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UTILITY SOLUTIONS

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Distributed Energy Resources

From the Margins to the Mainstream

A Case for Integrated System Planning and a Level Playing Field

Drawing on decades of experience across generation, transmission, distribution, grid operations, regulatory interaction, policy development and a passion for enabling the success of the utility industry.

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1. Executive Summary

The electric power industry stands at a genuine inflection point. Distributed Energy Resources (DERs), once treated as curiosities at the margins of the grid, have crossed a decisive threshold. Solar photovoltaic module costs have fallen more than 97 percent since 2006.[12] Lithium-ion battery storage pack costs have dropped over 90 percent since 2010.[11] The U.S. Department of Energy (DOE), through the SunShot Initiative, the Grid Modernization Initiative, and a sustained pipeline of R&D investment at the National Renewable Energy Laboratory (NREL) now National Laboratory of the Rockies (NRL), Pacific Northwest National Labs (PNNL), Oak Ridge National Laboratory (ORNL) and Lawrence Berkeley National Laboratory (LBNL), deserves substantial credit for catalyzing this cost revolution.[17]

Yet economic competitiveness alone does not guarantee that DERs will be deployed where they provide the most grid value, at the scale the grid needs, and in ways that strengthen rather than complicate reliable system operation. That outcome requires deliberate, structural change in how the electric utility industry plans its grid, values investments, and engages with the technology ecosystem growing up around it.

This paper presents three interconnected changes that are necessary to unlock the full potential of DERs:

- **An evolution in planning:** The industry must supplement and, in many contexts, replace the century-old top-down utility planning model, currently referred to most often as the Integrated Resource Planning (IRP) model with bottom-up Integrated System Planning (ISP) that begins at the distribution edge, identifies locational grid needs with granular precision, and recognizes the value that DERs present to solve these needs while, in aggregate, meeting overall resource portfolio requirements.
- **A regulatory correction:** The structural financial disadvantage DERs face under traditional cost-of-service regulation must be corrected. A DER Power Purchase Agreement that achieves the same grid outcome as a utility-owned peaking plant should receive equivalent financial treatment. This is not a subsidy; it is the removal of a distortion.[10]
- **A return to collaboration:** FERC Order 2222, which requires RTOs to allow DER aggregations to participate in wholesale energy markets, is more than a market rule change.[15] It is a call for the industry to collaborate effectively once again, building shared infrastructure, common data standards, and coordinated planning frameworks that no single utility, regulator, or technology provider can build alone.

Wood Mackenzie projects that 262 GW of new DER and demand flexibility capacity will be installed in the United States from 2023 to 2027, approaching the 272 GW of utility-scale central station resource installations expected in the same period.[3] The DOE estimates that Virtual Power Plants alone could reduce U.S. peak demand by 80-160 GW by 2030.[1] Used thoughtfully and planned deliberately, DERs are the fastest tool the industry has to address capacity shortfalls, defer infrastructure investment, and deliver cleaner electricity to customers who are already installing them with or without utility coordination.

There are no silver bullets, we need them all. Large baseload and dispatchable resources, including nuclear, hydro, and natural gas with carbon capture, remain essential to bulk energy delivery and grid stability. But DERs can be deployed dramatically faster, at lower cost, and with greater locational precision than large central station projects. The utilities that move first, embracing bottom-up planning, leveling the financial playing field for DERs, and leading broader collaboration initiatives, will find themselves with lower costs, more resilient systems, and a stronger relationship with their customers.

A second paper detailing the results of a blended ISP/IRP process to develop the actual value of DERs will be coming out soon!

2. Background and History of Distributed Energy Resources

Origins and Early Development (1970s-1990s)

The concept of Distributed Energy Resources, defined as small-scale power generation and storage technologies sited close to the point of consumption, traces its roots to the energy crises of the 1970s. The Public Utility Regulatory Policies Act of 1978 (PURPA) was a landmark early response, requiring utilities to purchase power from small qualifying facilities and cogenerators, laying the regulatory groundwork for distributed generation.[14]

During the 1980s and 1990s, DERs were largely synonymous with diesel backup generators, small-scale hydro, and early wind turbines, technologies that were costly, inconsistent, and viewed by most utilities as a nuisance rather than a resource. Solar photovoltaic (PV) modules in 1990 cost roughly $10-$12 per watt, placing them far beyond reach for mainstream deployment.[12] Battery storage technology remained an engineering curiosity confined to niche military, telecommunications, aerospace, and critical system applications.[11]

The DOE's Catalytic and Enduring Role

No single institution has done more to advance DER technology, economics, and policy than the U.S. Department of Energy. With early efforts taking shape in the Carter Administration, and expanding significantly in the 1990s, DOE's Office of Electricity and NREL invested heavily in R&D programs targeting solar, wind, advanced inverters, and energy storage.[17]

The DOE's SunShot Initiative, launched in 2011, set an audacious goal of driving utility-scale solar costs to $0.06/kWh by 2020. The industry achieved that target three years early, in 2017, a milestone that validated both the ambition of federal R&D investment and the power of market forces once properly catalyzed.[17,12] DOE's Grid Modernization Initiative simultaneously addressed the critical question of how to integrate high penetrations of DERs without compromising reliability.

The DOE's Vehicle Technologies Office and Loan Programs Office have been instrumental in catalyzing the battery storage industry, helping drive lithium-ion battery pack costs from over $1,200/kWh in 2010 to below $150/kWh by the mid-2020s.[11] The DER Interconnection Roadmap released in January 2025, a product of DOE's i2X initiative incorporating input from over 45 organizations, sets a national agenda for interconnection reform.[5]

The Cost Revolution (2000s-Present)

The story of DER adoption is, at its core, a story of relentless cost decline driven by technology maturation, manufacturing scale, and policy support:

Technology	Then	Now
Solar PV Module Cost	~$7/W (2000)	<$0.25/W (early 2020s): 96% reduction
Utility-Scale Solar LCOE	N/A (not viable)	$0.025/kWh (2024), new floor
Onshore Wind LCOE	~$0.08/kWh (2010)	<$0.03/kWh (best regions)
Li-ion Battery Pack Cost	>$1,200/kWh (2010)	<$150/kWh (mid-2020s): >90% reduction
Li-Iron Phosphate (LFP) Battery Cost	$750/kWh (2010)	$72/kWh (2024): 90% reduction

Sources: *BloombergNEF Battery Price Survey*[11]*; NREL Annual Technology Baseline*[12]*; IRENA Renewable Power Generation Costs*[13]*; DOE SunShot Progress Reports*[17]*; Wood Mackenzie 2023 DER Outlook*[3]

These economics have transformed DERs from boutique, subsidy-dependent projects into a cost-effective resource option in many U.S. markets. While the industry has still not effectively determined a consistent value framework for DERs that recognizes all the value streams they can provide in a resource portfolio, a framework is now taking shape. According to Wood Mackenzie's 2023 U.S. Distributed Energy Resource Outlook, 262 GW of new DER and demand flexibility capacity was projected for installation from 2023 to 2027, approaching the 272 GW of utility-scale resource installations expected in the same period.[3]

Growing Industry Acceptance (2010s-Present)

For much of their history, utilities and grid operators treated DERs as unpredictable, uncontrollable variables, specifically load modifiers to be tolerated rather than dispatched. That posture has fundamentally changed:

- **FERC Order 2222 (2020)** was a watershed regulatory moment, requiring RTOs to allow DER aggregations to participate in wholesale energy markets, effectively elevating rooftop solar, batteries, and smart thermostats to the same market standing as a natural gas peaker plant.[15]
- **Virtual Power Plants (VPPs)** have moved from pilot programs to operational reality. Rocky Mountain Institute's analysis confirms VPPs can provide dispatchable capacity at an equivalent or lower cost of constructing and operating a gas peaker plant. [2,4]
- **LBNL's VPP inventory report (2025)** catalogs active VPP programs across the U.S. with detailed operational profiles, providing the most comprehensive empirical database of real-world VPP performance data currently available.[8]
- **Electric Vehicles (EVs)** have emerged as the next frontier, with Vehicle-to-Grid (V2G) pilots proliferating across the country, turning millions of parked cars into a vast, distributed storage fleet.

With over 5 million rooftop solar installations in the U.S. and grid-scale battery storage additions doubling year over year, the challenge has shifted from *whether* DERs can play a meaningful role, to *how fast* utilities, regulators, and technology providers can evolve to harness their full potential.[3]

3. How Utilities Have Planned Historically: Top-Down Planning

The Century-Old Planning Paradigm

The electric utility industry was built on a top-down planning philosophy that made complete sense for its era. Beginning in the early twentieth century, utilities designed their systems from the bulk power level downward: forecast load growth, build or contract for large central generating stations, design high-voltage transmission to move power from plant to population center, and finally size distribution infrastructure to deliver that power to customers. The customer sat passively at the very bottom of this planning hierarchy, a load to be served rather than a resource to be engaged.

This model was rational when generation technology rewarded scale, when customers had no ability to generate, store, or manage their own electricity, and when information about system conditions was sparse and slow. While called many different names over time, the last two name changes for utility planning processes are significant. First, Least Cost Planning. The utility planning process became very focused on the mandated obligation of a utility to provide resources at the lowest cost, so the process was referred to as least cost planning. Second, Integrated Resource Planning (IRP). This evolution shifted focus to include social agendas. Mandated 'non-generation' programs such as energy efficiency and demand response and mandated renewable portfolio programs were now required, the barrier to these higher cost solutions removed by mandate, and stakeholders for the utility could engage in a public process to provide their input into the resource mix selected in the process. IRP is the formal framework most state-regulated utilities use today. Utilities project 20-year load forecasts, identify supply-side resource needs, and propose portfolios of generation to meet them, while incorporating regulatory mandates and stakeholder input. The distribution system is largely an afterthought, sized to carry load and not designed to host resources.

For nearly a century, this overall process has worked effectively. The system was reliable, rates were predictable, and the engineering logic was sound. Large economies of scale in central generation drove down the cost of electricity for generations of Americans, enabling financing of the electrification of rural America and powering the industrial expansion of the twentieth century.

The Structural Assumptions of IRP

Integrated Resource Planning rests on foundational assumptions listed here that, while valid for most of the twentieth century, have quietly eroded in the twenty-first:

- Customers are passive. Load grows predictably, shaped primarily by economic activity and weather, not by customer technology choices.

- Generation economies of scale dominate. Larger plants produce cheaper electricity. The optimal investment is almost always a bigger plant, not smaller plants or distributed infrastructure.
- The transmission grid is largely a given. IRP selects resources; transmission and distribution planning handles interconnection as a downstream consequence, not a co-equal variable.
- Demand-side resources are generally considered as load modifiers, not as resources.
- Long planning horizons are reliable. A 20-year IRP built on reasonable assumptions will remain directionally valid for its full term.

Why the Old Model Is Showing Its Cracks

The realities of dramatic new load growth are straining a model that has been predicated on central station resources and low sustained incremental load growth due to these drivers:

- **Load forecasting has become structurally unreliable.** The flat or slowly growing load curves utilities planned against since the 1970s have been disrupted by distributed solar, energy efficiency, and the explosive growth of EV charging and data center load. Forecasts that were once accurate within a few percent over a 10-year horizon are now routinely wrong within 3-5 years.[7]
- **The distribution system has become the most complex part of the grid.** Millions of rooftop solar systems, batteries, EVs, and smart devices are being interconnected with little coordinated planning. Distribution systems designed as passive delivery infrastructure are now asked to manage bidirectional power flows, voltage fluctuations, and hosting capacity constraints never contemplated in their original design.[7]
- **Supply-side solutions are no longer always the right answer.** When a distribution circuit approaches its capacity limit, the traditional top-down response is automatic: upgrade the conductor, add a substation transformer, or build a new line, costing tens to hundreds of millions of dollars. The question top-down planning rarely asks: could customer-sited resources solve this problem faster and at a higher value instead?[7,10]

4. Flipping the Model: Bottom-Up Integrated System Planning

The ISP Imperative

Bottom-up Integrated System Planning (ISP) inverts the traditional hierarchy. Rather than beginning with bulk generation needs and working downward, it begins with a granular, location-specific understanding of distribution system needs, circuit by circuit and substation by substation, and asks what combination of customer-sited resources, grid investments, and supply-side additions most efficiently meets those needs.[7]

While IRP is conducted by individual utilities asking “What resources should we acquire?”, ISP is a grid-level planning process asking “How should the system evolve as a whole”? ISP explicitly models the interdependencies between transmission and distribution infrastructure and resource siting decisions, recognizing that where one builds a solar array, a battery, or implements DERs matters as much as if one builds it.

Dimension	Integrated Resource Planning (IRP)	Integrated System Planning (ISP)
Conducted by	Individual utilities / LSEs	Grid operators with Stakeholders
Primary question	What resources should we acquire?	How should the system evolve as a whole?
Geographic scope	Single utility service territory with larger regional interactions	Targeted and then aggregated to bulk system level
Transmission treatment	Often assumed as fixed/given	Central variable in the analysis
Regulatory context	State PUC approval	Broad stakeholder engagement
Demand-side integration	Rarely Considered	Required Input
DER treatment	Load modifier / net load input	Utility-class dispatchable resource

Why ISP Is a Game Changer

- **It makes DERs visible as grid assets.** Top-down planning typically treats customer-sited solar, storage, and demand response as load modifiers, variables to be netted out of the forecast. Bottom-up ISP treats them as utility-controlled, dispatchable grid resources that can be sited, contracted, and dispatched to solve specific, localized grid needs that can scale to become an important part of the overall resource mix. The difference is not semantic; it determines whether a utility builds a $30 million substation or deploys a $4 million DER Plant instead.[2,7]

- **It enables Non-Wires Alternatives (NWAs).** Con Edison's Brooklyn-Queens Demand Management Program used customer-sited resources to defer a $1.2 billion substation project, the landmark demonstration that this approach works at scale in a complex urban environment.[18]
- **It aligns customer investment with grid needs.** When utilities know where distribution capacity is scarce, they can target DER investment precisely where it delivers the most grid value. Without bottom-up visibility and utility coordination, DER incentives and programs are geography-blind and routinely benefit areas with ample capacity while leaving constrained areas underserved.[9]
- **It improves resilience planning.** Top-down planning optimizes resources, not the system. Bottom-up planning identifies specific communities and circuits with elevated vulnerability and designs targeted resilience investments where they matter most, an increasingly important consideration as climate-driven weather events concentrate outage risk.[6]

Recognizing the Need for Bottom-Up Planning

States including California, New York, Hawaii, and Minnesota have made bottom-up distribution planning a regulatory requirement, recognizing that the grid of the future cannot be planned from the top-down alone.[7] The two processes are increasingly understood as complementary: a well-functioning ISP can inform individual utility IRPs by clarifying what transmission capacity will be available and where, while utility IRPs feed regional ISPs with load forecasts and resource plans.

> The utilities that master bottom-up Integrated System Planning will find themselves with a powerful competitive and regulatory advantage: lower infrastructure costs, faster response to changing load patterns, more resilient systems, and a genuinely collaborative relationship with the customers whose decisions now shape the grid as much as any central station plant ever did.

5. The Value Proposition for Distributed Energy Resources

DERs vs. Central Station and Utility Supply-Side Resources

For most of the twentieth century, the electric grid operated on a simple, elegant premise: build large, centralized power plants, transmit electricity over high-voltage lines, and deliver it to passive customers at the end of the wire. That model optimized for economies of scale at the generation level. While the resource mix was optimized, the grid system to deliver it was not part of this optimization analysis, leaving enormous value stranded everywhere else in the system. Distributed Energy Resources unlock that stranded value.

The value DERs provide is not simply supplying electrons, it is a fundamentally different type of value. DERs can deliver targeted response from many locations on the grid, helping the grid balance less predictable sources, like wind generation, and more erratic loads, like EV charging stations. Support includes not only energy balancing, but also the potential for voltage stabilization, phase balancing, power quality management, and enhanced system stability. Understanding this value stack is essential to making the economic case for DERs on a level playing field.

The DER Value Stack

1. Locational and Avoided Infrastructure Value

Central station plants generate power hundreds of miles from load centers, requiring massive investment in transmission and distribution (T&D) infrastructure and incurring significant losses to transport that energy to load. DERs, sited at or near the point of consumption, can defer or eliminate costly T&D upgrades by reducing peak demand on congested circuits and substations, and reduce losses. A well-placed 5 MW battery can defer tens of millions of dollars in substation and distribution upgrades, value that a remote gas peaker can never provide, regardless of its size or efficiency.[7]

2. Resilience and Reliability

Large central station plants and the long transmission lines connecting them represent single points of failure at enormous scale. DERs such as solar with storage, small generators, fuel cells, and even small-scale rooftop wind provide islanding capability, allowing critical loads including hospitals, emergency services, and water treatment plants to ride through grid outages entirely. Resilience value is increasingly recognized by regulators and insurance markets as a core grid attribute.[6,4]

3. Peak Demand Reduction and Capacity Value

Peaking power plants, typically gas combustion turbines, are among the most expensive assets in any utility portfolio, running as few as 50-200 hours per year yet requiring full capital build-out. DER portfolios with direct utility visibility and dispatch control, can provide equivalent or superior peaking capacity at a fraction of the capital cost, with zero fuel price exposure, and with lead times measured in months rather than the 5-7+ years required to permit and construct a new gas plant.[2,1]

4. Voltage Support and Power Quality

Transmission-connected resources operate far upstream of the distribution system and have limited ability to address local voltage fluctuations, harmonics, phase balance, and reactive power imbalances at the feeder level. Advanced inverter-based DERs such as solar, storage, and EVs equipped with grid-following and grid-forming inverter technology can provide real-time voltage regulation, volt/VAR optimization, and power factor correction precisely where the problem exists. This is a service that central station generation physically cannot perform from behind a high-impedance transmission network.

5. Avoided Emissions and Environmental Compliance Value

Central station fossil fuel plants carry long-term variable fuel price, potentially a greenhouse gas price, and environmental compliance risk. DERs, predominantly solar, wind, and storage, carry no fuel cost, no carbon liability, and no criteria pollutant emissions, insulating utilities and ratepayers from regulatory and commodity risk that grows more uncertain with each passing year.[13]

6. Customer Engagement and Load Flexibility

Central station resources can only supply power; they cannot shape demand. DERs embedded in customer premises can create new energy production resources while enabling load to be shifted, shed, or modulated in real time, effectively creating a new, reliable, and dispatchable resource for utilities that reduces system stress during peak periods.[1,10]

7. System Utilization and Load Factor Improvement

Perhaps the most underappreciated DER value is the ability to improve utility system load factor. Effective dispatch of DERs enables utilities to reshape the load duration curve and limit peak demand: feeder by feeder and at scale across the entire system. The electric industry has experienced a persistent decline in load factor for over thirty years. As with gas peaking units, infrastructure must be fully deployed yet is severely underutilized, driving fewer kilowatt-hours sold for every dollar of infrastructure invested, a fundamental contributor to rising rate pressure. For the first time in the industry's history, we have a cost-effective tool to arrest this decline and reverse the trend.[1,7]

Where Central Station Resources Still Lead

It is important to be intellectually honest: central station resources retain meaningful advantages that DERs cannot yet replicate. Bulk energy delivery, sustained output duration over many days or months, fuel diversity (hydro, fossil, nuclear), and inertia provision for grid frequency stability all continue to highlight the reality that a reliable grid must include a variety of resources. There are no silver bullets. DERs are a critical and increasingly cost-competitive part of the resource portfolio that will deliver significant value, but they are *part* of the solution, not the whole solution.

Central station plants provide bulk energy across the system. DERs deliver precision value at the grid edge: deferred infrastructure, local reliability, peak shaving, power quality, environmental compliance, demand flexibility, and load factor improvement.

The goal is not to choose between them; it is to ensure that every resource competes on a genuinely level playing field and is deployed where it delivers the most value.

6. Leveling the Playing Field for Distributed Energy Resources

The Fundamental Regulatory Distortion

Under traditional cost-of-service regulation, a utility earns its authorized return on equity only on capital it directly owns and places into its rate base. Every capital investment, be it a gas peaking plant, a utility-scale solar farm, or a new substation, all flow through the capital expenditure process, receive regulatory approval, and generate a return for shareholders year after year over a multi-decade depreciation schedule. This dynamic applies equally to municipal utilities and rural electric cooperatives, for whom it is far more effective to finance and own a resource than to expense a service in their annual operating budget. This is largely driven by the very low cost of capital that utilities can obtain for these long-term, guaranteed recovery investments that private developers cannot match. The utility has every financial incentive to build and own these assets, regardless of whether an equivalent, cheaper, or better-performing alternative exists.[10]

A DER deployment that meets the identical need of a comparable central station facility earns the utility precisely nothing if procured through a third-party Power Purchase Agreement. It is treated as an operating expense, not a capital investment. It does not grow the rate base. It does not generate a return for the investors. From a pure shareholder value perspective, it is a drag. This is not a hypothetical problem. It is a predictable, rational response by utility management to the incentive structure the traditional regulatory structure has created.[10,9] It is worth acknowledging that this regulatory compact has allowed for the delivery of reliable, affordable, and safe electricity for a century, a necessary structural evolution from the earliest days of electrification when competing utilities built incompatible systems down the same street. It is a model with proven results, but one that must be thoughtfully modified to level the playing field.

Why Utilities Should Not Own (All) DERs Directly

One might ask: why not simply allow utilities to own and operate DERs themselves? For larger-scale community systems that have public access and operate at utility voltage, utilities can readily design, own, and operate these resources effectively. However, when distributed resources live on customer premises, the acceptance of liability on private property and the deployment of utility line crews to customer rooftops does not fit well in any utility operating model. The reality is that most utilities are not structured or staffed for this model at scale, nor should we force them to be.

A robust ecosystem of third-party DER developers and operators has emerged precisely because they have built the competency, the technology platforms, and the risk appetite to do this work efficiently. This is a sensible division of labor: the utility procures the capacity, the third party delivers and operates the assets, and ratepayers get a cost-effective grid resource.[1,2]

The Regulatory Fix: PPA Rate-Base Treatment

The policy logic is straightforward: if the utility benefit is equivalent, the financial treatment should be equivalent. A utility that signs a 30-year PPA with a DER developer to deliver 50 MW of dispatchable DERs, capacity that demonstrably defers a gas peaker and potentially other utility system upgrades that would otherwise have been built, should be able to seek regulatory approval to finance and earn on that PPA in an equivalent fashion to a central station resource. There are several different regulatory mechanisms that may be considered, such as a capital PPA, designated regulatory asset, etc. While there is no single answer to the structure, and each regulatory authority should determine their preferred method, the simple point is that the playing field needs to be leveled appropriately to allow utilities the ability to effectively consider DERs as part of their resource mix. However, it is important that the DER resource be held to a truly equivalent standard: comparable performance guarantees and penalties, and equivalent visibility and control for the utility. The approved contract, with its defined performance standards and cost exposure, should be economically indistinguishable from building the peaker, except that it is likely to provide higher overall value, be faster to deploy, deliver reliability and resiliency the peaker cannot, create more effective partnerships between utilities and customers, and provide a clean energy resource without future fuel price risk.[10]

Regulatory commissions should establish clear pathways for utilities to:

1. Seek pre-approval of DER deployments through an integrated resource/system planning process or competitive solicitation process, applying the same scrutiny applied to traditional capital projects.
2. Define the regulatory structure to level the playing field for DERs.
3. Share the risk appropriately: utilities bear procurement and contract management risk; third-party operators bear performance and technology risk.
4. Track DER performance to improve grid parameters of efficiency, power factor, phase balance, and most importantly, system load factor.

This structure is not a gift to utilities. It is a correction, restoring the neutrality that should have always existed between “build-own-operate" and “procure-and-contract" strategies. The gas peaker or central station renewable facility does not deserve a privileged position simply because it fits neatly into a nineteenth-century regulatory model.

The Cost to Ratepayers of Getting This Wrong

Every year this regulatory gap persists, utilities face a quiet but powerful incentive to prefer capital-intensive, central station solutions over cost-effective and high-value distributed ones. The result is billions of dollars of potentially avoidable infrastructure: gas peakers that run only a handful of hours per year, transmission upgrades that could have been deferred, central station projects with decade-long lead times and a continually declining system load factor, while the DER alternative sits on the shelf, a new and valuable tool for utilities but financially invisible to the utility's income statement.[10,9]

7. The Opportunity FERC Order 2222 Provides for Collaboration

Thirty Years of Fragmentation

As we examine the regulatory landscape, we would be remiss not to recognize the significant step that FERC took with Order 2222. As with most regulatory mandates, the initial view from industry stakeholders was one of significant new compliance burdens. In reality, FERC Order 2222 is an incredible opportunity for the industry, one that deserves to be embraced with the same collaborative spirit that built the modern grid in the first place.

To understand why FERC Order 2222 is such a significant opportunity, one must first understand how profoundly the electric utility industry's capacity for collective problem-solving has eroded over the past three decades. From the 1930s through the 1980s, the electric utility industry operated as a network of regulated monopolies that collaborated extensively on planning, standards development, reliability, and shared infrastructure. The North American Electric Reliability Corporation (NERC) was founded in 1968 precisely as a collaborative response to the 1965 Northeast Blackout, an acknowledgment that the interconnected grid demanded interconnected governance.[16]

The deregulation wave of the 1990s fundamentally disrupted this collaborative culture. Beginning with FERC Orders 888 and 889, which opened transmission to competitive access, and accelerating through the creation of independent system operators, regional transmission organizations, and retail choice initiatives, the industry was deliberately restructured to promote competition among utilities. That competition has driven real efficiency gains in the bulk electric system, but it has come at a cost that is rarely acknowledged: the progressive fragmentation of the industry's capacity to solve problems together.

Over thirty years of deregulation, utilities, generators, transmission owners, distribution companies, retail suppliers, and technology providers have been increasingly incentivized to pursue their own interests rather than optimize system-wide outcomes. Data standards have proliferated without coordination. Interconnection processes have become balkanized across dozens of jurisdictions. The result is a grid whose physical infrastructure remains deeply interconnected, but whose governance, planning, and commercial frameworks have become deeply fragmented.

This fragmentation has been particularly costly for DER integration. DERs are inherently cross-system assets: a rooftop solar installation affects the distribution feeder, the substation transformer, the distribution utility's load forecast, the RTO's capacity market, and potentially the wholesale energy market, all simultaneously. The 3,000-plus electric utilities, cooperatives, and municipal systems in the United States, each pursuing its own path, have produced thousands of approaches to DER interconnection, metering, compensation, and data management, most of them incompatible and nearly all of them more expensive than they need to be.[5]

Order 2222: A Call to Collaborate Again

FERC Order 2222, issued in September 2020, is the most consequential federal DER policy action since PURPA. By requiring RTOs and ISOs to revise their tariffs to allow DER aggregations to participate in all wholesale electricity markets on a level playing field with traditional resources, Order 2222 creates a single, consistent national framework for DERs to be valued as grid resources.[15] LBNL's five-report series on DER aggregations and wholesale markets provides the most thorough regulatory analysis of Order 2222 compliance challenges currently available.[9]

But Order 2222 is more than a market rule change. Read carefully, it is an implicit acknowledgment that the fragmented approach of the past thirty years is no longer adequate for the grid challenges ahead, and an invitation, perhaps even a mandate, for the industry to rebuild its collaborative capacity. The basic design of Order 2222 requires all parties to coordinate and share information, which will necessitate, in many cases, the development of new tools to track and communicate. The question is whether the industry will seize that invitation or treat Order 2222 as yet another compliance exercise to be managed independently by each participant. While there are many potential collaborative efforts the industry could pursue, Order 2222 has highlighted four primary initiatives whose dramatic cost savings are only achievable through genuine industry collaboration.

Opportunity 1: A Non-Profit DER Registry

Today, DERs are registered and tracked through a patchwork of utility-specific systems that do not communicate with one another and require expensive, custom integration work for every market participant. A central DER registry, built once, governed by industry, maintained collaboratively, accessible to all participants, and operated efficiently as a not-for-profit service, could eliminate tens of billions of dollars in redundant systems development. Estimated savings to the industry over ten years: $20-$40 billion. This is not a technology challenge; rather it is a coordination challenge that thirty years of fragmentation have created a system which is harder to manage than it should be.[5]

Opportunity 2: Common Information Model (CIM) Data Structures

The Common Information Model (CIM) has long provided a standard data architecture for generation and transmission systems. Extending CIM data exchanges to the DER domain, creating known, standardized data structures that all utility systems can speak, would shift the integration burden from utilities to the vendor ecosystem, where it belongs. Rather than every utility paying for custom integrations, vendors would build to a common standard once for their product. Estimated value: $100 billion or more in avoided integration costs industry-wide, with a secondary benefit of dramatically accelerating the innovation cycle across the entire utility software ecosystem.[5] Recently, EPRI has helped advance the CIM with additional support for distribution grid as well as hosting events to help vendors interoperate their software solutions. Progress is being demonstrated effectively by the US research and national lab groups, but adoption by industry is significantly lagging.

Opportunity 3: Collaborative Meter Data and Settlement Infrastructure

Meter data management for DERs, the foundation of settlement, compensation, and market participation, is currently being built separately by thousands of utilities using proprietary systems that cannot easily share data across service territories or with the market. The Ontario model, with shared infrastructure, common standards, and distributed management, is a template the U.S. industry should adopt. Estimated savings from doing this right: $75 billion over time, with a compound benefit of making every future market initiative cheaper and faster to implement.[5] Europe is progressing even faster, implementing a technology called “data spaces” to dramatically expand access to data across multiple industry segments, including the electricity and broader energy ecosystem.

Opportunity 4: Shared Communication Infrastructure

Today's utility customers are served by multiple overlapping communication networks, including separate systems for electric AMI, natural gas AMI, water AMI, and many additional redundant networks, often owned and operated by different entities in the same geographic area. Consumers pay for all of these networks through their utility bills. A collaborative approach to shared communication infrastructure, built jointly by gas, water, and electric utilities within a service territory or state, would dramatically reduce cost while improving data quality and coverage.

> Order 2222 is not a burden to be managed. It is a once-in-a-generation opportunity. By having all of industry attack the DER integration challenge simultaneously and collaboratively, we have the unique opportunity to develop solutions at a fraction of the cost of 3,000+ utilities doing it ad hoc.
>
> The question is not whether the industry can afford to collaborate.
>
> It is whether it can afford not to.

8. Why Change Is So Hard in the Electric Utility Industry

A Perspective from the Field

After decades working across generation, transmission, distribution, and grid operations, we have watched the electric utility industry navigate wave after wave of technological transformation, from the electrification of rural America to the integration of digital controls, from the deregulation era to the rise of distributed energy resources. In every cycle, the same frustration surfaces from the outside world: why does the utility industry move so slowly? The answer is not stubbornness. It is a responsibility to maintain reliability.

Lives Hang in the Balance: Utilities Know It

Every decision made in a utility control room, every relay setting, every protection scheme, every software update pushed to a substation carries consequences that most industries never have to contemplate. When a hospital loses power during surgery, when a water treatment plant goes dark in a heat emergency, when a natural gas pipeline loses its electric-driven compressors in the dead of winter, people die. Electric utilities carry this weight every single day, and they do not take it lightly. The mandate is clear and unwavering: deliver reliable, safe, and affordable electricity. Not most of the time. All of the time.

This is why utilities invest so heavily in redundancy, why protection systems are engineered with multiple layers of fail safes, and why new technology and operational changes go through rigorous internal review before anything touches the live grid. It is not bureaucracy for its own sake; it is engineering discipline applied to a system where failure is measured in human lives and economic collapse, not customer churn or quarterly earnings.

The Frameworks Are Immense and Exist for Good Reason

The electric utility industry operates within one of the most complex regulatory and technical ecosystems on the planet. NERC reliability standards, FERC tariff obligations, state public utility commission rate cases, EPA environmental compliance, OSHA workforce safety mandates, and cybersecurity frameworks like NERC CIP all govern how utilities plan, build, and operate the grid. These are not arbitrary hurdles; they are the hard-won product of real failures, real disasters, and real lessons learned over more than a century of operation. Understanding them takes years of immersion. Dismissing them takes only a press release.

Interconnected systems mean that a decision made in one control area can cascade across thousands of miles in milliseconds. The 2003 Northeast Blackout left 55 million people without power from a sequence of events that began with a software alarm failure in Ohio.[16] The grid does not forgive small mistakes. A technology that performs flawlessly in a laboratory or well-controlled pilot program may behave in entirely unexpected ways when connected to an interconnected grid with thousands of simultaneous variables and millions of customers depending on an uninterrupted power supply.

The Problem With Disruption Over Collaboration

The technology community increasingly arrives at the utility industry's doorstep not as a partner, but as a disruptor, armed with compelling demonstrations, venture-backed urgency, and a narrative that frames utility caution as institutional inertia. What is missing from that narrative is intellectual honesty about the stakes. Proving a technology works in a lab with limited practical exposure is a long way from proving it is ready to be woven into the fabric of a grid that serves millions of people with little tolerance for unexpected failure modes.

Utilities are not opposed to innovation. They are opposed to unmitigated risk to the critical infrastructure. The difference matters enormously. When technology providers choose to work with utilities, understanding the interconnection studies, the protection coordination requirements, the cybersecurity protocols, the NERC compliance obligations, and the regulatory process, remarkable things happen. Smart grid deployments scale. Advanced metering infrastructure transforms demand response. Battery storage reshapes capacity planning. The innovation moves forward, and it moves forward safely.

The Path Forward Is Partnership, Not Pressure

The electric grid is the backbone of modern civilization. Every economic transaction, every hospital, every school, every home depends on it functioning reliably. The men and women who operate, maintain, and engineer that grid understand their obligation better than anyone. They are not the enemy of progress. They are its most important quality control, and they have earned that role through decades of delivering on a promise that most people only notice when it is broken.

The sooner the broader energy technology ecosystem embraces that truth and trades disruption for genuine collaboration, the faster and more safely the industry will transform. The utilities will get there. They always have. But they will do it on a timeline that reflects the weight of their responsibility, and without gambling with the lives of the people they serve.

9. Summary and Call to Action

Where We Are: A True Inflection Point

The electric power industry has arrived at a genuine inflection point in the story of Distributed Energy Resources. The foundation has been built. The question now is whether the industry can adapt its planning frameworks, regulatory structures, and collaborative culture to use it.

What Must Change: A Clear-Eyed Assessment

- **Re-Invent Planning.** Planning frameworks must evolve from purely top-down IRPs to bottom-up ISPs that begin at the distribution edge and appropriately values DERs as utility-class resources.[7]
- **Transform Regulation.** Regulatory structures that create systematic financial disadvantage for DERs must change, allowing utilities to earn authorized returns on DERs that achieve equivalent, and even enhanced, outcomes when compared to traditional resource investments.[10]
- **Re-Institute Collaboration.** Collaborative capacity must be rebuilt. FERC Order 2222 provides the clearest mandate in a generation for the industry to collaborate again, on shared registries, common data standards, joint meter and settlement infrastructure, and shared communication networks.[15,5]
- **Reduce Barries.** The relationship between utilities and technology providers must mature from adversarial disruption to genuine partnership. Neither side can build the grid of the future alone.

Throughout all of this, intellectual honesty demands acknowledgment: there are no silver bullets. DERs are a critical and increasingly cost-competitive and valuable part of the resource portfolio, but they are not the whole solution. The goal is not to replace one model with another; it is to ensure that every resource, distributed and centralized alike, competes on a genuinely level playing field and is deployed when and where it delivers the most value to the utility and their customers.

The Call to Action

For Regulators

- Encourage bottom-up ISP as a complement to IRP in every state, requiring utilities to track a new set of grid health metrics including load factor, power factor, phase balance, and distribution efficiency at a circuit level.[7]
- Establish clear pathways for utilities to receive appropriate compensation for DER investments that achieve equivalent, or enhanced, outcomes comparted to traditional resource investments, with appropriate risk-sharing, performance guarantees, and penalty mechanisms.[10]
- Engage with utilities to ensure technology being implemented meets the IEEE 1547 current standard, and that interconnection rules are structured to allow DER interconnection while

requiring all resources capable of injecting into the grid to follow safety protocols required to keep utility line personnel safe.

- Use the Order 2222 implementation process as a vehicle for developing shared industry infrastructure, including registries, data standards, and settlement systems, rather than allowing it to become thousands of separate compliance exercises.[15,9]

For Utilities

- Be willing to engage in the DER conversation with clarity and confidence. Be clear that utility visibility and control of resources connected to the grid you are required to manage is a non-negotiable requirement, not an obstacle. Integrate distribution capacity analysis and locational net benefit assessments into annual planning cycles to inform your IRP and ISP processes.[7]
- Engage proactively in Order 2222 implementation as a collaborative opportunity, not a compliance burden. Invest in the shared infrastructure that makes DER integration cheaper for everyone.
- Work with your regulatory authority to develop procurement frameworks that create a level playing field for DER investment without requiring utilities to assume non-traditional utility risk.[18]

For Technology Providers

- Invest in the regulatory, operational, and technical literacy that earns utility trust. Understand interconnection studies, protection coordination, NERC CIP compliance, and state commission processes before asking utilities to trust your technology with their grid. It is not the utility's responsibility to make your business model work; it is your responsibility to provide a solution that is competitive with, or more valuable than, existing options.
- Build to open, common standards, including CIM APIs, standard interconnection interfaces, and interoperable communication protocols, rather than proprietary architectures that lock utilities into single-vendor dependencies. While proprietary architectures may seem more profitable in the short term, vendors who invest in CIM compatibility will find dramatically greater market opportunity as the industry moves in this direction. The current construct of thousands of incompatible software interfaces is unsustainable, and those who help solve it will earn durable market share.

For the DOE and Federal Government

- Continue and expand investment in R&D programs targeting data standards and system architecture to support lower technology costs, advanced inverter and grid-enhancing technology capabilities, and the computational tools needed for bottom-up ISP.[17]
- Use the convening authority of DOE and FERC to accelerate the development of shared industry infrastructure, including the DER Registry, CIM data standards, and collaborative meter and settlement frameworks.[5]

The transformation of the electric grid is already underway. The distributed revolution is not coming; it is here.

The only question that remains is whether the utilities, regulators, and technology providers who share responsibility for the grid will adapt their planning frameworks, their regulatory structures, and their collaborative culture quickly enough to harness what is already being built.

The grid has survived every previous wave of transformation by combining engineering discipline with the courage to change. It will survive this one too, if the industry chooses collaboration over fragmentation, technology providers choose partnership over disruption, and regulators can support honest assessment over comfortable inertia.

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