Note: The percentages shown are rough approximations for the threshold levels at which significant institutional, business, and grid changes are required due to consumer actions, policies, and new business models. The term “market” in this paper applies to any transaction involving the use of DER services through one or more wholesale, retail, bi-lateral market, and compensation methods (e.g., tariff, program, procurement, bi-lateral trade, locational marginal price market, auction).

Evolutionary Stages

Stage 1: Grid Modernization

In this stage, the level of DER adoption is relatively low and can be accommodated within the existing distribution system without material changes to infrastructure or operations. A primary focus of Stage 1 is addressing the need to replace aging distribution network infrastructure as well as to deploy new advanced grid technologies to address reliability, resilience, safety, and operational efficiency. These initial grid modernization investments, beginning in the 2000s, continue the transition from an analog to a digital

¹ Grid modernization is associated with the deployment of digital information and operational technologies (IT/OT) that provide sensing, communication, control, and computing capabilities to deliver advanced functionality to the electric grid.

² FERC Order 2222, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, 2020

network through smart grid initiatives. For example, they include network connectivity models, enhancing circuit level monitoring, related situational awareness, and power system analytics along with enhanced reliability and resiliency investments in automated field switches enabled by field communications and operational systems (e.g., distribution management system and Volt-var optimization). Foundational investments in aging infrastructure replacement and initial grid modernization also enable increased adoption of DERs and utilization in Stages 2 and 3.³ Federal and state legislation has recognized the need to modernize the grid for over a decade.^{4,5}

Utilities in Stage 1 should proactively plan for an intelligent, flexible, efficient, open, and secure distribution system that can integrate transportation and building electrification as well as DERs. Advancing integrated distribution system planning, including hosting-capacity analysis, and investment prioritization provide immediate benefits and lay an important foundation for the future. This should also include addressing resilience needs based on an all-hazards threat risk assessment and understanding of resilience needs of critical facilities and vulnerable communities.⁶

Interconnection standards should be updated to reflect current technical standards (e.g., IEEE 1547-2018, IEEE 2030.5, NIST cybersecurity). In addition, utility interconnection process reengineering and automation, along with more advanced modeling capabilities based on industry best practices, should begin to be implemented in anticipation of forecast DERs and electrification growth. These are essential elements in a distribution grid code.⁷

The use of flexible demand in Stage 1 involves traditional demand response, typically addressing bulk power system emergencies as part of operational remedial action, as well as management of peak load for wholesale and distribution systems. For example, the housing boom of the mid-2000s created annual peak demand growth of 5% in places like Southern California and Florida. Utility air-conditioning cycling programs and time-based rates were also expanded to address this need.

As a result, load as a capacity resource became the predominant program in 2012, reaching a total of 20 GW (more than double from 2010).⁸ This represented a shift in the use of demand response from traditional emergency demand response, which was the largest program two years earlier in 2010, at 13 GW.⁹ The maturity of load as a capacity resource was also an important step in the evolution of demand response and other flexible DERs to potentially provide a broader range of bulk power system services, providing operating reserves and regulation. These bulk power services and utility distribution programs continue to provide value today.

Considerations

- Establish state objectives and priorities and related distribution planning criteria and performance metrics.

³ DOE, Modern Distribution Grid Report, Volume 4, 2020. <https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx#tabs-4>

⁴ Recent examples include the federal Grid Modernization Act of 2019 (<https://www.congress.gov/bill/116th-congress/senate-bill/2332/text>) and the New Mexico 2020 Grid Modernization Statute (<https://law.justia.com/codes/new-mexico/2020/chapter-62/article-8/section-62-8-13/>)

⁵ L. Schwartz and N. Frick, State regulatory approaches for distribution planning, Lawrence Berkeley National Laboratory, 2022. https://eta-publications.lbl.gov/sites/default/files/schwartz_state_distribution_planning_20220616.pdf

⁶ [https://gridarchitecture.pnnl.gov/media/advanced/Integrated Resilient Distribution Planning.pdf](https://gridarchitecture.pnnl.gov/media/advanced/Integrated%20Resilient%20Distribution%20Planning.pdf)

⁷ Distribution grid codes are a holistic set of reference institutional and business processes, engineering best practices, and technical standards that enable full-scale adoption and utilization of DER.

⁸ Staff Report, Assessment of Demand Response & Advanced Metering, FERC, 2012

⁹ Staff Report, Assessment of Demand Response & Advanced Metering, FERC, 2012

- Identify best and leading practices regarding integrated distribution system planning, including stakeholder engagement, forecasting load and DERs (with consideration of EVs, flexible buildings, and climate parameters), power engineering analyses, and investment roadmaps leveraging DERs.
- Identify and implement hosting-capacity analysis and related public information-sharing platforms with increasing sophistication, as needed.¹⁰
- Establish a cost-effectiveness evaluation and cost-recovery framework for grid modernization investments.¹¹
- Set requirements for data/device interoperability and cybersecurity protections.

Stage 2: Operational Markets

Stage 2 involves expansion of both DER adoption and use. The most common forms of DER adoption include growth of customer-sited storage, smart thermostats and other home automation, and EVs, in addition to solar photovoltaic (PV) cells. Stage 2 also involves front-of-the-meter independent community solar and storage developments. At this stage, DER adoption reaches a threshold (e.g., 5% of distribution system peak) at which regulators, stakeholders, and utilities recognize the need to enable integration of DERs and begin to utilize DER services provided by independent aggregators as a distribution NWA for some types of distribution system needs. This level of adoption typically results in pockets of high customer adoption in some neighborhoods and commercial districts.¹² Pacific Gas & Electric's experience in 2014 with DER capacity at the equivalent of 8% of distribution peak¹³ demonstrates an illustrative adoption pattern:

- One percent (1%) of all feeders may have DER capacity levels at or near 100% of the feeder peak load;
- Three percent (3%) of all feeders may have DER capacity levels exceeding 30% of the feeder peak; and
- Eight percent (8%) of all feeders may have DER capacity levels greater than 15% of the feeder peak.

At this level, two drivers become prevalent. One is pockets of high customer solar PV adoption, commercial solar garden/farm development, and/or material levels of EV adoption (including fleets) in some neighborhoods and commercial districts. Hosting-capacity constraints emerge along with bidirectional power flows or voltage variations that become increasingly problematic.

The second driver is increasing levels of DERs at a scale that can be leveraged to provide bulk power system and distribution grid services. For example, FERC took a series of proactive steps starting in 2008 and continuing into the 2010s to promote the use of responsive demand and other DERs (such as storage) in

¹⁰ Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021.

<https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses>

¹¹ DOE, Modern Distribution Grid Report, Volume 4, Ch.5, 2020. <https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx#tabs-4>

¹² System penetration of DER at 5% of peak load is a nominal guide. Individual portions of the distribution grid may encounter higher levels of DER penetration and require targeted mitigation and potential application of advanced solutions to maintain required reliability and safety of the network.

¹³ PG&E presentation at CPUC DRP workshop, September 2014: http://www.cpuc.ca.gov/NR/rdonlyres/139F207F-041D-4B7E-92A5-87282537DF63/0/DRPWorkshop_PGE_Distribution_Final.pdf

wholesale markets, including Orders 719,¹⁴ 745,¹⁵ and 755.¹⁶ These orders provided greater market competition for capacity reserves and ancillary services. Additionally, utility regulatory changes opened opportunities for DER service providers to offer distribution grid services in lieu of utility distribution investments. These NWA services are provided through a diverse set of DERs and microgrids combined with advanced information and control technologies.

DERs providing services to both the bulk power system and distribution system require the establishment of a coordination framework among the DER aggregator, independent system operator/regional transmission operator (ISO/RTO), and distribution grid operator.¹⁷ Typically, this begins with a simple model proportional to the scale and scope of DER aggregations and wholesale and distribution services provided by DERs.¹⁸ However, these initial coordination processes do not scale to support the scope of services and number of transactions involved in Stage 3 of the evolutionary framework for the distribution system.

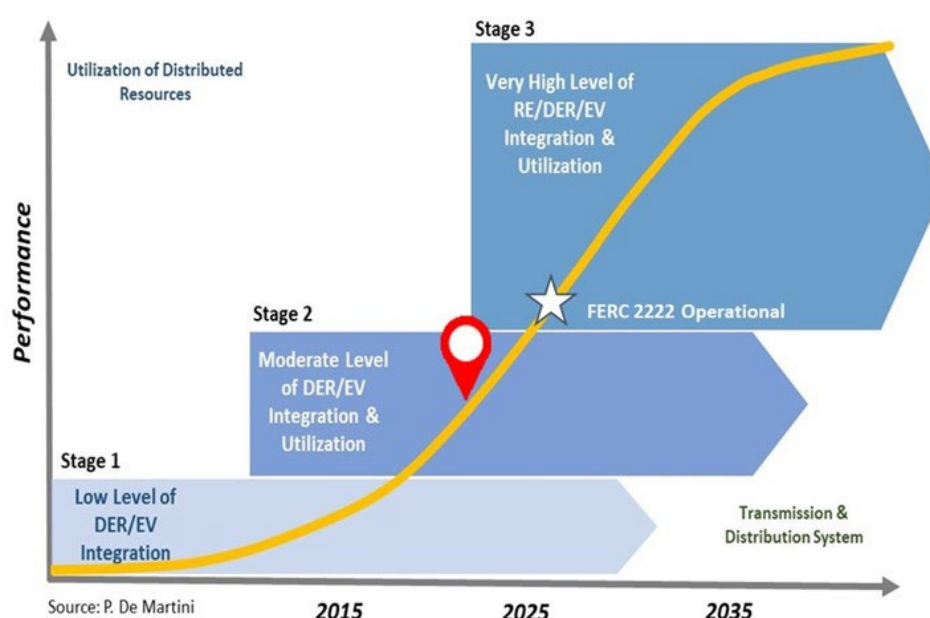


Figure 2. Evolutionary Progression in Several States

Additionally, as DER levels increase beyond 5% of distribution system peak, operational impacts may occur on the distribution system, including voltage variations and bidirectional power flows. These drivers create the need in Stage 2 for enhanced capabilities related to maintaining reliable operation of the grid and optimal use of DERs (Figure 2). Expanded distribution modernization though increased situational awareness, DER control, integrated distribution system planning, and distribution automation are typically required. These factors require changes involving new regulatory actions, utility business process

¹⁴ FERC Order No. 719, Wholesale Competition in Regions with Organized Electric Markets, October 17, 2008

¹⁵ FERC Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets, March 15, 2011

¹⁶ FERC Order No. 755, Frequency Regulation Compensation in the Organized Wholesale Power Markets, October 20, 2011

¹⁷ There are discussions of separating the distribution services market function from utility distribution grid operations. In any event, there will need to be coordination between the utility distribution grid operator and the RTO/ISO as required in FERC 2222 regarding planned and unplanned outages (for example).

¹⁸ The initial California coordination model is described in this Gridworks paper: https://gridworks.org/wp-content/uploads/2017/01/Gridworks_CoordinationTransmission.pdf

reengineering, enhanced planning, and operational capabilities for reliable distribution operation and enabling and optimizing the use of DERs.

Signposts of Change

The following signpost examples illustrate a number of drivers of change from Stage 1 to Stage 2 that continue to be experienced in some regions throughout the United States. Each state and locale will have a unique set of signposts and pace of change.

- **Consumer Solar Finance** – Introduction of innovative consumer solar finance options (e.g., loans and leasing) spurred rapid consumer adoption of rooftop solar when combined with tax credits and net energy metering tariffs, where parity with retail rates exist.¹⁹
- **Federal and State Tax Credits** – Applicable federal and state tax credits and other incentives to offset the initial cost of DERs.
- **Consumer Technology** – Smart phone launch in 2007, rapid expansion of internet commerce and “Internet of Things” and home automation (e.g., smart thermostats) beginning in the 2010s.
- **Community Solar/Storage** – State legislation and regulation that enable and incentivize development of community solar and storage projects.²⁰
- **Consumer Storage Incentives** – Legislation and regulation that foster development of “storage connected at the distribution feeder level, associated with a cluster of customer load.”²¹
- **State Integrated Distribution System Plans NWA Regulation** – State regulatory requirements for utility distribution planning, including the use of DERs as an alternative to traditional infrastructure solutions.²²
- **FERC Order 719** – FERC first opened wholesale markets for an initial set of ancillary services to aggregated demand response as allowed by states.
- **FERC Order 745** – FERC established its authority to compensate demand response resources at the same locational marginal prices that generating resources receive in the energy market.
- **FERC Order 755** – FERC required grid operators in organized markets to compensate frequency regulation resources based on the actual service they provide, including separate payments for capacity and actual performance.

Considerations

In the past 15 years, this industry has seen considerable advancements in consumer technology, including DERs and federal and state policies enabling DER use and grid modernization across the United States. State regulations, wholesale electricity markets, and utilities are striving to catch up with innovation at the grid edge while dealing with an apparent inflection point in climate-related grid resilience and reliability challenges.

The following are key considerations for further expanding DER adoption and utilization as well as requisite enabling grid capabilities. These illustrative considerations should be addressed throughout Stage 2 as DER and electrification levels increase and the scope and scale of DER services expand.

¹⁹ Rooftop Solar PV - Retail Rate Parity Map: <https://www.whatnextnow.com/home/solar/sunmetrix-grid-parity-map-for-residential-solar-energy-in-the-united-states>

²⁰ NREL, Community Solar: <https://www.nrel.gov/state-local-tribal/community-solar.html>

²¹ <https://www.utilitydive.com/news/community-energy-storage-what-is-it-where-is-it-how-does-it-work/518540/>

²² New York example: <https://jointutilitiesofny.org/utility-specific-pages/system-data/dsips>

- Apply Integrated Distribution System Planning^{23,24} to understand the evolution of consumer resources and their interaction with the grid and to align foundational grid investments.²⁵
- Identify the set of distribution grid services that DERs may provide and respective performance and compensation/participation models (e.g., pricing, programs, procurements, and markets).²⁶
- Leverage Grid Architecture²⁷ to provide insight into modern grid requirements and designs and address certain coordination issues, including the ability to scale markets and operations.
- Recognize that DERs owned by parties other than utilities require orchestration through a variety of price, control, and autonomous methods and enabling mechanisms (e.g., tariffs, programs, procurements/auctions, and real-time markets) as well as various entities (e.g., DER aggregators, manufacturers) at the grid edge for distribution and bulk power systems.
- Develop and implement a holistic set of distribution grid codes that address new regulations, business processes and practices, and technical standards to enable adoption and utilization of DERs at scale, including interconnection, data and information sharing, interoperability, cybersecurity, regulatory and commercial standardization, and governance.²⁸
- Consider DER tariff alternatives to address DER value potential, equity, and cost recovery of grid investments (e.g., cross-subsidization issues).^{29,30}

Stage 3: Virtual Power Plants

A characteristic of Stage 3 is a high level of DERs (e.g., solar PV nameplate capacity over 15% of distribution system peak). These high levels exist today in several states and utility service areas. For example, California and Hawaii are currently above this level and have considerable distributed storage and a growing number of EVs. At the Stage 3 threshold, a significant number of DERs are available to create VPPs. VPPs are aggregations of DERs, such as rooftop solar, EVs and chargers, energy storage systems, and smart buildings and equipment that are controlled to act like a traditional power plant. They are large enough to be utility scale and dependable enough to be utility grade. Unlike traditional power plants, VPPs may both export energy and manage demand.

Stage 3 involves advancing the use and sophistication of DER aggregation services to serve as increasingly continuous and automated flexible resources to address system dynamics. Specifically, the need for bulk power system ramping services and regulation, in addition to spinning reserves, is expected to expand significantly. Flexibility needs identified by Midcontinent Independent System Operator, Inc. (MISO),³¹ other regional grid operators, and states involve DERs to “shape, shift, shed and shimmy” consumers’ net

²³ J. Taft and A. Becker-Dippmann, Grid Architecture 2, Pacific Northwest National Laboratory, 2022 [https://gridarchitecture.pnnl.gov/media/advanced/Integrated Resilient Distribution Planning.pdf](https://gridarchitecture.pnnl.gov/media/advanced/Integrated%20Resilient%20Distribution%20Planning.pdf)

²⁴ L.C. Schwartz and N. Frick, State regulatory approaches for distribution planning, Lawrence Berkeley National Laboratory, 2022. https://eta-publications.lbl.gov/sites/default/files/schwartz_state_distribution_planning_20220616.pdf

²⁵ P. De Martini, et al., Modern Distribution Grid, Volume 4, Pacific Northwest National Laboratory, 2020. <https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx#tabs-4>

²⁶ P. De Martini and A. De Martini, Bulk Power, Distribution & Edge Services Definitions, DOE Office of Electricity, 2022

²⁷ J. Taft and A. Becker-Dippmann, Grid Architecture 2, Pacific Northwest National Laboratory, 2016

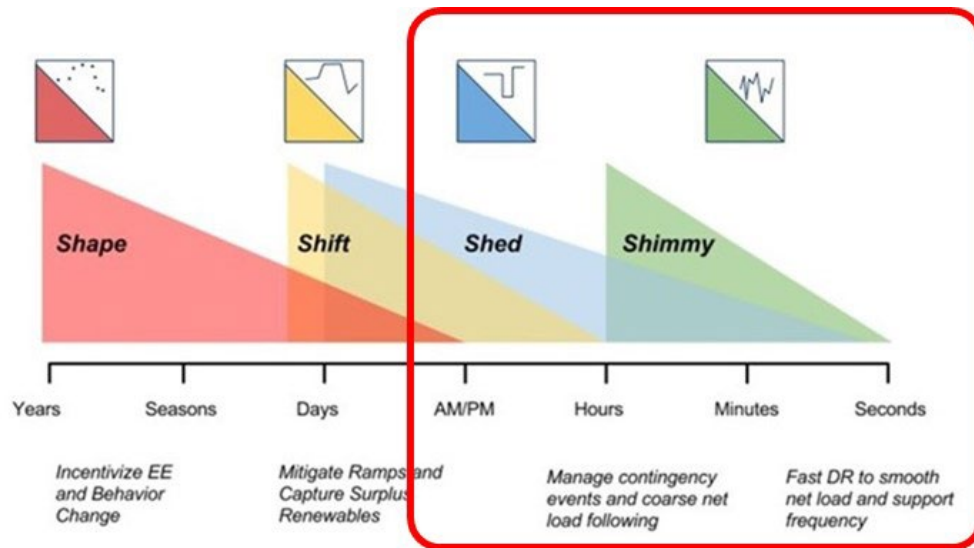
²⁸ Grid codes also support a transition to Stage 3 (including FERC Order 2222 requirements), as applicable.

²⁹ New York Value of Distributed Energy Resources, NYSEDA. <https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources>

³⁰ Hawaii Public Utilities Commission, Smart Export Programs. https://puc.hawaii.gov/wp-content/uploads/2017/10/Hawaii_PUC_Smart-Export_CGS_Fact_Sheets_FINAL.pdf

³¹ MISO Forward, 2019. <https://cdn.misoenergy.org/MISO%20FORWARD324749.pdf>

electricity consumption through new flexible resource initiatives (Figure 3).



Source: LBNL

Figure 3. Flexible Consumer Resource Management Spectrum³²

In particular, there is a focus on shed- and shimmy-type flexibility that operates on shorter time cycles and more frequently to manage a significantly more dynamic grid. This means that DER requirements for grid services, energy dispatch, and load management systems operate more continuously, like a traditional power plant (Figure 4).³³

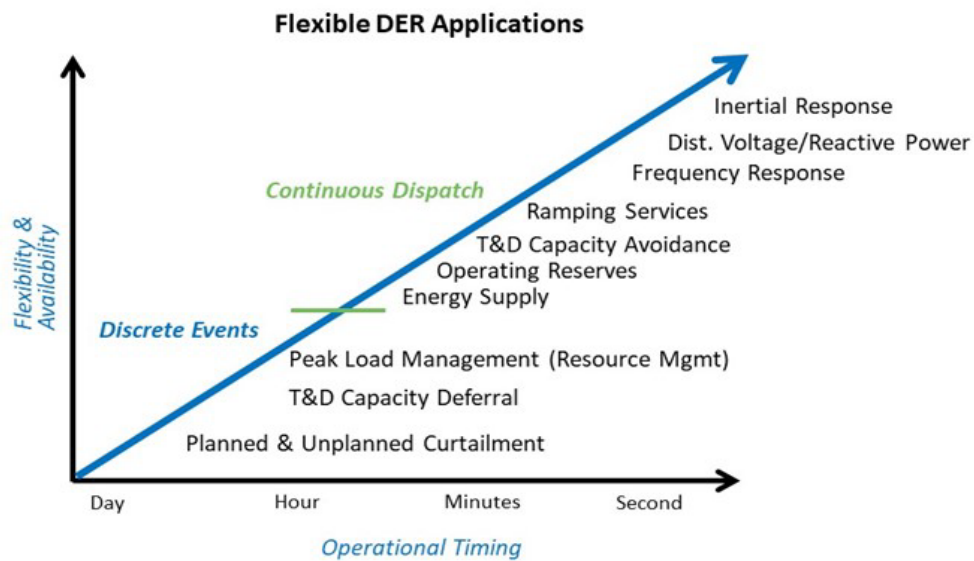


Figure 4. Potential Flexible DER Applications

³² P. Alstone et al., 2025 California Demand Response Potential Study – Charting California’s Demand Response Future: Final Report on Phase 2 Results, Lawrence Berkeley National Laboratory, March 2017. <https://escholarship.org/content/qt2m68c4xh/qt2m68c4xh.pdf>

³³ P. De Martini, DR 2.0 Future of Customer Response, Lawrence Berkeley National Laboratory, July 2013. <https://s3.amazonaws.com/fonteva-customer-media/00Do0000000Yi66EAC/DR%202.0%20A%20Future%20of%20Customer%20Response.pdf>

FERC Order 2222 is a major milestone for enabling VPPs to more fully contribute their potential to address this flexibility need. Order 2222 ushers in a transition from Stage 2 to Stage 3 as it lays out a foundational set of enabling market design, utility, and aggregator business functions, as well as regulatory roles and responsibilities. As Order 2222 recognizes, VPPs may be used for both wholesale markets and retail applications as an energy supply option, as well as flexible alternatives to traditional investments in transmission and distribution systems. ISO/RTO compliance plans are targeting between 2026 and 2030 for launch of Order 2222 provisions.

This includes managing distribution system hosting capacity dynamically with high levels of solar PV, storage, and electrification. In the United States, an emerging vision is for the distribution grid operator to manage distribution capacity by orchestrating DERs—to enable full energy export from solar and distributed storage and energy use for EV charging. Orchestration in the United States in Stage 3 involves leveraging flexible loads and storage to offset distributed generation exports or EV charging load so that net power flows on the distribution system remain within operational limits (i.e., hosting capacity). This approach is unlike current efforts in Australia, where “dynamic operating envelope” is viewed as a DER curtailment and derate mechanism, throttling DER to stay within distribution operating limits.³⁴

Additionally, wider adoption of distributed generation and storage can enable the formation of multi-user/community microgrids³⁵ to form an island of interconnected loads and DERs in a contiguous section of a utility distribution circuit during black-sky events. These community microgrids are an option to address specific local resilience needs or broader social objectives.³⁶

In the latter part of Stage 3, a combination of high DER adoption and policy and regulatory decisions may provide an opportunity for development of distribution markets for multi-sided transactions between DER owners/operators and entities seeking to buy or trade energy at the distribution level. A prerequisite is high levels of DERs that can supply dispatchable energy and that are not encumbered by tariffs, interconnection rules, or other regulations that effectively prevent the resale of the energy produced to another party across the distribution system. The vast majority of energy-producing DERs installed in the United States (notable exceptions include Texas and Hawaii) is encumbered in that manner. It is unlikely that Stage 3 distribution energy markets will develop until regulators further reform DER rates and incentives. However, it is likely that some limited energy transactions will occur in Stage 3 related to multi-user microgrids and community-based energy suppliers (e.g., California Community Choice Aggregators,³⁷ Ann Arbor Sustainable Energy Utility,³⁸ Sunnova Microgrid Communities³⁹).

A formal distribution-level market structure is needed to facilitate such grid-edge energy transactions in addition to local markets within each local distribution area. This may, for example, involve a distribution substation as a distributed trading hub and interchange point for a bulk power market node. DER owners/operators may also want to transact across multiple distribution systems. That will entail utilizing

³⁴ <https://iced.sanu.edu.au/research/research-stories/dynamic-operating-envelopes-what-are-they-and-why-are-they-so-important>

³⁵ U. Chivukula, Community Microgrids, NARUC Bulletin. <https://www.naruc.org/bulletin/the-bulletin-08-08-2017/community-microgrids/>

³⁶ Kiera Zitelman et al., User Objectives and Design Approaches for Microgrids: Options for Delivering Reliability and Resilience, Clean Energy, Energy Savings, and Other Priorities, National Association of Regulatory Utility Commissioners, January 2021. <https://pubs.naruc.org/pub/E1F332D4-155D-0A36-31CB-889ABED753D5>

³⁷ <https://www.prnewswire.com/news-releases/four-california-ccas-procure-over-15-mw-of-local-solar-power-with-8-mwh-of-storage-within-their-service-areas-301812874.html>

³⁸ [https://www.a2gov.org/departments/sustainability/Sustainability-Me/Pages/Ann-Arbor's-Sustainable-Energy-Utility-\(SEU\).aspx](https://www.a2gov.org/departments/sustainability/Sustainability-Me/Pages/Ann-Arbor's-Sustainable-Energy-Utility-(SEU).aspx)

³⁹ <https://www.microgridknowledge.com/editors-choice/article/11427088/sunnova-wants-to-build-and-run-community-microgrids-as-a-utility>

the transmission system, as well as the distribution system, placing greater emphasis on coordination between distribution grid operators and ISOs/RTOs at transmission-distribution interfaces.

In summary, the evolution of DERs into VPPs has been a 40+ year journey that is about to make a significant step-change for a decarbonized future (Figure 5). This evolution will involve structural transformation across the electric industry. The industry has already entered a transitional period to address the dual challenges and opportunities associated with FERC Order 2222 and electrification. In effect, the industry is “crossing the Rubicon.”

Evolution of VPPs

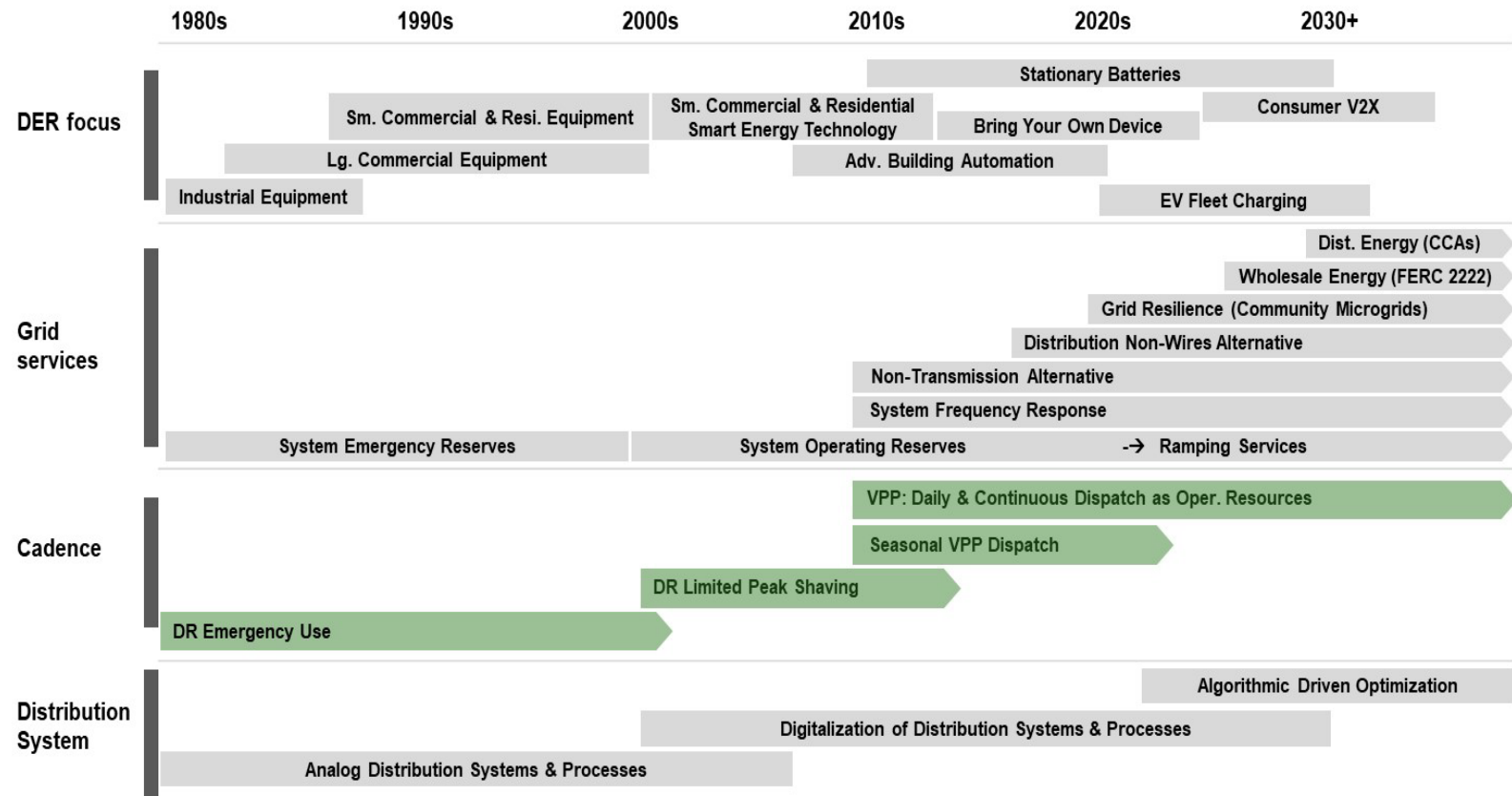


Figure 5. Evolution of Flexible Load Management and Other Distributed Energy Resources

Signposts of Change

The following signpost examples illustrate a number of drivers of change from Stage 2 to Stage 3.

- **FERC Order 2222** – Expansion of DER aggregations in ISO/RTO markets
- **Federal Legislation** – Inflation Reduction Act and Infrastructure Investment and Jobs Act
- **Federal Incentives** – Clean energy and electrification tax credits, grants, and loan guarantees
- **Automaker EV Model Launches** – Forty battery EV models in the United States (2023)⁴⁰
- **Vehicle to X** (including Home) – Ford F-150 Lightning with bidirectional charging
- **Community Microgrid Legislation and Regulation**⁴¹
- **Community Energy Systems** (e.g., community choice aggregation) legislation and activities⁴²
- **U.S. Electric Resilience and Reliability Degradation**⁴³ due to climate change impacts and aging and inadequate grid infrastructure
- **State EV Legislation and Regulations**⁴⁴ enabling adoption of EVs and related charging infrastructure
- **State Zero Net Energy Building Codes**⁴⁵ driving adoption of DERs in new and remodeled buildings

Considerations

Stage 3 is initially focused on FERC Order 2222 implementation by ISOs/RTOs, utilities, DER aggregators, and state utility regulators. Each has its respective roles and responsibilities in the required market structure. Additionally, transportation electrification is forecast to create significant challenges for distribution systems, as full vehicle electrification equates to a 50% increase in electricity consumption based on 2021 levels.⁴⁶ While VPPs can mitigate some of these challenges, the sheer magnitude of additional electric loads will require significant grid investments. Below are a sample of key considerations for Stage 3 that some jurisdictions may need to begin planning for now.

- Expand the range of customer segments and total number of customers who are able to adopt DERs to enable flexible grid services from VPPs.
- Expand VPP participation by addressing customer acquisition inefficiencies, decision-making factors, and value propositions for customers and DER aggregators.
- Identify operational capabilities and potential process reengineering and organizational changes for utility distribution systems to implement FERC Order 2222, as well as new state regulatory

⁴⁰ Source: EV Adoption website: [https://evadoption.com/ev-models/bev-models-currently-available-in-the-us/#:~:text=Battery%20Electric%20Vehicles%20\(BEVs\)%20Available,Audi%20\(5\)](https://evadoption.com/ev-models/bev-models-currently-available-in-the-us/#:~:text=Battery%20Electric%20Vehicles%20(BEVs)%20Available,Audi%20(5))

⁴¹ California PUC Community Microgrid: <https://www.cpuc.ca.gov/resiliencyandmicrogrids>; Hawaii legislation: https://www.capitol.hawaii.gov/sessions/session2018/bills/HB2110_SD2_.HTM

⁴² Institute for Local Self-Reliance, Community Power Scorecard: https://ilsr.org/2022-community-power-scorecard/?gad=1&gclid=CjwKCAjwx_eiBhBGEiwa15gLN6WGH6NCmAdgkuZURAJCAozb25AEQmo6-gPMqR2FIWjucNI0fp5SZxoCiOEQA vD_BwE

⁴³ Wall Street Journal article: <https://www.wsj.com/articles/americas-power-grid-is-increasingly-unreliable-11645196772>

⁴⁴ Vermont, ZEV policies: <https://dec.vermont.gov/air-quality/mobile-sources/zev>

⁴⁵ California, Zero Net Energy Building Codes: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/zero-net-energy#:~:text=All%20new%20residential%20construction%20will,will%20be%20ZNE%20by%202025.>

⁴⁶ Source: Lawrence Livermore National Laboratory, 2021 Energy Sankey Diagram

governance needed for utility and DER aggregator activities.

- Develop Integrated System Planning (e.g., resource, transmission, and distribution) processes, as applicable, to properly evaluate a more distributed and electrified system as well as the value of VPPs across all levels of the electricity system.
- Adopt distribution grid codes that address the capability maturity needed for Stage 3 scale and complexity, including new institutional and business processes, commercial standardization, codes of conduct, technology interoperability, and regulatory governance.
- Develop alternative grid architectures and reference designs that reflect emerging multi-level energy systems (e.g., bulk power, distribution, community-based, and customer).
- Develop and implement coordination models that reflect the evolving and expanding landscape of market participants across multi-level energy systems.
- Implement foundational grid infrastructure and technologies necessary to enable deep decarbonization and climate adaptation⁴⁷ while also creating a delivery system for VPPs to deliver grid services by providing clean energy and demand flexibility to help minimize costs, improve resilience, and provide other consumer benefits.

Conclusion and Next Steps

To plan and operate distribution systems with DERs, in order to achieve the envisioned potential benefits of VPPs^{48,49}, requires advancing U.S. electric industry capabilities and institutional maturity. Regulatory, policy, business, and technical considerations for markets and electricity grids must be addressed to enable and establish a greater level of services provided by VPPs. Figure 6 adapts Carnegie Mellon's Capability Maturity Model,⁵⁰ designed to assess organizational maturity, as a framework for considering how to address the issues and considerations raised in this paper.

⁴⁷ <https://www.c2es.org/document/greenhouse-gas-emissions-targets/>

⁴⁸ R. Hledik and A. Faruqui, The Potential for Load Flexibility, Brattle, 2019. <https://www.naseo.org/Data/Sites/1/ue-190698-ue-191023-demand-response-potential-and-target-setting-workshop.pdf>

⁴⁹ R. Hledik and K. Peters, The Value of Virtual Power, Brattle, 2023. <https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power-Full-Report.pdf>

⁵⁰ CMU Software Engineering Institute, Capability Maturity Model for Software. <https://resources.sei.cmu.edu/library/asset-view.cfm?assetid=11955>

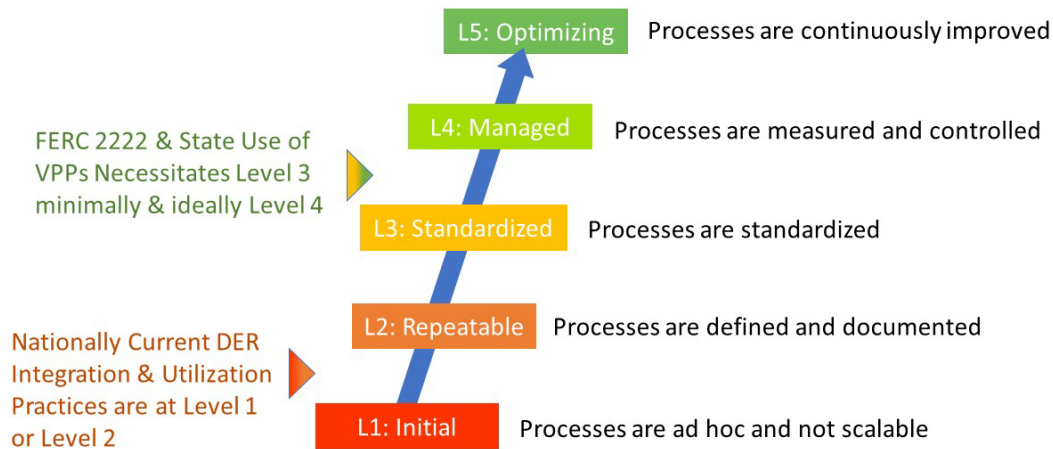


Figure 6. Electric Industry Capability Maturity Model for VPPs

This model provides an effective way to assess both the required level of technical capabilities and the maturity of regulatory and business processes related to the integration and utilization of VPPs. Today, these processes for DERs are between model Level 1 (Initial – ad hoc processes) and Level 2 (Repeatable – defined and documented processes), depending on the state and utility service area. However, they are not scalable.

For example, several states in RTO/ISO markets that will be implementing FERC Order 2222 have not yet instituted hosting-capacity analysis, established integrated distribution planning, or updated interconnection rules that reflect current inverter standards (Level 1). Other states have implemented these elements and instituted distribution grid services through documented processes and procedures (Level 2). However, to satisfy Order 2222 requirements, the industry, including VPP aggregators, needs to advance to a minimum of Level 3 (Standardized) and preferably Level 4 (Managed), where processes and practices for VPPs, markets, and operational coordination are monitored and controlled—meaning there is effective performance evaluation and regulatory governance by FERC and state utility regulators. Ideally, the electric industry achieves Level 5 (Optimizing). Order 2222 identifies a number of these aspects and provides a useful reference on VPPs for jurisdictions outside an RTO/ISO region to consider.

Correspondingly, there is a need to upgrade utility capabilities for Stages 2 and 3. The electric distribution system in the United States today is based on the Edison-Tesla grid architecture of the 1890s, overlaid with a mix of 100 years of technological evolution in electric power delivery, control systems, and computing and telecommunication. Most of this infrastructure was installed over the past 50 years and is undergoing a significant analog-to-digital transformation. This includes, for example, replacement of electromechanical devices with digital devices such as protection relays. This infrastructure refresh started largely in the mid-2000s and will continue into the next decade given the expanse of the distribution system nationwide and the recognition of customer affordability challenges with such large capital investments. Distribution system operations will also necessarily need to evolve toward greater visibility regarding situational awareness and dynamic algorithmic optimization with human operator oversight, given increasing system dynamics.

Considering the implications of grid evolution, it is essential to move toward a common view of what functions the grid needs to enable and when those functions are needed. This requires proactive engagement between regulators, customers, utilities, DER aggregators, and other stakeholders. It is important to consider the pace of DER and EV innovation (approximately two-year product development cycles) compared to process times for institutional decision-making in the electric industry (about five to seven years). Innovation cycles are outpacing industry decision-making cycles for new rates and general

rate cases by a factor of more than two, and that does not include implementation timelines. The industry is lagging behind and will need to find ways to leap ahead to manage the systemic changes underway (Figure 7).

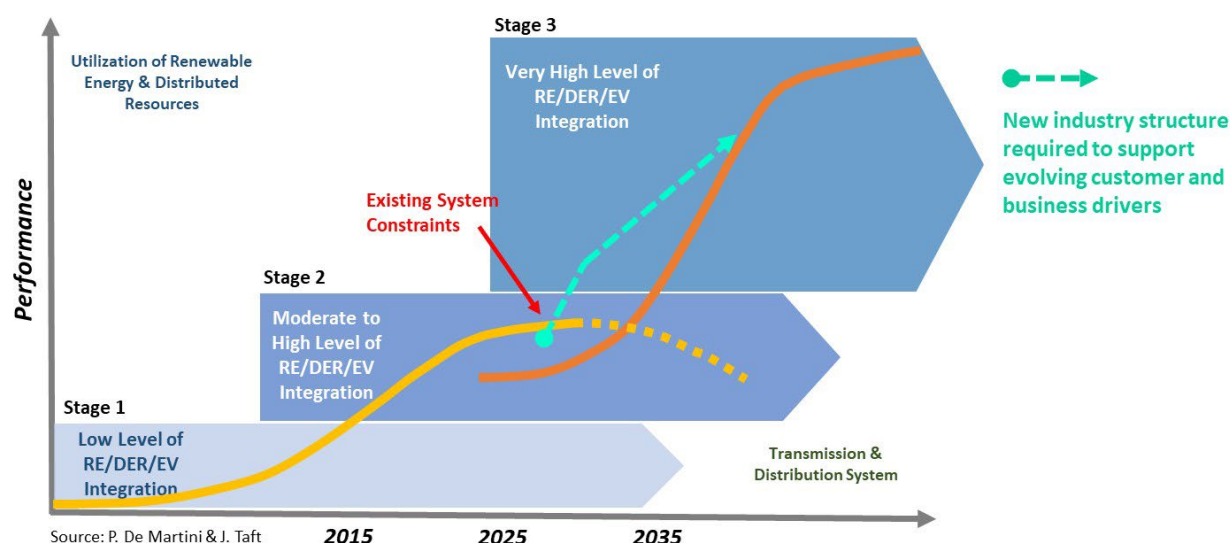


Figure 7. Second Generation of Electric Industry Structure and Capabilities

A common understanding of grid investments to enable utilization of DERs and VPPs for both grid and market operations is needed. VPPs cannot deliver value if grids cannot deliver their services to intended markets. Further, reliability and resilience investments for the distribution system are crucial as resources at the grid edge contribute a significant portion of grid services over the next decade in a number of states pursuing distributed generation and storage policies.⁵¹ Failure to address foundational grid modernization capabilities in a timely manner will create significant barriers to a more distributed electricity system and impede development of VPPs and, perhaps most importantly, decarbonization through electrification.

⁵¹ For example, see Hawaiian Electric, Integrated Grid Plan, May 12, 2023. <https://hawaiipowered.com/igpreport/>