ENERGY PARKS

A New Strategy to Meet Rising Electricity Demand

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Photo Credit: NextEra Energy Resources

EXECUTIVE SUMMARY

On December 15th of 2023 at a public meeting in Gray County, Texas, the clean energy company, Intersect Power, presented an innovative new billion-dollar project to produce hydrogen from clean electricity in this wind- and solar-rich region[i] The Meitner project would leverage long-term tax incentives from the 2022 Inflation Reduction Act (IRA) to feed 400 Megawatts (MW) of electrolyzers (capable of producing almost a half-ton of hydrogen per day) with 460 MW of on-site wind and 340 megawatts of on-site solar renewable electricity, creating 750 construction jobs and 15 permanent jobs along with significant annual tax revenues.

This single project shows the impact of both cheap renewables and federal clean energy support, while serving as a promising example for how large electricity consumers across the country could leverage similar benefits—speed, direct access, shared infrastructure, and credit for clean energy—in an "energy park."

Energy park projects like the Meitner project have common features defined in this paper. They can integrate multiple renewable energy sources, storage solutions like batteries, and potentially co-located electricity consumers such as manufacturing facilities or data centers, all connected to the grid at a single point.

As wind and solar power costs continue falling alongside cost declines in battery energy storage systems, these clean energy resources are attracting retail customers and wholesale loads that are willing to assume additional costs, risks and responsibilities that have traditionally been addressed by existing markets and utilities in return for getting faster and cheaper access to clean energy. For large consumers (especially flexible consumers), energy parks remove barriers to efficiently accessing the low-cost power they need and the clean energy they demand.

Along with defining energy parks and sharing real-world applications, this paper explores the potential for energy parks to be coordinated with the grid itself, providing benefits to energy park economics and all electricity customers as the energy transition accelerates.

Energy parks provide faster access to clean energy for power consumers, but if they fully defect from the grid, they leave significant benefits on the table. For example, a wind-solar-hydrogen project without any grid connection will sometimes curtail energy generation that could otherwise flow onto the grid to meet other demands, and a flexible load could ramp down to provide more power to the grid in response to grid needs. An isolated project may make economic sense on its own but could be even more valuable and less risky to potential financiers if it were interconnected with the grid.

But integrating energy parks with the grid of today will require changes to markets including rules for how resources participate in those markets. Today, the grid in the United States functions under a traditional operating paradigm that centralizes control and dispatch of generators as a response to load. This approach evolved naturally from the days of having a few large generators (coal, hydro, nuclear, etc.), but the usefulness of this paradigm is evaporating as wind, solar, demand flexibility, and storage become the lowest-cost resources in a low-carbon future. While renewable resources are variable and storage is energy-limited, they are also digitally controllable and can respond to grid needs more quickly and accurately than existing generators. New market rules can encourage and fairly value these benefits, while explicitly determining which services can complement them. Properly integrated into electricity markets, energy parks can become even more versatile and flexible resources that can provide a wide range of services benefitting the grid.

Far from a hypothetical concept, energy parks are informed by existing hybrid projects, and increasingly complex energy parks are cropping up in the U.S. today. For instance, solar power plants increase their inverter-loading ratios to provide additional energy and grid services to the grid, and renewable-storage hybrids expanded upon this by adding dedicated storage behind a single point of interconnection (POI). Even more complex arrangements are now emerging, including multiple utility-scale resources bundled together, energy parks with thermal storage, and hydrogen energy parks.

These examples suggest that even more variety and potential are rapidly emerging. Energy parks are modular—able to add elements like additional storage, load, and generation behind a single POI to optimize for the needs of both the on-site load and the grid. Energy parks with on-site loads can achieve multiple benefits, building on what hybrid resources already have proven:

- Larger equipment savings: Directly connecting load and generation to the same grid interface, such as sharing the same single-directional or bi-directional high-voltage transformer, can significantly reduce equipment costs.
- Leveraging tax credits, green product certification, and local economic development benefits: Investors and local governments eager to secure government incentives for clean energy and clean manufacturing could combine supply- and demand-side projects to improve project viability and boost local economies.
- Modularity: allowing for adding different components to the energy park as market and project needs evolve.

The flexibility that energy parks provide is essential to an affordable, reliable, clean electricity system. This paper details the policies that can help lay the foundation for an electricity system that encourages and fairly values energy parks that co-locate load, variable renewables, storage technologies, and whatever comes next.

We’re on the precipice of a huge clean energy economic opportunity that policymakers and utilities can seize by opening their regulatory and legislative forums to energy parks and the stakeholders eager to invest in their states and communities.

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INTRODUCTION

In recent decades, significant cost reductions in wind and solar energy, coupled with decreases in the costs of enabling technologies like lithium-ion batteries, have positioned renewable energy as a front-runner in the U.S. energy market.

The "2035" series of reports by the University of California, Berkeley, GridLab, and Energy Innovation illustrates how integrating affordable wind and solar projects alongside storage solutions can help the U.S. achieve 90 percent clean energy levels by 2035 at costs comparable to today's electricity prices.[1] The IRA also included at least 10 years of tax credits for these clean energy technologies, increasing expectations of rapid growth.[ii] Renewables currently represent most new planned energy capacity in the U.S., with wind, solar, and batteries accounting for 93 percent of planned additions for 2024,[2] prompting a significant shift in energy planning and interconnection processes.

As expected,[3] cost-competitive renewables are already being built at an increasing clip. However, massive amounts of renewables must be deployed (while ensuring reliability and affordability) to capitalize on the opportunity they offer to cut costs and emissions by electrifying vehicles, buildings, and industry. But challenges like siting, interconnection, transmission, and integration into grid operations are major barriers that are slowing deployment. Insufficient transmission and distribution capacity for interconnecting new renewables is particularly challenging, as it limits where additional renewable projects can interconnect and leads to more costly case-by-case transmission and distribution upgrades.

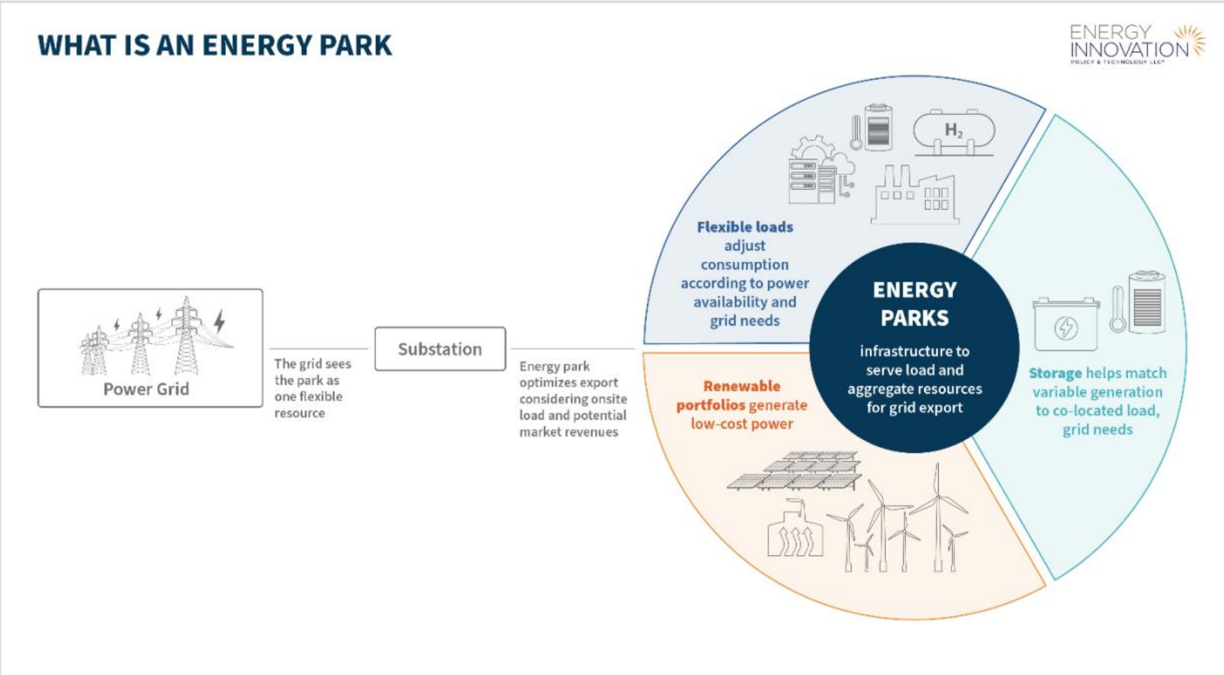
Energy parks could overcome these challenges. With the right guardrails and market rules, energy parks could significantly reduce electricity delivery costs for large, co-located commercial and industrial consumers. In a world where this optimization thrives, large consumers, grid customers, and the climate all benefit from a faster, reliable transition to clean electricity.

While energy parks are gaining momentum, they face numerous regulatory hurdles that impede their development and connection to the grid. This paper aims to define energy parks, provide case studies, explain their commercial and societal benefits, and discuss the non-technical barriers they encounter. We also provide recommendations for policymakers to foster a supportive regulatory environment for energy parks, emphasizing the broader benefits of accelerating their development.

[1] See generally 2035report.com, which contains each of the technical and policy reports from the series.
[2] See U.S. Energy Information Administration 860M 2024 data at https://www.eia.gov/electricity/data/eia860m/.
[3] The latest cost numbers show that wind and solar are more competitive than other power generation options on a levelized cost basis: https://www.lazard.com/research-insights/levelized-cost-of-energyplus/.

WHAT IS AN ENERGY PARK?

Figure 1. Energy Park



An energy park combines generation assets, complementary resources like storage, and connected customers (co-located loads). Energy parks can feed electricity and grid reliability services to the bulk power grid while maintaining a degree of self-sufficiency to provide crucial support for co-located loads. Essentially, an energy park is a large-scale microgrid.[4]

Energy parks with co-located loads are particularly compelling for large customers due to the cost advantages of sourcing electricity directly from the cheapest, cleanest sources and due to the challenges of connecting large capacities to the existing grid. Energy parks also provide new pathways to achieving the massive increases in clean electricity generation needed to achieve U.S. climate goals, including the target of halving economy-wide emissions by 2030.

Energy parks can connect to clean energy resources and the grid in a variety of ways. They could in theory be fully isolated from the grid, an outcome that leaves significant grid benefits and project economics on the table. They could export power to the grid without importing it. An export-only energy park would meet all its internal load with co-located generation and storage resources, then export at will to the grid as a flexible generator. Flexible arrangements, where the energy park sometimes draws from the grid to meet its own demand, are also possible. The body of this paper describes these arrangements at a very high level, and the appendices delve into more detail.

The widespread availability of very cheap, geographically concentrated, variable renewable resources along with the modularity and falling cost of storage technologies have made

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[4] For clarity, we distinguish energy parks connected to the grid at the transmission level from smaller microgrids connected on the distribution network, but the distinction is somewhat academic. Others refer to energy parks where loads bring their own generation as microgrids. See, for example, https://www.aei.org/articles/data-center-electricity-use-v-implications/.

energy parks a viable concept that complements the grid and its economies of scale. In regions with high quality renewable resources, enterprising large consumers find portfolios of renewables and storage that provide consistent power economically competitive with grid power. New inflexible loads like data centers[5] looking to connect as fast as possible to new clean generation resources would have to be willing to incur some extra premium associated with serving all of their electricity consumption locally, while other new industrial-scale flexible loads associated with the energy transition such as hydrogen electrolysis, fleet EV charging, and thermal batteries will have an easier time than baseload demand in matching local supply directly.

Energy parks also benefit from the convergence of declining busbar costs[6] of renewable resources with rising grid access and interconnection fees.[7] This cost dynamic makes co-located load-generation projects increasingly attractive. By integrating generation and load at a single connection point to the high-voltage grid, energy parks can streamline transactions and provide unique grid services that would be harder to sustain on an individual basis. They can provide services that help stabilize and balance the power grid, such as quickly adjusting to changes in supply and demand.[8]

The combination of generation and load simplifies transactions and optimizes the use of shared resources such as inverters, power electronics, controls, and personnel. Furthermore, shared equipment and reduced transmission needs also implies reduced land-use needs, which means less money spent buying or leasing land and less time dedicated to siting and permitting. Co-location not only reduces overhead costs but also strengthens the business case for energy parks.

Far from being an isolated solution, energy parks are essential for providing clean, efficient, and locally optimized energy services. They can play a crucial role in the rapid electrification and renewable resource build-out needed to meet economic and climate goals, accelerating the transition to a sustainable energy future.

THE HISTORICAL EVOLUTIONARY PATH FOR ENERGY PARKS TO DATE

Combining generation and storage to reduce costs and increase flexibility is not a new idea. It has already flourished in some distinct cases where market opportunities aligned with consumers' and investors' bottom lines. The impetus can come from the generation side when a developer is looking for ways to increase margins to sell a differentiated product and get to market faster. It can also come from the load side, when the developer of a new industrial or commercial project with heavy electrical usage wants to find a faster, cheaper

[5] Data centers currently are characterized as inflexible but could become flexible with the right incentives and innovative practices as these large energy consumers evolve and become more sophisticated.
[6] "Busbar cost" represents the cost of generating electricity at the power plant before it is sent to the grid. It does not include transmission and distribution costs or balancing and integration costs. For data on falling busbar and system integration costs, see, for example, https://www.nrel.gov/solar/market-research-analysis/solar-installed-system-cost.html.
[7] See https://emp.lbl.gov/interconnection_costs.
[8] Examples of grid services are energy shifting (sometime over multiple days, weeks, or years), reactive power, regulation (grid balancing of shorter periods), rapid frequency response, and short-circuit strength.

way to meet its energy needs, to directly show that it is using carbon-free energy, or to reduce its energy costs through subsidies on carbon-free energy.

Historically, there have been five broad categories of benefits from building energy parks that go beyond simply building one type of resource and connecting it:

1. *Equipment savings*: Savings from sharing equipment or reducing the need for equipment.
2. *Tax savings*: More tax credits available, avoided loss of credits from wasted generation.
3. *Storage*: The ability to store excess energy beyond what the grid connection or local inverters can accept to be sold later. This also includes some opportunistic purchases from the grid.
4. *Synergies*: Savings on development time and grid access charges by sharing a common POI for different types of resources.
5. *New abilities*: Increasing the flexibility/dispatchability of the hybrid resource to better align production with grid value and offer grid services beyond just energy (ancillary services, capacity, etc.).

Developing energy parks must be a gradual process because developers need to raise significant capital, and financiers are often cautious about new project models. The evolution of this concept is driven by the need to maximize financial returns and fulfill contractual obligations by learning how to plan and operate new equipment configurations while balancing different sources of capital costs. Each new project uncovers new ways to increase efficiency, reduce costs, and provide additional value to the grid. Once completed, these successful examples provide a foundation to understand energy parks' potential today, and they can become an even bigger part of a cost-effective, low-carbon energy system in the future.

Below, we outline three key stages in this evolution, framing each around an opportunity, an example, and an insight. More detailed information for each example can be found in Appendix 2.

OPPORTUNITY ONE: OVERGENERATION (BENEFIT 1)

Overgeneration occurs when the generation resources behind a POI to the bulk power system exceed the equipment's ability to export power, or when operational or administrative constraints require a reduction in output. While this might seem wasteful for a zero marginal cost resource like wind and solar, it can sometimes be justified by cost savings elsewhere. Solar farms are a clear example of this trade-off, where generating more power than can be immediately used maximizes the return on investment, even with occasional energy losses.

In the solar industry, projects often increase what's known as the inverter loading ratio (ILR). This refers to the ratio of the solar panels' DC capacity to the AC capacity of the inverters that convert energy for the grid. According to Lawrence Berkeley National Laboratory, the average ILR for new solar-only projects has increased from 1.2 in 2010 to more than 1.3 in 2017, where it has remained steady. The rationale behind this increase is that a small amount of energy loss during peak generation—known as clipping—is outweighed by the cost savings leveraged from the increased use of AC equipment during non-peak periods.

Example One: Solar Star
To illustrate how overgeneration can be economically viable, consider Solar Star, one of the country's largest solar farms. It has a 776 MW_{DC} capacity and a 585 MW_{AC} grid connection, yielding an ILR of 1.32.

While approximately 1 percent of energy is lost to clipping, this is offset by lower AC equipment costs and more efficient inverter usage during non-peak periods. Historical price analysis shows that the revenue loss from clipping balances is compensated for with savings from avoiding 200 MW of additional AC conversion costs, confirming the viability of an ILR around 1.32.

Insight One: Decoupling. Decoupling refers to situations when what a grid operator sees at the POI is not the predictable result of what generation hardware sits behind that point. In the example above, whatever the solar panels generate goes straight onto the grid most of time, minus some losses along the way. But at or near peak output, some of that electricity gets clipped and doesn't reach the bulk power system. Without knowing the ILR, the grid operator cannot anticipate or predict the exact output of the solar farm based on local insolation.

In this example, what we see is just the green shoots of decoupling. Presumably when the solar farm gets interconnected, ILR is part of the information the developer provides so that the grid operator is not blind to the effect of clipping. Under normal conditions, there is no "internal operator" making choices on a moment-by-moment basis about how much power will flow through to the grid. But we would argue that the adoption of high ILR pushed developers to start considering the separation between the electric output seen by the grid at a project's interface with the bulk power grid from the exact electric generation available behind this interface. In this shift of thinking, the equipment taking the raw DC output and feeding it to the bulk AC power grid (inverters, transformers, etc.) goes from a simple conversion step to being a bridge keeper. Further evolution of the energy park concept with batteries and flexible co-located loads means the bridge-keeping function involves fixed equipment choices as well as real-time decisions about how much power to feed to a co-located load or take in or out of a battery inside the park.

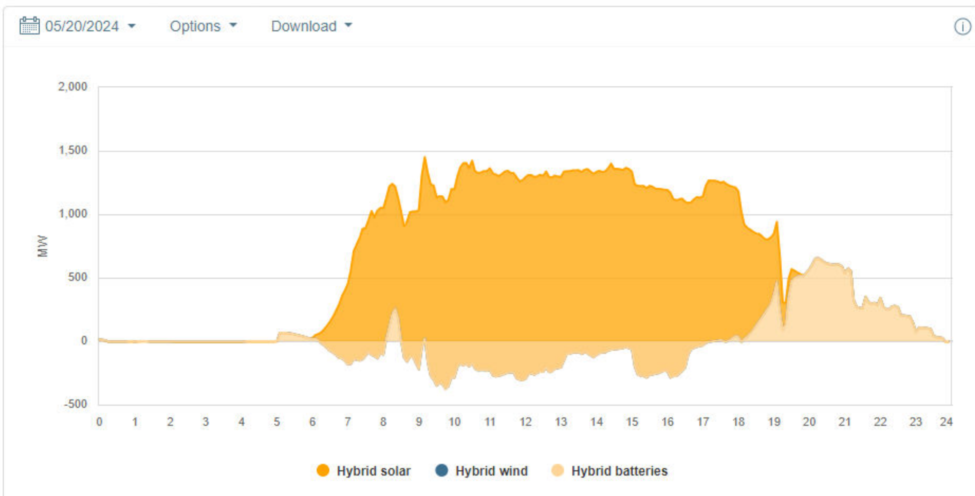
OPPORTUNITY TWO: SOLAR-PLUS-STORAGE HYBRIDS (BENEFITS 1-4)

In the mid-2010s, as battery costs dropped, solar-plus-storage hybrids emerged as a key innovation in energy parks. These systems extended the benefits of overgeneration by storing excess energy instead of simply clipping it, allowing that energy to be used later when the AC equipment isn't fully utilized or when market prices justify shifting generation. This further leveraged capital savings from shared infrastructure. While batteries involve significant up-front costs, they provide additional financial advantages by time-shifting energy to periods of higher market value or selling it as firm capacity to utilities. These advantages, available in both stand-alone storage and hybrid systems, were particularly lucrative in hybrid configurations due to the 30 percent federal tax credit offered for solar-charged batteries. These tax rules helped seed the early solar-plus-storage hybrid projects, yet despite the introduction of the stand-alone storage tax credit through the IRA, interest in hybrids remains strong because of their ability to share equipment (reducing capital costs) while controlling and optimizing solar energy output. Solar-plus-storage hybrids are especially attractive in mature markets like California and Texas.

Example Two: California's Solar-Plus-Storage Hybrid Fleet

Solar-plus-storage hybrids are an especially attractive form of energy park in solar-heavy markets like California, where they also qualify for resource adequacy payments from electricity buyers. More than 98 percent of the solar capacity proposed in the California Independent System Operator (CAISO) footprint is hybrid.[iii]

Figure 2. Combined output of solar + battery hybrids on CAISO system on May 20, 2024 (5-minute resolution)



Source: CAISO, 2024

The operational advantages of these systems are clearly demonstrated in the aggregate effect of solar-plus-storage hybrids in California.

Figure 2 shows the real-time dispatch of the CAISO hybrid fleet on May 20, 2024, with batteries dynamically responding to grid signals. This fleet adjusts its output throughout the day, smoothing solar generation, extending energy delivery into the evening, and actively adapting to grid conditions. This flexibility not only supports grid reliability but also enables the hybrids to provide firm energy and capacity when solar alone would fall short.

Insight Two: Beyond Time-Shifting

While the main advantage of solar battery hybrids is their ability to store excess solar generation and time-shift output to periods of higher demand, their potential goes beyond this. Hybrids can capitalize on additional revenue streams by providing ancillary services, adjusting output to real-time price signals, and responding to local and regional grid conditions. This makes hybrids more valuable participants in the energy market, capable of earning revenues from both traditional energy delivery and flexible grid services.

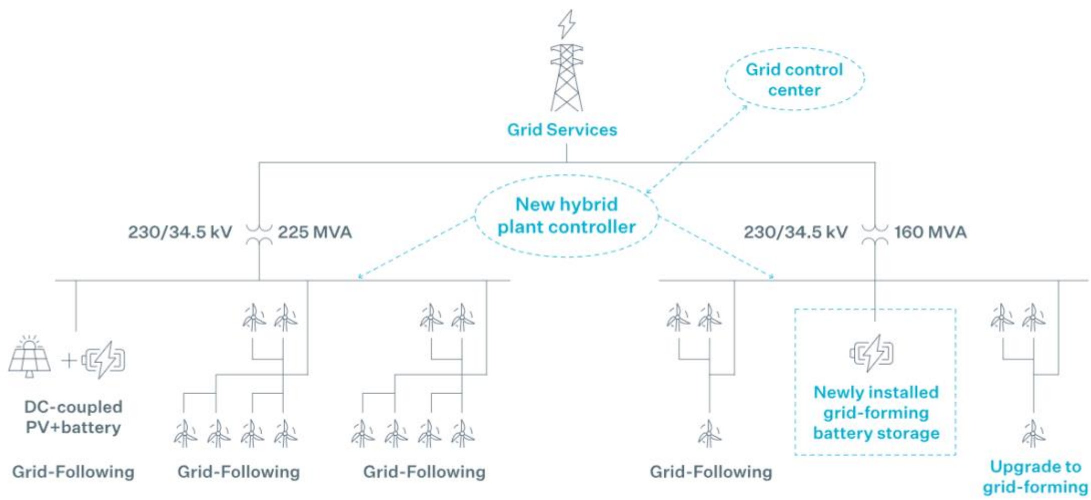
With their new dispatchability, solar-plus-storage hybrids catalyzed new perspectives on what grid participation models should look like for modern generators. A report from the Energy Systems Integration Group (ESIG) task force titled *Hybrid Power Plants – Flexible Resources to Simplify Markets and Support Grid Operations*[iv] suggested that future deployment of energy resources on the electric power system would increasingly take a more general form that the task force called "hybrid resources," essentially an energy park (although at the time co-located loads in these energy parks were not yet on the horizon).

OPPORTUNITY THREE: MAXIMIZING HYBRID RESOURCES (BENEFITS 1-5)

As solar-plus-storage hybrids advanced energy park design, developers recognized the potential to diversify resources and further enhance flexibility. By combining multiple types of generation and storage behind a single POI, energy parks could increase their ability to match production with grid needs, offer a range of services such as ancillary support and capacity, and become more dispatchable like traditional power plants.

Example Three: The Wheatridge Hybrid Renewable Energy Facility

Figure 3. Wheatridge Hybrid Renewable Energy Facility



Source: Portland General Electric

The Wheatridge facility in Oregon is a pioneering example of a hybrid energy park, combining 200 MW of wind, 50 MW of solar, and a 30 MW, four-hour battery. While it already delivers multiple types of generation and storage through a single POI, planned upgrades will develop it further by adding advanced controls and grid-forming inverters. These enhancements are supported by a $4.5 million grant from the U.S. Department of Energy's (DOE) Solar Energy Technology Office and underscore the cutting-edge nature of the project. By de-risking these technologies, the DOE is helping push the boundaries of what hybrid energy parks can offer in terms of grid flexibility, capacity, and ancillary services, marking Wheatridge as a key step in the future evolution of energy parks.

These upgrades will equip the facility to provide new grid services, and future versions could further enhance this by incorporating co-located loads and islanding capabilities.

Insight Three: Gradually and Flexibly Replacing Traditional Firm Generation

The Wheatridge facility shows how energy parks can evolve into cleaner, more flexible alternatives to traditional power plants, offering the dispatchability needed to support grid reliability without relying on fossil fuels. While no single generation facility is immune to drops in output, the range of services that energy parks like Wheatridge can provide is impressive. Even more impressive is the ability to upgrade these facilities by adding new components, such as additional storage and grid-forming inverters, which allows them to better support the grid both locally—through voltage support and system stability—and across the broader network.

The modularity and ability to upgrade energy parks is a key advantage of their concept. Wheatridge lays the foundation for continually improving energy parks, allowing them to adapt over time and better serve grid needs. This flexibility enables developers to prioritize specific services, but utilities and system operators must provide the right incentives to encourage upgrades and ensure energy parks deliver the services the grid requires.

Although some traditional power plants could theoretically invest in new capabilities to provide a wider range of grid services, their high operational costs and dirty emissions make such upgrades less practical. By contrast, energy parks—unburdened by these legacy constraints—can evolve to offer a more diverse and tailored range of services over time.

Looking ahead, the modular design of energy parks prepares them for the next stage of development, including integrating co-located loads. This step will further enhance the value of energy parks by optimizing resource use and creating new opportunities for grid support.

The current state: To summarize so far, renewable projects are trending toward hybridization where developers assume the risk of more complex projects to take better advantage of scarce grid connectivity and better serve their customers.

TAKING THE NEXT STEP: ADDING CO-LOCATED LOADS TO AN ENERGY PARK

Historical examples reveal that the economics of hybrid and controllable energy portfolios behind a single POI are already promising and will continue to grow. Despite energy parks' potential societal benefits, such as helping decarbonize dirty industries or manage grids with high levels of renewable energy, they will only be developed if they provide sufficient private benefits for the investors who finance them. Developing variable energy projects is difficult as it is—and will be even more so when energy park configurations increase in complexity and involve many different technologies. Further development of more complex projects is not a foregone conclusion; these projects must offer significant financial advantages for any developer to bother and for investors to take on the risk of a new development model.

Adding a customer for electricity (co-located load) onto the internal network of a hybrid resource is a big new step in the evolution of energy parks. Adding load to a hybrid energy park that was previously dedicated to generation for export increases complexity even more than adding storage to a simple solar or wind project. This is distinct from an industrial-scale behind-the-meter or combined heat and power project, where large consumers' primary energy source is the grid, and the on-site resource offsets some demand.[9] Pairing load and generation behind a single point of grid interconnection is an emerging trend mostly driven

[9] Combined heat and power systems are typically sized based on the thermal energy needs of the local facility, since the primary benefit of these systems comes from using the waste heat. Often, the electrical output of the system is smaller than the facility's total electricity needs, meaning it might supplement but not fully replace grid power.

by corporate demand for clean electricity, difficulty accessing deliverable clean energy at scale, new classes of flexible consumers, and the cost advantages of getting clean electricity straight from the source. These expanded energy parks extend the five categories of benefits listed in the previous section:

1. *More savings on equipment*: Directly connecting load and generation to the same grid interface, such as sharing the same single-directional or bi-directional high-voltage transformer, leads to significant equipment cost savings.
2. *Further tax credits, green premiums, and local economic development benefits*: Investors and local governments eager to take advantage of the new government support for clean energy and clean manufacturing could combine supply- and demand-side projects to improve project viability and boost local economies.
3. *Reduced losses*: Directly connecting load and generation to the same local bus avoids the need for electricity to flow through high-voltage transformers and over long-distance transmission and can save an estimated 2-5 percent in transmission and distribution losses.[10]
4. *Power-to-X technologies:* Beyond the ability to use electrical storage, the ability to store electricity from variable renewable generation in alternate energy carriers (e.g., hydrogen or heat) that can be used on-site by the co-located load opens whole new possibilities for project configurations and grid value.
5. *Directly monetizing load flexibility*: The energy park operator can co-optimize on-site storage with load flexibility for maximum financial advantage without having to participate in any outside party's load-management program.

Co-locating customer loads adds another possible benefit type:

6. *Faster to market*: Bypassing the bulk power system to directly serve local loads can potentially accelerate the "time to power" for serving the local load when bulk power supply and delivery are limited, and it may take years for new generation to interconnect and transmission to be built. The lost opportunity cost of expensive investments, such as modern data centers, sitting idle for lack of power outweighs any extra costs of local generation and storage.

The complexity of these energy parks with loads is significantly higher than traditional generation-focused energy parks due to the need to serve the grid and the co-located load. Previously, hybrid resources only served one purpose: selling electricity and other power-provision-related ancillary services to the grid. Once co-located loads are included, the operator must decide how to allocate electricity between the grid and the co-located load, simultaneously considering various storage options within the energy park.

Beyond the operational complexity, energy park developers must make several critical decisions. These include determining the output power of the generation assets relative to the input power required by the co-located load, deciding on the size and type of the grid interface (e.g., whether it should be export-only or bi-directional) and therefore the terms of interconnection study and interconnection agreement, and selecting the appropriate types and sizes of internal electrical connections and storage options. Energy parks are inherently flexible in their configurations—they can add or remove elements (e.g., extra hours of

[10] National U.S. Energy Information Administration data for all transmission and distribution losses is around 5 percent, but some of these may occur on lower-voltage equipment that would not be relevant for larger loads.

storage) after the project is operational and should be encouraged to make such enhancements to their capabilities and performance in response to changing conditions (subject to grid rules and permissions).

Unlike the previous stages of energy park evolution, which followed a relatively linear path of increasing complexity from simple renewable generation to storage hybrids, the future of energy parks will be defined by a diverse range of possible configurations. These configurations don't just vary in technological complexity but rather reflect the unique demands and characteristics of different co-located loads. Each load—whether it be a thermal battery, an electrolyzer, or a data center—brings a distinct set of priorities, financial considerations, and operational dynamics. This diversity means that policies to enable energy parks should focus less on accommodating specific configurations, and more on removing barriers to developers who hope to find their own optimal internal operation strategies for generation, storage, and load that serve diverse objectives.

As we explore these possibilities, it becomes clear that the energy park model is not just evolving but branching into multiple directions, each unlocking different opportunities for innovation, cost savings, and grid services. Below, we outline key examples of how energy parks can be configured to serve various types of loads, presented through an opportunity/example/insight framework. More detailed explanations for the first two examples can be found in Appendix 3.

It is critical to note that the complexity of an energy park is internal to the energy park itself, and this complexity is being voluntarily borne by the operator of the energy park. At the POI with the bulk power system, the energy park can present a very simple and capable interface for the power system operator. To the operator of the power grid and power market, the energy park can look like a simple, idealized generator or storage resource.[v] This may have dramatic implications for simplifying and managing the computational complexity of future market designs.

OPPORTUNITY FOUR: MAXIMIZING LOCAL ENERGY USE AND ELECTRICITY EXPORT VALUE IN ENERGY PARKS

As energy parks evolve with co-located loads, the ability to flexibly transform and store energy locally opens new opportunities to optimize both local load supply and energy export. By converting energy into alternate forms, such as heat or hydrogen, parks can use the least valuable electricity to meet on-site demands while reserving higher-value energy for export. Any surplus renewable output can also be traded over the bulk power system. This strategy enables energy parks to capture more value by adjusting both the timing and the destination of energy use, thus increasing financial returns. Furthermore, the ability to store energy in forms that go beyond short-term solutions (e.g., thermal batteries or hydrogen storage) adds resilience, allowing parks to better manage energy fluctuations and respond to dynamic market conditions.

Thermal batteries, for example, achieve this by storing excess electricity as heat for industrial processes. This enables energy parks to use low-cost electricity for local consumption while exporting higher-value energy to the grid. By effectively managing when and where energy is used, thermal batteries allow parks to maximize revenue from grid sales while ensuring a steady, cost-efficient energy supply for on-site demands.

Example Four: Thermal Batteries

In July 2023, Energy Innovation published a report exploring the concept of thermal batteries, also known as heat batteries. [vi] These systems convert electricity into heat, store it for hours or days, and release it when needed. In practice, long-duration storage can convert variable electricity into the baseload heat that many industrial end users currently source from fossil fuel combustion. The report reviews two primary configurations: one where the thermal battery is directly connected to the grid in a "price-following" mode, and another where it sits within an energy park in a "generation-following" configuration. In the latter, the system is modeled as siloed, with no grid exports, which optimizes the use of low-cost renewable energy for local industrial heat but limits external market interaction.

Insight Four: Grid Connectivity Decreases Financial Risk and Allows Bigger Projects

In Appendix 3, we expand on the thermal battery report by looking more closely at a configuration with grid exports and providing a deeper analysis of how connecting these systems to the grid can enhance their operational and financial performance. We found that with real-world 2023 price data, used as one example year, export revenues were enough to completely support annual capital expenditure requirements for the solar farm (essentially free heat for the on-site industrial partner). We also explored the economics of converting stored heat back to electricity by reusing retired or mothballed steam power plants.

A park with thermal battery demand is more than theoretical—commercial projects already exist that incorporate thermal batteries into energy parks.[11] As developers look to expand these parks, they will recognize the value of enabling grid exports, which will appeal to financial backers who want to manage the risks associated with new technology by having the option to sell energy to the grid if the technology does not perform as anticipated. Additionally, integrating thermal batteries into energy parks allows for shared infrastructure, such as power electronics and transformers, which can facilitate faster charging and support the use of larger thermal storage capacities. Over time, operators will optimize the balance between local consumption and grid exports, increasing revenue from electricity markets while efficiently meeting the needs of co-located industrial loads.

OPPORTUNITY FIVE: CONVERT ELECTRICITY INTO A TRADEABLE COMMODITY WITH CREDIBLE CLEAN SOURCING

In the previous example, a thermal battery within an energy park converted inexpensive electricity from variable renewable generation into a steady supply of industrial heat. Since industrial heat creates huge demand for energy today (usually in the form of fossil fuels), this conversion type is very useful. Unfortunately, heat does not travel well, so it is necessary to use the heat on-site. However, other forms of transformation for electricity create much more portable forms of energy or energy-intensive products like liquid or gaseous fuels or chemicals. This opens the possibility of flexible delivery schedules from energy parks to

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[11] For example, Rondo Energy already operates an energy park that captures intermittent renewable electricity, stores it at high temperatures, and delivers continuous industrial heat on demand for Calgren Renewable Fuels G at its Pixley, California, facility (https://rondo.com/calgren-case-study). It has announced funding for three further projects in Europe (https://www.prnewswire.com/news-releases/rondo-energy-announces-75m-project-funding-with-breakthrough-energy-catalyst-and-the-european-investment-bank-302183325.html).

markets other than electricity—markets that potentially put a premium on the clean credentials that come with clean local generation.

One broad class of transformations that turn electricity into tradeable and transportable industrial products is through electrolysis, which involves using DC electric current to drive non-spontaneous chemical reactions. Electrolysis has the potential to revolutionize industrial decarbonization, not just by producing hydrogen but also in producing other products. Apart from hydrogen and feedstocks like sustainable fuels and ammonia made with hydrogen,[vii] there exist applications such as cement production[12] (responsible for about 7 percent of global carbon emissions) and the direct reduction of iron[13] (iron and steel account for 8 percent of global carbon emissions). Still, the most well-known, or at least well-publicized, application of electrolysis today is the electrolysis of water using clean electricity to produce green hydrogen.

Example Five: Electrolysis of Hydrogen from Water

Hydrogen production via electrolysis requires significant electricity. The DOE's 2023 Clean Hydrogen Strategy and Roadmap targets 10 million metric tons of hydrogen by 2030, requiring 500 terawatt-hours (TWh) annually, representing about 12 percent of U.S. electricity.[viii] Electricity costs directly impact hydrogen prices, with every $20 per megawatt-hour (MWh) increase adding $1/kg.[14]

Electrolysis has high capital costs, so running an electrolyzer as close as possible to continuously is key to cost-effective unit costs for hydrogen output. Given the limited supplies of cheap, round-the-clock energy, if clean power is the requirement, some allowance for flexible production can be made to optimize access to cheaper but variable wind and solar resources.[15]

The IRA's $3/kg tax credit made clean hydrogen affordable much faster than market forces would have on their own. By passing a credit that disappears in 10 years, the IRA created two eras[ix] for clean electrolytic hydrogen: a tax-subsidized era where electrolytic hydrogen is competitive even with higher electricity prices, and a post-subsidy era where competitiveness depends on very cheap electricity.

Energy parks are well suited to both eras, providing clean electricity for tax credits and cheaper power later. Flexible hydrogen production, supported by export-enabled energy parks, is critical to financial viability in both periods.

Hydrogen primarily serves as an energy intermediary or carrier, and three energy parks include hydrogen production:

- Intersect Power's Meitner Project in Gray County, Texas, would combine 340 MW of solar with 460 MW of wind to power 400 MW of on-site electrolyzers for producing sustainable aviation fuel.

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[12] See https://sublime-systems.com/.
[13] See https://www.electra.earth/media/ or https://www.bostonmetal.com/.
[14] For reference, the typical cost for hydrogen derived from methane is $1-2/kg.
[15] In the best resource areas, combined wind and solar portfolios (with some amount of overgeneration) can produce very reasonable power costs with more than 80 percent utilization of the electrolyzer. For examples, see appendix B of https://energyinnovation.org/publication/smart-design-of-45v-hydrogen-production-tax-credit-will-reduce-emissions-and-grow-the-industry/, or explore the Levelized Cost of Hydrogen calculator at https://zenodo.org/records/7948769/files/Interactive_LCOH_Calculator_v3.xlsx?download=1.

- The HyStor energy park in Mississippi has agreed to supply hydrogen to SSAB's green steel project.
- Hydrogen City, Texas proposes to serve a 2.2 GW hydrogen electrolyzer plant with 3.75 GW of on-site solar and wind power, with "additional renewable energy drawn from the ERCOT grid during periods of low prices." The hub would expand as needed and serve local facilities including ammonia and rocket fuel production.

The IRA's $3/kg production tax credit (PTC) is contingent on hydrogen production's emissions intensity, so combining the electrolyzer and generation resources via energy parks ensures these projects face no risk qualifying for lucrative tax credits.

In Appendix 3, we argue that in both eras, flexible hydrogen production is vital to project viability. Furthermore, making a hydrogen-producing energy park financially viable in either era will require the energy park to export power to the grid. As in the thermal battery example, these projects open the possibility of reconverting hydrogen back to power for sale on the open market when prices are high: Hydrogen stored on-site can also serve as a fuel in a combustion turbine to supplement output during high wholesale price periods.[16]

Insight Five: Premium on Connectivity to the Grid and Diverse Commodity Offtakers

In the tax-subsidized era, hydrogen energy parks will want to lean into overgeneration even more than energy parks feeding a thermal battery or traditional generation-only hybrid resources. The high value of collecting as much PTC as possible from a fixed input capacity of electrolyzer will lead the parks to super-scale their generation with peak output two to three times higher than the electrolyzer's peak capacity. This means they will need very good connectivity—a high megawatt AC export capacity relative to peak megawatts of generation—to sell surplus clean power (and de-risk the generation investment in case the co-located hydrogen electrolysis falls through). In the post-subsidy era, these energy parks will want to sell even more power to the grid.

OPPORTUNITY SIX: FASTER TO MARKET

Sometimes the impetus for an energy park is not only access to cheap, clean power but also faster access to power. Bypassing the bulk power system to directly serve local loads has the potential to drastically accelerate the pace at which additional demand can be met, especially when bulk power supply and delivery are constrained. Rapid demand growth is often driven by new manufacturing facilities and, notably, new data centers.

At first glance, data centers might not seem like ideal candidates for energy parks, which typically involve large, variable energy resources spread over vast areas, often far from urban centers. Data centers prefer proximity to the markets they serve—partly due to data latency issues—and benefit from being near pools of skilled labor. However, not all data center loads are equally sensitive to latency, and access to electricity—especially clean and firm supply—has quickly become a significant constraint on data center growth.[x] As previously mentioned, speeding the "time to power" for new data center loads can be highly valued. The lost opportunity cost of expensive investments sitting idle can be significant, and data centers

[16] Theoretically, with the PTC in place there are wholesale price levels where it makes sense to both produce hydrogen from electricity and consume electricity for power exports at the same time. We assume the IRS will disallow tax credits under these conditions.

can be built relatively quickly, while it may take years for new generation to interconnect and transmission upgrades to be built.

Example Six: The Amazon Web Services/Susquehanna Nuclear Plant Deal

This paper has mostly discussed energy parks in an implicit greenfield frame where new load and new generation come together in a new park. However, energy parks can also bring new load to existing generation (or the other way around[17]), potentially on an even faster path to market than co-locating with new generation with its own development timeline. The recent Amazon Web Services (AWS)/Susquehanna Nuclear Plant deal is an interesting case, revealing some of the issues all energy parks may face.

In March 2024, Talen Energy sold a data center campus in Pennsylvania to AWS for $650 million, and AWS plans to supply it with power directly from the Susquehanna Nuclear Plant.[xi] This direct connection to a nuclear plant effectively resolves some of the challenges data centers face: It offers clean baseload power near existing infrastructure and markets. AWS has agreed to purchase power in 120-MW increments, with the possibility of scaling up to 960 MW. Meanwhile, PJM Interconnection has requested approval from the Federal Energy Regulatory Commission (FERC) to increase the behind-the-meter connection from 300 MW to 480 MW. However, this arrangement has raised fairness concerns among other PJM stakeholders, who are wary of the potential impacts on reliability and AWS's ability to bypass charges that other loads must pay.[xii]

One notable aspect of this example is that because the clean power supplying the data center is not new or additional, it will remove existing generation from the market by load that potentially could be sited in another market.

Insight Six: Not All Stakeholder Concerns About Energy Parks Are Immediately Obvious

While the relationship between load and generation behind the POI for an energy park may seem like it should be a simple bilateral deal between private parties, connecting the park to the bulk power system (especially when diverting significant amounts of power from existing generation sources) can provoke considerable pushback from stakeholders concerned not only about fairness to consumers but also about reliability, cost allocation for infrastructure, emissions impacts, and competition for new loads.[xiii]

The AWS/Susquehanna deal demonstrates that questions can still be asked about why energy park loads should be exempt from costs and requirements that affect other loads—especially tariff riders that are not directly tied to transmission and distribution, like ancillary services for grid stability or support for low-income customers.

It is unclear whether concerns like those raised by the AWS/Susquehanna deal will present a widespread problem for other energy parks. For example, should we be looking at the policy stakes with a wider lens,[xiv] or are most concerns specific to this kind of data center deal? For concerns about repurposing existing generation, a ready solution may involve tying exceptional exemptions, tariffs, or legislation supporting export-only energy parks to some form of additionality—ensuring they provide new energy to the grid ("Bring Your Own Generation")—and other technical performance requirements around instantaneous

[17] However, typical existing loads are not directly connected to the transmission system so are not easy candidates to seed a new energy park.

backflow from the grid. However, even projects involving new supply could encounter technical issues.

Circling back to the general data center case, for example, AI-driven data centers tend to have spiky load profiles, a challenge that some developers aim to mitigate with battery storage[xv]—another likely common feature of energy parks. Data centers, especially in areas where they are heavily concentrated, like Texas, have become increasingly unpopular.[xvi] Some critiques center on their consumption of precious grid resources, and clean energy parks could help address these concerns. However, other issues, such as water use, might point to the kind of stakeholder engagement that will be essential for future energy park projects.

ENERGY PARK POLICY STAKES AND CHALLENGES

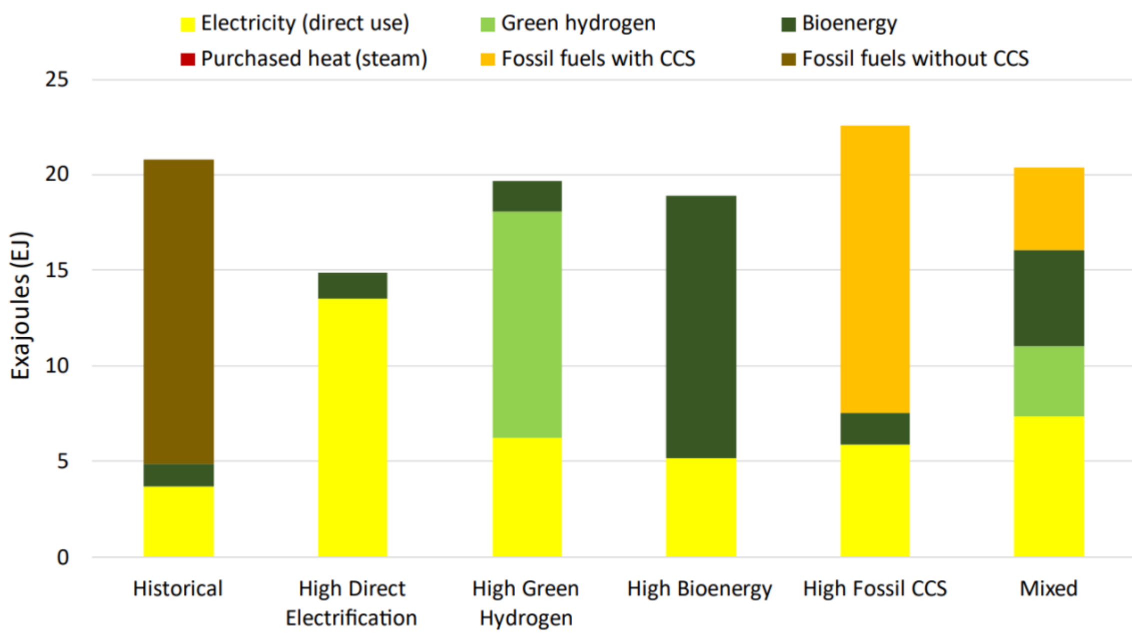
This paper has introduced what energy parks are, explored what they might become, and explained the combination of technological advancements and economic strategies that drive energy park economics. Energy parks are new portfolio resources that could be tremendously valuable to managing a cleaner grid with lots of variable energy resources.

Well-executed energy parks can create tremendous benefits, both private and public, especially when dedicated customers are able to co-locate with the generation resource in the energy park. What is at stake with energy parks?

A great deal is at stake for U.S. decarbonization goals and energy competitiveness when it comes to energy parks, even if we just limit the stakes to industrial loads.

A recent report from Energy Innovation[xvii]” analyzes several different scenarios for decarbonizing the U.S. industrial sector. Depending on the scenario, it foresees an incremental demand for electricity that could double total U.S. electricity consumption across all sectors. If energy parks became widely feasible, they could carry a significant fraction of that load, perhaps scaling up to between a fifth to a half of incremental demand, without unduly burdening (and perhaps even supporting) our existing bulk power system. Proper policy could make the difference between deploying energy parks solely in unique situations over the coming decades or deploying hundreds of thousands of gigawatts of new clean energy at scale.

Figure 4. Industry sector non-feedstock energy use in the U.S. (historical data and built-in scenarios)



Source: Jeffrey Rissman and Nik Sawe. The Industrial Zero Emissions Calculator. Energy Innovation. August 2024.

To get to that point, energy parks with co-located loads will need to overcome three broad buckets of challenges: rules of the road for connecting to the grid, wholesale market participation challenges, and resistance from monopolies in transmission, distribution, and retail markets. Below, we summarize some of the key elements of these challenges, with further details available in Appendix 1.

RULES OF THE ROAD FOR CONNECTING TO THE GRID

Energy parks face several technical and regulatory hurdles when attempting to connect to the grid. These challenges stem from the complex processes and standards required to ensure grid reliability while accommodating new types of hybrid energy systems.

Regulatory and Operational Uncertainty: The current rules governing interconnected generation (primarily FERC-approved tariffs as developed by Independent System Operators (ISOs)/Regional Transmission Organizations (RTOs), and transmission-owning regulated utilities) create uncertainty for energy parks with co-located loads. Grid operators require highly accurate models to predict how these parks—both their internal loads and their various generation and storage components (viewed as separate resources)—will behave under different conditions. Adding loads further complicates the interconnection study and approval processes: What if, for example, a large bank of hydrogen electrolyzers suddenly goes off-line and creates a large surge in supply where the energy park connects to the grid? Existing tariffs were designed for conventional generators (and are only recently struggling to adapt to storage resources), while loads have largely been addressed through state-regulated distribution utilities, leading to significant confusion and complexity for interconnection of energy parks.

Overwhelmed Interconnection Queues: Energy parks must navigate an already complex interconnection process that includes multiple studies assessing viability, grid impact, and necessary upgrades. However, the sheer volume of projects in the queue exceeds grid planners' capacity to process them in a timely manner, and overly simplistic and reductive treatment of energy parks with co-located loads would further strain these overloaded processes.

Lack of Generalized Approaches for Hybrid Resources: Despite some progress, the lack of standardized approaches for hybrid resources—such as solar with storage, and now co-located loads—delays interconnection and increases costs. Each new technology requires detailed, custom models for short circuit, stability, and power flow analysis, further complicating and slowing down the process. Given the traditional approach where the grid operator feels compelled to have separate models for each component of generation, storage, and load (rather than a unified model of the energy park as a system), such considerations make it more difficult to plan around integrating energy parks smoothly into the bulk power system. Thus, energy parks with on-site loads face lengthy timetables before their unique attributes can be incorporated into standard practice.

MARKET PARTICIPATION CHALLENGES FOR ENERGY PARKS

Beyond the technical interconnection challenges, energy parks face significant difficulties when participating in competitive energy markets and maintaining compliance with operational regulations. These challenges arise from the evolving nature of energy generation and consumption in the hybrid systems that drive energy parks.

Market Participation Models: If energy parks are to participate in wholesale markets, market operators will need to address how energy parks interact with various market structures (energy, capacity, ancillary services), and the complications of adding co-located loads to these models.

Market Benefits and Concerns: Energy parks, particularly large ones, may have the potential to affect power prices and market stability. Energy parks' ability to rapidly switch between supplying the grid and serving internal loads makes them a significant and agile market participant. However, that coin has two sides. On the one hand, these qualities should help with market efficiency and price formation, and energy parks should stand to collect financial benefits from that benign role. On the other hand, energy parks could unduly influence market prices in tight supply conditions, potentially requiring more oversight and regulation.

Energy Import Rules: Ambiguity surrounds how participant energy parks should be categorized and treated by the grid: Are they generation assets, storage, or traditional loads? Today each of these categories falls under different tariffs and rules, meaning a load-generation hybrid energy park faces significant regulatory uncertainty.

CHALLENGES TO ENERGY PARKS FROM MONOPOLIES FOR DISTRIBUTION AND RETAIL SALES OF ELECTRICITY

Energy parks face not only grid connection and market participation challenges, but issues related to the monopoly rights of utilities in providing power within certain territories.

Retail Sales Monopolies: Under the Federal Power Act (FPA), FERC regulates wholesale electricity sales while states control retail sales and distribution. This creates a patchwork of regulations that energy parks must navigate. In practice it likely requires prospective parks in monopoly services territories to negotiate bilaterally with monopoly utility companies for grid access and then get regulatory approval for any utility expenses associated with giving the project access to the grid. Current strategies, like single-entity ownership to avoid sales between separate entities, are inefficient and increase financing costs without benefiting the public.

Internal Networks Versus Power Distribution Monopolies: Energy parks that require building internal transmission networks might conflict with state-granted utility monopolies, and the legal landscape around these issues is nebulous. On the one hand, generators typically own essential interconnection facilities (lines and equipment to connect to the bulk power system substation) as part of their generation facility without running into problems with the local utility transmission and distribution franchise. On the other hand, once a co-located load is in the picture, generators can't include the lines and hardware to connect to the load in the same way. If the generation and load don't share the same parent company and investors, an issue arises as to who bears the regulatory risk around grid equipment behind the POI.

Addressing these challenges is critical for unlocking energy parks' full potential, ensuring they can contribute meaningfully to decarbonization and grid modernization efforts.

POLICY SOLUTIONS

ENGAGE WITH TECHNICAL BODIES EARLY AND PERSISTENTLY

To overcome the technical and regulatory challenges energy parks face in interconnecting with the grid and participating in markets, engaging with key technical bodies—such as ISOs/RTOs, FERC, and state regulators—early and persistently is critical. Energy parks are new and complex systems, and proactive collaboration will help streamline processes, standardize rules, and ensure energy parks' unique needs are considered in the evolving regulatory framework.

Key Participants:

- **Market Operators (ISOs/RTOs):** Responsible for designing and managing interconnection and participation processes for energy parks.
- **FERC:** Provides the regulatory framework and oversight for interconnection and wholesale market participation at the federal level.

- **State Regulators and Legislatures:** Critical for ensuring state laws and regulations accommodate the unique structure and needs of energy parks, especially regarding retail sales and local transmission networks.

Summary of Solutions:

1. **Address Regulatory Uncertainty:** Policymakers and grid operators need to develop clear rules to handle the complexity of energy parks with co-located loads, including how they participate in energy and capacity markets, and to what extent they can participate in wholesale electricity markets outside the restructured markets. Standardized and generalized models should be developed to simplify the interconnection approval process and allow ongoing energy park innovation.
2. **Alleviate Overwhelmed Queues:** Existing interconnection queues are overloaded and—under current modeling approaches—integrating complex energy parks will add further strain. Much of this strain could be avoided if energy parks were treated as a "net" resource at the POI. Meanwhile, solutions like the "connect and manage" model should be adopted, focusing on immediate physical interconnection while deferring more complex deliverability studies. When they have the flexibility to serve internal co-located loads, energy parks are particularly well adapted to approaches like these that speed up the interconnection approval process at the expense of some increased wholesale market risks.
3. **Establish Generalized and Standardized Approaches:** The lack of standardized approaches (interconnection, operational protocols, obligations during contingencies, etc.) to hybrid resources, especially those with co-located loads, increases delays and costs. Persistent collaboration with technical bodies can help develop generalized models and frameworks for hybrid systems, viewing them as flexible and capable sources of energy and grid services at their POI rather than as a group of separate components, and making the interconnection process more efficient.
4. **Market Participation Models:** Complex hybrid resources face barriers to full participation in wholesale markets. ISOs and FERC should develop standardized participation models that allow energy parks to integrate into wholesale markets with certainty and without undue complexity. These models should account for the presence of co-located loads and offer flexibility for energy parks to participate in energy, capacity, and ancillary service markets.
5. **Mitigating Market Manipulation Concerns:** Energy parks pose unique challenges for market regulators to prevent the exercise of market power. Implement oversight measures with market operators to prevent large energy parks from manipulating power prices. Potential market power abuses can be mitigated by tracking internal operations and monitoring power flows between energy parks and the grid. FERC and market operators must ensure clear guidelines are in place for how energy parks operate during periods when prices are already high because supply is tight, while appreciating and rewarding them for their contributions to reliability and efficient market price formation.
6. **Energy Import Rules:** Unlike conventional consumers, energy parks serve as both demand and supply, and in theory they can pull from the grid as well as export power. Collaborate with state regulators and market operators to develop clear rules on how

energy parks can consume power from the grid. This includes ensuring energy parks that consume electricity are treated fairly under tariff structures. In some markets, like ERCOT, an energy park could switch back and forth between being treated as generation or load based on the net flow of electricity during each pricing interval. In markets where loads incur extra charges (like capacity payments), new forms of dynamic tariff adjustment to account for energy parks' hybrid nature (both producers and consumers of electricity) will be necessary.

This subsection sets the stage for persistent and coordinated engagement, crucial for addressing technical and regulatory barriers. Further details are available in Appendix 1.

FOSTERING A NEW PARADIGM

As energy parks evolve, they will join and reinforce a trend governing how the grid interacts with a multitude of very different resources, transitioning toward a more flexible, "digital resource" model that accommodates more complexity while keeping the task of the grid operator manageable. This is a paradigm shift because it involves a fundamental rethinking of how the grid should operate when it starts to integrate advanced electronics, software, and energy storage, and the dynamic capabilities of energy parks. The flexibility of energy parks offers tremendous potential for the grid, but energy park benefits to the grid will only achieve their full potential if current frameworks fundamentally shift as to how grid participants are managed, compensated, and planned for.

Key Participants:

- **Industry Experts:** Engineers and grid operators responsible for implementing new control and communication technologies that will allow energy parks to function as digital resources.
- **Academics and National Laboratories:** Researching the techno-economic advantages of energy parks, investigating the ramifications of digital resources in modeling modern grid frameworks.
- **Research Funders (e.g., Electric Power Research Institute, DOE):** Funding studies and pilot projects that explore how energy parks can transform grid operations.

Summary of Solutions:

- **Universal Participation Model:** A universal model may be best to accommodate energy parks within the grid. This model would focus on essential operational parameters—like ramp speeds, energy limits, and maximum/minimum output and input—offering flexibility for energy parks without the need for customized frameworks for each configuration. This approach allows operators to focus on outcomes (grid stability, reliability) without needing detailed knowledge of internal energy park operations.
- **Leveraging Energy Parks as Digital Resources:** Energy parks have the potential to serve as "digital resources" that interact with the grid in real time. Through advanced telemetry and software, energy parks can provide services like fast frequency response and rapid reserves, responding automatically to grid disturbances and maintaining balance. These parks' ability to combine generation, storage, and flexible loads means they can adapt dynamically to the grid's needs.

- **Modernizing Grid Operations:** Current grid operations still rely on mechanical-era principles, but energy parks are forcing a transition to more modern, software-driven methods. The key challenge is convincing grid operators to embrace these new methods, as many still view them as a entailing a loss of control over grid reliability. By adopting digital transaction and control systems that allow for simpler, more resilient and reliable management of dynamic resources at the POI, grid operators can unlock the full potential of energy parks. Learning from the design principles of complex software systems, well-established concepts of object-oriented design and systems of cooperating intelligent agents should be applied, allowing the system operator to manage the power grid at a higher level rather than as an exponentially growing collection of components.

The shift to this new paradigm is not just a technological shift but also a regulatory and cultural one. More details on the technical implications and proposed models are available in Appendix 1.

NEW STATE LEGAL FRAMEWORKS

Energy parks face significant hurdles due to existing monopoly rights over retail sales and power distribution, which are regulated by states. Energy parks involving new generation selling power to new demand implicate state definitions of public utilities subject to public utility commission (PUC) oversight, which could grind energy park development to a crawl. Parks could potentially violate exclusive monopoly rights already granted to incumbent utilities, prohibiting their development without involving the incumbent utility and requiring new tariff development.

To enable energy parks' full potential, states must take the lead in creating new legal frameworks that balance utility rights with the need for greater flexibility in directly connecting energy production and consumption. Cooperation between federal and state policymakers will be crucial to overcoming these regulatory challenges, but most of the responsibility will fall to state governments, including regulators, to foster the legal and political consensus required for these changes.

Key Participants:

- **State Legislatures:** Primarily responsible for creating the legal frameworks that address monopolistic control over retail sales and distribution.
- **State PUCs:** Regulators that will implement and oversee any new tariffs or rules designed to allow energy parks more freedom in power distribution and retail sales.
- **FERC:** regulates wholesale electricity and cooperates with state bodies to help reduce conflicts between state laws and federal energy policies.
- **Utilities:** Major stakeholders that will likely resist changes but could be brought into the fold through negotiations and compensation mechanisms.

Summary of Solutions (see Appendix 1 for more detail):

- **Reduce utility power:** One potential solution is to require utilities to accommodate energy parks but allow utilities to retain ownership of the internal distribution networks within energy parks. These terms must not compromise the financial viability of the parks and could evolve into pro forma agreements that allow for quick approval. State regulators should, as a least-regrets step, investigate the viability of energy parks under current regulations, assess industry interest in developing these projects in their state, and develop policy positions that anticipate and encourage development that does not unduly harm the existing utility or other customers.

- **New State Legislation:** States could amend utility codes to grant energy parks more freedom, particularly in bypassing utility monopolies on distribution and retail sales. States not ready for this could at least require their PUCs to adopt policy proposals and recommendations to the legislature that promote the economic development of energy parks. State legislatures must navigate stakeholder concerns over fairness, but new laws could offer clarity and legal flexibility for energy parks to operate more efficiently, avoiding the current inefficiencies of single-entity ownership models.
- **Regulatory Cooperation:** The FPA gives FERC jurisdiction over wholesale electricity sales and transmission, while granting states jurisdiction over distribution and retail sales. Energy parks interacting with the bulk electricity system and on-site load implicate both state and federal regulators, so these distinct regulatory bodies must collaborate closely to ensure that they do not create conflicting regulatory frameworks. This cooperation is crucial for creating a cohesive regulatory environment where energy parks can flourish without running afoul of monopoly rights or state-federal jurisdictional conflicts.

By updating legal frameworks and fostering collaboration between utilities and energy parks, states can unlock the full potential of these innovative resources. More details on these legal challenges and proposed solutions are available in Appendix 1.

STAKEHOLDER ENGAGEMENT

Advancing the policy solutions needed for energy parks requires a broad coalition of stakeholders who have a vested interest in clean energy, economic development, competition in electricity markets, and environmental sustainability. At the same time, addressing the concerns of affected parties—such as incumbent utilities, local communities, and environmental justice advocates—will be key to building political momentum and fostering compromise. Stakeholder engagement is not only a technical and regulatory challenge but also a political one that requires finding common ground among groups with overlapping but sometimes conflicting priorities.

Key Participants:

- **Clean Energy Developers:** Interested in advancing renewable energy projects through energy parks, they are central advocates for scaling up clean generation technologies.
- **Industrial Loads (e.g., Data Centers):** Major energy consumers that would benefit from co-locating with energy parks to secure energy supplies more quickly and with desired clean attributes.
- **Governments and Economic Development Advocates:** community representatives that can influence energy park design to drive local job creation and investment in rural communities and other areas where economic development is encouraged.
- **Climate and Environmental Advocates:** Supporters of energy parks who serve as key drivers of decarbonization and sustainable energy infrastructure.

- **Land Use Advocates:** Focus on ensuring that energy parks are developed in a way that balances economic growth with responsible land use.

Example Stakeholders with Concerns to Address:

- **Incumbent Utilities:** As existing monopoly holders over energy distribution, incumbent utilities may resist changes that threaten their business model. They will need to be part of the conversation to find workable solutions.
- **Consumer Advocates:** Advocates who are concerned about energy affordability and access, especially for low- and fixed-income populations, can offer crucial support for equitable policy development.
- **Local Environmental and Land Use Stakeholders:** Communities that may face land or water use issues stemming from large energy parks, and possible pollution, will need to be engaged early to mitigate opposition.
- **Environmental Justice and Equity Advocates:** Ensuring that energy parks do not disproportionately impact vulnerable communities will be critical to gaining broad political support.
- **Local Government:** Providing some financial upside for local government and citizens is often the key to moving projects forward.

Summary of Solutions:

- **Broad Coalition Building:** Clean energy developers, industrial consumers, rural economic development interests, and climate advocates must come together to form a powerful coalition in support of energy parks. This coalition should focus on aligning economic, environmental, and social benefits to build a shared narrative that energy parks can advance a sustainable and prosperous future.
- **Compromise and Engagement:** Effective stakeholder engagement must go beyond coalition-building to directly address the concerns of utilities, local citizens, consumer advocates, and environmental justice groups. Transparent dialogue, public consultations, and ensuring that local communities see tangible benefits from energy parks will be essential to managing opposition.
- **Political Advocacy and Negotiation:** As the regulatory and policy landscape evolves, stakeholder engagement will need to include active participation in political advocacy. Compromise on key issues, such as utility compensation, consumer protections, and environmental impact mitigation, will help unlock legislative and regulatory reforms.

This effort will require a thoughtful, inclusive approach to engagement, acknowledging the diverse interests of all parties while finding common ground to support the growth of energy parks.

CONCLUSION

Energy parks are a new but rapidly changing concept, with projects emerging at an unprecedented pace and scale. This paper introduces energy parks, establishes the economic rationale and potential climate and grid benefits of energy parks, and shows how current markets and policies create barriers to innovation and rapid deployment of energy parks. Policymakers interested in responding to this emerging economic development opportunity should consider whether their grids and electricity marketplaces are well positioned to accommodate these innovative resources and maximize their value both to existing consumers and the parks themselves.

APPENDIX 1: ENERGY PARKS AND THE BULK POWER SYSTEM

In this appendix, we examine in more detail the relationship between energy parks and the grid, both at the technical and regulatory levels. This means looking at permitting issues, participation models for market dispatch and consumption, and associated market concerns. Any serious analysis of energy parks also requires a careful examination of how they mesh with current state law and monopoly mandates as well as how energy parks challenge the delicate balance between state and federal jurisdiction over the modern power grid.

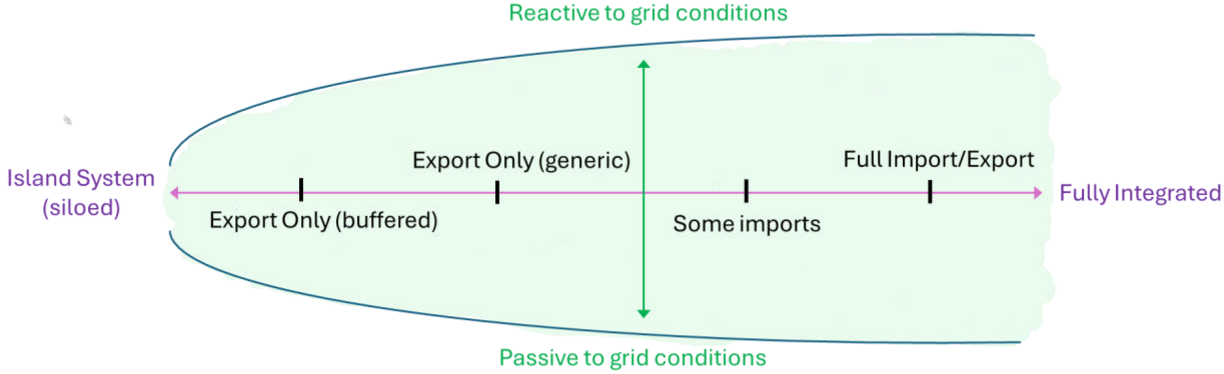
This appendix attempts to identify and crystallize some (but not likely not all) challenges for energy parks within the context of the current grid. In tandem, we also suggest some solutions addressing these issues and set out a paradigm shift that we think organized markets need to make to properly foster and take advantage of energy parks. We close by looking at permitting and franchise issues for serving a local load inside an energy park.

ENERGY PARK CONNECTION TYPES ON A SPECTRUM

Energy parks (we are mostly thinking of those with co-located loads here) have many options for how they connect to the grid. At one extreme, they may choose not to connect at all, preferring to avoid the technical, logistical, procedural, and legal challenges inherent to connecting new and complex projects like energy parks to the grid. With a co-located load, an energy park could become a self-sufficient island. Yet historical experience has taught us that interconnecting grids to share resources tends to yield tremendous benefits for all parties concerned. Islanding an energy park leaves significant benefits unrealized, deprives other grid participants of valuable resources, and makes large-scale projects like hydrogen electrolyzer parks financially risky or even infeasible. At the other extreme, keeping load and generation separate even though they could be co-located increases transactional costs, forgoes savings on shared equipment and, if these components end up geographically separated, creates extraneous power flows and an undue call on incremental transmission resources.

Figure A1. Energy Park Design Continuum

Energy parks connect to the grid on a continuum of possible arrangements for how much energy is exported and imported across the POI, and with a variety of operational arrangements for reacting to grid conditions: reacting to market prices, providing ancillary services, or actively responding to exceptional conditions in different ways.



Traditionally, energy parks have operated without co-located loads, functioning solely as export-only facilities. Even when storage is included, energy parks often maintain this export-only status. For energy parks looking to add loads, continuing as export-only may seem the simplest path, as it avoids incremental complications with grid operators and regulators. These parks can buffer their interactions with the grid using storage or power electronics to smooth large internal fluctuations in supply and demand, ensuring they maintain a steady source of export power within contracted trading or dispatch windows and are seen as "good citizens" on the grid (avoiding backflow, power and voltage spikes, etc.). Over time, as experience with these systems grows, some buffering needs may disappear.

With even more extensive deployment and increased engagement with grid operators and regulators, energy parks may choose to import a small fraction of their power. This might occur when very cheap power is available on the grid during specific intervals or when the energy park needs a backup source, like shared reserves between neighboring grids. As energy parks evolve and engage in more complex interactions with the bulk power grid, they will need to decide how best to tap into their inherent flexibility—either to help operators manage transmission contingencies or to capitalize on swings in power prices.

INTERCONNECTION CHALLENGES FOR ENERGY PARKS

Energy parks that seek to interconnect to the grid will face at least three kinds of problems tied to interconnection: regulatory and operational uncertainty, already overwhelmed interconnection queues, and lack of common standards.

Problem: Regulatory and Operational Uncertainty

Energy parks with co-located loads face regulatory and operational uncertainty under the current rules of interconnected generation in organized markets (often governed by "ISO tariffs") because these markets typically treat generators and loads very differently. It's not even clear to us whether such energy parks, neither fish nor fowl, would be allowed under existing rules and tariffs. Furthermore, grid operators prefer to have a clear picture of how each generator they dispatch is likely to behave. The internal dynamics of an energy park can muddy this picture. Power engineers responsible for approving interconnections need highly accurate models to predict how these hybrid resources, especially their internal loads, will behave under various stressed conditions. These models could vary significantly from energy park to energy park, complicating the approval process. Further, if an energy park wants to participate in other electricity markets such as capacity markets, planners will need detailed models (and perhaps ex ante commitments) of how it is likely to behave for their production cost models to calculate figures of merit like effective load-carrying capacity and determine appropriate compensation for capacity services.

Problem: Overwhelmed Interconnection Queues

Connecting energy parks with co-located loads to the bulk power system for export requires navigating an already highly complex interconnection process.[18] This process includes feasibility studies, system impact studies, and facilities studies, all aimed at assessing the project's viability and its impact on grid reliability, and identifying necessary upgrades and costs associated with adding a new project to the grid. However, interconnection queues are currently overwhelmed, with total capacity in process far exceeding what grid planners can study in a timely way. The more complex energy parks with internal loads are naively[19] incorporated into this work stream, the more they will stretch the limited capacity of grid operators and transmission owners to complete these studies quickly.

Problem: Lack of Generalized Approaches to Hybrid Resources

Despite efforts to streamline the interconnection process for hybrid resources, progress has been inconsistent. Hybrid solar/storage projects began emerging in the mid-2010s, but it wasn't until 2021 that FERC held a technical conference to address the issue. ISO and transmission operator responses remain fragmented, with some helpful standardizations but many organizational idiosyncrasies that delay widespread adoption of generalized approaches. A core issue is the need for detailed information about the internal workings of machines behind the POI for conducting short circuit, stability, and power flow analyses. Historically, even photovoltaic (PV) systems required new approaches to aggregate multiple components into a single model. Adding storage and loads to these hybrids introduces even more complexity to dynamic modeling, although it also presents new opportunities for optimization.

Solution: Reform Interconnection

One policy that could facilitate the interconnection of complex hybrid resources (and generation and storage resources in general) is the "connect and manage" approach. A team at the Center for Global Energy Policy, looking at the international experience with such an approach,[xviii] describes it as follows:

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[18] Many ISO/RTOs still study storage interconnection as if storage could inject or withdraw power at the worst possible time for the grid. The result of these studies allocates to projects excessive network upgrade costs that are only needed in these unrealistic scenarios.

[19] Later in this appendix, we discuss the potential of more modern market participation models to simplify interconnection for energy parks.

> Under the "connect and manage" model, the grid operator narrows the scope of the interconnection study process to look at the grid enhancements necessary to allow the generator to physically interconnect to the grid. Questions around deliverability of the power are deferred to subsequent studies. This reduces the complexity of the interconnection process, resulting in faster studies and increased ability to process interconnection requests. In exchange, interconnecting generators accept higher congestion and curtailment risk until deliverability studies and necessary upgrades are completed.

In the ERCOT region of Texas, a similar approach applies:[xix] The "connect and manage" approach could be tuned to focus less on the internal details of an energy park and more on what that facility is expected to achieve, its capabilities, and how expectations will be enforced. Instead of trying to preempt every problem that might occur, it allows the grid operator to take mitigating measures, shifting some delivery and curtailment risk to the developer as the price for a simpler connection process. While this can be detrimental to the economics of a project selling power to the grid, for a load-generation hybrid whose main value proposition lies in serving the native load, the ability to sell excess generation with significant curtailment risk is less daunting. State and federal regulatory bodies working together to encourage transmission operators to adopt this approach could help streamline the interconnection process, leveraging the flexibility of actively controlled energy parks to avoid many contingencies and reduce system impact modeling and cost estimation complexities.

In a recent report from Grid Strategies LLC and The Brattle Group,[xx] the authors propose a vision for a more efficient interconnection process centered on the values of "cost certainty and transparency," "speed and schedule certainty," and "non-discrimination." These values should hold for energy parks, and it would be interesting to see how the reforms they propose would fit into the context of energy parks with co-located loads.

MARKET PARTICIPATION MODELS

To the extent load-generation hybrids want to participate in organized markets, they face similar issues around uncertainty and lack of standards regarding how they are allowed to participate in various markets, including energy, capacity, and ancillary service markets.

Problem: Non-Existent or Hodge-Podge Participation Models for Energy Parks

Most competitive wholesale markets have at least some kind of participation model for generation-storage hybrid energy parks. They accept either a *co-located* model for hybrid participation where individual resources participate separately in energy markets, capacity markets, and ancillary services, or an *integrated* model where all the resources are treated as one. With the addition of loads behind the POI, the co-located model seems impractical, as loads are treated very differently in organized markets and carry extra obligations (paying for transmission access, capacity payments, etc.) even if they never draw power from the bulk power system. The integrated model for hybrid resources can be quite different from one market to the next and will likely need some significant changes to accommodate co-located loads, even in the simpler export-only version.

FERC, which regulates resource participation in organized electricity markets, is aware of market participation issues brought up by hybrid resources[xxi] (along with the interconnection and accreditation issues mentioned above). It has mainly focused on generation-plus-storage hybrid resources (historical energy parks), although co-location with generation is at the table in 2024.[xxii] We note that in Order No 2222, which requires RTOs to accommodate distributed energy resources (DER) aggregators, FERC explains in footnote 7[20]: "In addition to tariff provisions that apply to all market participants, the RTOs/ISOs create tariff provisions for specific types of resources when those resources have unique physical and operational characteristics or other attributes that warrant distinctive treatment from other market participants. The tariff provisions that are created for a particular type of resource are what we refer to in this final rule as a participation model." FERC has in the past required RTOs to ensure that their rules accommodate specific resource types, such as storage and DER aggregators. It has not yet issued any rule specific to more general energy parks, but there's precedent for FERC doing so in the future.

Solution: Follow the Experts

In anticipating and resolving issues with market participation models, RTOs and FERC would do well to listen to the experts. In a March 2022 Report, *Unlocking the Flexibility of Hybrid Resources,*[xxiii] ESIG examined many of the issues we detail, with the following guiding principles for consideration when implementing market policies, interconnection requirements, and incentive mechanisms for hybrid resources:

- Become less prescriptive and more technology agnostic with definitions
- Leverage existing POIs for additional resources
- Create multiple participation model options to facilitate greater flexibility and innovation, while allowing resources to provide all services they are technically capable of providing
- Develop broad participation models in advance for technologies that are not yet tested
- Give the asset owner the option to manage internal operation of the hybrid facility when they choose to do so, as long as they aim to meet performance targets defined by the system operator
- Consider synergistic effects and diversity benefits of combining complementary resources
- Reconsider traditional requirements that close doors for future flexibility and services in a transforming grid

Hybrid resources and task forces related to their implementation, operation, and benefits remain an active topic at the ESIG System Operation & Market Design Working Group.[21]

MARKET MANIPULATION CONCERNS

With a load included, energy parks raise unique issues for monitoring market integrity and market manipulation that may require new regulatory approaches and rules. Manipulation of energy market prices can occur when a supplier has a large enough share of the market that

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[20] We thank Ari Peskoe for drawing our attention to these matters and this footnote.
[21] https://www.esig.energy/system-operation-working-group/.

its decisions about whether to produce or withhold generation can set the price and affect all the bidders in the market. FERC has tests to determine whether these suppliers are “pivotal,” and therefore earn additional regulatory scrutiny and reporting requirements in their bidding behavior.[22] Hybrid and storage resources already create unique issues related to market manipulation, and including a load in an energy park requires market operators to be more concerned about economic withholding during periods of scarcity regardless of whether the resource is a pivotal supplier. The concerns over withholding could be heightened if an energy park is part of a larger fleet of resources. Concerns are further intensified by the inclusion of co-located loads in energy parks because these provide an alternate sink for generation that an operator may want to pull off the market.

Any energy park of sufficient magnitude providing or withholding its power can materially affect power prices. Generically, their flexibility should help with market efficiency and price formation, and energy parks should stand to collect financial benefits from that benign role. However, more self-interested behavior such as influencing prices to enrich themselves at the expense of consumers, could be of concern. Market operators guard against such behavior in several ways, but these roughly boil down to two categories: tracking the marginal costs of generators and instituting controls on pricing during problematic periods.[23]

Smaller load-generation hybrids are unlikely to be of concern, unless they are part of a fleet of coordinated assets, but large energy parks with hundreds or thousands of megawatts of potential output, like the hydrogen electrolysis parks with a large export capacity, can switch quickly from feeding the grid to feeding their co-located load and back with potential material impacts on prices. In such cases, i.e., so long as any internal generation is serving any amount of internal load, the marginal cost for these large hybrid energy parks is the opportunity cost of not serving their internal co-located load, rather than their marginal cost of production. Where large pivotal generators must document and let the market operator know their fuel costs, ramp rates, and minimum/maximum output potential, large energy parks should do something similar.[24]. In a universal participation model (see below) there might not be any difference in how these parameters are presented, except for some additional parameters.

ENERGY IMPORT RULES FOR LOAD-GENERATION HYBRIDS

One way an energy park could look substantially different from existing bulk power system generating resources would be when they become a net consumer of power from the bulk power system.

Problem: Should Energy Parks Be Treated Like Generation or Load?

In today’s grids, providers and consumers of power face very different tariffs. While generators may need to pay for some transmission upgrades as part of their interconnection process, in general they do not pay for the transmission and distribution of power—we live in a “consumer pays” world. One exception to this rule is energy storage, which is allowed to buy power at a wholesale rate. This is in recognition of the fact that it will sell it all back (albeit

[22] See generally https://www.ferc.gov/horizontal-market-power.

[23] These periods can include times when some market power criteria are satisfied, or when live modeling indicates a problem.

[24] For example, energy parks could provide their the local opportunity cost of supply as their “fuel cost,” and “ramp rates” and output constraints set by the flexibility of their co-located load, storage, on-site backup and variable generation forecasts.

with some round-trip losses). It is possible that an importing energy park might not give the power back, raising the question of whether it is taking advantage of its situation to get unfair purchase rates relative to other loads on the grid.

Solution: Net Wholesale Power Sales

One way to reasonably enable imports for energy parks would be to institute a special form of metering, where all power purchases are credited against sales during each clearing interval. Any negative balance would incur a penalty to reflect transmission and delivery costs (easier said than done, but a deeper dive is beyond the scope of this paper). In the Texas market run by ERCOT, hybrids can operate as "private use networks" (PUNs) with billing along these lines.[25]

This net or bi-directional metering raises some complicated jurisdictional issues that Texas avoids because it regulates both retail and wholesale sales of electricity in ERCOT. FERC says that it has no jurisdiction over net metering, which is true at the level of retail customer transactions and DERs connecting to distribution systems but could be challenged when it comes to large loads that interconnect to the interstate transmission system and could effectively participate much like storage resources or "negative generation" at the wholesale level.

The term net metering comes up in two contexts at FERC.[26] First, FERC has determined that it has no jurisdiction to preempt state net metering programs for rooftop solar and other DERs. Second, more relevant to our context, FERC has said that it has no jurisdiction over "station power" netting. "Station power" refers to energy that a generator consumes for its own operations. "Netting" refers to billing conventions that can offset the generator's station power consumption from the transmission network by its own production. But FERC has distinguished what it calls "permitted netting," which it does assert jurisdiction over. Here's FERC's explanation from 172 FERC P 61243 at page 100:

> With Permitted Netting, a generating facility is using its own real-time electric generation to supply its station power behind-the-meter—it is not receiving station power supply from the interconnected grid. Self-supply monthly netting, on the other hand, concerns the ability of a generating facility to net the electric energy it consumes from the interconnected grid when it is offline and not producing against its wholesale sales. When a generating facility is offline and not producing energy and seeks to acquire power from the interconnected grid for its station power, this is a retail sale of electric energy for end use. There is no such sale with Permitted Netting.

Applying this to energy parks, FERC could allow for netting of production and consumption that is all behind the POI. But under the framework above, FERC may assert it cannot allow netting when some of the consumption is energy from the transmission network. Any energy delivered over the transmission network could potentially be ruled a retail sale subject to state regulation (although FERC has authority over any transmission charges associated with that delivered energy).

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[25] For an example discussion on PUNs, see https://www.jdsupra.com/post/contentViewerEmbed.aspx?fid=f3dc0287-b274-4636-8368-bab1f43905a8. More legal analysis is available for a nominal fee at https://utcle.org/index.php/ecourses/get-asset-file/asset_id/52804/code/OC8860/.

[26] Thanks again to Ari Peskoe for legal feedback here. Any mistakes and slips of wording are ours, not his.

Hence, some kind of state regulatory role (likely in collaboration with FERC) will be required to sort this out. Net-metering schemes have become contentious with distribution consumers, but the hope is that an acceptable solution can quickly be found for energy parks that only operate at the wholesale level. In the near term, most energy parks will likely stick to an export-only model, so there is some extra time to work with.

Co-Location in the News: The AWS/Susquehanna Deal

However, even in the export-only model, when an energy park subsumes an existing source of energy, objections still come up. Just as demand reductions affect supply and demand dynamics like new supply (hence the nickname "negawatts"), the sudden removal of previously available supply looks a lot like extra demand on the grid. As noted above, in March 2024 Talen sold a data center campus in Pennsylvania to AWS for $650 million and plans to supply power from its Susquehanna nuclear plant.[xxiv] AWS has agreed to purchase power in 120-MW increments, potentially growing to 960 MW, while PJM has requested FERC's approval to increase the behind-the-meter connection to the data center from 300 MW to 480 MW.

While the relationship between load and generation behind the POI for an energy park may seem like it should be a simple bilateral deal between private parties, connecting the park to the bulk power system (especially but not only when diverting significant amounts of power from existing generation sources) could provoke considerable pushback from stakeholders concerned not only about fairness to consumers but also about reliability, cost allocation for infrastructure, emissions impacts, and competition for new loads.[xxv] The AWS/Susquehanna deal demonstrates how questions can still be asked about why energy park loads should be exempt from costs and requirements that affect other loads (especially tariff riders that are not directly tied to transmission and distribution, like ancillary services for grid stability or support for low-income customers).

A PARADIGM SHIFT: ENERGY PARKS AS "DIGITAL RESOURCES"

Energy parks, especially ones with storage and flexible co-located loads, can orchestrate the behavior of multiple machines behind the POI to supply the demands of the co-located load and choose how to dispatch power to the grid. In this orchestration, failure to satisfy the co-located demand becomes an opportunity cost much like the ones encountered by ordinary hybrid resources due to fuel costs and energy limitations on batteries. The energy park portfolio can act as a flexible resource to the grid, within technical constraints, and responding to the economic incentive to serve the co-located load. One of us, Mark Ahlstrom in his capacity as ESIG President, referred to this phenomenon in his 2020 remarks to FERC[27] as the rise of power plants as a "digital resource" where potentially "given sufficient electronics, software, energy and storage, we can create essentially any kind of electrical machine that we want." Adding a flexible load only adds to the toolset for making such resources flexible grid participants.

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[27] Written Remarks from Mark Ahlstrom – Panel 1. https://www.esig.energy/wp-content/uploads/2020/07/Ahlstrom-Comments-FERC-Hybrid-Resources-Conference.pdf.

Ahlstrom has further called for a "universal participation model"[xxvi] where instead of creating a framework for each possible hybrid resource, transmission owners, grid operators, and power markets start with a generic "universal" model and then add back in only the most relevant parameters, like ramp speed, energy limits, and maximum/minimum output. This allows a more abstract and generalized approach to integrating grid resources that offers the most flexibility in putting together all kinds of useful resources.[28]

To illustrate what this means for energy parks, we can look at the ancillary services for frequency response.[29] In the "analog" world full of large rotating iron masses, a sudden frequency drop suddenly creates an inertial response in all connected synchronous generators, which resist slowing down in a manner that arrests the frequency drop. Then an automated "governor response" in participating generators proportionally increases steam/fuel supply to restore frequency until human intervention can restore balance.

In a digital world, energy parks would sign up to provide similar services like "fast frequency response" and "rapid reserves." The grid operator doesn't need to know internal details of the hybrid but is in constant communication via telemetry to know how much of this service the hybrid is able to provide at any time. If a hybrid is currently committed during a grid disturbance, then it will automatically react to a frequency drop by injecting extra power in a pre-agreed manner and amount at the POI within a pre-determined time frame and then provide the requisite reserve power as it awaits further instructions. The grid operator doesn't need to know if the hybrid is discharging an electric battery or turning down demand from the co-located load to accomplish its task, it just wants the committed response.

Current power grids are still organized in ways that would be very familiar to a mechanic or power engineer of the early 1900s. They have moved on a little, since some of the abstraction above has already been partially implemented in grid-operator dispatch systems. Unfortunately, other elements of a universal model are still anathema to these same operators because they interpret them as a loss of control on their part over key aspects of their responsibility to maintain reliability. However, energy parks by their very nature will challenge that paradigm and force a reckoning with more modern methods of organizing large numbers of interacting machines in a resilient and reliable way.[30] Those responsible for the health of the bulk power grid will face the choice of evolving their framework in order to capture the techno-economic potential of new grid-participating energy parks with co-located loads, or see these resources either fail to appear or retreat to a siloed mode of operation at a loss to society if their contributions to grid reliability are not appreciated and used. This conundrum has tremendous implications for norms, laws, and regulations that touch on the power grid.

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[28] This is analogous to the software concept called "object-oriented programming" crucial to the development of modern software and the creation of Arpanet (the precursor to the internet). For a compact history of the subject see "The Forgotten History of OOP" at https://medium.com/javascript-scene/the-forgotten-history-of-oop-88d71b9b2d9f.

[29] When there is a sudden change in the balance of generation and load, the grid frequency will change in ways that are problematic beyond an allowed range. Resources that provide frequency response help grid operators manage this over small timescales like seconds (or less).

[30] A subsequent ESIG blog by Ahlstrom argued that even without supporting the fully parameterized approach of the universal participation model, similar results could be obtained by fully embracing a flexible energy storage market participation model (but system operators have also resisted this for similar reasons). Since an energy storage resource can both inject power like a generator and extract power like a load, it follows that a flexible energy storage model could be used for market participation by more general energy parks. See https://www.esig.energy/why-storage-might-solve-really-big-problems-but-different-ones-than-you-think/.

CHALLENGES TO ENERGY PARKS FROM MONOPOLIES FOR DISTRIBUTION AND RETAIL SALES OF ELECTRICITY

Outside of grid connection and market participation issues, energy parks may also face challenges concerning the rights of monopoly utilities to be the exclusive provider of power to consumers in each service territory. Energy parks provide energy on-site to storage and potentially loads, with further potential to interact with the grid. They may be co-owned, or could be owned by different entities in ways that more fairly distribute operational and financial risk. These new configurations raise novel questions about what counts as a "wholesale" versus "retail" electricity sale, and therefore whether and how different energy park configurations may conflict with existing monopoly jurisdiction.

Problem: Retail Sales Monopolies

Under the FPA, FERC regulates the interconnection of resources into the grid and wholesale sales of power. FERC decisions have held that transmission operators must provide open access to wholesale generators, allowing those generators to own and operate infrastructure that connects the generator to the bulk electricity system. States regulate retail sales to end-use customers, as well as the distribution systems that represent low-voltage poles and wires that connect customers with the bulk electricity system. Regulated monopolies, be they full-service electricity or just "poles and wire" suppliers, have a fair amount of discretion in implementing FERC's rules. There is also a lot of deference to states on how best to weigh the benefits of protecting the natural monopoly versus subjecting it to competitive forces—even in this context. For example, even though utilities must open their transmission systems to independent power producers, state jurisdiction over retail sales means incumbent utilities are under no obligation to procure that power or facilitate access to customers.

Energy parks raise novel issues when it comes to monopoly utility regulation when they involve both generation and load on-site that use local networks behind the POI. Intuitively, parks such as hydrogen electrolyzers paired with generators involve the sale of energy to a retail customer—something that has historically fallen under the purview of an incumbent retail monopoly. An argument could be made that the distribution of electricity between generator and load also constitutes distribution infrastructure—another facet of electricity service that likely falls under exclusive monopoly rights. In practice, this means an energy park faces the risk that its design will require the involvement and service provision of the monopoly utility—increasing project complexity, extending development timelines, and subjecting it to the oversight of both the utility and state regulators. However, this construct presumes a sale between distinct entities. Today, energy parks are practically forced to get around this patchwork of state and federal regulatory concerns about electricity sales between separate entities by having the whole project owned by the same entity, where there is technically no buying or selling. This strategy is inefficient, as it tends to increase financing costs with no particular benefit to the public.

Problem: Internal Networks and Power Distribution Monopolies

Any energy park with clean energy resources of significant size will involve building new poles and wires connecting the energy park over significant distances. For traditional generation or generation/storage hybrids, these "gen-tie" lines are considered part of the private asset, and ownership of these lines does not interfere with the distribution utility's monopoly. However, once co-located load is part of the internal network behind the POI, private ownership of the internal network may run into issues with state-granted utility power distribution monopoly franchises and new transmission right of first refusal.

Structures like the PUNs in Texas exemplify both how prospective energy parks might navigate this space, and the need for further reforms. ERCOT defines PUNs as “an electric network connected to the ERCOT Transmission Grid that contains Load that is not directly metered by ERCOT (i.e., Load that is typically netted with internal generation).” These PUNs may engage in net energy metering with ERCOT, but arrangements like energy parks risk violation of Texas utility law. PUNs are also subject to Texas regulation, which requires that only a retail electric provider may provide retail electric service.[xxvii] PUNs are allowed to construct and maintain their own distribution infrastructure because Texas law (ERCOT rules and state legislation) grants exemptions to state jurisdiction when PUNs demonstrate self-service or co-ownership between generator and load, or if the generation facility is a “qualified facility” under the Public Utility Regulatory Policies Act (PURPA). However, for more complex multi-party transactions, utility law is somewhat unclear, and recent litigation has left unresolved the matter of whether energy park infrastructure would constitute an unregistered public utility under Texas law.[xxviii] The Texas model shows that it’s possible to work around or provide meaningful exceptions to utility monopoly jurisdiction, though the larger and more complex these projects become, the more likely it is they will run afoul of narrow exemptions under existing utility codes. Therefore, much more work can be done to reduce barriers to energy park development.

Given the potential benefits of energy parks and the leeway allowed states under the FPA, it would be worthwhile for legislatures to pass laws allowing private ownership of power lines behind a single POI, ideally with diverse ownership models that promote efficient development and financing of energy parks.

Solution: Reduce Utility Power

One solution to get around various utility franchise rights is to co-opt the utility: let utilities own the internal poles and wires and meter the internal sales with some compensation. The issue is that this compensation will need to be light for the financials of the energy park to make sense. Additionally, any utility cost recovery for service constitutes a new tariff that needs to be developed through stakeholder engagement and regulatory processes, then approved by the appropriate regulator (e.g., the PUC or a municipal utility’s governing body). Other stakeholders may object to what they see as preferential treatment for one customer class, especially if they avoid some of the charges that account for the current gap between wholesale rates and retail industrial rates. But regulators could spell out the conditions under which other customers would be unaffected and bake those conditions into new participation rules.

Still, the utility’s involvement is not a necessary condition for energy parks and policymakers should question the wisdom of extending traditional regulatory frameworks to this model, which is limited to sophisticated buyers and sellers. Requiring a monopoly distribution or retail utility’s involvement may disrupt energy parks’ development by subjecting these innovative new configurations to lengthy regulatory processes and oversight. Meanwhile it is not clear that regulating parts of energy parks as public utilities is justified by the same principles that demand regulation of monopoly distribution and retail utilities.. Texas PUNs provide an example of proactive wholesale market regulation that works with existing state regulations to create exemptions that energy parks can navigate. At the very least, it is timely now for state regulators to examine the issues raised by large generators and co-located loads in order to develop policy positions that anticipate the coming wave of energy park proposals.

Solution: New State Legislation

Another solution is for state legislatures to get involved and pass a special law that amends their utility codes to allow energy parks to evade the monopoly retail and distribution rights of incumbent utilities (within limits). State legislatures need not necessarily reach into the regulatory arena with specific changes to the utility code. Instead, they can require PUCs to examine whether exemptions to monopoly regulation and oversight are appropriate, and what measures would protect customers and maintain the preferred scope of utility monopoly. However, this takes what might have been a contentious process with the utility regulator and places the same stakeholder tensions (are the energy park rules “fair” to other consumers?) in an outright political context.

APPENDIX 2: HISTORICAL EXAMPLES OF ENERGY PARKS

In this appendix, we provide more detailed information on the examples given in the main text of historical energy parks.

EXAMPLE 1: SOLAR STAR

One of the largest solar farms currently in operation in the U.S. is the Solar Star farm, a pair of projects in the Antelope Valley of California. This is a single axis tracking solar farm with a 776 MW_{DC} capacity[xxix] but only 585 MW_{AC} of grid-interconnected capacity.[31] Its ILR is 776 divided by 585, or an ILR of roughly 1.32.

There are two ways to look at this kind of project: either as an AC-connected solar farm with extra DC panels backing it up (how much value is gained from increasing DC power for a fixed AC amount), or as a clipped DC solar farm (how much value is gained from decreasing AC capacity for a fixed DC amount). The first way is how the grid sees this asset in practice, but the second is important to understanding the financial rationale for a larger ILR.

The financial logic for a 1.32 ILR like that seen at the Solar Star farm is simple. While some revenue will be lost when power is clipped (about 1 percent), the inverters that convert the DC power to AC power are a relatively expensive part of the overall power plant, and oversizing the DC solar panels ensures sufficient power to use the inverters more fully (e.g., providing additional power during the “shoulders” of the solar day), savings from use of smaller inverters and other AC equipment, and potentially lower interconnection upgrade costs because the maximum power injection is smaller. The ILR that a developer chooses is determined by balancing these financial flows: lost revenues against reduced cost. However, while the reduced cost—dominated by the reduced capital expense in inverter equipment—is easy to estimate, the lost revenue estimate is a bit trickier.

[31] EIA 860 Net Summer capacity.

Calculating lost revenue comes in two steps. The first step is to figure out how many megawatt-hours the project can expect to lose to clipping; the second is to figure out how much that clipped energy is likely to be worth. For the Solar Star farm, clipped energy typically comes when the entire California market is flush with solar power and prices are lower, so the lost revenue will be lower than average market prices. On the other hand, even if much of the clipping happens during the low-value hours of the spring when noon-time peaks are driven by clear skies and more ideal outside temperatures, some clipping still takes place during some of the higher-value hours of summer, so there is still a financial opportunity cost to clipping power. Today this opportunity cost (likely significantly lower than 1 percent of annual revenues) typically balances with equipment savings at an ILR around 1.3. Any more clipping and a project forgoes too much revenue, any less and it is spending too much on DC/AC conversion equipment. Using a variety of assumptions for financing costs and the market value for the clipped power, we found that the revenue loss from clipping balances out with savings from avoiding 200 MW of additional AC conversion costs around the stated ILR of 1.32. This tipping point matches up well with estimates of \$10-30 per kW_{AC} for avoided inverter capacity. Modeling with higher discount rates or increased hardware prices (decreasing the net present value of forgone revenues relative to equipment savings) implies that even higher ILRs might be coming.

EXAMPLE 2: CALIFORNIA SOLAR BATTERY HYBRIDS

Starting in the mid-2010s, some developers began combining solar projects with on-site batteries. This was triggered by further cost reductions, this time in battery energy storage systems. Furthermore, for developers interested in batteries, a 30 percent federal investment tax credit was available for projects integrated in a solar farm and charging on solar power (they can now earn the credit as a stand-alone facility), so there was a big tax advantage to including them in a hybrid configuration. Solar battery hybrids, typically with about four hours of storage capacity, were also able to sell a firm capacity product to interested customers like utilities. Solar battery hybrids are especially popular in markets like California with significant solar penetration—97 percent of the solar capacity in CAISO's queue at the end of 2022 was paired with a battery.[32]

As developers gained experience with solar-plus-battery systems, the control systems evolved over time, leading to significant balance of system (BOS) cost reductions, inclusive of interconnection costs. One big differentiator was between AC-coupled system, where the PV system and battery system are connected via an AC bus (despite being native DC), and DC-coupled systems, where the two communicate over a DC bus. The former is generally cheaper and more modular, and a battery can be added on later, while the latter offers the possibility of further efficiency (fewer losses going back and forth through inverters) and the possibility of larger inverter-loading ratios. A 2017 National Renewable Energy Laboratory (NREL) study[xxx] estimated a reduction (relative to separate solar and storage projects) of \$118/kW (30 percent savings on BOS costs) for AC-coupled hybrids, and a reduction of \$158/kW (40 percent of BOS) for DC-coupled hybrids (average total costs for a hybrid are around \$2,000/kW per the 2023 NREL Annual Technology Baseline).

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[32] EIA 860 Net Summer capacity.

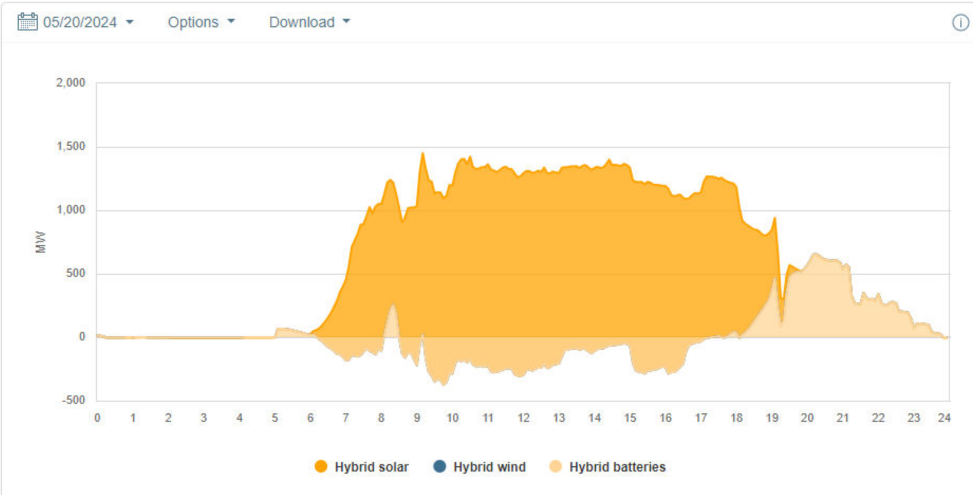
The IRA made the investment tax credit (ITC) available for stand-alone storage, removing charging from solar energy as a condition for receiving the ITC. Despite this, strong interest in hybrids remains. According to U.S. Energy Information Administration (EIA) data, there are 31 GW(AC) of proposed battery projects across the U.S., with 42 percent of that capacity in hybrids (a handful with wind) by 2030. We also see 82 GW(AC) of solar projects, with a quarter in solar-battery hybrids.[33]

With their new dispatchability, solar-storage hybrids opened new perspectives on what grid participation models should look like for modern generators. A report from an ESIG task force titled *Hybrid Power Plants – Flexible Resources to Simplify Markets and Support Grid Operations*[xxxi] suggests that future deployment of energy resources on the electric power system will increasingly take the form of "hybrid resources." The report defines a hybrid resource as "a combination of multiple technologies that are physically and electronically controlled by an owner/operator ('hybrid owner/operator') behind the POI and offered to the market or system operator ('market/system operator') as a single resource at that POI." In the case of a higher ILR (step 1 above), the AC inverter was a passive bridge to the POI, but can become a more active "intelligent agent" approach whereby the hybrid owner/operator manages the characteristics of the components behind the POI and offers energy, ancillary services, and resource adequacy capacity at the POI in the same way as a conventional dispatchable thermal or hydro resource, albeit still an energy limited one. While in theory the report's definition of a hybrid resource could encompass all that is meant in this paper as energy park, we will use the term to represent a subset of the energy park concept: a complex resource solely dedicated to producing energy and services for the grid at the POI.

These hybrid resources are not just using batteries to smooth output and extend generation further into the day—they are also quite responsive to control signals from the grid operator and will adjust their output quickly to local and regional conditions. Figure A2 displays the combined solar + battery output of the CAISO solar hybrid fleet on a 5-minute schedule on Monday May 20, 2024. Note how much the battery component adjusts dispatch during the day.

Figure A2. Combined output of solar + battery hybrids on CAISO system on May 20, 2024 (5-minute resolution)

[33] The Lawrence Berkeley National Laboratory 2024 *Queued Up* report (https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_1.pdf) points to >1 TW of solar, >1 TW of batteries, and >360 GW of wind in interconnection queues nationwide, but observes, "Only ~19% of projects (14% of capacity) requesting interconnection from 2000-2018 reached commercial operations by the end of 2023."

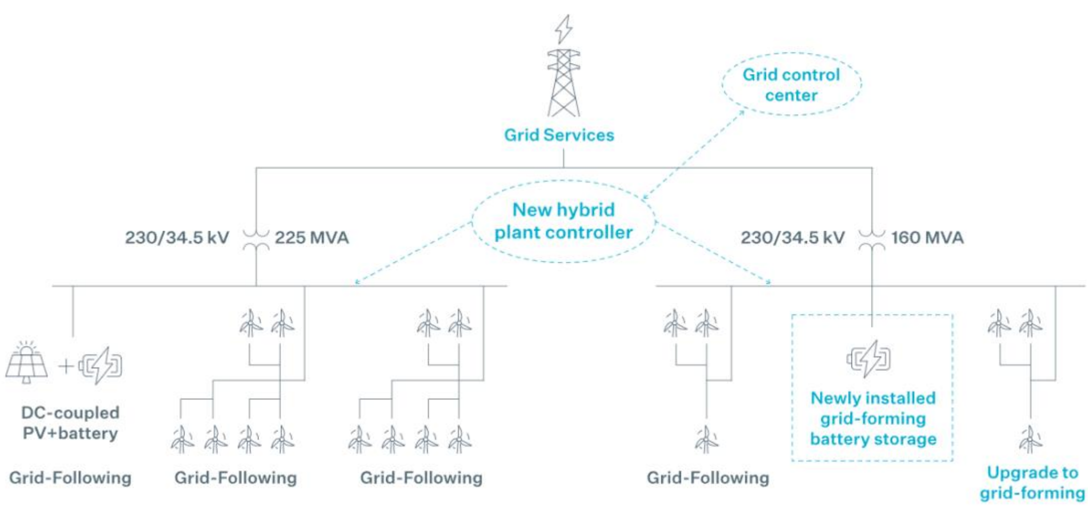


Source: CAISO, 2024

EXAMPLE 3: THE WHEATRIDGE HYBRID RENEWABLE ENERGY FACILITY

The Wheatridge Hybrid Renewable Energy facility in Oregon is North America's first energy park to combine wind (200 MW), solar (50 MW), and energy storage systems (4-hour 30 MW battery) in one location (with 200 MW more wind generation planned for 2025). It is at the cutting edge of hybrid resources, with planned upgrades to include extra controls and grid-forming inverters, with a recent $4.5 million grant from the DOE's Solar Energy Technology Office. Figure A3 provides a schematic of the project structure:

Figure A3. Wheatridge Hybrid Renewable Energy Facility



Source: Portland General Electric

There are a couple interesting takeaways from the Wheatridge energy park's line diagram:

1. The solar facility is DC-coupled to a battery, with a common DC bus that then connects via a shared inverter to a local AC bus. Such batteries are becoming a more and more common add-on to solar PV projects.

2. The upgraded project will have more than one battery, with both DC and AC coupling at different locations. Batteries can serve multiple functions inside an energy park.
3. The energy park shares two common 34.5 kV local AC buses, which then connect to the higher-voltage transmission system. Multiple resources on the local AC bus can share the transformer that accomplished this. Also, 34.5 kV is of the right scale for large commercial and industrial loads.
4. The addition of grid-forming inverters allows this hybrid resource to provide grid services to the broader bulk power grid. Other grid-forming inverters (which come in many flavors) could also be used to island a project like this if there were co-located load.

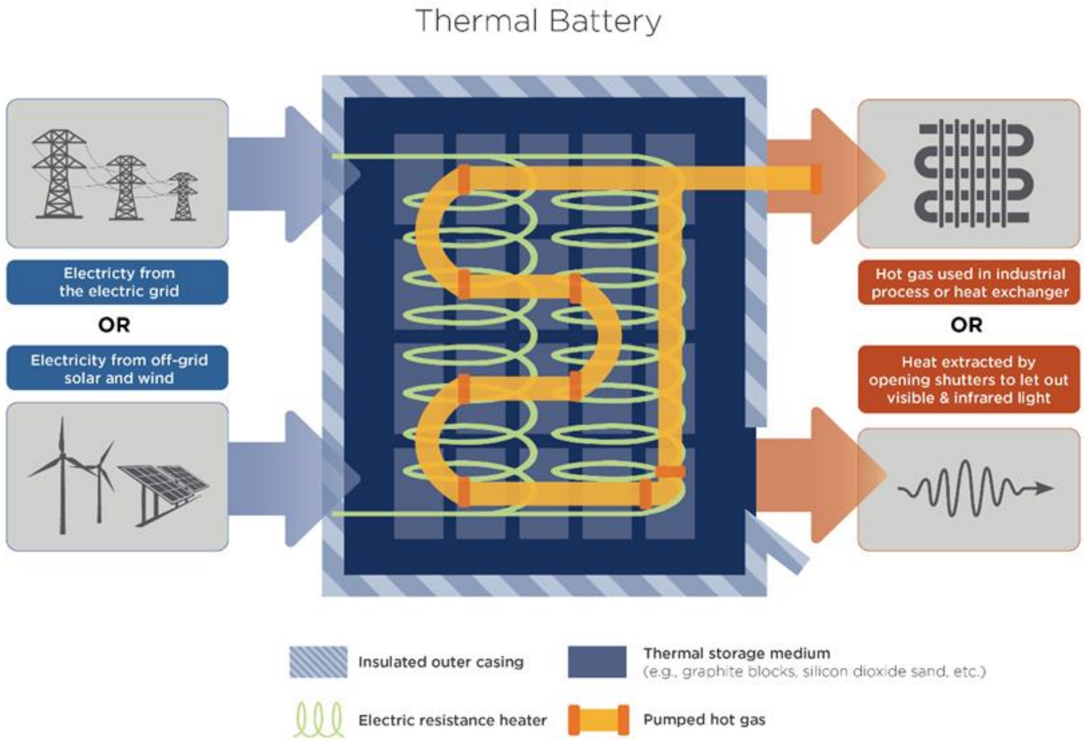
The Wheatridge energy park is an example of the kind of hybrid resource anticipated by the authors of the ESIG paper on hybrid resources. It reflects a growing sophistication and value proposition associated with hosting multiple technologies behind a common POI to provide more value to the electricity grid, whether that's energy, capacity, or ancillary services. This work, which involves generation and demand in the form of storage, has laid a foundation for expanding this model to load-generation hybrids.

APPENDIX 3: EXAMPLE FUTURE DIRECTIONS FOR ENERGY PARKS

Example 4: Industrial Thermal Battery

In a July 2023 report, *Industrial Thermal Batteries*, Energy Innovation explored the concept of thermal batteries, also called heat batteries. These batteries convert electricity into heat, store the heat for hours or days, and release it when needed.[xxxii] They consist of a large quantity of thermal storage material, such as bricks or graphite, enclosed in an insulating shell that minimizes heat loss. Electrical resistance heaters inside the battery convert the electricity to heat. When the heat is needed, it can be extracted by pumping a gas through the storage material and into the industrial facility or by opening shutters in the battery's outer casing to emit visible and infrared light. The battery can deliver heat at 1,500 to 1,700°C, hot enough to meet at least 93 percent of the industrial heat demand by combustible fuels in the U.S. (see Figure A4). This market is substantial: theoretically, thermal batteries could supply 11,600 petajoules per year in the U.S., or 75 percent of industrial non-feedstock energy demand. This is the equivalent of over 3,000 TWh per year (at 100 percent conversion efficiency) or 75 percent of all U.S. electricity consumption!

Figure A4. Thermal Batteries as Energy Parks



Source: Rissman and Gimon, "Industrial Thermal Batteries: Decarbonizing U.S. Industry While Supporting a High-Renewables Grid." Energy Innovation. 2024.

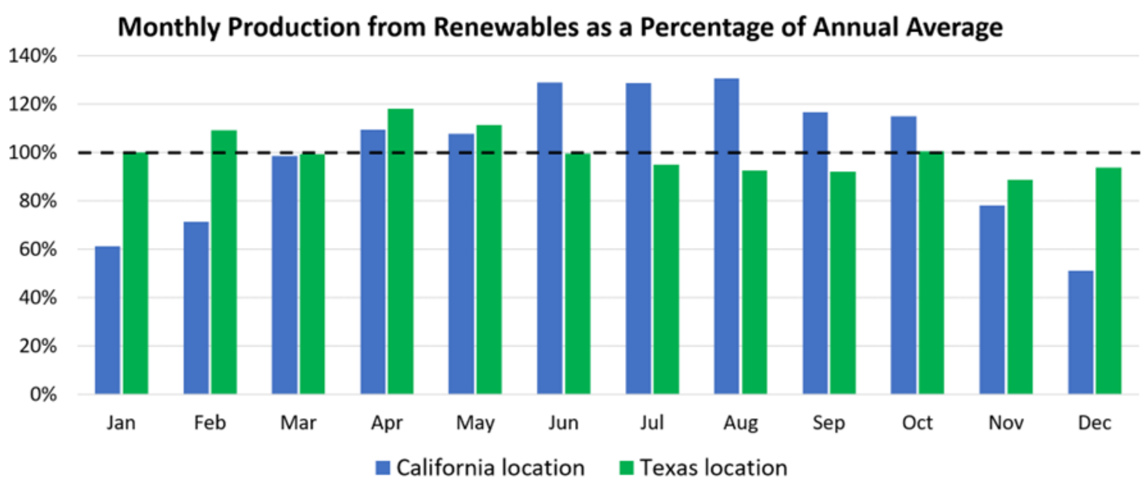
The report considered two scenarios for supplying the electricity to a thermal battery: directly from the bulk power grid and from a siloed (off-grid) solar/wind energy park. In the first scenario, the thermal battery leverages its demand flexibility and multi-day storage capacity to consume electricity during times of the lowest prices (price-hunting). In the second scenario, this flexibility is used to accommodate the variable output from the dedicated energy park generation along with some curtailment (generation-following). In the second scenario, the energy park is siloed so cannot lean on the bulk power grid for help, but it still maintains strong (95 percent to 99.9 percent availability) reliability targets.

A siloed (fully off-grid) hybrid project is potentially economically viable but leaves value on the table. In this basic setup, the park operates simply: using wind/solar to generate electricity that charges the battery if it isn't full, and otherwise curtailing the excess generation. A small, on-site backup boiler ensures 24/7 reliability by covering the last 1 percent of hours when renewable generation and stored energy are insufficient. The operator primarily needs to decide when to run the backup boiler, manage the battery's charge to minimize thermal losses, and schedule maintenance during periods of low battery charge. It also helps if the thermal customer can adjust its seasonal demand to better fit the generation profile.

Things become more complex when the energy park starts to export power to the grid. Consider a large California-based solar farm paired with an 84-hour thermal battery, which is explored in detail in Energy Innovation's thermal batteries report mentioned above. Here, the energy park is powered solely by solar energy, while the thermal load remains constant throughout the year. To ensure adequate supply during winter (see Figure A5), the solar farm must generate significantly more energy than necessary during summer and shoulder seasons, leading to almost half of the solar power being curtailed. This almost doubles the input power cost for the project, although high natural gas prices in California still make the project viable.

A siloed configuration of this energy park wastes vast amounts of power, while an export option offers the opportunity to sell otherwise curtailed power on the open market. This export option entails significant incremental costs and hassle to interconnect with the grid, but in return these power sales can provide a substantial additional income stream. A simple analysis of the same battery case with 2023 modeled production shows that sales of otherwise curtailed power[34] with no change in the dispatch between grid and thermal battery completely offsets the cost of all the power produced by the solar farm (assuming the same 2021 installed cost of solar as the original paper).

Figure A5. Comparison of monthly production from a solely solar project in California with a mix of solar and wind in Texas balanced for more steady production across the year



Further financial gains can be achieved by optimizing solar dispatch to feed the load or the grid based on wholesale prices. For example, if the thermal battery is relatively full and the solar farm is producing more daily output than needed, the operator can lean on its multi-day thermal storage to adjust the day-to-day amount of solar output sold to the grid based on daily price fluctuations, maximizing revenue while maintaining the same level of service to the co-located heat customer. This flexibility allows an energy park with a thermal battery to behave similarly to a solar-battery hybrid during solar production windows, including providing ancillary services like regulation, even though it doesn't necessarily have the option to reconvert heat to electricity. However, it differs in that it cannot produce power when the sun is down and it has a stronger seasonal skew in energy availability.

The unique ability of the 84-hour thermal battery in this energy park to bank or loan out daily solar energy output between days or even weeks offers significant advantages over

[34] (At conservative SP15 trading hub hourly day-ahead prices.)

conventional solar-battery hybrids.[35] This makes it an asset for both the economics and reliability of the bulk power grid, providing complementary dispatchability at a lower cost of capital.

Another benefit of going from a siloed energy park to one with export capabilities has to do with the U.S. federal tax structure. Due to changes in the IRA, solar power plants can now choose between claiming the ITC and the PTC. In some cases, especially with high-capacity-factor solar farms, PTC is preferable, but siloed projects may make the PTC inaccessible, as there may be concerns that a significant amount of the curtailed power would not qualify for this credit (with large financial impact). Exporting energy parks with greater production optimization and lower curtailment bring the PTC back into play.

We will skip summarizing the complexity and downside of grid interface here, as we cover that topic below. For early deployment projects, where simplicity is at a premium when deploying a new technology and first-mover customers can be chosen with heat demand that most closely matches available generation, a siloed project may make sense. However, we believe that in most cases, while transitioning a solar-plus-thermal-battery project from a siloed energy park to one that can also export significantly increases operational complexity, it is likely worthwhile.

To optimally dispatch exports from an energy park with a thermal-battery-served load, the operator must monitor current solar production, the thermal battery's state of charge, forecasted solar production, and wholesale price forecasts. Additionally, the operator can adjust the thermal load and use a backup boiler[36] not only for reliability but also to supply extra electricity to the grid. To grow into this complexity, projects will likely evolve from simpler configurations and operating models to more sophisticated arrangements over time. A further step in this evolution may include a bi-directional interface with the bulk power system (open hybrid), allowing occasional draws on wholesale grid power when it is very cheap, providing additional backup options, and further optimizing internal production for later use. The owner could also choose to add an electric battery for more operational and trading flexibility. In all cases, the planning and operations of a thermal battery load-generation hybrid will depend significantly on the regulatory and tariff environment.

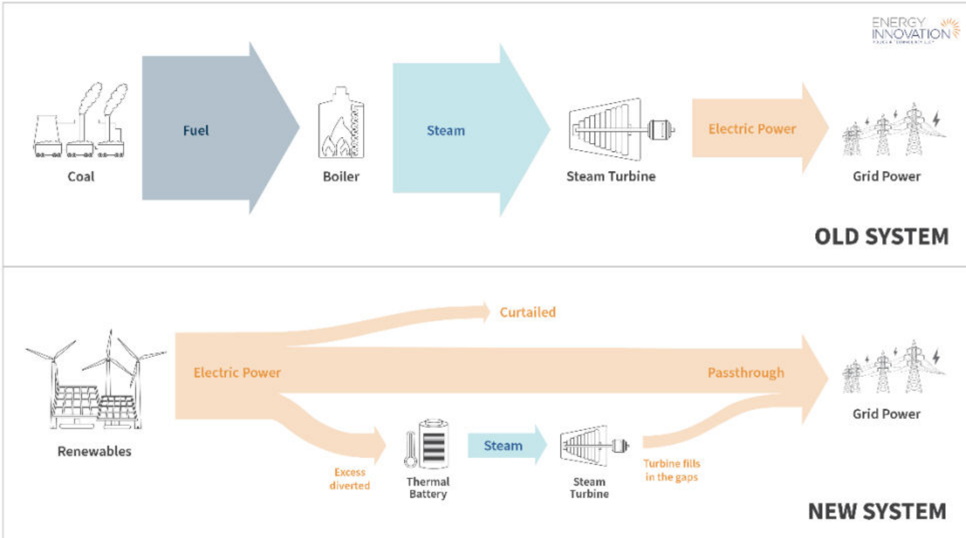
Coda: Coal plant replacement with thermal battery/renewable energy combo

Some energy parks with thermal batteries could also reconvert heat to electricity: pulling back some of the electricity the co-located load consumed via a reverse process at some efficiency cost but at a later, more valuable time. This is typically not possible for a co-located load that makes generic things, but many loads that are flexible enough to be attractive in an energy park context will involve intermediate energy-intensive steps (like heat and hydrogen) that involve energy carriers that can be stored. Many of these can be re-converted to electricity.

Figure A6. Coal Plant Replacement with Clean Energy Portfolio and Thermal Battery

[35] Electrical batteries can export power outside the solar production window but have a limited duration and tend to operate on a daily cycle. Also, the thermal battery supplying an energy park has a much better round-trip efficiency when acting as a virtual electrical battery this way because it is just deferring deliveries to the thermal load, not reconverting thermal energy into electricity.

[36] Here, a backup boiler provides extra heat to make up for any shortfall in electric heat or to supplement it. Because the boiler's primary purpose is providing heat, in this supplementary mode the net effect is like 100 percent conversion of heat to electricity.



An especially promising place for reconversion at an energy park is to transform coal or gas steam boiler-based electric generation plants that have recently retired or are about to retire into re-powered clean dispatchable generation resources. Many of these coal or gas plant sites can host local renewable generation nearby,[37] and the existing interconnection infrastructure can be recycled. If the intermediate energy medium is heat, it can be used to make steam that can drive an existing turbine—the reconversion equipment is already there. This type of arrangement is illustrated in Figure A6. It returns the load-generation hybrid in example 3 back into a generation-only hybrid resource—although some waste heat could be recovered in a combined heat and power-like arrangement to serve thermal loads.

For thermal batteries as an intermediate storage, the round-trip efficiency is competitive with closed-loop long duration systems being proposed today and offers even higher end-use efficiency in a combined heat and power configuration. The opportunity set is huge: hundreds of gigawatts of U.S. steam generator fossil plants that have already retired or could retire make good candidates for this kind of repowering.

EXAMPLE 5: ELECTROLYSIS OF HYDROGEN FROM WATER

In the previous example, a thermal battery was used within an energy park to convert inexpensive electricity from variable renewable generation into a steady supply of industrial heat. Another method of transforming electricity into useful industrial products is through electrolysis, which involves using DC electric current to drive non-spontaneous chemical reactions. Electrolysis has the potential to revolutionize industrial decarbonization, particularly in applications such as cement production[38] (responsible for about 7 percent of global carbon emissions) and the direct reduction of iron[39] (iron and steel account for 8 percent of global carbon emissions). Still, the most well-known, or at least well-publicized,

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[37] One estimate is 250 GW of potential (including battery storage) using generator replacement and surplus interconnection processes already in place. The actual potential is much higher: https://rmi.org/wp-content/uploads/dlm_uploads/2024/01/clean_repowering_web_deck_new.pdf.
[38] For an example of cement from electrolysis, see https://sublime-systems.com/.
[39] For some examples of steel from electrolysis, see https://www.electra.earth/media/ or https://www.bostonmetal.com/.

application of electrolysis today is the electrolysis of water using clean electricity to produce green hydrogen.

Hydrogen primarily serves as an energy intermediary or carrier, used as a feedstock or fuel. Several large new energy parks focused on hydrogen production have been announced. These include Intersect Power's Meitner Project in Gray County, Texas, which combines 340 MW of solar with 460 MW of wind to power 400 MW of on-site electrolyzers for producing sustainable aviation fuel and the HyStor energy park in Mississippi, which will supply hydrogen to SSAB's green steel project..

Production of materials via electrolysis at the scale of modern economies takes a tremendous amount of electricity.[xxxiii] For example, the DOE's June 2023 National Clean Hydrogen Strategy and Roadmap envisages 10 million metric tons of new production of hydrogen per year by 2030 from various sources including electrolysis. If it were all produced at current efficiency levels of around 50 kWh of electricity per kg of hydrogen produced from electrolysis, it would take 500 TWh per year of new electricity supply, equivalent to about 12 percent of all U.S. electricity demand today. On a unit basis, the cost of electricity to make hydrogen is also an important factor. At the efficiency level mentioned above, every $20 on the price of a megawatt-hour increases the cost of produced hydrogen by $1/kg. For context, the DOE's "Hydrogen Shot" target is $1/kg hydrogen through net-zero-carbon pathways by 2031. With its huge need for new electricity and high price sensitivity, hydrogen production at energy parks should be a great fit.

One major obstacle to using energy parks for producing hydrogen via electrolysis from clean electricity, so-called "green hydrogen," is the capital cost of the equipment: paying for the electrolyzer stack and the balance of system (pumps, compressors, etc.). While the equipment to convert electricity into heat (before storage) in the thermal battery example above was around $100 per kW, the all-in conversion capital cost for hydrogen production is around $1,500 per kW. This incentivizes running the facility around the clock to keep down the capital expenditure per unit of produced hydrogen. However, cheap, round-the-clock clean energy sources are hard to find. Because of their price sensitivity, electrolyzer load-generation hybrid energy parks make the most sense if the co-located load is flexible.

Fortunately for those interested in kick-starting the green hydrogen industry, the IRA provides for up to $3/kg in PTCs over 10 years for low-emission hydrogen (the equivalent of a $60 per MWh subsidy for the input electricity, if it is deemed clean enough). This is meant to get the industry started while capital costs go down the learning curve. It also creates a world of two eras for green hydrogen projects—the tax-subsidized era, and the post-subsidy era.[xxxiv] In the first era, a project with an offtake price of $1 per kg can afford to pay up to $80 per MWh for electricity with the tax credit so long as it's clean, helping it to run more of the year (70 percent+) to cover capital expenses for the electrolyzer and some hydrogen storage. In the second era, after the tax credit runs out, a lot of the capital expenses will have been paid off and the electrolysis stack replaced with something cheaper and more efficient, leaving a lot less need to pay off capital expenditures. The project now runs much less of the year (less than 30 percent) because it can only afford to buy power under $15-20 per MWh if it still wants to sell hydrogen around $1 per kg. Projects coming online after the expiration of tax credits (in 2032) face more challenging economics from the get-go that require flexible hydrogen production and access to cheap, clean electricity from the start.

Energy parks are perfectly positioned to operate in both eras—in the first era, because they directly provide clean energy that will easily qualify for the tax credit on an emissions basis, and in the second era because they directly provide electricity cheap enough to produce competitively priced hydrogen. In both cases, the electrolysis load needs to be flexible.

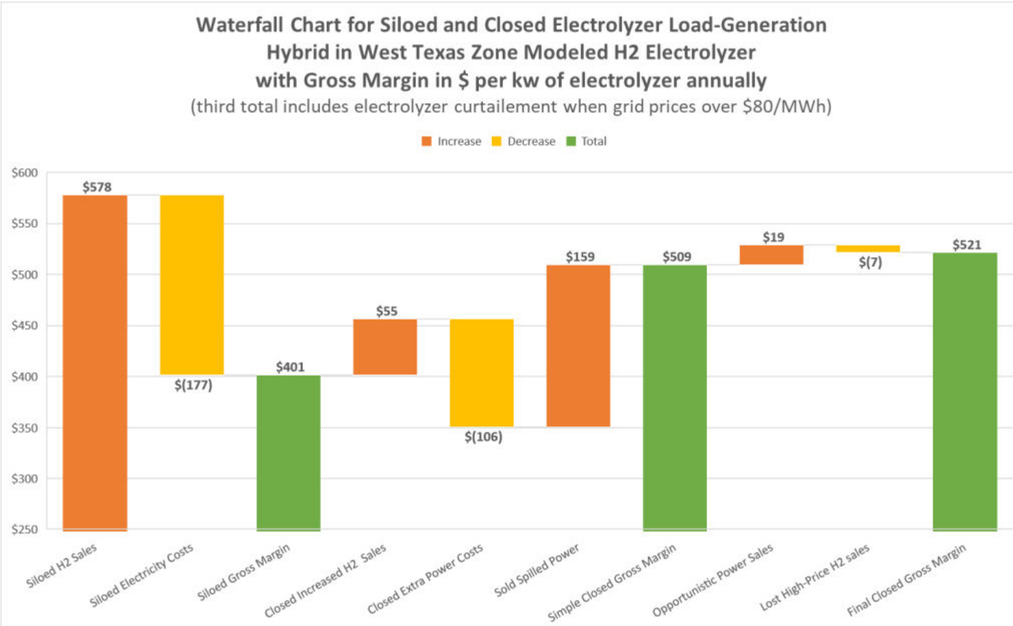
In more detail, for the first era, having co-located variable renewables or other clean generation resources guarantees local provenance for green power, and if the park is built all together there are no questions of additionality. The electrolyzers can ramp up and down, matching the generation profile, and can provide a steady supply of hydrogen if there is storage capacity. Given the high fixed costs (mostly capital) that must be recovered, it still makes sense to keep utilization as high as possible. The key is to locate the energy park where there are plentiful good new wind and solar resources (with perhaps a smidge of clean firm sources like geothermal) whose complementary profile helps provide a reasonably constant supply.

To better understand this dynamic, we modeled a wind and solar project making hydrogen in West Texas. Starting with a siloed configuration, we found using modeled 2020 weather data that 180 MW of solar and 150 MW of wind could feed 100 MW of electrolyzers at 82 percent of capacity. Assuming $16.2/MWh and $/19.2 MWh for co-located solar and wind (using 2021 NREL Annual Technology Baseline capital costs), 20 kg of hydrogen per MWh, a tax credit of $3/kg, and an offtake price of $1/kg, the project returned $401 per kW-year of hydrogen capacity. For context, a reasonable measure of annual fixed costs for a project with a $1,500 per kW electrolyzer is around $300 per kW, so this first pass leaves plenty of room for a healthy profit margin (although this is wiped out if we add $5/MWh to the solar and wind costs).

Going to a closed load-generation hybrid model adds more room for profit. With the possibility of selling excess power to the grid, it makes sense to oversize the generation in the energy park by another 60 percent (288 MW of solar and 240 MW of wind) for some incremental utilization of the electrolyzer (now 90 percent). The diminishing return on electrolyzer load factor means that this project will make $55/kW in extra revenue in hydrogen sales at the cost of $106/kW in extra power purchases (see Figure A7). However, if we choose a simple model for selling power to the grid—just sell the excess—then even in a low market price year for wholesale power in the West Texas trading hub (2020), the project makes an extra $159/kW in revenue from power sales, bringing the gross margin to $509/kW. Figure A7 also shows how by forgoing some hydrogen production when prices are high, even more profits can be achieved.[40]

Figure A7. Gross Margin per kW of Electrolyzer for a Modeled System in West Texas

[40] We have assumed here that the electrolyzer can be turned down to zero, but typically there is a minimum turndown during regular operations, e.g., the electrolyzer must continue to consume 10-20 percent of max power.



Even though the closed hybrid model means extra delays to get through interconnection and requires nearby transmission, the extra profit (along with the potential tax benefits of a PTC) appear to justify it.

In fact, for the early proposed hydrogen mega-project mentioned above, the closed hybrid model is essentially mandatory for financial viability. Given the billions of dollars in capital expenditure involved, almost no developers can afford to build these energy parks using their own capital—they will need to borrow money. However, because wind and solar projects are a known quantity, financiers are much more comfortable funding this side of the load-generation hybrid. They will want assurances that there is still a path to market for hundreds of megawatts of wind and solar if somehow the load side of the hybrid falls and any associated offtake contracts fall through.

These market access considerations are also important for the project's second era, when much more of the generated power from the energy park will be intended for market (with the electrolyzer providing a price floor for about 20-30 percent of hours).

There is also the question of how much grid access capacity will satisfy the financiers, and how this impacts the interconnection costs the generation-load hybrid must pay. In the closed hybrid configuration modeled above, the mix is optimized to provide for a 100 MW electrolyzer at a 90 percent load factor. However, the combined wind and solar plant can produce as much as 476 MW peak power and, net of load, the maximum output to the grid for the load-generation hybrid is 411 MW. To save some on equipment (as in our first example) the hybrid might want to limit itself to a grid-tie capacity of 400 MW (1-2 percent clipping for a worst case with no electrolyzer) or 350 MW (1-2 percent clipping with native load), but ultimately the grid-tie sizing will depend on how much capital and interconnection costs, as well as interconnection study delays, rise with requested interconnection capacity.

Adding a 100 MW/MWh battery could eliminate most shortfall of supply to the electrolyzer and significantly improve wholesale revenues while reducing the grid-tie capacity needs. It could help condition power to the electrolyzer, maintain minimum input levels, and even island the park in case of bulk power system failures.[41] From the wholesale market point of view, the battery could also supply regulation, fast response services, and other ancillary services like voltage support, as well as black start and short-current strength (if combined with a grid-forming inverter).

Another way for the hydrogen energy park to cover gaps in production for the electrolyzer is to adopt an open hybrid model—occasionally buying some power from the grid when the electrolyzer is not at full capacity. In the first era, it might need to purchase some green certificates to do so, and in the second era it will want to do this when prices are below a certain threshold (in 2020, it could do this for about 80 percent of the missing MWhs with a max purchase price of $20 per MWh).

Finally, with a hydrogen energy park there is the possibility of reconverting hydrogen back to power for sale on the open market when prices are high and the electrolyzer is turned down by installing a hydrogen turbine or fuel cell in the park that could draw from the on-site hydrogen storage to supplement output during high wholesale price periods.[42] Again, this introduces additional complexity from the grid interconnection side if additional generation resources are added to the mix.

Planning and sizing the various components of a hydrogen energy park will be a sophisticated endeavor, but not all components will need to be in place at the start if developers adopt a modular approach: install the basics first and then add more hardware as they gain experience.

APPENDIX 4: GENERAL CONSIDERATIONS RELATING TO ENERGY PARKS

In today's financial markets, participants trade many assets on public markets and thus create public prices for various stocks, bonds, and commodities. There are also so-called "derivatives" of these underlying asset prices: financial instruments that provide the option, but not always the obligation, for buyers to exercise the right to buy or sell tangible assets and stocks at set prices. The very existence of such products—the fact that options have value at all—reflects the uncertainty of future outcomes. Through sophisticated models, this option value is made tangible—it exists on balance sheets all over the world. Hence, to understand the case for energy parks, and generation-load hybrids in particular, it is important to understand how they derive value for their investors not just by converting capital and inputs into returns under one given set of conditions, but by offering choices under multiple future scenarios. These can be grouped under three broad categories:

- Price choice
- Quantity choice
- Capital investment choice

[41] For islanding, the storage inverter would have to be grid-forming.
[42] Theoretically, with the PTC in place there are wholesale price levels where it makes sense to both produce hydrogen from electricity and consume electricity for power exports at the same time. We assume the IRS will disallow tax credits under these conditions.

Each of these sources of option value will depend on expectations for weather, economic conditions, policy context, market rules, and grid operator behavior.

PRICE CHOICE

Traditional fossil generators have implicit price option value through the choice of whether to generate. In an electricity market, they express their preferences by providing offers to generate to the market mostly based on marginal costs—the cost of fuel and incremental maintenance costs of running the plant. If market prices are too low, their offers will not clear the market and they don't dispatch; otherwise they do. Crudely speaking, to market traders these generators are derivatives—a financial option to convert fuel to electricity (engendering terms of art like "spark spread"). Variable energy resources like wind and solar, on the other hand, are price takers with little option value. They produce what they produce based on weather and sunshine regardless of grid prices. Energy parks with co-located loads allow their owners more choices on what prices they are paid—or pay—for electricity.

In the special case of a generation-battery hybrid (example 2), the battery is typically sized to take advantage of otherwise spilled energy that otherwise will not go out to the grid. In this regard, it is effectively a price taker for the energy it stores unless it chooses to draw even more energy from its generation partner when market prices are especially low. Where this hybrid has choice, within its physical limits, is with regard to when it sells back its stored energy to the grid: it has the choice to wait for peak prices later in the day. This choice is limited, however, as the battery must discharge eventually to make room for more inputs from its generation partner and its fortunes are still completely tied to the price dynamics of the grid. Energy parks with an import capability offer a bit more choice, in that they can choose to draw cheap power from the grid if the timing is right, but they still face many of the limitations of their export-only cousins.

Connecting a captive load to the generation load increases price choice. The captive load is like a "put" option in finance—a guaranteed floor value for the generator's output. For example, if a hydrogen electrolyzer has a guaranteed offtaker at $4/kg (selling for $1/kg with the tax credit), this price floor will be at $80/MWh, but once the hydrogen PTC expires this floor might drop to $20/MWh or follow the price of hydrogen on the market. Load-generation hybrids create optionality by connecting the electricity market to whatever industry (widgets, commodities, computation, etc.) is served by the captive load, much like fossil generators connect a fuel market and the electricity market. If the generation-load hybrid also includes a battery, it can choose whether to direct its generated electricity directly to the grid, to the battery, or to the captive load based on comparative price considerations. If grid prices are high, it will maximize its output to the grid, save the rest to sell later with the battery, and whatever is left can go to the captive load. With lower external prices it might dispatch differently, and if they are especially low then the captive load provides a useful sink for production.

QUANTITY CHOICE

Variable energy resources like wind and solar produce power on nature's schedule. In a plain vanilla project, the maximum quantity the operator can generate from available wind or insolation is exactly what it will offer to the market—no more, no less (setting aside congestion-driven curtailment). Similarly, a clean firm resource like a geothermal project, which does not burn fuel and has scant variable costs, will want to run 24/7 to maximize return on investment.[43] In a generation-load hybrid, having a flexible captive load allows a project choice in the quantity (and timing) of electricity it offers. When demand on the grid is high, it transmits as much as it can through its POI, while if demand is low or generation is being curtailed it can redirect energy to its captive load. Of course, similar considerations apply for the connected market served by the co-located load.

In an efficient market, supply-demand dynamics are tightly connected to prices, so quantity choice is intimately tied to price choice. The advantage of load-generation hybrids is their ability to supply the grid with more elasticity of supply through the internal elasticity of flexible co-located loads. On the flip side, if a project is set up to create a dedicated source of clean but variable power to a dedicated load with a relatively constant demand profile, the ability to siphon off some of its output for sale to the grid provides a valuable source of demand elasticity for that surplus.

Creating more elasticity of supply can be especially valuable to clean grids over longer time scales as they incorporate fewer and fewer fuel-based resources. For example, in California today, hydropower can provide 5 to 15 percent of total supply each year, depending on winter rainfall. It would not be economical to overbuild solar and wind farms for the worst years of hydropower production, but the main work of buffering these natural variations goes to natural gas-fired generators which can adjust how much fuel (much of it from out-of-state sources) they choose to buy every year. In a 100 percent carbon-free grid, unabated gas cannot play this role. With adjustable captive loads, the opportunity costs of production (i.e., the maximum price they are willing to pay for electricity inputs) become an effective proxy for fuel costs. For example, a hydrogen electrolyzer might produce much more quantity of hydrogen in a high hydro year than in a low hydro year because doing so is profitable during the lower prices that a hydro glut produces. However, the viability of this mechanism depends on a fairly liquid market for hydrogen, where hydrogen or hydrogen-derived products can be exported or imported to adjust for varying production costs.

CAPITAL INVESTMENT CHOICE

Capital investment choice is the freedom that developers have to size their initial investment to today's market conditions while preserving the possibility of further investment as market conditions change. This is facilitated by the inherent nature of load-generation hybrids as synthetic resources. "Synthetic," here, refers to the grid operator interacting at the POI with not just a single machine but the controlled output of a combined set of resources, effectively a mini grid. Once this mini grid is in place to facilitate energy flow behind the POI, new resources can be added to or removed from it. So long as these don't break the conditions under which interconnection and/or capacity value are assessed at the POI with the grid, there is no necessary reason why upgrades in the mini grid should require any extra permitting, interconnection studies, transmission upgrades, etc. With the construction of a

[43] Apparently, this is not entirely true, as geothermal projects can make use of in-reservoir energy storage. See https://zenodo.org/record/6385742#.Ymm888jMKUk.

load-generation hybrid, the owners acquire the option to invest more capital with minimal headache.

One example illustrates the capital optionality value: battery storage developers in Texas are choosing to build shorter-duration batteries (less than two hours at max output) while making sure to purchase enough nearby space nearby for more batteries, allowing them to increase duration in the future without changing the power ratings of the facility. This reflects current market conditions where shorter-duration batteries make more sense, but longer-duration batteries are expected to become advantageous as penetration of wind and solar resources in the Texas grid continues.

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