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How to Determine the Real Value of DERs

A Practitioner's Guide to Capturing the Full Value Stack of Distributed Energy Resources

Distributed Energy Resources have been transformational to the utility industry across the world as their costs have declined. Unfortunately, most have been deployed without utility visibility and control. This has created many, or more, problems for the grid technically and economically than they have been able to solve. Coordinated planning and evaluation of DERs represent the single greatest opportunity to help affordably serve customers in decades but we must value these resources appropriately and create equivalent regulatory recovery mechanisms to level the playing field.

Creation Energy
Empowering the energy transition

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Executive Summary

Distributed Energy Resources are the most misvalued assets in utility planning today. When a utility's Integrated Resource Planning model compares a DER portfolio against a gas peaker on capacity and energy alone, DERs appear more expensive. That comparison is wrong: the math is not bad, but it accounts for less than half the value DERs actually deliver.

This paper provides utilities and regulators with a practical framework for evaluating DERs in their systems. It provides a structured, evidence-based breakdown of the major value stream that a properly designed and deployed DER portfolio produces: from the reduction of peak load and the improvement of system load factor, to the elimination of grid losses through the correction of power factor and phase imbalance and transport losses, the deferral of distribution infrastructure, and a dozen additional streams that rarely appear in any IRP model.

A direct comparison illustrates the point: a 50 MW DER portfolio deployed in the load pocket produces a net system effect of 63.5 MW. A 50 MW central station peaker produces a net system effect of only 36.5 MW. Directly comparing the actual effect on utility system can be viewed this simply. However, within the utility and regulatory framework, DERs must be modeled in an Integrated Resource Plan (IRP) to provide both the utility and their regulator the comfort that this new resource (DERs) is a cost-effective and valuable part of utility resource portfolio. This paper will move through some of these simple comparisons to set the stage and help explain how DERs deliver value and then provide a deep dive with a specific utility to demonstrate these values.

In the specific utility example, deploying DERs across 25,000 homes and 250 grid optimization stations reduces system peak by 679 MW, improves load factor from 0.46 to 0.63, and unlocks over $577 million in annual latent revenue capacity within the existing infrastructure footprint, before a single dollar of non-wires alternative savings, power factor correction value, or REC revenue is counted.

The playing field is not level today. Planning frameworks do not recognize these DER values in the analysis and regulatory frameworks do not allow equivalent earning potential for the utility. Even if a DER can provide equivalent, or higher value, a utility is clearly advantaged by choosing a central station facility they can own versus a DER they cannot. To effectively move forward and provide an affordable, reliable, and clean energy future, DERs must be appropriately analyzed and allowed equivalent recovery.

> *DERs are not simply another resource choice. They are the first technology in over 100 years capable of simultaneously fixing the three root-cause problems of the electric grid: the Load Duration Curve Peak (System Load Factor), Power Factor, and Phase Imbalance. Any valuation framework that ignores a complete value framework is not a fair DER analysis; it is a partial, systematically biased accounting that will produce an answer that undervalues DERs and does not recognize the significantly positive impact they can deliver for a utility and their customers.*

1. The Foundation: Understanding What the Grid Actually Costs

1.1 The Load Duration Curve Drives Everything

Before any DER value can be quantified, the utility's Load Duration Curve (LDC) must be understood at a granular level. The LDC ranks all 8,760 hours of the year from highest demand to lowest, revealing exactly how much capacity the utility must maintain at every level of system load. It is not merely a planning tool; it is the single most important driver of every generation investment, every wires upgrade, and every rate increase the utility pursues. Figure 1 shows the traditional line chart for a utility LDC.

Traditional Utility Load Duration Curve

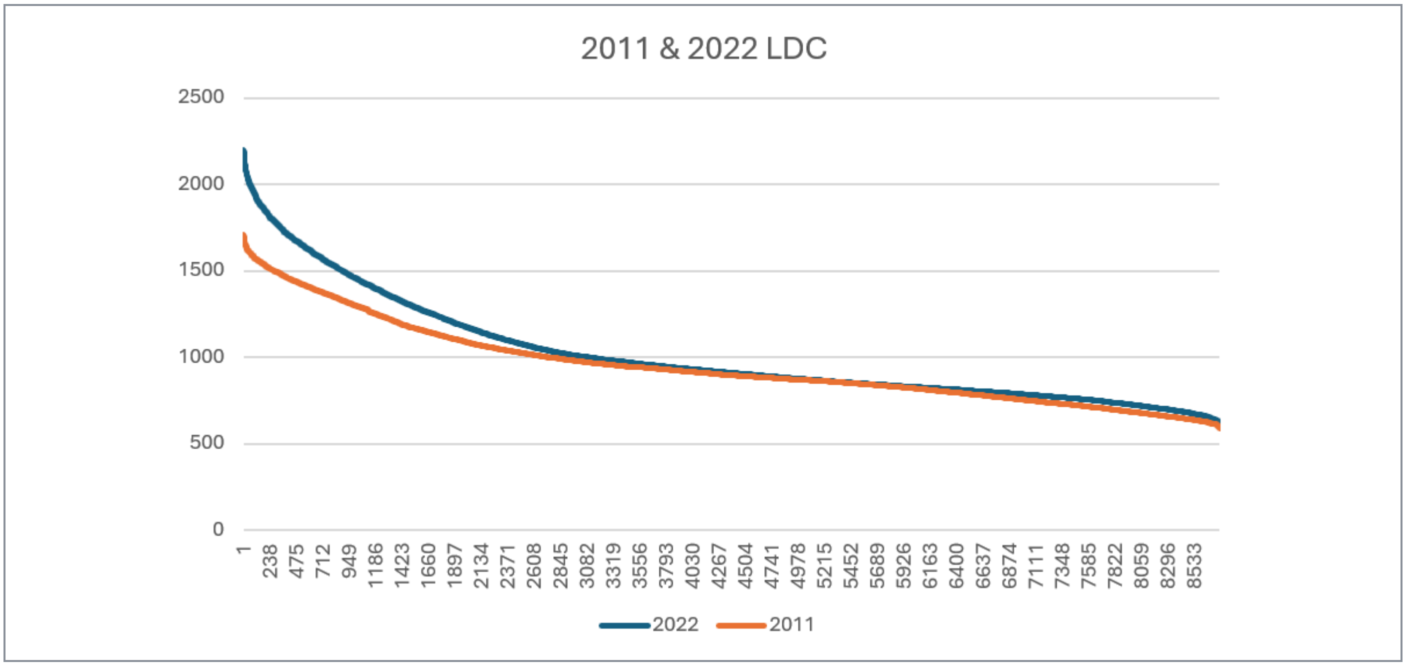

Figure 1: Traditional Utility Load Duration Curve

The fundamental problem the LDC reveals is one of radical imbalance between investment and utilization. Utilities are legally obligated to serve peak demand reliably. But peak demand, the top of the curve, occurs for only a tiny fraction of the year. Every megawatt of capacity built to serve that peak must be financed, maintained, and staffed whether it is utilized for one hour or 8,760 hours.

Examining the 2022 LDC reveals precisely what kind of solution is required to reshape and flatten the curve. The utility managed approximately 750 MW of peak load that existed for only 800 of the year's 8,760 hours. The chart below shows the precise hourly exposure at each MW threshold. This analysis must guide the required solution to improve the LDC:

Utility Hourly Exposure by MW Threshold (2022 Data)

MW Threshold	Total Hours / Yr	Max Cont. Hours	Annual Exposure ▶
2200 MW	1	1 hrs	1 hrs
2100 MW	14	4 hrs	14 hrs
2000 MW	54	6 hrs	54 hrs
1900 MW	128	8 hrs	128 hrs
1800 MW	251	10 hrs	251 hrs
1700 MW	417	11 hrs	417 hrs
1600 MW	632	12 hrs	632 hrs
1500 MW	887	13 hrs	887 hrs
1400 MW	1,174	15 hrs	1174 hrs
1300 MW	1,505	17 hrs	1505 hrs
1200 MW	1,883	22 hrs	1883 hrs

Figure 2: Utility Hourly Exposure by MW Threshold (2022 Data)

> *Critical design insight: A 4-hour product has very limited effect on the LDC. An 8-hour product that can permanently shift load, or directly serve peak demand, for at least 251 hours per year can remove 400-500 MW from the top of the curve. Duration matters as much as nameplate capacity.*

1.2 Peak Load Grows Faster Than Base Load

Everything in the electric system, including generation equipment, conductors, transformers, and customer loads, becomes less efficient as temperature rises. Air conditioning, which drives the residential and commercial peak, is simultaneously the largest single contributor to peak demand and the load that grows fastest as temperatures increase. The result is a structural, physics-driven tendency for peak load to outgrow base load over time.

While the traditional LDC line graph captures the same underlying data, viewing the full 8,760-hour profile in three dimensions reveals a much clearer understanding of this challenge for the utility.

Three Dimensional 8760 Shapes (2011 & 2022)

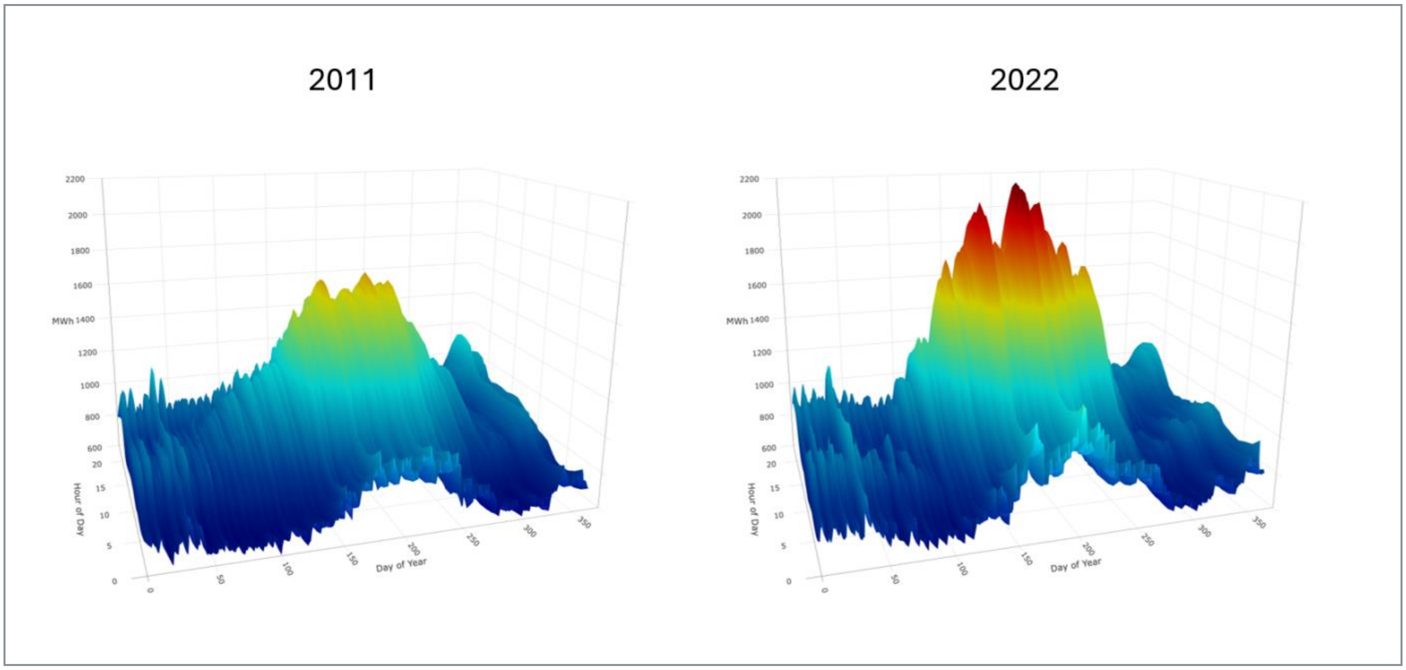

Figure 3: Three Dimensional 8760 Shapes (2011 & 2022)

This demonstrates clearly that the LDC does not remain static, nor does it grow uniformly across all hours of the year. Its peak grows faster than its valley, year after year. Each degree of warming, each new air conditioner installed, each new data center brought online widens the gap between the peak the utility must build for and the average load that actually recovers their investment. This widening gap is captured precisely by a single metric: the load factor.

1.3 The Load Factor: The Single Most Important System Efficiency Metric

Load factor is the ratio of average load to peak load. It measures how efficiently the utility's generation, transmission, and distribution assets are utilized. A load factor of 0.60 means assets are used, on average, at 60% of their rated capacity. A load factor of 0.46 means 54 cents of every dollar of infrastructure investment is idle on average.

The utility's load factor data from 2011 through 2022 tells a consistent and troubling story:

Figure 3: Utility Annual Load Factor 2011-2022 (Higher = Better)

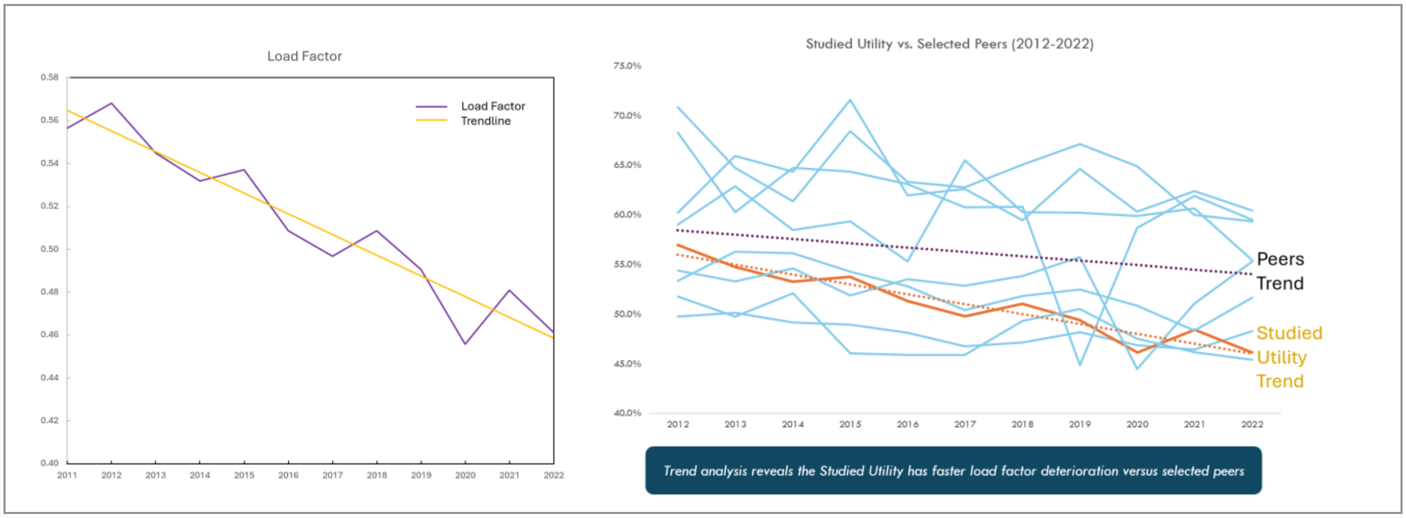

Figure 4: Utility Annual Load Factor 2011-2022 (Higher = Better)

The downward trend, from 0.56 in 2011 to 0.46 in 2022, is not coincidental. It reflects the compounding effect of peak-driving loads (largely cooling) growing faster than base load, while the utility continued to build central station capacity to match peak rather than investing to reshape the LDC. Every year the load factor declines, the utility serves less energy with more infrastructure, raising costs for all customers.

Benchmarked against peer utilities, the data tells a striking story.

Load Factor Peer Benchmarking: UTILITY vs. Selected Balancing Authorities (CY2022)

Utility	CY2022 Load Factor	Annual Linear Trend
Utility A	60.4%	(0.38%)
Utility B	59.5%	(0.88%)
Utility C	59.3%	(0.60%)
Utility D	55.4%	(0.14%)
Utility E	55.3%	(0.24%)
Utility F	51.7%	(0.55%)
Utility G	48.3%	(0.29%)
STUDIED UTILITY	**46.2%**	**(1.00%)**
Utility I	45.4%	(0.44%)
WITH DERs (Projected)	**63.1%**	**+17.0%**

Figure 5: Load Factor Peer Benchmarking - Utility vs. Selected Balancing Authorities (CY2022)

> *At 1.00% per year, the utility's load factor deterioration is the fastest of all nine utilities in the benchmark group. Peer utilities range from 0.14% to 0.88% annual deterioration. At current trajectory, the utility will reach the 0.40 threshold within a decade. DERs are the only proactive tool available to reverse this trend.*

This is not new information for the utility industry. The economic reality is that no cost-effective technology solution to reshape the LDC has existed until now. Technology solutions were simply not available to address the root cause of the LDC. For the past 30 years, the industry has relied on non-technology workarounds. Time-of-Use (TOU) rates and Demand Response (DR) programs are the primary tools deployed. These policy-driven tools have been piloted and implemented across every utility shown in Figure 5. It should be very clear that they are not addressing the problem. This paper does not evaluate TOU or DR program efficacy in depth, but it is important to note that these efforts, regardless of their reported value, have had little measurable impact on peak load management or the declining load factor trend evident across the industry. DERs, a technology-enabled and dispatchable resource, offer the first viable solution to this problem in the industry's history.

2. Value Stream 1: Peak Load Reduction and Load Factor Improvement

2.1 The Transformational DER Effect at Scale

The most powerful and most consistently undervalued contribution DERs make to the utility system is the reshaping of the load duration curve itself. Unlike any central station resource, a DER portfolio deployed in the load pocket can simultaneously reduce peak demand and raise the base load floor, improving load factor from both directions simultaneously.

The following analysis compares two development scenarios against the utility's 2022 baseline LDC: (1) the addition of 25,000 homes through conventional non-DER development; and (2) the addition of 25,000 DER-enabled homes combined with 250 Grid Optimization (GO) Stations. The full magnitude of the DER effect is captured in Figure 6 and illustrated in Figure 7.

Load Duration Curve Scenario Comparison

Metric	2022 Baseline	Non-DER Development (+25,000 homes)	DER Development (+25,000 homes + 250 GO Stations)
Load Factor	0.46	0.46	0.63
Peak Load (MW)	2,201	2,314	1,635
Min Load (MW)	617	633	617
Avg Load (MW)	1,015	1,068	1,026
Peak Delta vs Non-DER	—	+113MW	−679 MW

Figure 6: Load Duration Curve Scenario Comparison

These numbers tell a multi-layered story. Conventional development without DERs makes an already-deteriorating situation worse: 25,000 new homes push peak demand from 2,201 MW to 2,314 MW, further straining infrastructure and suppressing load factor. DER-enabled development reverses the trajectory entirely: the same 25,000 homes, paired with grid optimization stations, reduces peak to 1,635 MW, a 679 MW swing from worst to best case, all without a single new wire or substation.

Load Duration Curve Scenario Comparison: Utility System

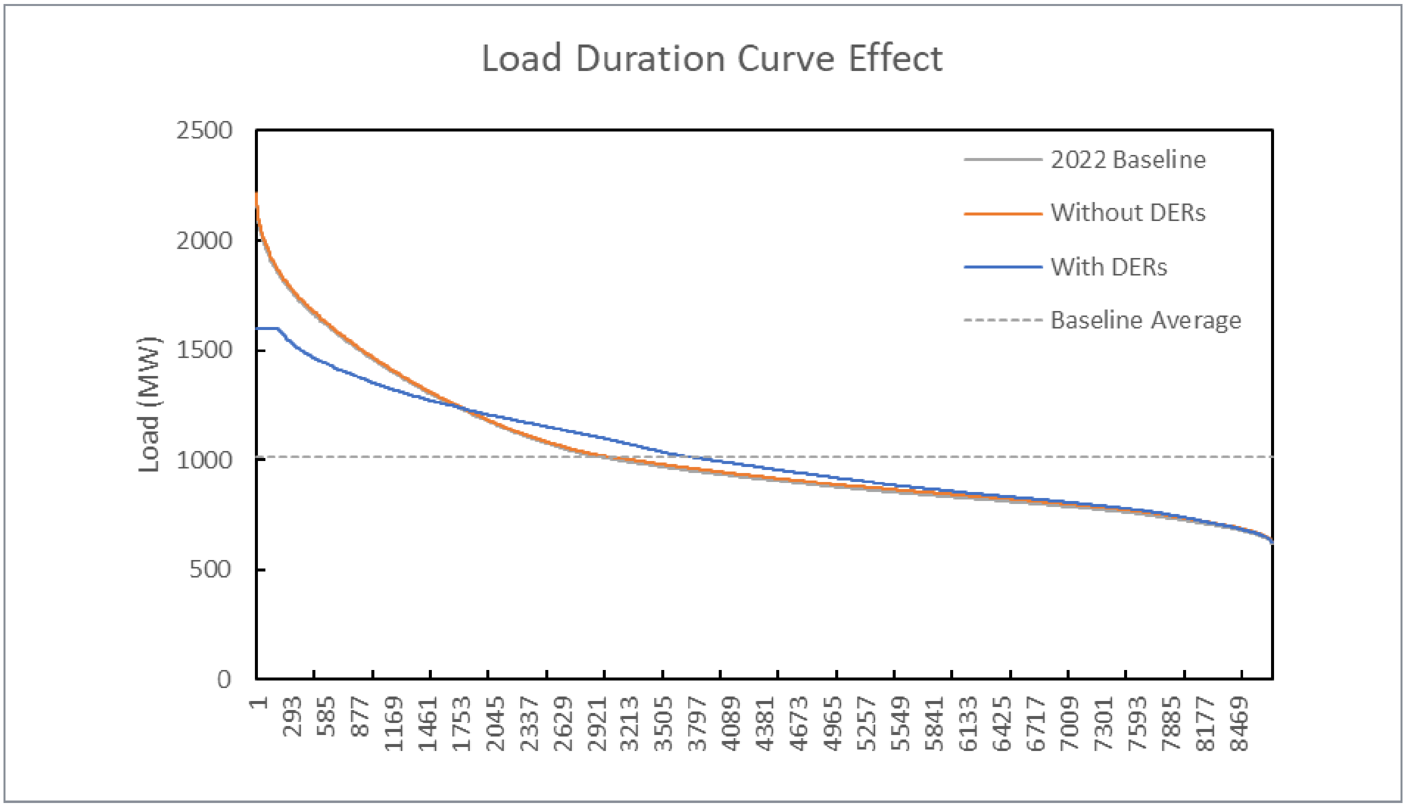

Figure 7: Load Duration Curve Scenario Comparison - Utility System

2.2 Quantifying the Value of Load Factor Improvement

When DERs flatten the top of the load duration curve, they accomplish something no central station resource can: they unlock latent capacity already embedded throughout the generation fleet and wires system. Infrastructure built and financed to serve peak demand suddenly has headroom to serve additional load without new capital investment.

To translate this into dollar terms, the analysis shifts the DER-improved load duration curve back up to the previous peak level and calculates how much additional energy could be served using the existing asset base. At this utility's scale, the result is:

MWH's and Revenue Unlocked with DERs

Incremental MWh Unlocked	Revenue at $0.12/kWh	Conservative 10-yr View (50%)
4,813,463 MWh / year	**$577,615,554 / year**	**~$288M / year by Year 10**

Figure 8: MWH's and Revenue Unlocked with DERs

This value, serving more customers on infrastructure already built and financed, is the equivalent of filling empty seats on an aircraft already in the air. Incremental cost is minimal; incremental revenue is nearly pure margin.

> *The load factor improvement value alone, conservatively estimated at 25% capture in the short term, represents over $144 million in annual revenue potential for the utility without any additional capital investment in generation, transmission, or distribution.*

3. Value Stream 2: The In-Load-Pocket IRP Advantage

3.1 Why Location Changes Everything

The most fundamental error in comparing DERs to central station resources is treating them as though they occupy the same position in the power system; they do not. A central station peaker, whether gas, utility-scale solar, or large battery, is sited outside the load pocket. Its output must travel through transmission conductors, through substation transformers, and along distribution feeders to reach the customer. Every step of that journey incurs losses, requires spinning reserves to cover contingencies, and demands infrastructure investment.

DERs, by definition, are located at or near the point of consumption. They eliminate transportation losses rather than incur them. They reduce the amount of spinning reserve the system requires rather than add to it. And because they correct power factor and phase balance at the point of load, they generate energy efficiency benefits that propagate back through the entire feeder, substation and transmission system upstream.

IRP System Effect: 50 MW Central Station vs. 50 MW DER In-Load Pocket

Traditional 50 MW Central Station Peaker	50 MW DER In-Load Pocket Portfolio
Starting Nameplate: 50 MW	**Starting Nameplate: 50 MW**
T&D Losses (10%): LOSE 5 MW	**NO T&D Losses:** GAIN 5 MW
Spinning Reserve (12%): LOSE 6 MW	**Reduces Spinning Reserve:** GAIN 6 MW
PF/PB Efficiency: LOSE 2.5 MW	**PF/PB Correction:** GAIN 2.5 MW
NET IRP EFFECT: 36.5 MW	**NET IRP EFFECT: 63.5 MW+**

Figure 9: IRP System Effect - 50MW Central Station vs 50MW DER In-Load Pocket

The net result: a 50 MW DER portfolio delivers a system IRP effect of 63.5 MW while a 50 MW central station peaker delivers only 36.5 MW. That is a 74% greater effective contribution per nameplate megawatt, a differential that should appear explicitly in every utility resource comparison but almost never does. This is a simple comparison to illustrate the comparative nature of central station and DERs. It helps to understand the results of an IRP tool like Plexos achieves positive results when running much more complex dispatch and economic strategies of these two options.

> *This is not double-counting. An IRP model compares how each solution affects the total system. The T&D loss savings, spinning reserve reduction, and power factor efficiency gains are real, measurable changes to system-wide load. The IRP process is structured to compare the outcomes of different case studies and then compare those outcomes. They belong in the analysis.*

3.2 Deployment Timeline: An Undervalued Dimension

Central station resources require four to six years, and sometimes decades, to plan, permit, site, and construct. DERs can be deployed in months. In an era of rapidly rising peak demand driven by data centers, industrial electrification, and EV adoption, this speed advantage has direct financial value: avoided carrying costs on deferred capacity, avoided risk of supply shortfalls during the construction window, and avoided exposure to construction cost overruns that plague large infrastructure projects.

Construction Time Frames

Build Timeline Comparison		Years
Gas Peaker (Traditional)		6+ years
Utility-Scale Solar Farm		4 years
Utility Battery Storage		3 years
DER Portfolio (50 MW)		1.5 years

Figure 10: Construction Time Frames

4. Value Stream 3: Power Factor Correction

4.1 The Problem That Has Never Been Solved

Power factor is the ratio of 'true power' (the kilowatts actually doing work) to 'apparent power,' the total current drawn from the system. A power factor of 1.0 means every ampere flowing through the grid is doing useful work. A power factor of 0.85 means 15% of the current flowing through every wire, transformer, and conductor in the system is non-productive reactive current, generating heat, consuming capacity, and degrading efficiency at every point from the generator to the customer meter. A simple explanation of power factor is shown in Figure 5.

Power Factor Explained via the Power Wagon

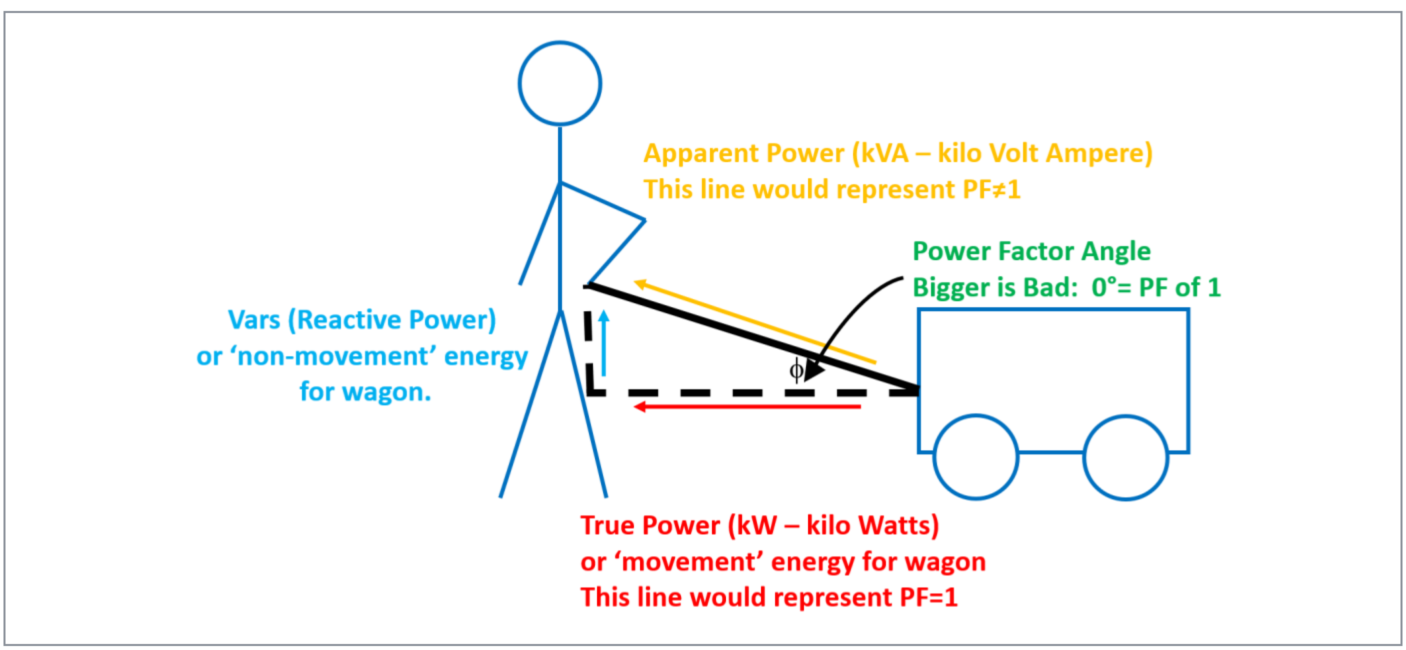

Figure 11: Power Factor Explained via the Power Wagon

Distribution feeders in the United States today typically operate between 0.84 and 0.92 power factor lagging. This is not a design choice but a structural consequence of the inductive nature of residential and commercial loads (motors, ballasts, HVAC compressors). For over 100 years, utilities have had no practical way to correct it at scale. They have simply absorbed the losses, built extra capacity to compensate, and passed the cost to ratepayers.

Power Factor: Before and After DER Correction

PF = 0.84 - 0.92 (Typical Today)	PF = 1.00 (With DER Correction)	Improvement
15-16% of current is reactive (wasted)	0% reactive current	**Eliminates reactive losses entirely**
Central generation must produce VARs	VARs generated at the load point	**No long-distance VAR transport**
i^2R losses elevated throughout network	i^2R losses minimized at all levels	**40-60% reduction in losses**
Grid stability reduced by VAR flow	VAR flow eliminated from bulk system	**Improved stability margins**
Equipment operates above rated current	All equipment at rated efficiency	**Life extension for all grid assets and customer equipment**
Required: larger conductors & transformers	Existing infrastructure used optimally	**Deferred infrastructure upgrade or replacement**

Figure 12: Power Factor - Before and After DER Correction

4.2 How DERs Fix It

Modern four-quadrant inverters, the type paired with solar and battery DER deployments, can dynamically adjust power factor anywhere between 0.8 and 1.2 leading or lagging. Receiving real-time signals from substation SCADA systems, a fleet of residential inverters can collectively correct power factor for an entire distribution feeder, 24 hours a day, 365 days a year.

The key insight is that power factor correction via inverter requires only that the inverter has a source on its DC bus, which solar and battery provide, and incurs virtually no additional energy losses at the customer site. It is, in effect, a free system efficiency improvement that comes embedded in every DER installation that is IEEE 1547 compliant. Testing at Pecan Street has confirmed that four-quadrant inverters can achieve unity power factor at the feeder level through real-time SCADA integration[1].

4.3 Quantifying the Value

Correcting power factor and phase balance on the distribution system could eliminate 40 to 60 percent of the technical losses. Applied across the U.S. grid, which consumed approximately 4,000 terawatt-hours in 2022[2] and incurred roughly 400 GWh in technical losses, even a 5-percentage-point improvement in loss reduction through DER deployment represents 200 GWh in annual savings nationally. At the individual feeder level, the value is 1 to 2 million kWh of energy efficiency per feeder per year, classified and certifiable as White Tag energy efficiency savings.

Power Factor Correction: Value Components
1. Energy efficiency savings: 1-2M kWh per feeder per year (White Tag certifiable) 2. Capacity release: Correcting PF from 0.86 to 1.0 effectively increases feeder capacity by 14% without hardware changes 3. Life extension: Reduced reactive current lowers thermal stress on all conductors, transformers, and customer motors 4. Grid stability: Eliminating VAR flow from traditional central station generation to the distribution system reduces reactive power demand on the bulk electric system, improving voltage stability margins across the network

5. Value Stream 4: Phase Balance Correction

5.1 A Structural Problem Built Into Every Feeder

American distribution networks serve homes on a single-phase basis. When a subdivision of 52, 119, or 18 homes is connected to a three-phase feeder, perfect balance is impractical to achieve, and even if it were achieved at the moment of construction, it would not survive the first change in customer behavior.

Phase Balance for One Day

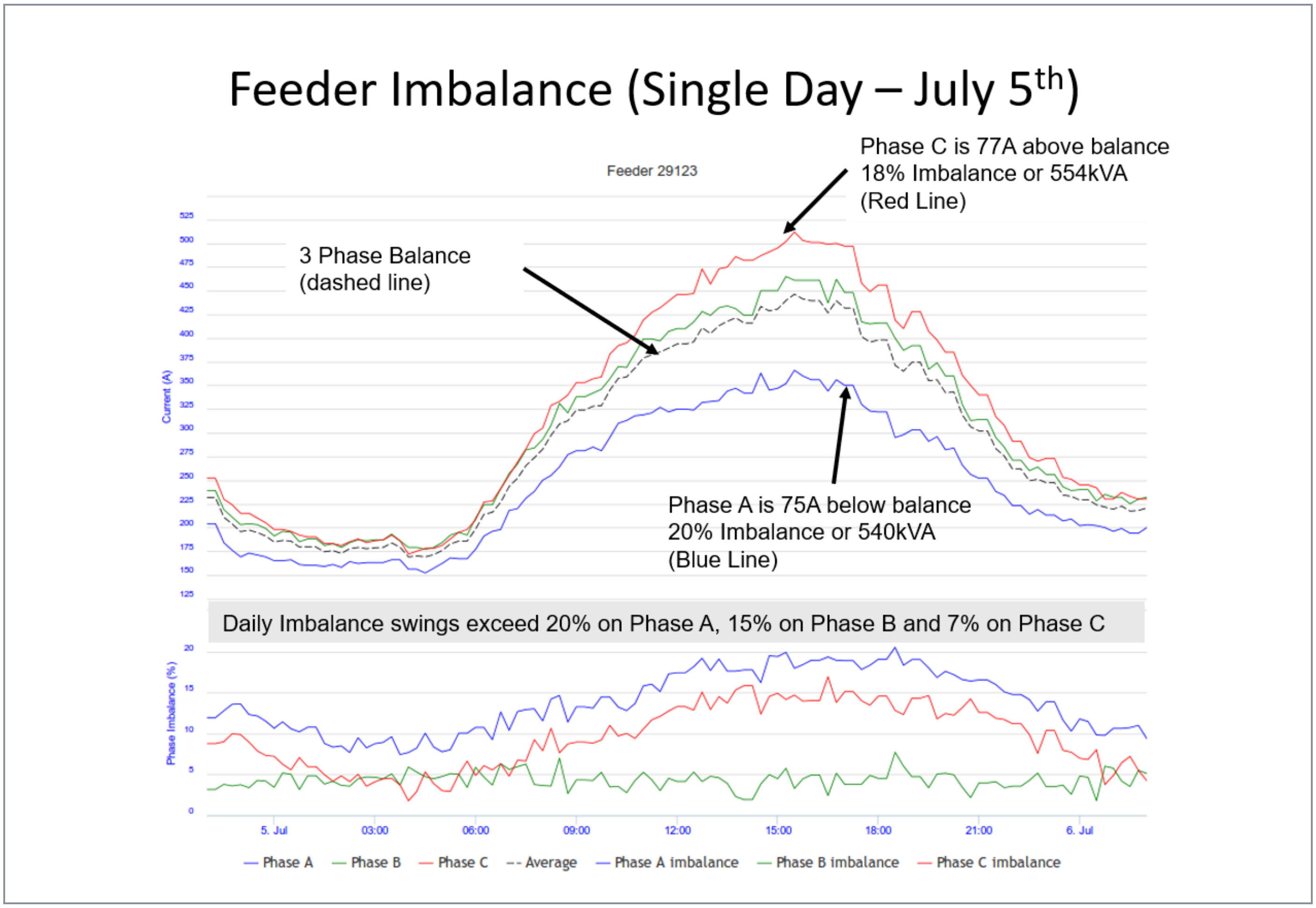

Figure 13: Phase Balance for One Day - Feeder Imbalance

Phase imbalance is dynamic: it shifts throughout the day as customers wake up, turn on appliances, run air conditioning, and charge vehicles. It shifts seasonally as heating and cooling loads redistribute across phases.

Phase Balance in Winter and Summer

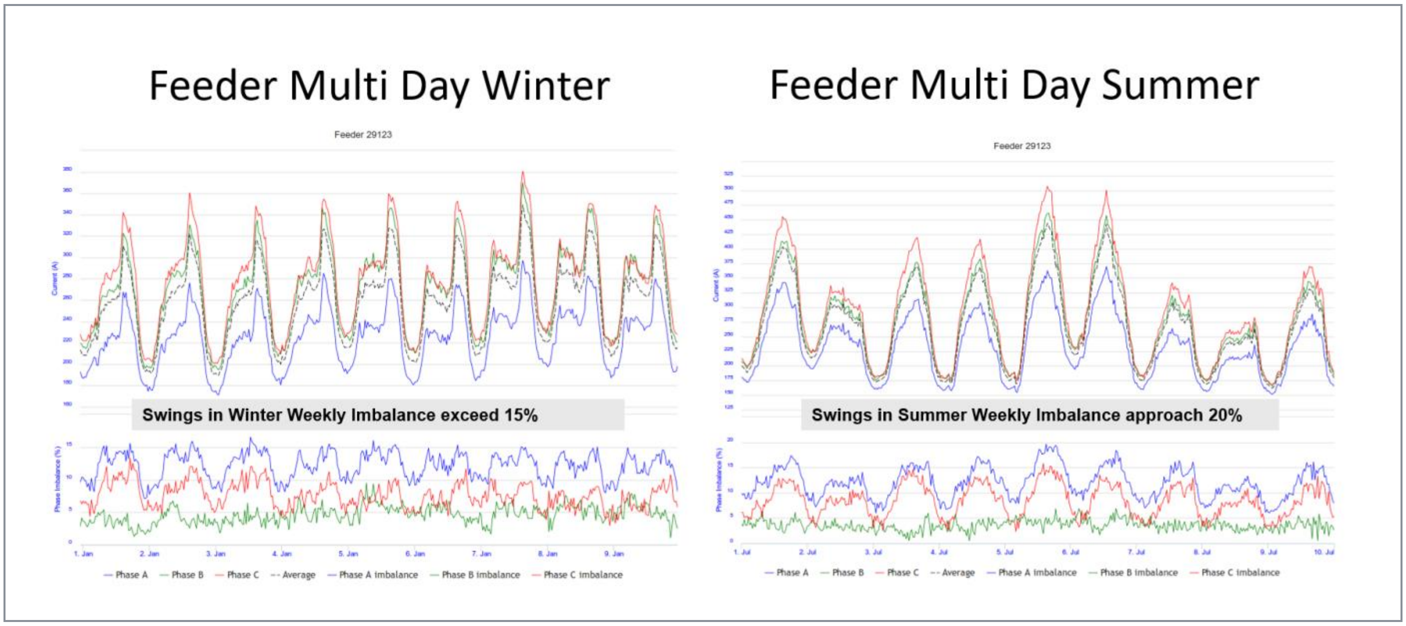

Figure 14: Phase Balance in Winter and Summer

Traditional correction methods, such as manually repositioning transformer taps, cannot track this dynamic imbalance. A correction made for summer peak conditions can worsen winter imbalance on the same feeder. A study of 3,000 distribution feeders[3] found that 87% operated with imbalance greater than 10% and 24% were critically imbalanced above 25%. These feeders were not being managed; they were being tolerated.

5.2 The Cost of Tolerating Imbalance

The cost of tolerating phase imbalance has been studied extensively. An Enernex modeling study[4] is unambiguous: correcting just 4% of phase imbalance on a typical feeder reduces both grid-side and customer-side motor losses by approximately 40%. This is not a marginal improvement; it is a fundamental reduction in the waste that has been baked into every distribution circuit for the past century.

Value of Correcting Phase Balance

Phase Imbalance: Loss Reduction Opportunity		% Loss
Feeder losses at 0% imbalance (ideal)		5 % loss
Feeder losses at 2% imbalance		6.5 % loss
Feeder losses at 4% imbalance (typical)		9 % loss
Motor losses at 0% imbalance		4 % loss
Motor losses at 2% imbalance		5.5 % loss
Motor losses at 4% imbalance (typical)		7.5 % loss

Figure 15: Value of Correcting Phase Balance

5.3 DERs Solve What No Previous Technology Could

Phase imbalance is dynamic, so its correction must be dynamic. Four-quadrant inverters connected to solar and battery DER systems can inject or absorb current on a per-phase basis in real time, tracking the imbalance as it shifts throughout the day and across seasons. A fleet of DER-enabled homes on a feeder, coordinated by a simple signal from utility SCADA, can maintain near-zero imbalance continuously, something no previous technology has been capable of achieving.

> *Phase balance correction via DERs produces 40-60% reduction in distribution technical losses and extends the life of every transformer, conductor, and customer motor on the served feeder. This is a perpetual, ongoing efficiency gain with no fuel cost and no incremental operating expense beyond the DER deployment itself.*

6. Value Stream 5: Non-Wires Alternatives

6.1 The Distribution Planning Window Opportunity

Every utility with a significant distribution system has feeders and substations approaching their thermal capacity limits. Historically, the only solution has been reconductoring (replacing undersized wire with larger-gauge wire), substation transformer upgrades, or new substation construction. These are capital-intensive projects that take years to plan and permit, cost millions of dollars each, and produce additional capacity that immediately begins to deteriorate toward the next upgrade threshold.

DERs offer a fundamentally different approach. By reducing peak demand at the feeder level through local solar generation, battery dispatch, and permanent load shift, a 1 to 2 MW DER deployment on a single feeder can defer or eliminate the reconductoring project that would otherwise be required within the planning horizon. At the substation level, deploying 5 to 10 MW of DERs across several feeders fed by a common substation can defer or eliminate a transformer upgrade.

Solution Cost Comparison

Non-Wires Alternative: Cost Comparison		$K
Substation transformer upgrade		5000 $K
Feeder reconductoring (per mile)		1200 $K
5 MW DER on 3-4 feeders (vs substation)		2000 $K
1-2 MW DER per feeder (vs reconductor)		400 $K

Figure 16: Solution Cost Comparison

The economic comparison is compelling. A 1 to 2 MW DER deployment on a feeder that would otherwise require reconductoring costs a fraction of the traditional infrastructure alternative, is deployed in months rather than years, and delivers a full value stack of peak reduction, power factor correction, phase balance, energy efficiency, and renewable generation, rather than simply adding wire capacity. A 5 to 10 MW DER deployment across a substation area defers a $3 to 5 million transformer upgrade while delivering all the same additional value streams. It is critical to understand that these options can only be pursued if the utility has both visibility and control of the DERs. Random actions of customer installed DERs cannot provide this unique value to the grid if the utility cannot depend on their performance and dynamically control their dispatch.

6.2 EV Infrastructure: Build It Right the First Time

Unmanaged EV adoption is already forcing utilities to retrofit electrical services, upgrade transformers, and reconductor feeders to serve charging loads that were never anticipated in the original distribution design. These retrofits are expensive: $2,000 to $8,000 per home for service upgrades, and substantially more for feeder-level infrastructure. Worse, uncontrolled EV charging often occurs during the evening peak, adding to the very peak demand problem that is already driving load factor deterioration.

DER deployments designed from the outset to include EV-ready infrastructure, including service entrances sized for up to three EVs per home and community fast-charging stations that can serve managed charging, to eliminate the retrofit problem before it occurs. The avoided cost of future service upgrades, measured across a portfolio of thousands of homes, represents a significant and entirely avoidable capital expenditure for a utility.

7. Value Streams 6 Through 8: Ancillary Services, Environmental, and Resilience

7.1 Ancillary Services: Reserve Margin and System Support

Every megawatt of peak demand that DERs reliably reduce is a megawatt for which the system no longer needs spinning reserve. Reserve margin requirements, typically 12 to 15 percent of peak capacity, are expensive to maintain. They require generating units to be kept synchronized to the grid, burning fuel and incurring wear, even when their output is not needed. A reliable DER portfolio that consistently reduces peak by 400 to 600 MW reduces the reserve margin requirement by 48 to 90 MW, with direct, quantifiable savings in fuel costs and generating unit wear.

Beyond reserve margin, DER inverters can provide frequency regulation, voltage support, and reactive power locally, all of which are ancillary services that the system must otherwise procure from central station generators. In markets where these services are priced and compensated, DER aggregations can participate directly, generating revenue streams that further improve their economics.

7.2 Renewable Energy Certificates and Carbon Value

Every megawatt-hour of solar energy produced by a DER deployment is certifiable as renewable generation, producing Solar Renewable Energy Certificates (SRECs) or standard RECs depending on the jurisdiction. In states with Renewable Portfolio Standards, these RECs have direct compliance value for the utility. Beyond RECs, zero-carbon peaking, achieved by using DER solar and storage to displace gas peaker starts, produces measurable, verifiable carbon reductions that translate directly into emissions compliance value and support for corporate and regulatory sustainability commitments.

Grid energy efficiency improvements through DER deployment are recognized as White Tags and can far exceed the impact of all existing utility site/building energy efficiency programs. We have focused holistically on energy efficiency as a behind the meter solution. Attacking power factor, phase balance and deploying DERs in the load pocket provide a new, and very significant opportunity to address grid efficiency.

7.3 Resilience: Critical Customers and Community Value

DER deployments can be designed with islanding capability for designated critical customers: police stations, fire departments, emergency medical services, and critical care facilities. This provides resilient backup power without a separate, expensive backup generation program. The value of this resilience, measured in avoided outage costs, regulatory compliance with critical facility reliability standards, and community trust, is real and material, even if it does not appear in a traditional cost-benefit model.

DERs deployed in affordable housing communities address an equity dimension that traditional DER programs, such as rooftop solar incentives, demand response enrollment, and EV charger rebates, consistently fail to reach. Studies have repeatedly shown that incentive-based DER programs disproportionately benefit affluent customers who can afford upfront equipment costs, shifting program costs to all ratepayers while concentrating benefits on a few. A DER deployment integrated into new affordable housing construction eliminates this inequity by delivering clean energy resources and bill savings to customers who would not otherwise have access to them.

> *Social equity is not merely a soft value. Cross-subsidy from conventional DER incentive programs creates regulatory exposure and public legitimacy risk for utilities. DER deployments in affordable housing eliminate the subsidy problem at its root while expanding the customer base that benefits from the grid's transition.*

8. The Complete DER Value Stack

8.1 All Value Streams, Consolidated

The table below consolidates all value streams identified in this analysis, organized by category and quantifiability. A DER evaluation that accounts only for capacity and energy is capturing, at best, 20 to 30 percent of the value these resources actually deliver.

Complete DER Value Stream Reference Table

Category	Value Stream	Quantifiable?	Description / Proxy Value
Capacity & Energy			
Capacity & Energy	**Peak Load Reduction**	High	Direct avoided cost of peaking generation; ~$700-1200/kW-yr
Capacity & Energy	**Load Factor Improvement**	High	Latent revenue from serving additional MWh on existing infrastructure; ~$577M/yr at scale
Capacity & Energy	**Permanent Load Shift (8-hr)**	High	Displaces highest-cost energy hours; valued at hourly LMP during on-peak periods
Transmission & Distribution			
Transmission & Distribution	**T&D Loss Elimination**	High	+5 MW effective gain per 50 MW DER portfolio vs. central station
Transmission & Distribution	**Non-Wires Alternatives**	High	Deferral/elimination of feeder reconductors & substation upgrades; ~$1-5M per project
Transmission & Distribution	**Reserve Margin Reduction**	High	+6 MW effective gain per 50 MW DER portfolio; reduces spinning reserve procurement
Power Quality			
Power Quality	**Power Factor Correction**	High	Eliminates reactive power flow; reduces i^2R losses 40-60% on served feeders
Power Quality	**Phase Balance Correction**	High	Reduces technical losses 40% with only 4% imbalance correction; 1-2M kWh EE/feeder/yr
Power Quality	**Energy Efficiency (White Tags)**	High	~2.5 MW continuous EE per 50 MW DER deployment; ~20,000 MWh/yr per portfolio
Ancillary Services			
Ancillary Services	**Spinning / Operating Reserves**	Medium	Reduced reserve procurement requirement for the system
Ancillary Services	**Frequency Regulation**	Medium	Rapid inverter response for frequency support; market value varies by RTO
Ancillary Services	**Voltage Support (VARs)**	Medium	Local VAR injection eliminates need for central station reactive dispatch
Environmental			

Environmental	**Renewable Energy Certificates (RECs)**	**Medium**	Certified SREC/REC delivery for each MWh of solar production
Environmental	**Carbon Offset / Emissions Avoidance**	**Medium**	Zero-carbon peaking displaces gas combustion; value tracks carbon market
Strategic / Unquantified			
Strategic / Unquantified	**Speed of Deployment**	**Qualitative**	6-24 months vs. 2-6+ years for central station; critical in high-growth periods
Strategic / Unquantified	**Critical Customer Resilience**	**Qualitative**	Islanding capability for emergency services without separate backup program
Strategic / Unquantified	**EV Infrastructure Avoidance**	**Qualitative**	Built-in EV-ready design eliminates future costly service upgrades
Strategic / Unquantified	**Social Equity**	**Qualitative**	DERs in affordable housing; eliminates affluent-customer cross-subsidy in traditional programs
Strategic / Unquantified	**Community Investment**	**Qualitative**	Capital deployed in service territory vs. remote central station site
Strategic / Unquantified	**System Stability Improvement**	**Qualitative**	Reduced VAR flow improves bulk system stability margins across the network

Figure 17: Complete DER Value Stream Reference Table

8.2 The Quantified Value Summary

For the utility case study, the quantifiable value streams, those for which defensible proxy values can be established, are summarized in Figure 18 below. Values are presented per the scale of the 25,000-home plus 250 Grid Optimization Station deployment modeled throughout this analysis:

Quantified Value Summary (Utility Scale Deployment)

Value Stream	Estimated Value	Basis
Peak Load Reduction (679 MW avoided)	**$476-815M**	Capital cost avoidance at $700-1,200/kW
Latent MWh Revenue Unlock (4.8M MWh)	**~$577M/yr**	At $0.12/kWh on existing infrastructure
T&D Loss Savings (63.5 vs 36.5 MW IRP effect)	**Significant**	Per 50 MW deployment; system-wide loss reduction
Non-Wires Alternative Deferrals	**$1-5M each**	Per substation/feeder upgrade avoided
Energy Efficiency via PF/PB Correction	**$2-4M/yr**	1-2M kWh per feeder × ~250 feeders × $0.08/kWh
Renewable Energy Certificates (RECs)	**$5-15/MWh**	Market rate per certified solar MWh produced
Spinning Reserve / Reserve Margin Reduction	**Significant**	+6 MW effective per 50 MW; reduces procurement cost
Speed of Deployment vs. Central Station	**3-5 yr savings**	Avoided cost of multi-year permitting, siting, financing
Critical Customer Resilience	**Program avoided**	Eliminates need for separate backup gen programs
EV Infrastructure Avoidance	**$2-8K/home**	Cost of retrofit service upgrades vs. built-in design
Phase Balance & Stability Improvement	**Qualitative**	Reduced cascading failure risk; equipment life extension
Social Equity / Affordable Housing DERs	**Qualitative**	Eliminates cost-shift from affluent rooftop solar programs

Figure 18: Quantified Value Summary (Utility Scale Deployment)

> *The combined quantifiable value streams comfortably exceed the full cost of the DER program that generates them. When non-wires alternative deferrals, ancillary service value, and REC revenue are added to the load factor improvement and T&D savings, the economics of a well-designed DER portfolio are not marginal, they are decisive.*

9. Critical Caveat: Not All DERs Are the Same

The value stack described in this paper is not automatically delivered by every DER. It requires DERs designed, sited, integrated, and dispatched with the explicit goal of delivering grid services, not solely customer bill reduction. The distinction is critical.

Low-Value DER Deployment	High-Value DER Deployment
Sized only for customer bill optimization	Sized for feeder peak demand and grid needs
Single-quadrant inverter (energy only)	Four-quadrant inverter (PF/PB correction capable)
No utility communication or control	Real-time SCADA integration with utility dispatch control and visibility
Dispatched only for customer benefit	Co-optimized for customer + grid benefit
Retrofit installation (30-50% cost premium)	New construction (lowest possible cost)
Single value stream: net metering	Full value stack: 8+ simultaneous streams

Benefits one customer	Benefits all utility customers

Figure 19: Low vs High Value DER Deployments

DERs focused on a single value proposition, such as energy arbitrage, demand charge reduction, or net metering, lose the ability to provide multiple simultaneous services to the grid. The evaluation framework a utility uses to value DERs must reflect the deployment type it is actually procuring or incentivizing, not an idealized version. In addition, the contracts for these DERs must also be equivalent. They must have the same performance guarantees and penalties a utility would include in a utility scale contract.

10. Leveling the Playing Field for Distributed Energy Resources

10.1 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 rate base. A gas peaking plant, a utility-scale solar farm, and 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 PPA service in their annual operating budget. The utility has every financial incentive to build and own these assets, regardless of whether an equivalent, cheaper, or better-performing alternative exists[8].

A DER deployment that meets the identical system need as a comparable central station facility earns the utility precisely nothing if procured through a service or Power Purchase Agreement structure. It is treated as an operating expense, not a capital investment. It does not grow the rate base. It does not generate a return. 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[7,8]. It is worth acknowledging that this regulatory compact enabled 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.

10.2 Why Utilities Should Not Own (All) DERs Directly

One might ask: why not simply allow utilities to own and operate DERs themselves? The answer is absolutely yes: if the resources is of adequate scale, it will make sense for the utility to own and operate that asset. For example, A large-scale community system operating at utility voltage. This is the type of DER utilities that can readily design, own, and operate within existing regulatory structures and with existing utility personnel. 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 type of 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[5,6].

10.3 The Regulatory Fix: Equivalent Regulatory Structures for DERs

The policy logic is straightforward: if the grid benefit is equivalent, the financial treatment should be equivalent as well. 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, utility owned resource. 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, is 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[8].

Regulatory commissions should establish clear pathways for utilities to:

1. Seek pre-approval of DER PPAs through an integrated resource planning or competitive solicitation process, applying the same scrutiny applied to traditional capital projects.
2. Capitalize the PPA obligation on a present-value basis, subject to ongoing performance true-ups, and earn an authorized return on the approved balance.
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.

10.4 The Cost to Ratepayers of Getting This Wrong

Every year this regulatory gap persists, utilities face a quiet but compounding 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[7,8].

11. Conclusion: Valuing DERs Correctly

The electric utility industry has undervalued distributed energy resources for decades because it has evaluated them through a framework designed for a different era. Capacity and energy metrics, applied in isolation, will always make DERs appear more expensive than a gas peaker. They are not, when their full value is properly accounted for.

A properly designed 50 MW DER portfolio delivers 63.5 MW of effective system benefit to the IRP. A 50 MW gas peaker delivers 36.5 MW. DERs correct power factor and phase balance, eliminating 40 to 60 percent of distribution technical losses. They defer substation and feeder upgrades that would otherwise consume millions in capital. They improve load factor, unlocking latent revenue capacity in existing infrastructure. They generate RECs and displace carbon emissions. They can be deployed in months, not years. They deliver resilience to critical customers and equity to communities that traditional programs have consistently failed to reach.

None of this value appears automatically in a conventional resource planning model. It must be explicitly identified, quantified where possible, and listed where it cannot yet be quantified, with a commitment to improve those estimates as DER deployments are monitored over time.

The Central Principle of DER Valuation

> *DERs are not another generation resource to be compared just on $/kW-yr basis. They are a system transformation technology that provides value at every level of the power system simultaneously: bulk generation, transmission, distribution, and customer. Any valuation methodology that evaluates them at only one level will produce a result that is both mathematically incorrect and strategically dangerous. The correct question is not 'what does a DER cost per kW'; it is 'what is the full system cost avoided and value when DERs are deployed instead of the alternative?' Answer that question correctly, and the playing field will be level for DERs to become a crucial part of the utility resource portfolio.*

Appendix: Bibliography

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