Informal Comments and Recommended Solutions on the Draft Green Book

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1. Introduction. Eric Gimon is a Senior Fellow at Energy Innovation and Steven Corneli is an independent advisor and consultant on clean energy, markets and innovation related to decarbonization of the power sector. We have recently developed similar but independent proposals for wholesale market reform intended to facilitate the rapid and efficient deployment of optimized portfolios of supply side, demand side and infrastructure resources needed to reliably integrate growing levels of clean energy resources at an efficient cost level, while providing ample and non-discriminatory access to low cost sources of capital to both competitive developers and regulated utilities, while supporting efficient and reliable supply options for competitive and regulated load serving entities. We believe these concepts have the potential to address and resolve a number of the critical challenges and questions raised by the Draft Green Book and articulated in the Request for Comments and Recommended Solutions (the Request). To that end, we offer this brief set of comments and recommendations, and provide links to recent papers and articles that explain our related concepts for market reforms in greater detail.

2. Issues and questions we address. We address primarily the questions raised in the first bulleted list of items in the Request[1], the first two sub-bullets in the third bulleted list,[2] and the first bullet in the last bulleted list.[3] We also address the related topics of centralized procurement, credit backing for long term contracts, decarbonization and IRP, the future role of IOUs and resource adequacy. For brevity, we characterize all these issues as essentially dealing with the following overarching questions:

i. How to **optimize** the evolving portfolio of supply side, demand side and infrastructure assets needed to achieve growing levels of decarbonization reliably and at low cost;

ii. How to **integrate** competitive asset development and reliable operation into this optimization process while ensuring non-discriminatory, comparable and equally efficient treatment for cost-regulated and competitively owned assets; and

iii. How to also **ensure competitive energy supply** and energy service providers offerings are part of, or entirely consistent with, this optimized portfolio of resources.

We note that these issues exist in the intersection between increased consumer choice, SB 350's mandate in Section 454.51 (a) for the CPUC to "[i]dentify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner", and its requirement in subsection (d) to ensure community choice aggregators share in this optimized portfolio or its equivalent in terms of integration and efficient achievement of the state's energy policy objectives. Thus, our comments involve the integrated resource plan (IRP)

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[1] This is the list that begins with "How does California continue its course as a global leader in achieving deep decarbonization … ?"

[2] "Can California provide investment and operational certainty to address reliability and resiliency … ?"

[3] We address the specific question "who will execute the long-term contracts that can be used to finance construction of new facilities going forward?"

proceeding, the long-term procurement (LTP) program and other programs and proceedings that address CCA and other energy supplier obligations and roles in helping achieve the state's decarbonization and related energy policy goals. The comments also go to the core of how to ensure efficient, low-cost financing of an optimal portfolio of diverse clean energy resources when there are multiple retail energy suppliers and service providers for customers to choose from. Finally, because the long term markets we envision are designed to provide the regional and inter-regional optimization needed for low cost, deep decarbonization, our comments also involve the growing role of both the CAISO and the Energy Imbalance Market, which, consistent with the legislative direction of SB 350, is expanding with considerable success into the much of the western grid.

We do not address in these comments the many critical and important questions about other aspects of retail choice, though we do comment on approaches to implementing our ideas in the context of either full retail choice or a robust CCA market.

3. Brief summary of our market reform concept. As is explained more fully in the attached papers, our market reform concepts are based on the observation that the efficient deployment of high levels of variable energy resources (VERs), along with the complementary resources needed to integrate them, is a far more complicated matter than was achieving resource adequacy and an efficient mix of historical, dispatchable generation resources and energy efficiency.

The primary reason is that the location and type of VERs affect their cost and performance in reliably meeting load in three different ways: their direct cost, the cost of transmission needed to deliver their energy to load, and how well their aggregate hourly output (or "shape") matches the shape of aggregate load. This latter aspect determines in large part how much additional cost and effort will be needed to achieve the real-time balance between injections and withdrawals of energy from the grid, which is essential for reliability. Inadequate attention to these details can raise direct costs and have an even bigger impact on indirect costs associated with ensuring reliability. These significant indirect costs include, for example, the cost of excessive curtailment of VERs due to overproduction at times of high winds and insolation, or the cost of procuring and ramping up sufficient other resources when the wind or sunshine stops as load is increasing. To make optimizing such portfolios even more complicated, the cost and performance of many of the most promising complementary technologies, such as battery storage and flexible load, also are key factors in determining how many VERs, in which locations, and connected by what transmission, are part of the optimized portfolio.

The solution which we each developed, independently but at about the same time, is to adapt innovative and emerging system planning tools to serve as a platform for operating a periodic (e.g., every three to five years), regional long-term investment market for the specific mix (in terms of quantity, type and location) resources needed in an integrated, high VER, low or no carbon system. Such a market, which Corneli calls a "configuration market", would select only those resources and assets that are found, analytically, to be parts of the least cost portfolio that meets reliability, integration, carbon emission and related standards. It would be superior to current planning approaches because it would replace planning cost assumptions with actual competitive bids to develop and operate new resources – supply side, demand side, storage and transmission -- (as well as to maintain and operate existing resources). It could also, when used by regional and interregional market operators, avoid the artificial constraints on optimization and decarbonization created by state and utility service territory boundaries. Further, these bids would not only identify real costs, but also would identify commercially feasible projects, rather than assuming them.

This would allow the configuration market to identify least cost and reliable combinations of feasible resources that would support each other rather than cannibalize, curtail or otherwise conflict with each other. The periodic, regular nature of the market would support the development of a "ladder" or "stair" of clean energy projects and PPAs over time, allowing the portfolio and the market as a whole to identify, support and embrace changing technologies, innovation, and energy use patterns over time.

This long-term market would also support long-term cost recovery, where the short term operating market (which we both envision as a continued evolution of today's centrally dispatched wholesale LMP markets) does not. This long-term cost recovery, for competitive resources selected in the configuration market, would take place through medium to long term PPAs or tolling agreements for costs net operating revenues between the market operator and each asset owner or developer. The PPAs would have strong performance requirements to incent execution, performance and compliance with operating signals. The net aggregate cost of these PPAs or tolling agreements would be recovered, from load serving entities, on a pro-rata load basis and through a non-bypassable charge from load. This assurance of cost recovery for performing assets would facilitate efficient debt financing, while the tenor length could be adjusted to incent developers to manage technology and obsolescence risk efficiently.

Regulated assets that are selected in the configuration market would also be eligible for cost recovery, but through state or federally approved tariffs rather than through a combination of competitive PPAs and operating market revenues. States could simply add selection in the configuration market as a necessary condition to their other criteria for cost recovery from retail customers.

4. Key benefits of our approach in terms of questions raised in the Request.

a. Efficient access to capital markets for innovative technologies, competitive investors, utilities and for inter-dependent portfolios of complementary clean energy technologies. The long-term investment market extends and broadens the benefits of a fully credit worthy counterparty for clean energy projects historically offered by California's long-term procurement program, while freeing up IOU balance sheets from the debt-like burden of large portfolios of PPAs and the credit risk of potential future full or partial bypass by competitive customers and alternative providers of those PPA payment obligations. This creditworthiness and ability to support low cost project finance for innovative projects of all kinds, as long as they fit in an optimized total supply portfolio, is a critical need for the success of the state's RPS goals and for deep decarbonization. Further, the long-term optimized market approach would simultaneously assure reliability, including local or regional needs and whatever resource adequacy evolves into as increasing amounts of flexible load and storage make involuntary load shedding less and less likely, while also supporting the efficient allocation of both local and system wide costs.

b. Simple and non-discriminatory ways for competitive load serving entities, CCAs and large corporate buyers to participate in the long-term market. There are several ways competitive load serving entities, corporate energy buyers and CCAs could participate in such a market. First, they could bid specific resource types (especially, perhaps, flexible load, distributed storage, and other demand side resources) into the configuration market, with the objective of receiving a competitive return on the investment while being able to legitimately claim they are producing balanced and integrated clean energy as well as buying it for their customers. Second, they could simply take a "short" fundamental position in the configuration market, pay their allocated share of the market's costs, and aggressively pursue energy efficiency and passive, price-driven DERs to minimize their share of costs while enhancing the value they provide to their customers. Finally, they could enter into financial, as opposed to physical, energy transactions, with developers of resources that bid into the configuration market, which would entitle them to an attractive long-term price for energy, environmental attributes, or both. Further, such environmental attributes would be more robust than current renewable energy credits in a world without optimized supply portfolios and, therefore, with growing levels of renewable overproduction, curtailment and continued unnecessary fossil fuel use for ramping and reserves. The depth and diversity of the supply of the laddered PPAs of various tenors, together with their underlying performance requirements and the credit-worthiness of the market operator and its non-bypassable cost allocation to load serving entities, should also support a robust and liquid secondary market that will allow buyers to reconfigure their supply options physically or financially to adapt to changing load obligations and to better manage their cost profile.

c. Efficient resolution of many utility business model issues. While we do not believe our concept would completely resolve the many challenges facing the regulated utility business model, we do think it offers significant benefits in that regard. For example, by moving competitive procurement to the configuration market operator, it would relieve the utilities of any added drag on their balance sheet or their SG&A cost structure of carrying out competitive procurement, allowing them to have a more efficient cost structure and allocate their resources to the regulated assets that create the greatest value and therefore the best risk-adjusted return for their investors. Further, by providing a clear benchmark for determining optimal levels and locations of T&D investment, including that needed to support and facilitate optimal levels and locations of DERs, it would streamline and enhance the efficiency of these largely regulated utility specialties. Finally, by providing a platform for both regulated utility and competitive investment to compete on a level and integrated playing field, it would allow the CPUC to consider authorizing both appropriate arm's-length participation by competitive companies owned by utility holding companies, and by regulated units investing in traditional utility poles, wires and platform assets.

5. Implementation considerations.

We recognize that the concept of a regional, long-term market for optimized investment in the clean energy technologies, assets and resources needed for deep decarbonization is in some ways fundamentally different from the complex set of state procedures California currently uses for resource planning, long term procurement, preferred resource selection, energy efficiency programs, distributed energy resource policy making, and a host of other programs currently intended to drive deep decarbonization. We offer this idea here for two basic reasons. First, we agree strongly with the Customer Choice team that, due to changing technologies and institutions, "the CPUC must now review long-held assumptions in its regulatory framework."

Second, we believe that California cannot achieve affordability, reliability and decarbonization by simply following the path of retail competition in other states and countries. Some of these approaches may well be superior pathways to retail choice, per se, but none of them can solve the problem of optimizing a deeply decarbonized power sector's interdependent mix of VERs, complementary resources and transmission and distribution enhancements. Indeed, all of these jurisdictions are themselves struggling with the challenges of curtailment, cannibalization and conflict between existing and new energy sources, including between clean energy sources themselves.

Our view is that affordable deep decarbonization requires the optimization of the overall clean energy portfolio in ways that today's state-level retail markets, regional wholesale markets, and state and utility-level regulation and planning simply are incapable of.

Our long-term market concepts were designed to address this problem, while also harmonizing the participation of regulated utilities, numerous competitive energy suppliers and energy service companies, and continued innovation in clean technology. Further, as is clear in the attached papers, our long-term market concepts are designed to be implemented incrementally, rather than at one fell swoop. We believe, as SB 350's mandates suggest, such a path forward to optimizing an affordable clean energy system is readily available in California, in an environment of increasing competitive customer choices.

California's incremental path forward could, and should, start simply. For example, it could focus the coordination of IRP, transmission planning and long-term procurement into an integrated process that uses procurement bids as inputs into the planning process, and awards LTP PPAs to those resources that are part of the overall optimized solution. This is not revolutionary or untried, indeed, it is the approach Hawaiian Electric Company is implementing as a central part of its deep decarbonization process, while a similar approach is being explored by Xcel[4]. As SB 350 calls for, the CPUC could require CCAs and other LSEs, to participate in this optimizing, forward looking procurement process physically (with bids for supply side, demand side and storage resources) as well as financially. In parallel, the EIM could explore how to provide the benefits of this long-term optimization process to voluntary participants throughout the West, much as it is increasingly providing them with the savings of optimized short-term scheduling and balancing services today. Success in these areas could lead to a fuller implementation of long-term, clean energy optimizing, competitive markets for California and other states that choose to pursue affordable deep decarbonization.

We refer to and provide links for you to access our two recent papers, below, for more detail on our ideas for such portfolio optimizing long term markets. In addition, we provide an electronic copy of Mr. Corneli's more comprehensive paper *Efficient Markets for 21st Century Electricity.* We also provide a link to related paper by Brendan Pierpont and David Nelson of the Climate Policy Institute, which explores additional concepts for a market based around long term contracts and procurement designed to meet both reliability and state or national energy policy needs.

We would be pleased to answer questions you may have or discuss these issues further.

Sincerely,

Steve Corneli　　　　　　　　　　Eric Gimon

[4] See "Market Based IRPs: A new paradigm for grid planning?" *Utility Dive,* April 2, 1918. Available at https://www.utilitydive.com/news/market-based-irps-a-new-paradigm-for-grid-planning/520376/ .

Attachments:

Corneli, Steven. *Efficient markets for high levels of variable renewable energy.* June 4, 2018. Oxford Energy Forum Issue 114, p. 15. Available at: https://www.oxfordenergy.org/publications/ .

Corneli, Steven. *Efficient markets for 21st century electricity.* December 19, 2017. Included as email attachment.

Gimon, Eric. *On Market Designs for a Future with a High Penetration of Variable Renewable Generation.* October, 2017. Energy Innovation. Available at: http://americaspowerplan.com/wp-content/uploads/2017/10/On-Market-Designs-for-a-Future-with-a-High-Penetration-of-Renew.pdf .

Pierpont, Brendan and Nelson, David. *Markets for low carbon, low cost electricity systems (working paper).* October, 2017. Climate Policy Initiative. Available at: https://climatepolicyinitiative.org/publication/markets-low-carbon-low-cost-electricity-systems-working-paper/ .

EFFICIENT MARKETS FOR 21ST CENTURY ELECTRICITY

An institutional analysis

Abstract

Renewable and other clean energy technologies are becoming increasingly attractive in cost, and essential for meeting climate risks in a responsible manner. Yet today's power markets and regulatory institutions were created in response to 20th century innovations, and are ill suited to this century's evolving clean energy technologies. Without reform, these institutions are likely to fail in their duty of rewarding efficient investment in innovation that brings lower costs and greater benefits to customers. This paper identifies the changes needed for these market and regulatory institutions to catch up to 21st century technologies and support a vibrant, competitive clean energy system that will meet society's growing need for both affordable electric services and rapid, responsible decarbonization.

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This paper was commissioned by the Clean Air Task Force to stimulate thought on the topic of electricity markets and clean energy deployment. The analyses and proposals it contains are, however, those of the author and not necessarily those of the Clean Air Task Force.

Executive Summary

It is widely accepted that responsibly managing the risks of climate change will require a decarbonized energy system before the end of the present century, and a carbon-free electric grid sooner than that to support electrification of much of transport and industry. An affordable zero carbon grid will ultimately need to include not just the expansion of currently available variable renewable energy (VRE) resources such as wind and solar, but also controllable, flexible power from zero carbon sources, which are likely to be made of a mix of resources such as hydro power, flexible load, energy storage, advanced nuclear, and fossil generation with carbon capture.

Yet current US organized wholesale markets, which serve 60% of the nation's electric load and two-thirds of its population, seem increasingly unlikely to function in such a future. Prices and hence power plant revenues in these markets have, for the last ten years, been cut by roughly one-half due to the abundant supply and low price of natural gas made available by hydraulic fracking, perhaps the last great energy innovation of the 20th century. The first great energy innovation of the 21st century – dramatically falling VRE capital costs due to a combination of scale deployment, learning by doing, and competition in wind and solar power -- is poised to further erode power market revenues in the coming decade. It is quite possible that the result will be current market designs will fail to either attract or incent the development, maintenance and operation of an efficient mix of power plants – including VREs themselves and the other clean energy resources that are likely to be essential for successful decarbonization.

This is especially likely since VRE capital costs have fallen to where they are now the lowest cost source of energy production in regions with good wind and solar natural resources. But VREs have few or no marginal costs, and have very limited ability to match real-time generation output to consumption, as is required for reliability. These three features – increasing competitive capital costs, no marginal costs, and limited controllability – pose major challenges for current electricity markets. Low costs virtually ensure high levels of deployment in areas with good levels of wind and sunshine. In turn, high levels of VRE with minimal marginal costs suppress marginal-cost based energy market prices. And their variable output, relative to load levels, will profoundly reduce the utilization and increase the flexibility required of all other generating technologies. The combination of low prices and frequent cycling is likely to render many existing power plants, especially relatively inflexible nuclear plants, uneconomic to maintain. Further, overproduction of energy from locally concentrated VRE resources, relative to consumption, can lead to frequent curtailment of those and other resources. The resulting reduction in production can impair the economics of VRE projects and other emerging clean technologies needed for both decarbonization and reliable, safe and affordable electricity services.

There are straightforward ways to help manage these problems. VRE facilities can be developed in places that combine high quality resources whose energy production is less correlated over time, connected by new transmission to multiple load centers with more diverse and less peaky aggregate electricity consumption. Load itself can increasingly be managed by smart devices to balance it with generation, rather than the other way around. And continued innovation in new storage technologies, more flexible nuclear and CCS technologies, and carbon-free liquid fuels offer the potential for full decarbonization without relying on unrealistically high levels of VRE, transmission and flexible load.

Yet today's electricity market, grid operating and regulatory institutions are, in combination, failing to support these current and future potential solutions. Even the largest RTOs are not large enough to link high plains wind or southwestern solar with major US load centers. And even within their current scope, they must bridge numerous utility territories and state borders that frustrate efficient transmission planning and expansion. Flexible load seems likely to be ubiquitous, but without both distribution level platforms that support its optimal use and full-fledged commercial transaction pathways to participate in ISO and RTO markets, its true scale and potential are unknown.

Meanwhile, most of these new resources have low or no marginal costs, and will put continued downward pressure on energy prices as more are deployed. The dwindling amount of market revenue needed to support investment and ongoing operation will be further depressed if distributed storage and flexible load reduce the frequency and duration of energy scarcity events. These trends are warning signs that current markets, along with key aspects of the current regulation of transmission and distributions systems, are increasingly poorly suited to new and emerging clean technologies, despite their potential to drive both lower cost service and decarbonization.

This paper calls for coordinated reforms to ISO and RTO wholesale markets, transmission planning, and distribution system management, designed to unlock both the cost savings and the emissions reductions made possible by new and emerging technologies. Indeed, these reforms appear to be as essential for unlocking the economic benefits of the 21st century's clean energy technologies as vertically-integrated monopolies, open access transmission and competitive markets were for unlocking the economic benefits of large boiler-driven turbine generators in the 1920s and of gas turbine-based technologies over the last three decades.

Those 20th century regulatory and market innovations were crafted to leverage the unique cost and performance characteristics of the innovative power technologies of the last century. This paper analyzes the radically different cost and performance characteristics of VREs and other emerging clean energy technologies, and identifies the core reforms to 20th century market, operating and regulatory rules and practices – the key institutions of the power sector – needed to leverage them.

These resulting new wholesale markets would identify and procure those combinations -- considering quantity, type and location -- of incremental VRE, existing and new emerging types of generation, transmission, flexible load, storage and other distributed energy resources that will result in the least cost configuration of the nation's electric systems. For this reason, they are called *configuration markets*. These markets would use new computing and data analysis technologies to evaluate and select competitive bids to build and operate any and all of the key elements of the electric system.

Resources and projects whose cost, location and value put them into this optimal configuration can be thought of as "clearing" in the configuration market. Such projects would be eligible for participation in the ISO or RTO operating market and for competitive fixed cost recovery through single clearing price markets, PPAs, or other means deemed suitable for different types of resources. Cost recovery would be reduced for failing to meet marginal performance requirements, which would create operational incentives to augment or replace those provided in today's markets by marginal cost-based prices. Regulated utility projects would participate in the configuration market, with bids consistent with the cost basis used to justify cost recovery through retail rates. Indeed, states may consider clearing in the configuration market as a rebuttable presumption of reasonable, prudent and needed investment.

The paper develops the configuration market concept in three parts. Part I examines features of existing market and regulatory institutions that evolved in response to the breakthrough 20th century power sector technologies. Part II contrasts the key characteristics of the new 21st century clean energy technologies to those historic technologies. Part III identifies changes in market and regulatory paradigms, centered around the configuration market concept, needed to realize the cost savings and other benefits of these technologies -- along with the rapid decarbonization they can deliver -- as effectively as 20th century regulation and competition supported 20th century technologies.

I. The role of institutions in decarbonizing the power sector

1. Institutional barriers to power sector decarbonization.

Climate science indicates that even moderately protective reductions of the worst risks associated with climate change require the complete decarbonization of global energy use within the next 50 years.[1] For this to happen, near complete decarbonization of the power sector must occur on a faster but parallel path, so that other energy uses can be powered by zero carbon electricity rather than by fossil fuels. For power sector decarbonization to be achieved in that time frame, it must begin to accelerate immediately and continue to progress rapidly.

There are good reasons to think such emission reductions are an achievable goal: emission-free wind and solar technologies, in regions with good wind and insolation resources, have recently become less costly sources of energy than new natural gas-fired power plants. New renewable deployment, globally, far exceeds that of either coal or gas. US natural gas itself has fallen dramatically in cost due to innovations in exploration and production, and is spontaneously displacing growing amounts of more carbon intensive coal fired power production, so far primarily through the shift of generation to existing gas power plants rather than a wave of new ones. Rapidly increasing efficiency in the end use of electricity and less energy intensive structural changes in the economy are supporting continued economic growth without higher levels of electricity use. Battery, thermal storage and decentralized end-use load management technologies are proliferating and their costs are falling. And rapid improvements in computing technology, big data and analytical approaches now allow us to better understand how these new technologies can best be integrated into the electric grid.

Studies using these new computing capabilities suggest, for example, that from 30% to 50% of our electricity could be provided by wind and solar, without violating major reliability requirements or making extreme assumptions about energy storage technologies. Adding substantial amounts of strategically located transmission could potentially increase these levels while further reducing power supply costs.[2] Many of the technical and operational challenges related to growing levels of VRE

[1] See Rocsktrom, Gaffney et al. (2017) for a recent and concise overview of the science regarding greenhouse gas emission reduction timelines consistent with a 2 degree centigrade increase in average global temperature.

[2] Much of this innovation in computing and analytics is being carried out by NREL and other national labs. See, in particular, the integrated summary of these efforts at https://www.nrel.gov/analysis/seams.html and the specific high renewable integration studies summarized and available at https://www.nrel.gov/analysis/high-renewable-generation.html . Additional research and modeling capabilities are being developed in the private sector and used by power sector clients. See, for example, the overview of E3's Resolve model at

deployment can be met with relatively straightforward minor changes in rules and operating protocols to access the flexibility of existing power sector resources.[3]

Yet, despite all this good news, there are major challenges for decarbonization. As many of the renewable integration studies indicate, the levels of VRE deployment that are currently technically feasible will require significant changes to markets, operating protocols, and power sector business and regulatory models to actually be achieved. These challenges must be addressed head on, because they have the clear potential to prolong or delay the needed emission reductions beyond the limited remaining window of opportunity for effective decarbonization.

Equally important, additional VRE capacity alone will not be able to support complete decarbonization without additional complementary and enabling technologies and investments. To ensure the lowest cost, fastest path to a decarbonized power sector, markets and other power sector institutions need to quickly evolve to be able to identify and incentivize the mix of technologies that will be best suited and most economical in achieving that goal while maintaining reliable, safe and affordable electricity services. That mix is certain to include more VRE deployment, but is likely to also include some combination of transmission expansion to connect VRE intensive regions with load, more flexible demand response and load management technologies, continued operation of many of today's large-scale hydro and nuclear plants, new energy storage, advanced nuclear, carbon capture and sequestration and any number of other technologies that are not yet commercially viable.

Success in both early and full decarbonization thus depends on significant reform of the key operational, market and regulatory institutions of the power sector. This reform must be achieved in ways that support the rapid replacement of current heavy emitting technologies with less costly combinations of VREs and essential enabling technologies, while also encouraging rather than foreclosing the emergence of new and improved technologies that will be needed to achieve full decarbonization. The importance of these reforms to both decarbonization and to lower cost, higher quality electricity service should not be underestimated, given the many barriers to change in the power sector, and the way those barriers are typically well embedded in the sector's key institutions.

2. **An overview of institutions and technological change.**

We have already touched on how the combination of supportive policies and falling costs for VRE resources have led to unintended consequences from their growing deployment. These unintended consequences include the risk of higher VRE costs due to curtailment and non-optimal location, the impairment of cost recovery for transmission and distribution systems from high levels of behind-the meter solar compensated in ways that allow customers to avoid paying for the wires they use as well as the electricity they don't, and the economic disruption of other resources – including those that supply 20% of the US' electricity without emitting CO_2. We have seen, too, how high levels of VREs contribute to the debilitation of electricity markets, which were intended to promote the least cost, most innovative technologies but, instead, appear to being wiped out by them.

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https://www.ethree.com/tools/resolve-renewable-energy-solutions-model. VCE's analytics and their various applications for clients and peer reviewed research are available at www.vibrantcleanenergy.com.

[3] For a concise survey of such changes, see Orvis and Aggarwal (2017).

Many of these concerns have been raised by those who are resistant to rapid change in the power sector, including from interests whose fundamental goal is to stop VRE deployment or to delay decarbonization. But the growing experience of these unintended consequences shines a light on what may be the biggest challenge of all to decarbonization: the existing body of policies and rules that collectively govern our electric system – call *institutions* in this paper -- were not designed with today's clean energy technologies in mind, do not understand how to support their efficient growth, and may actually force them to fail despite their increasingly attractive cost and performance characteristics. Without making light of the opponents to change, one must consider that even the total lack of opposition may be insufficient for success, as long as the core institutions of the power sector are designed to support 20th century technologies rather than those of the 21st century.

To change this significant risk of failure into assured success, the key institutions of the power sector – its wholesale and retail electricity markets, the way states and the federal government regulate utilities and utility services, the standards and approaches to system operation and reliability -- all need to evolve to support, in parallel, both decarbonization and the more reliable, efficient, low cost provision of universally available electricity services.

These latter, traditional goals continue to be important.[4] But the power sector's current institutions evolved to support 20th century technologies, which had their own unique cost and performance characteristics. Indeed, it was these cost and performance characteristics that dictated many of the key institutional features that govern the power sector today. The emerging clean energy technologies have very different cost, performance and operational characteristics than the majority of historic generation technologies, so the historic institutions are not always well suited to achieving the underlying social goals through the use of these new, often more efficient, technologies, and can actually act, often inadvertently, as barriers to more efficient and beneficial electricity services. Indeed, institutions that fail to keep up with changing technologies can contribute to *path dependence,* a problem in markets that can keep more efficient technologies and practices from gaining market share, even though society as a whole would benefit. [5]

Accordingly, efforts to promote both decarbonization of the grid and continued to provide reliable, affordable and safe electricity need to include parallel efforts to update and adapt existing institutions to emerging technologies. To be effective, these efforts should be well-grounded in an understanding of power sector institutions and their relationship to historical and evolving power technologies.

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[4] It seems unlikely that decarbonization of the power sector can succeed through measures that do not also meet regulatory criteria such as just and reasonable rates, universal service, and avoiding undue discrimination.

[5] The classic example of such path dependence is the QWERTY arrangement of keys on typewriters, which is said to have arisen from the need for typebars on manual typewriters to alternate from side to side so as not to jam together when approaching the paper. Regardless of the reason for it, once typists have mastered the QWERTY layout, they tend to strongly favor it in future typewriters and user interfaces without typebars, even if newer layouts (e.g., DVORAK) may allow faster and more accurate inputting with fewer ergonomic problems. See Arthur (1983). Arthur attributes this type of inefficient equilibrium to increasing returns and network externalities from adoption, and offers a number of power sector examples, e.g. the adoption of AC over DC power, and the prevalence of light water nuclear reactors over gas cooled reactors. This suggests that path dependence in the power sector may be a significant barrier to decarbonization, and needs to be designed out of the system.

3. Institutional dynamics and technological change.

Economics is the study of how society makes use of scarce resources, with a general focus on the role of decentralized decision making by consumers and firms using markets and market price systems for most transactions. While this focus on markets and decentralized decisions yields many important insights, it can overlook the central role that other institutions, besides markets, play in society generally and the power sector in particular. "Institutions" in this context means the social and political rules that govern production and exchange, along with the bodies and organizations that implement them.[6] The power sector has a plethora of institutions. First, there are the fundamental institutions of legislative and judicial bodies and the evolving set of rules they promulgate, adjudicate and interpret. There are also distinct, legislatively authorized market, regulatory and reliability institutions, each with direct responsibilities for making and enforcing rules unique to the power sector.

Numerous other institutions, such as financial regulators, environmental regulators, antitrust authorities, and various safety standards boards, also make rules that are not exclusive to, but affect, various power sector activities. We also have a number of types of corporations and other organizations, which are authorized to conduct business and set their own rules for employees and contractors, which may go beyond the requirements of regulators. Social norms and conventions add yet another layer that significantly affects the power sector's behavior and activities.

Institutions have inertia, and may even have the ability to gain momentum and follow their own erratic paths, much as a tropical storm can grow by sucking in warm, humid air and, through condensation, converting it to rising heat and angular velocity. Institutions also clearly evolve over time, and this evolution tends to have certain predictable characteristics, which allow it to be influenced by those seeking more efficient and socially beneficial outcomes.

Institutional change and design are complicated subjects, but the basics may be best grasped by thinking of institutional change as reflecting the evolution of technologies and forms of social organization that create additional wealth, and at times also harms, that can affect society's aggregated preferences.[7] The new streams of benefits, along with any new harms, create incentives for the governing institutions, such as those implemented by legislative, judicial and regulatory bodies, to redefine their rules in ways that are more consistent with aggregate social preferences.

4. Historical examples of technologically induced institutional change in the power sector.

[6] The definition follows Eggertson (1995). Some institutions are implicit in even the most laissez faire market theories, e.g., for establishing and enforcing stable property rights. Assuming such rights implies society has the ability to aggregate and rank social preferences and translate them into sustainable legal authority. Thus at least two institutions – a legislative one for non-coercive law making regarding property and other fundamental rights, and a judicial institution for dispensing justice compatible with these laws and rights– appear implicit in even the most autonomous and decentralized micro-economic theory.

[7] Economists who study institutions from a game-theoretic perspective may prefer to think of the institutional set of rules as the game-form, and the stream of costs and benefits as the payoffs associated with the strategies of various players of the game. See Hurwicz (2008). The proposition underlying this paper is that changes in technologies change the payoffs, and those changes can work, along with other factors, through the various means by which preferences are aggregated to change the rules of the game themselves. There is a rich literature on how this process actually works and how to influence it in the real world, e.g., Kingdon (2011).

The process of new technologies creating new benefits and costs, which in turn help spur the evolution of institutions, is evident in power sector history. Major new power sector institutions, such as cost of service monopolies in the first half of the 20th century, competitive wholesale and retail markets in the 1990's, and regional transmission and independent system operators in the 2000's, each followed key technological innovations. In each case, as discussed below, fundamental changes in the cost and performance characteristics of power sector technology drove corresponding changes in power sector institutions.

Importantly, the cost and performance characteristics that drive institutional change entail far more than just cost per kilowatt (kW), kilowatt-hour (kWh) or megawatt-hour (MWH). These matter, but the deeper *cost structure* of new technologies and of the systems that incorporate them is even more important. A cost structure is the relationship of fixed cost and incremental cost at various levels of output. This cost structure is relevant to the entire technological system of a firm or an industry, not just a particular piece or type of technology. The design and function of this system, in turn, is largely determined the characteristics of the various types of technologies and other resources (such as fuel, labor, and environmental services) that are used in it. Typically, there are tradeoffs between these technologies and other resources based on the costs and performance of each. The cost structure and performance characteristics of the aggregate system of these technologies determine how well consumers needs are met, at what cost, and with what returns to investors.

This aggregate cost structure and its cost performance, not the cost of a particular generator or a transmission line, lay behind the dramatic reductions in electricity's cost in the nation's first large scale integrated utilities. The best example is that of Samuel Insull, who built what became Commonwealth Edison in Chicago between 1890 and 1920, replacing a number of what we would today call microgrids, each powered by its own small 600 kW steam engine and serving a small number of local customers through its own distribution wires, with large, 35 MW boilers and an integrated distribution system for the entire Chicago area. In the process, he reduced rates from 20 cents per kWh to under 6 cents, and the amount of coal burned per kWh from 12 pounds to 2 pounds.[8]

Insull's low delivered cost depended on building expensive but efficiently large power plants, with enough expensive transmission and distribution equipment to aggregate a large enough number of customers, with a flat enough load shape, so he could run the large power plants flat out in as many hours of the year as possible. With only half the customers, generators and wires, the fixed costs of his system per customer might have been the same, but would have been spread over a much peakier load shape, and thus over substantially less than half the kilowatt-hours (kWh). This would have made his cost per kWh much higher. And the performance characteristics of his remaining efficiently large boiler plants would have been less well suited to the more variable production levels needed by this peakier, more variable load shape, further increasing his cost per kWh.

Cost structures and performance characteristics are as important for the evolution of power sector institutions today as they were in Insull's time. In particular, the cost structure and performance characteristics, of existing and emerging clean energy technologies have major implications for the way

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[8] See Bradley (2011). Chapters 2 – 3 document Insull's innovation in what became Commonwealth Edison and his policy agenda of establishing cost-regulated utility monopolies with exclusive service territories to enable the replication of these efficiencies throughout much of the US. For data and the basic arithmetic of the cost savings Insull realized by expanding service to Lake County, IL , see E. Kahn (1988), Chapter 1.

the power grid is designed, operated and capitalized, and thus for the kinds of institutional changes needed for a decarbonizing power sector. But to understand these needed changes, we first need to review the key historical innovations in technologies whose cost and performance characteristics helped the sector's institutions evolve to their current status.

5. A brief history of critical power sector institutions prior to electricity markets.

A number of such innovations were highly influential in forming today's market and regulatory power sector institutions. The first, as just discussed, was the combination of new, large scale boiler and turbine technology with urban and exurban distribution systems, whose economies of scope unlocked the economies of scale in the larger generation equipment. The key institutional change drivers and their impacts are described below.

Natural monopoly technologies produced legal monopoly institutions. The cost reductions that resulted from replacing multiple small power supply firms with one large firm in these urban-centric markers were dramatic examples of what economists call natural monopolies.[9] The combination of better service at much lower prices for customers and impressive returns for investors convinced policy makers to adopt the institution of exclusive service territories (i.e., legal monopolies) for utilities, coupled with cost-of-service regulation of their prices.

The need to continually balance generation with load created complex operating, reliability and market requirements. State utility regulation was based largely on the disciplines of accounting and law. It was accompanied by a parallel but almost entirely distinct institutional body of technical and engineering rules and practices governing the design and operation of the electric systems.[10] These were, to a large extent, driven by one of the most fundamental requirements for the reliability of such electric systems -- that the amount of electricity injected into the system by generators must precisely match, in real time, the amount of electricity withdrawn from it by customers. Electricity consumption was almost always substantially more economic than the human, animal, steam, kerosene and other alternative means to do work and create light it displaced, so the amount of consumption was driven almost exclusively by the amount and timing of the work that needed to be done. To utilities, this meant load was taken as given, and the balancing had to be done entirely by controlling the output of their generators. Today's myriad operating, market and reliability rules and practices still embody and reflect this basic approach to system balancing, and have only begun to interact with cost-based regulation by states and federal authorities in the last two decades.

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[9] For the economics of natural monopolies and their regulation see Berg and Tschirhart (1989).

[10] For example, there is no entry in the subject matter index of either Phillips (1993), a comprehensive 922 page treatise on *The Regulation of Public Utilities* or of A. Kahn (1993), an authoritative overview of *The Economics of Regulation* for any of the following terms: ancillary services, area control error (ACE), balancing, frequency regulation, inadvertent interchange, load shedding, the North American Electric Reliability Council (NERC), reliability or reserves. NERC's voluntary, self-regulating approach to setting reliability standards only became mandatory and subject to FERC's authority in 2007, based on provisions and procedures established under the Energy Policy Act of 2005. Before that, reliability standards and best practices were fully managed through voluntary self-regulating, groups of utility engineers, reflecting both utilities' interest in avoiding supply interruptions and their near monopoly on the engineering and technical knowledge necessary to operate the system reliably.

Economies of scale and scope made it important to break load into three basic categories: base, intermediate, and peaking load. Because early monopolists had strong incentives to achieve a flatter load shape to realize the scale economies of their larger generation equipment, the critical balancing requirement lead directly to a division of labor among generating equipment that would allow the large, efficient generation to run at full output as constantly as possible, with smaller generators, which were less efficient for full time operation but also less expensive to own and operate, taking on the balancing requirement by starting, stopping, and ramping production up and down to continually match load. This lead to the stratification of aggregate load itself into three categories: *Base load*, which is the amount of MW that were always being consumed in all the hours of the year, and is equal to the minimum hourly load level in a typical year; *intermediate load,* which is the difference between base load and typical daily consumption; and *peak load,* which is the difference between the sum of base load and intermediate load and the highest levels of actual consumption in the year.

This lead to three types of generation technologies, each with cost and performance characteristics that made it the most economical to serve one type of load. This stratification of load types allowed the selection of a mix of generation technologies that were most cost-efficient to serve each type. As we have seen, large boiler-turbine technologies, burning coal or oil prior to nuclear technology's emergence, were optimal for serving base load, since this allowed their very high total fixed costs to be spread over a very large number of MWHs of electricity. At the same time, their size and technology made them relatively inflexible – it takes a long time to bring all that water to a boil, and the most efficient operating range for producing steam in the boiler and extracting its energy in the turbine is fairly narrow. More flexible technology, such as smaller boiler-turbines and larger stationary diesel reciprocating engines, came in smaller and hence less expensive sizes, but had lower operating efficiencies and were therefore uneconomic to use for long periods of time. This made them the most cost-efficient for meeting intermediate and peaking load. As a result, the concepts of baseload, intermediate and peaking *generation* became engrained in the power sector, as shorthand for the types of technologies that were the most efficient to serve these three categories of load.

All these fossil fuel technologies had a positive correlation of flexibility with per MWH costs of energy, but a negative correlation of fixed costs with per MWH energy costs. That is, the more flexible technologies had higher marginal costs of production but lower fixed costs, while the less flexible technologies had lower marginal costs of production and higher fixed costs.[11] This made it surprisingly easy to use simple linear heuristics to calculate the most efficient mix of them to meet a given amount of load.[12] And, since throughout the first 60 or 70 years of the 20th century, load was growing exponentially, fuel prices were stable or falling, and economies of scale in generation were increasing, utility planning was largely the relatively simple exercise of extrapolating previous trends into these simple, forward-looking heuristics.

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[11] Hydro power, which was the source of early electrification in cities like Minneapolis and Niagara Falls, does not share this set of cost and performance characteristics. It has very high fixed costs and very low or even zero marginal costs, but is also an extremely flexible resource, especially when it has a large reservoir and is not limited to variable "run of river" production. Consistent with these unique cost and performance features, there are significantly different power sector institutions in areas with substantial hydro resources.

[12] Edward Kahn, op.cit., gives examples of such heuristics and data on the underlying cost, scale and demand growth trends.

These same unique correlations between unit cost, flexibility and fixed cost allow today's power markets to minimize the cost of balancing energy production and load, while simultaneously supporting an efficient quantity and mix of competitive generation technologies and fuel sources.**[13]** In particular, these characteristics gave the generation fleet its smooth, upward-sloping supply curve for the bundled energy and balancing service the fleet produces**.** The shape of this supply curve serendipitously matches the shape assumed in neoclassical price theory, and thus allows many of the insights of that theory to be engineered into the market clearing and price setting algorithms.[14]

Utility transmission development and planning and state regulation have produced limited interstate and especially inter-regional transmission, despite the emergence of reserve sharing, power pools and markets. During much of the growth of the regulated utility from its start at the beginning of the 20th century, the focus on transmission was to connect each utility's large, efficient power plants and their economies of scale to its own large aggregated pool of customers with their diverse and therefore relatively flat load shape. This meant early transmission systems were urban-centric, with few or no interconnections with other utilities. State cost of service regulation generally reinforced this local optimization of transmission and generation development, and limited interstate interconnections.[15] As a result, many transmission systems have "seams" or constraints that limit the transfer of large amounts of energy across utility service territories, state borders or regions. However, over time, the economics of reserve sharing led many utilities to further interconnect their transmission systems with enough transfer capability so that a smaller number of reserve units could fill in for the occasional reliability-threatening outages of a much larger number of generators.[16] In some areas, reserve sharing and multiple transmission interconnections led to the development of power pools, in which utilities also deployed a common dispatch of their power plants to reduce the entire pools' cost of balancing generation to load.

Each of the features outlined above remains deeply embedded in the power sector regulatory institutions they helped give rise to. Many of them are also embedded in the design, operation and public interest rationale of modern electricity markets, to which we now turn.

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[13] This condition for efficient power markets is often taken for granted in microeconomic analysis of power markets, though it is sometimes explicitly assumed by economists. See, e.g., Joskow (2007) at p. 8.

[14] Many economists have been pleasantly surprised by the historic power sector's easily visible electricity supply curves and demand curves, and at the almost spooky way those it could reach the sort of equilibrium posited analytically in Viner (1932). In most markets that are based on marginal costs, it is empirically much harder to identify supply curves, which typically have to be inferred through complex econometric statistical analysis. For insights into more typical markets whose pricing, clearing and equilibrium conditions are not explicitly based on short run marginal costs, see Gramlich and Ray (2015). For a discussion of substantial segments of modern competitive economies that do not even have short run marginal costs, see Murphy (2013).

[15] For a much fuller discussion of the need for and challenges of more and more rational transmission development to reduce power sector CO_2 emissions, see Chapter 8 of Fox-Penner (2010), which also offers an early and influential framework for considering a variety of roles for individual utilities in optimizing the deployment of distributed energy resources and clean technologies in general.

[16] Reserves are typically needed to cover the single largest generator capacity in a region in case of failure. Because such failures are typically uncorrelated, the same reserve unit can cover one or of a number of generators. Hence enough transmission for reserve sharing is usually not sufficient for importing a substantial share of the generation needed to meet load.

6. The emergence of electricity markets.

By the 1970s, the trends discussed above reached their high-water mark. But then, in rapid succession, major power sector cost and performance characteristics began to change. One of the first shocks came from high oil prices, which suddenly revealed that the planning heuristics of the previous decade had missed the mark, and not enough "baseload plants" had actually been built. The utility industry moved to address this by building coal and new nuclear plants. But many of the new plant designs led to cost overruns and construction delays. The resulting high costs and occasional regulatory denial of cost recovery made it clear that scale economies in boiler technology were either gone or diminishing. This eroded the primary reason for including generation in the legal monopoly bundle intended to bring lower costs to customers and reasonable returns for the investors who enabled those lower costs.

Meanwhile, a new generation technology – the combustion turbine – had been quietly developing since 1939. These turbines dispensed with the boiler entirely, and were spun by burning the fuel, either natural gas or liquid fuels, directly in the turbine itself. In 1961, the combined cycle was introduced, which added a steam boiler driven by waste heat from the combustion turbine, and used the steam to generate even more electricity from the same fuel. Combustion turbine (CT) and combined cycle (CC) technologies reached efficient commercial scale at much smaller sizes than nuclear and coal plants, were highly flexible, while the CC technology was also suited for operation for extended periods of time.[17] This meant it could provide both intermediate service and baseload service, if the price of gas was low enough to make the latter economical. The gradual transition to competitive natural gas price regimes from 1978 through 1992 made CC and CT technology look even more attractive compared to coal and nuclear plants.

This new generation technology did not need the massive scale of boiler technologies to be efficient. It could meet all three types of load service, and could be paid for without massive utility balance sheets. It offered a compelling alternative to the nuclear and coal plant cost overruns that plagued the utility sector in the 1970s and 1980s and drove cost-based rates to new highs. Consumer, industrial and public interest advocates embraced the new technology, and called for regulators to deregulate generation, while keeping transmission and distribution in the legal monopoly construct. Congress modified the Public Utilities Holding Company Act to allow certain wholesale generators to be exempt from the implied utility ownership requirements of the act. Numerous state legislatures and regulators in regions with high cost electricity agreed, and required utilities to sell their generation to competitive power companies as part of state restructuring initiatives. A remarkable group of visionary FERC commissioners and chairs responded by creating new open access transmission rules designed to let wholesale transmission customers easily buy transmission service under the same terms and conditions utilities applied to the use of their own transmission assets.

[17] However, CC and CT technology maintained the trade-offs between increasing unit cost and flexibility, on the one hand, and declining fixed costs, on the other hand. CTs are cheaper to build, more flexible, and more expensive to operate, and are thus classic examples of peaking technology. CCs are more expensive to build, somewhat less flexible, and less expensive to operate, and thus can fit into both the baseload and intermediated service categories.

The combination of independent power producers and an open access transmission market created competitive bilateral wholesale markets. In parallel, new computing and digital information technologies were allowing existing power pools and utilities to do a better job of simulating their systems and using those simulations to perform economic dispatch over their systems and even larger areas. FERC began to require the reporting of "system lambda" – the marginal cost of generating power at a given moment in a utility control area – in 1994. These marginal costs in 1993 averaged 1.5 to 2.2 cents per kWh for PJM and AEP, respectively – a fraction of their typical average cost-based retail rates.[18] Those high rates, coupled with the belief that markets would instead provide much cheaper marginal cost power during periods of surplus, and ruthlessly efficient development of new plants when needed, led consumers and the new IPP industry to advocate for the creation of competitive wholesale spot markets for power. FERC responded with its Order 2000, laying out the characteristics and requirements for ISOs and RTOs, and calling for utilities to consider joining or forming such an organization. This and subsequent FERC orders and related case law formed the basic blueprint and legal authority for today's organized US energy markets, other than the ERCOT market, which nonetheless shares most of the design and architecture of the other organized markets.

The central feature of all these markets is based on innovations in information technology in the 90s and early 2000s. Market operation involves evaluating and selecting generator bids, dispatching generation based on those bids to match load levels across the grid without violating its many transmission and reliability constraints, and calculating and posting locational energy prices at every node where power is injected or withdrawn from the system. All of this is done every five minutes. And it is all done by computer models. To be able to capture the reliability and operational constraints of the grid, these market operation models must run on top of another set of models that provide a complex, detailed digital simulation of the grid itself, including real time and near real time status of all key elements. Similar models must be run hours ahead and a day ahead of real time, to allow time to commit slower starting generation units and to arrange fuel and other variable inputs for operation. The amount of computing power, sophisticated software, and continually updated data involved is staggering. Without the IT breakthroughs of twenty years ago, today's wholesale electricity markets would not be feasible.

7. The impacts of US electricity markets.

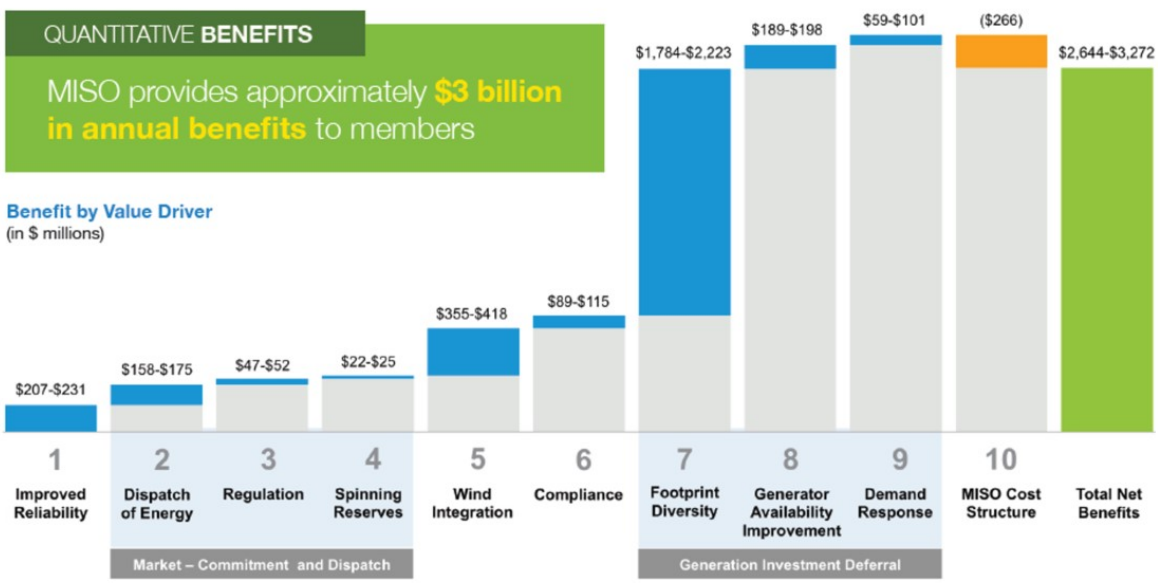
The immediate results of this market transformation were dramatic. Between 1995 and 2002, competitive developers built nearly 200 GW – approximately 1/5th of the current US fleet of power plants – of gas-fired combined cycle and combustion turbine power plants. While arguably this was a lot more than was needed, and helped precipitate a number of bankruptcies by competitive suppliers, it unambiguously modernized the US generation fleet, substantially reduced emissions and power supply costs, and did so without putting captive customers at risk. Most of this wave of exuberant gas-fired development took place before ISO and RTO markets were fully functioning, before forward markets for power, heat-rates and emissions were available, and before debt markets learned (the hard way) to require a rigorous pro-forma before loaning money to merchant developers.

[18] See Booth and Rose (1995). System lambda, in electric systems before the adoption of locational marginal prices (LMPs), was the marginal cost of running what was characterized as the marginal plant on the system. It did not account for congestion or losses, and thus did not accurately identify the true marginal cost of balancing generation with load while meeting the binding constraints on the system. LMPs in most US wholesale markets do reveal this marginal cost, which can vary dramatically by location.

As organized markets developed, they created numerous benefits, including liquid forward markets, more efficient dispatch for energy, reserves and ancillary services and much greater load diversity benefits that allowed not only the more efficient use of generation, but the avoiding of new generation that would have been locally needed but was already available elsewhere in the RTO's footprint. As shown in Figure 1, the Midwest ISO estimated these benefits amounted to some $3 billion in 2016, far exceeding the MISO's operating costs of $266 million. Other RTOs report comparable benefits.

But the benefits of competitive markets went well beyond these readily measured results, by creating stronger incentives for competitive generation owners to increase the efficiency of their plant's operations and to develop new power plants at their own risk rather than that of captive customers, and to incorporate market information about supply, demand, load shapes, fuel costs and technology costs into those decisions rather than relying on central planning and static heuristics such as screening curves and assumed load growth.[19]

Figure 1



Source: MISO 2016 Value Proposition, available at www.misoenergy.org

[19] These competitive development benefits are now concentrated in PJM, ISO-NE and ERCOT, all of whose markets are designed in ways intended to provide cost recovery for efficient and needed resources when supply and demand are in balance. By contrast, MISO, CAISO and SPP have evolved into operating markets, focusing only on short-run marginal cost based prices and operation. In these three wholesale markets, fixed cost recovery development costs – whether from mandated competitive procurement programs and the state's RA program in California, or from vertically integrated utility owned plants in the other states -- largely defrayed by recovery through regulated utility rates. Former FERC commissioner Tony Clark calls these operating markets "Joint Dispatch Markets" in Clark (2017).

The physical impacts of the wave of enthusiastic gas development, prior to the market's discipline, continues to impact the markets themselves. This ample supply of gas power plants that combine flexibility with low cost of continuous operation, especially at the lower gas prices that have prevailed since the widespread adoption of directional drilling and hydro-fracking, has supported a highly reliable system with falling power costs and falling CO2 emissions. These same low gas and power prices are putting continued economic pressure on the merchant nuclear and coal plants that were designed to perform baseload service in an era when intermediate duty was primarily provided by inefficiently small, oil-fired boilers. Especially with low gas prices, combined cycle plants are increasingly the most economical technology for meeting minimum load levels for extended periods of time.

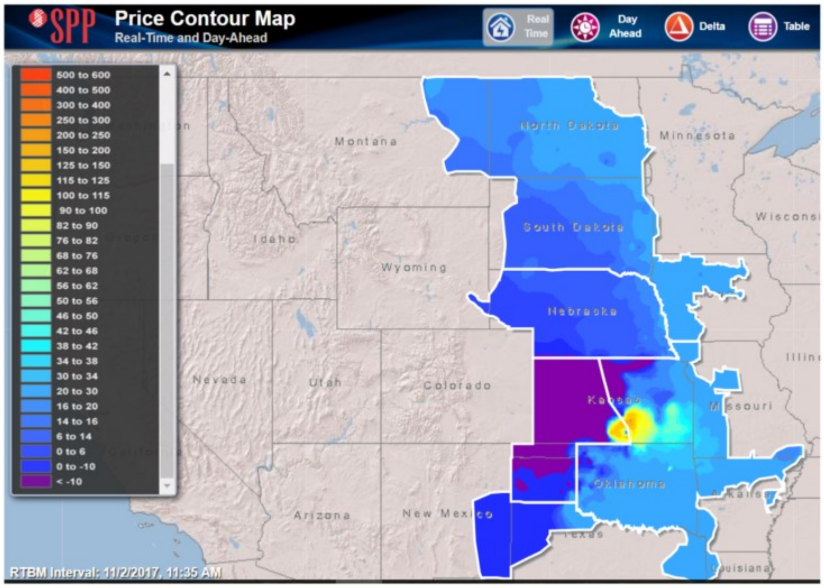
This prolonged period of relatively suppressed prices has disciplined power plant development and led many developers and lenders alike to insist on power purchase agreements (PPAs) or similar contracts with creditworthy counterparties to ensure that projects will receive enough revenues to be able to continue to service their debt. Where the counterparty is a regulated utility, such PPAs do shift some of the risk of long term falling market prices to the utility's captive customers, but they can also provide both parties with protection against market price volatility, and they typically keep the risk of project completion, performance and cost on the developer rather than the captive customer.[20] Such competitive procurement for new power supplies maintains most of the benefits of competitive merchant power, while allowing lower cost debt and hence lower overall project costs due to reduced market price risk. This competitive procurement approach has been used to develop large amounts of renewable energy under various state renewable portfolio standards, including a number of the nation's largest solar and wind projects, and has helped support the continuous and dramatic reductions in renewable energy costs in the US.[21] In fact, this wave of competition driven cost-reductions in clean energy may be both the highest achievement of the competitive power sector, and the last straw for the market design it has depended on for almost 20 years.

8. Clean energy technology cost and performance characteristics are now challenging this version of electricity markets.

The basic dynamics of the problem high levels of VRE resources pose for competitive markets are well known. When VRE plants bid their energy production into ISO and RTO markets at levels reflecting their very low marginal costs and substantial opportunity costs of curtailment, they tend to suppress prices and, during times of high production and relatively low load, can produce zero or negative market prices. Further, because they recover their fixed costs outside of markets, there is no feedback loop leading to retirement or decreased production in response to the suppressed price signal.

[20] Where the PPA takes the form of a *contract for differences*, it shields buyers from high market prices and sellers from low market prices.
[21] The California PUC's RPS Monthly Project Status website lists nearly 150 competitively procured renewable projects totaling 13,713 MW. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453096, accessed November 2, 2017.

Figure 2



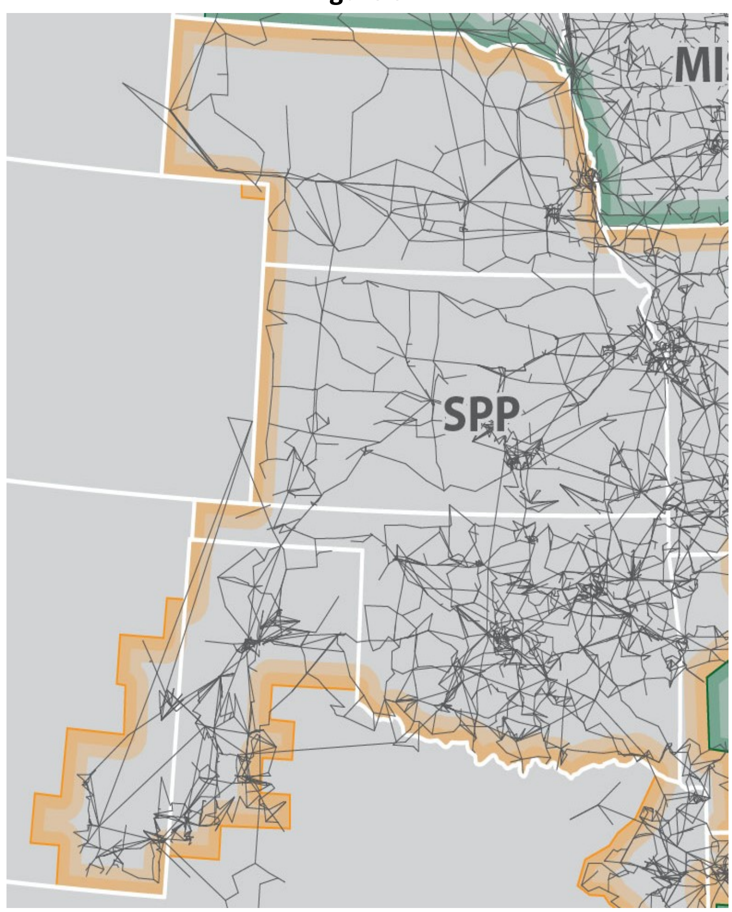
Source: http://pricecontourmap.spp.org/pricecontourmap/

Figure 2 shows real time prices in SPP at 11:35 a.m. on November 2, 2017, with a substantial area of zero or negative prices due to high levels of wind production extending from eastern New Mexico, across the entire Texas panhandle, the entire western half of Kansas, and into southwest Nebraska. Purple indicates prices below -$10 per MWH, and the darkest blue indicates prices between $0 and -$10. The challenge of transmitting wind power from the high plains into the urban load centers of Kansas is easy to see – at least for this five-minute interval, prices in the Witchita area were well above $100 per MWH, just a few miles east of where prices were well below zero.

The historical pattern of optimizing local transmission to serve local load is, to a large degree, responsible, as can be seen in the regional transmission system as shown in Figure 3. Note how the high wind production areas with negative prices in Figure 2 are bottled up by extremely limited east-west transmission lines between the high plains and cities further east.

Such patterns of zero and negative prices are common and increasingly frequent in SPP, MISO, CAISO and other areas with high levels of local renewable energy production, especially during seasons and times of the day with relatively low load levels. Under such conditions, negative prices may indicate excessive local energy production relative to accessible demand and as such can be a precursor to renewable curtailment.

Figure 3

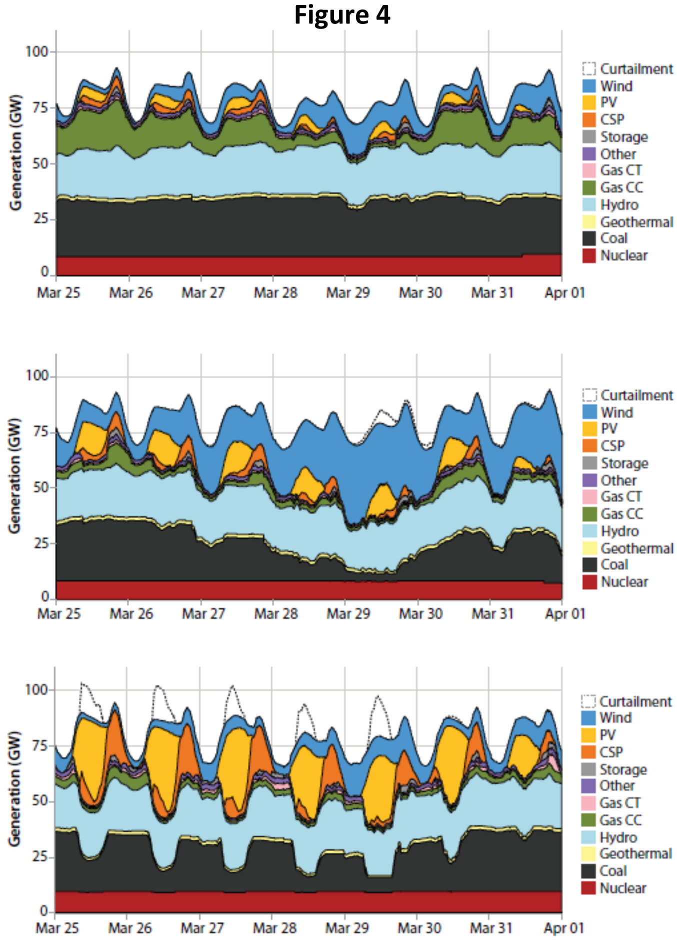


Source: NREL 2010 Eastern Interconnection Base Transmission Map, available at https://www.nrel.gov/grid/assets/images/ergis-transmission-letter.jpg

Unbottling these local excesses of renewable production through targeted transmission expansion can avoid curtailment and negative prices in the bottled up zone, but will also reduce the run time and can limit cost recovery opportunities for power plants in a much larger region, including those needed for reliability and valued for their carbon-free energy production. The power price suppression due to growing levels of wind and solar deployment in the high plans and the west is likely to contribute increasingly to retirements of other assets, including existing coal and nuclear plants, combined cycle plants and even VRE plants that are not shielded from low market prices through out-of-market contracts.

It is not just the price impacts of large amounts of VRE production that threaten the types of generation previously known as baseload. The variability in VRE production itself can cause generation that used to run relatively flat out throughout the year to need to cycle on and off to accommodate the cheaper wind and renewable energy. NREL analyzed the cycling that would occur throughout the western interconnection with 33% of energy from renewable sources, and estimated that the cycling would increase operating costs by up to $157 million per year, while saving approximately $7 billion in annual fuel costs and displacing from 29% to 34% of the CO2 emissions that would otherwise occur.[22] While this could be a really good deal, depending on the cost of the wind and solar assets themselves, it glosses over potential retirement and replacement costs and emissions, which would be especially likely in competitive markets with comparable amounts of VRE deployment.

Figure 4



The increased cycling results not only in more wear and tear and fuel costs, but also far fewer run hours and far less revenue, especially in light of the price depression that, as we just saw in Figure 2, results when large amounts of VRE energy is injected into wholesale markets. Figure 4, drawn from the study just cited, shows NREL's modeled variability in coal and gas generation during the lowest net load week of the year associated with the study's business as usual scenario (top graph) and a high wind and high solar scenarios (middle and bottom graphs), and clearly identifies the increased cycling of coal, which is the main source of the displaced CO2 reductions, due to 33% of VRE energy in either scenario. Also note the substantial curtailment of mid-day solar production in the high solar scenario.

These increased cycling costs, reduced run time and lower market prices could easily render many coal and nuclear facilities, built to serve the year-round "base load" of the 20th century,

[22] NREL (2013). See p. 11.

economically unviable. While the loss of coal production could be consistent with rapid decarbonization, provided it is not replaced with new gas assets, the potential loss of nuclear plants due, at least in part to increased levels of VRE deployment, is likely to continue to raise significant questions about the effectiveness of our current market designs and the most appropriate state and federal policies towards markets and clean energy deployment.

Section Summary: Backwards or forward? The history of the co-evolution of innovation in power sector technologies and institutions thus brings us back to the questions at the beginning of this paper, where 21st century VRE and other emerging technologies threaten the viability of wholesale markets, as currently designed, and the efficacy of integrated local monopoly utilities.

The history just discussed should raise serious doubts about a return to the balkanized, utility-by-utility approach to constructing generation and transmission to meet local load, which is unlikely to be economical in a high VRE environment whose price and load impacts extend across both utility service territories and state boundaries. And even a fully regional approach would not make it sensible for society to rely on regulated utilities, or indeed anyone else, to build large scale and inflexible generation, such as most existing nuclear designs and many CCS technologies, now that economies of scale in large boiler technologies have tapered off and been displaced by renewables and turbine technologies. These technologies, in turn, have a tremendous track record of successful competitive development and operation, and have no particular natural monopoly characteristics that justify their ownership by a legal monopoly with captive customers. Trying to reverse the technological and institutional innovations of markets and go back to the century-old paradigm of cost-of-service regulated legal monopolies for these technologies seems unlikely to achieve either society's needs for economical, affordable and safe electric service, or its needs for rapid decarbonization.[23]

So -- if we can't afford to go back to prior institutions for either decarbonization or efficient, low cost service, and the current ones are not up to those tasks, it would seem there is no place else to go but forward. In this case, forward means towards a new iteration of power sector institutions better suited to both decarbonization and, not coincidentally, to better assuring just and reasonable rates for more efficient, and more competitively priced, universally accessible, energy services.

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[23] Indeed, recent spectacular failures and cost overruns in utility CCS and nuclear projects create a sense of *déjà vu* regarding the era of tremendous cost increases, overruns and delays that plagued a number of nuclear and coal projects in the 1980s and which, as discussed above, helped give rise to competition in the generation sector. Indeed, it is striking in this regard that the only successful commercial scale CCS facility in the US power sector, PetraNova, was built – on time and on budget -- by NRG, a competitive electricity company. See http://investors.nrg.com/phoenix.zhtml?c=121544&p=irol-newsArticle&ID=2236424 . NRG previously attempted to build a PPA-backed new nuclear facility, back when high gas prices made nuclear potentially economic. However, as gas prices fell and financing the plant became more challenging, NRG stopped spending on the nuclear project and, with no captive ratepayers, simply wrote off the hundreds of million dollars it had spent. See, http://www.world-nuclear-news.org/NN-NRG_withdraws_from_Texan_project-2004114.html . While there are many factors involved in the cost, success and failure of large innovative projects, the contrast with new regulated utility CCS and nuclear projects suggest that competitive, PPA-based development of clean energy technologies may be more likely to succeed, and less costly in both success and failure, than efforts by regulated utilities with open-ended assurances of cost recovery from captive customers.

II. Institutional changes for clean energy cost and performance characteristics.

We turn now from a retrospective view of why our current institutions are not well-suited to the emerging mix of clean energy technologies, to a prospective view of the specific cost and performance characteristics of those technologies that will require new institutional arrangements. This will allow us to better understand the institutional features that will be best suited to supporting the efficiencies, cost savings and other benefits these new technologies can unlock. The characteristics which appear to most urgently require new institutional approaches are as follows.

1. Co-optimizing regional and interregional transmission with supply side and distributed resource deployment. In the historical grid, the cheapest resources were typically the largest generators, which could be built almost anywhere that made sense and then connected to load centers with relatively short transmission lines. In a decarbonized grid, there is likely to be much less choice about where to site new resources, and much more need to consider new transmission and balancing load with generation over very large distances.

For example, VREs are least expensive when located in regions with high average wind speeds or insolation. CCS plants relying on enhanced oil recovery will most economically be located near oil production regions. New nuclear technologies may be difficult to site near population centers. Remaining large scale hydro development opportunities are likely to be similar. By contrast, much of the unbundled control technology, such as fleets of controllable water heaters and EV chargers, are likely to be in those population centers. Making sure these geographically diverse resources are capable of physical integration and delivery is likely to be central to effective decarbonization, especially if new zero carbon controllable and flexible technologies prove uneconomic or achieve commercial capabilities too slowly.

Further, the value of large scale VRE development is itself highly dependent on diversity of location. Too much VRE production in a single area, especially if of just one type, can dramatically increase its cost due to curtailment at times of high production and relatively low load. Conversely, connecting the best renewable energy sites across weather patterns and time zones achieves not only lower cost VRE energy, but a flatter and smoother aggregate shape of VRE energy production, which can be better matched to customer load shape. As we saw in Figure 3, the benefits of a more diverse load mix are one of the major benefits of large markets and balancing authorities. These flatter, smoother shapes of load and of VRE production would reduce the challenges of balancing and should support the more efficient use of both demand and supply side resources - including by preserving more headroom for existing and emerging clean energy technologies, such as nuclear and CCS, that may only be economical if used in a large percentage of the hours of the year.

However, identifying the optimal configuration of such bundles of load, VRE production, new transmission and various existing and emerging supply side and demand side technologies will require looking across multiple utility service territories and multiple states. This means it cannot be carried out by individual utilities or state regulators. But even with the appropriate interstate, regional or national scope, it will require new analytical and decision-making processes to identify the optimal configurations, along with new market and regulatory institutions to incent their efficient development, integration and operation.

2. The unbundling of control and balancing from electricity production. As we have seen, 20th century generation technologies collectively provided both all the energy society needed and, simultaneously, continually matched total generation output to varying load. This ability was due to fossil and hydro technologies' ability to produce electricity, combined with the ability to start, stop, ramp up and ramp down that production on command. Over time, these performance characteristics were allocated, due to trade-offs with cost, among plants designed for baseload, intermediate and peaking duty.

The emergence of wind and solar energy as cost competitive (in regions with good wind and sunshine regimes) with the energy produced by new natural gas plants means we now need to find ways to achieve this balance beyond simply controlling generation output. Wind and solar, in regions endowed with high levels of sunshine and wind, produce the lowest cost energy, but cannot be turned on or ramped up when the wind is not blowing or the sun is not shining. And when they are, wind and solar must turn off or ramp down as soon as the wind stops blowing or the sun stops shining, even if load is high or increasing at that time. To capture the value of the very low-cost energy from wind and solar, the electric system needs to find additional means to balance load and generation.

In effect, this will require the unbundling of balancing and control from energy production into two distinct inputs. Prices and operating signals for the two inputs may also likely need to be unbundled, so they can be procured in ways that will elicit the cheapest combination of both in the varying proportions needed for reliable service. Our current market and regulatory institutions were not designed for this unbundling of energy production from control and balancing, and will need to evolve in two ways. First, they need to be able to identify and incent the most efficient, least cost, and matching levels of both, especially in regions that are rich in wind and insolation; second, they need to support efficient transactions for and performance of these services.

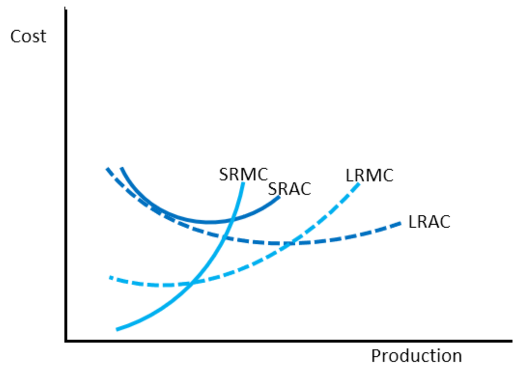
For example, the cheapest bundle in many locations may be solar and wind plus smart water heaters, electric vehicle chargers, and other forms of thermal and chemical storage, coupled with new long-distance DC transmission lines. Or it may be new modular nuclear plants that, when VREs are at maximum output, use their heat to produce carbon neutral hydrogen-based liquid fuels for aviation and fast start electricity generation, and only use their heat to produce electricity when VRE output falls below some level. Or it may be enough DC transmission, storage and flexible load to allow large scale deployment of carbon capture and sequestration along with rapidly growing solar deployments,[24] or any number of other new technologies that are on the cusp of successful commercialization but are currently unknown.

But the emphasis is on the "may" – we can't predict future technologies or the ability to execute ambitious new projects such as DC transmission networks. Identifying optimal bundles of existing and new technologies and new transmission will require an ongoing process of discovering cost, performance and feasibility of these elements – a process that markets perform better than analysts, planners and advocates for specific technologies.

[24] CCS plus solar may be an especially important technological combination in parts of the world, such as India and China, with rapid ongoing economic development, vast solar resources, and substantial number of newer coal power plants.

3. The decoupling of short run and long run marginal costs and the erosion of economic equilibrium conditions. But those markets will also need new approaches to price formation and cost recovery, as we saw in the examples of VRE-driven price suppression in the last section. The basic problem is that average short run marginal costs are declining with increasing VRE deployment, and the opportunities for scarcity pricing to make up the difference between short run and long run marginal costs are also likely to diminish and perhaps disappear as flexible load and storage proliferate.

Figure 5



This may seem to violate the basic concepts of price theory in economics, or at least its typical graphical representation. As illustrated in Figure 5, those graphs show short run marginal cost (SRMC) smoothly curving upward as consumption and output increase, until SRMC exceeds long run marginal cost (LRMC) and, eventually, short run average costs (SRAC) and, by implication, competitive prices. Prolonged prices above the cost of new facilities (LRMC) will then attract entry or expansion of facilities and lead to lower prices, with an equilibrium over time based on the tangency points between the envelope formed by the long run average cost (LRAC) curve and the short run average cost curves associated with each phase of capital deployment. This vision of how equilibrium prices drive efficient capital deployment dates back to at least Jacob Viner's 1931 *Cost Curves and Price Curves* article.[25] The notion holds up well under restrictive assumptions about the curvature of total and marginal cost functions. It is an important concept in those markets where (a) prices are really based on short run marginal costs, and (b) can easily transition into scarcity levels without the deployment of additional capital. Historical generation technologies, with their bundled energy production and control technology and correlation between unit costs and flexibility, tend to produce average and marginal costs that correspond neatly to these curvature assumptions.

But VRE sources with free energy inputs, very limited operational costs and general lack of enough control to match load at all times, do not correspond to such cost curves. To reach a long-run cost equilibrium with high levels of VRE would at least require some other balancing or generating resource with much higher short run marginal costs to set prices at levels that would ensure all other resources producing energy at that moment can expect to recover enough fixed costs to remain in the market. And even that marginal resource would need periods of scarcity – when the absence of any generating or balancing resources causes prices to rise to the point where they both reduce demand and cover the fixed costs of the marginal resource.

These scarcity events, however, are likely to be quite infrequent if flexible load, storage and distributed generation are widely deployed and have low variable costs, as seems plausible or even likely in a high VRE world. Infrequent scarcity events would have to produce enormously high price levels to result in fixed cost recovery for all operating resources. The financial and political risks associated with such prices are likely, in and of themselves, to drive fixed cost recovery for needed resources out of energy

[25] Viner (1932).

markets and into various subsidized and socialized institutions, which may be far less efficient than well-designed markets.

But even infrequent scarcity events would be eliminated if, as seems likely, many applications of these technologies are driven primarily by value propositions outside of energy markets, which in some cases are likely to be enough to fully defray their capital costs. For example, low cost batteries may become ubiquitous for transportation and distributed resilience solutions, and flexible load technologies may become standard equipment in homes and commercial buildings. Even so, they are likely to participate actively or passively to help balance and control load and generation in wholesale markets.[26] For such resources to support long run cost equilibria in the power market, they would have to recover their fixed costs through power market prices. But if they instead recovery their fixed costs through prices for housing, appliances, transportation equipment, online shopping service subscriptions, or distribution utility rates, there could be no scarcity events. The electricity market could, instead, be flooded with resources that will gladly bid their very low short run marginal costs into electricity markets while their long run marginal costs are defrayed elsewhere.

There is nothing wrong with this, per se. Indeed, multiple value streams embedded in multiple sectors could be a powerful benefit to the power sector as a whole, to customers, and to the process of deep decarbonization. But fixed cost recovery outside of the power market for a supply of peaking duty capabilities that exceeds power sector needs would eliminate or drastically reduce the frequency of scarcity pricing. This means some other market mechanism, in addition to a short-run marginal cost operating system, is needed to establish equilibrium conditions and to ensure the recovery of the efficient fixed costs that represent the entire system's long run marginal cost.

4. Finding new ways to identify and tap into unbundled balancing and control services and other emerging technologies. Many observers, entrepreneurs and activists see the potential for large amounts of flexible load and storage to become economic in the near future and to support much higher levels of VRE deployment and rapid, low cost decarbonization. With breakthroughs in cost, performance and commercial deployment, the amount of distributed control and balancing capability from distributed energy resources (DERs) could be much larger than it is today.

But for this fleet of millions of controllable devices to facilitate more VRE integration on the grid, while also meeting the energy service needs of their customer-hosts and respecting the constraints of the distribution system, will require a new approach to co-optimizing their operation across these three very different value streams. The architecture, ownership and control of the distributed energy resource management systems (DERMS) are the focus of significant innovation and debate in the power sector. But only a few approaches currently appear to offer critical features such as computational tractability and hierarchical control that would allow co-optimization across DER host, distribution system, and wholesale grid value streams.[27]

[26] Active participation involves responding to a control or dispatch signal. Passive participation involves responding to a price or correlated condition, such as weather events.

[27] Two documents that help define the state of the art today are HECO (2017) and More Than Smart (2017). For an intriguing mix of centralized and decentralized optimization approaches to solve this problem, see Caramanis, Ntakou, Hogan, et al. (2016).

The lack of a scalable, efficient DERMs architecture would limit the degree to which DERs could help balance VRE energy output, and thus could constrain VRE deployment. But even with well-suited architecture for the co-optimization of DERs, their ability to participate in the wholesale market may still be constrained by the lack of products, prices and participation pathways designed with their capabilities in mind.[28] Without both a suitable DERMs platform and participation pathways, there is no good way to know the amount of control and balancing that could really be supplied by DERs, the optimal type of DERMS, and the additional level of VRE deployment such distributed, flexible load and storage can economically and reliably support.

Institutional reforms spanning the wholesale grid, distribution system, and emerging universe of cloud-based, internet-connected DERs are needed to understand and untap the full scale of its potential contributions and the types of clean energy resources they help enable. Other emerging technologies – such as the flexible hydrogen and nuclear cogeneration units mentioned above, or new synergistic results of electrifying transportation and manufacturing – are likely to need their own version of platforms and participation pathways in the future. Power sector institutions must quickly evolve to identify and provide such platforms and pathways for all emerging, scalable technologies.

***5. Efficient integration of climate and energy policy with the evolving electric system*.** Many current clean energy policies fail to consider location, system balancing needs, wholesale price impacts, cost recovery for transmission and distribution assets, and other system efficiency and cost drivers. As we have seen, ignoring these critical system features contributes to unintended inefficiencies in the deployment and integration of clean energy and impedes the fundamental goal of rapidly eliminating power sector CO2 emissions.

Clean energy and climate policy's tendency to ignore power system dynamics should not be surprising, given the arcane and complex nature of the power system and the many rules, practices, requirements and incentives of its regulatory, market and operating institutions. Further, these institutions have historically been almost completely siloed from each other. As a result, few stakeholders and advocates understand the entire system well enough to avoid serious unintended consequences from well-intended policies.[29]

Many observers attribute much of the incompatibility between climate policy and energy markets to the lack of a federal price on carbon, and the resulting rush of states to fill the vacuum through less market-compatible policies such as renewable portfolio standards, net metering and a variety of programs by regulated utilities.[30] An economy-wide, economically rational policy to incent innovation and deployment of clean energy technologies would certainly help focus and accelerated decarbonization.

But it is not clear how a national price on carbon would, on its own, resolve the problems facing clean energy deployment identified so far in this section – i.e., the unbundling of system control and energy

[28] FERC Notice of Proposed Rule, November 17, 2016, Docket NO RM16-23-000.

[29] One might wonder how much of the spectacular reductions in the valuation of various leading clean energy companies in the past several years was due to them betting on business models and technologies predicated on such policies, rather than on creating real value in efficient markets.

[30] This was a common theme at FERC's May 1-2 2017 technical conference on state policies and wholesale markets, Docket No. AD17-11-000. Record available at https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=&View=L.

production, the growing wedge between long run and short run marginal costs, the lack of a uniform and efficient platform for using flexible load and distributed storage, and the need to co-optimize the configuration of all these resources (types, locations and quantities) along with that of the transmission system. Nor would such a policy cause states to stop promoting favored resources, responding to utility and other stakeholder demands, and pursuing their own visions of economic development. And of course, there is no reason to think that the US Congress will pass, and the president sign, such legislation in time for it to help achieve decarbonization.

For all these reasons, the rapid and efficient deployment of existing and emerging clean energy technologies would be facilitated by institutional reforms that better integrate the power sector's market, regulatory and operating institutions, while making them highly transparent to legislative, regulatory and business decisionmakers. This transparency should support the development of more efficient state and federal clean energy policies, and help ensure that they create better outcomes and fewer unintended consequences.

These same institutional reforms should also be better suited than today's to making it easier for a national price on carbon, if one emerges, to result in an efficiently configured mix of clean energy resources. And, in the absence of such a rational national policy, these reforms should support the most efficient implementation of the clean energy and climate policies of the various states, while also assuring a reliable, low cost and safe power supply for the entire country.

6. Comity and comparability for regulated and competitive investments.

Two critical elements for reducing the balkanization and inefficiency of the power sectors' uptake of clean energy involve co-optimizing transmission development with supply side resources -- nearby and distant, existing and new -- and with distributed flexible load and storage technologies. Since transmission and distribution systems are likely to remain cost-regulated, and both supply side and distributed resources are likely to continue to include both competitive and some utility-owned assets, it is important the institutional reforms treat both regulated and competitive assets in comparable manners, across state lines and across jurisdictions. This comparability, of course, should not require a rewriting of the Federal Power Act or the abandonment of its basically federalist approach to the bulk power system. Even if it were desirable, such a predicate would almost certainly involve, like a price on carbon, an indefinite delay. Nor should the idea of comparability called for here require either competitive assets to undergo some vague sort of "re-regulation" or regulated assets to somehow become "de-regulated". Instead, it should focus on creating incentives for both types of ownership and fixed cost recovery to be efficient in three ways: in committing capital to the best configurations of the entire system, managing the risks of deploying that capital in the most prudent manner, and operating their respective elements of the system in a non-discriminatory manner as required for just and reasonable market-based or cost-based rates, reliability and safety.

7. A new enabling digital technology.

We saw in Part 1 how innovations in digital technologies in the late 20th century allowed power pools to evolve into the much more dynamic and broader wholesale markets of today, with their state estimators, security-constrained unit commitment and economic dispatch engines, and the related settlement software. These digital technologies essentially create a nested set of digital simulations – models -- of the RTO's entire transmission network, loads, and generating assets, and then plug into this model the competitive bids of generators and of LSEs to serve load. The simulations then clear the market, set the prices, and record the transactions and prices so all parties can settle their financial positions. Without computer systems to simulate the grid and perform the myriad and complex calculations rapidly and accurately, wholesale markets as we know them would not be able to exist.

Achieving efficient configurations of the grid, as opposed to simply efficient configurations of the dispatch of its power plants, will require a step change in computing technology. Fortunately, the last decade has seen an explosion in digital technologies and computational capabilities, and in the ability of both private and public entities modelers and processes to analyze the grid in ways that already are helping answer the complex uncertainties raised in the preceding five clean energy cost and performance characteristic challenges.[31]

Many of these analyses are based on power system models that, in somewhat similar ways to the RTO market software described above, simulate the load, transfer capabilities and constraints, and power plants of the grid and their dispatch to meet load without violating key grid reliability and operating constraints. Some researchers have expanded such models to include weather data (insolation and wind speed) with a high degree of geographical and temporal granularity. This allows such models to estimate optimal locations and combinations of renewable generation, and by including estimates of the cost of transmission development, to estimate the optimal set of renewables and transmission, along with natural gas and other traditional resources, to meet load. Such models can provide estimates of total system cost, energy production costs, and CO2 emissions across various configurations of renewables, historical generation, and transmission.[32]

Conceptually related approaches to answering these same questions were used by Hawaii Electric Company (HECO) to develop their most recently filed Power Supply Improvement Plan (PSIP), laying out their proposed approach to meeting the Hawaii legislature's mandate to achieve 100% renewable generation by 2045. HECO's process, as described in their PSIP, entailed first using the Resolve model of the E3 consulting firm to identify compatible renewable production shapes available on the islands HECO serves, and iteratively refining potential optimal renewable portfolios through layers of more sophisticated, off-the-shelf system planning and load flow models to identify combinations of various renewables, in various locations, and the transmission and distribution investments that would be needed to access and integrate them.[33] This iterative analytical process allowed not only HECO's engineers and consultants, but regulators and interested stakeholders to engage in and understand the development of the plan. As such models advance, the system planning already required of ISOs and RTOs under FERC Order 1000 could readily incorporate similar processes, in partnership with state regulators and market participants, to identify regional and state configuration opportunities that would create the most efficient, lowest cost, reliable and clean power supply.

Section summary. The seven cost and performance characteristics of existing and emerging clean energy technologies, as outlined above, are unlike those that formed the basis of the core market, operational and regulatory institutions of the power sector. For low cost clean energy deployment to succeed, those institutions need to reform in ways that will recognize these unique characteristics and

[31] See the resources cited at fn. 1, above.
[32] For a relatively early example, see MacDonald et al. (2016).
[33] See HECO (2016).

help unlock the efficiency, cost savings, performance, reliability and safety benefits of the new technologies – in addition to their clear environmental benefits. Central to realizing these benefits will be new ways to identify efficient equilibrium configurations of the entire system, including transmission, both VRE and controllable generation, flexible load and storage; to incent capital to flow into those efficient configurations and innovative technologies and to achieve high levels of successful development; and to create strong incentives for the efficient operation of all the critical elements of the system – including those that as of yet are not operationally or transactionally integrated into the system. It will be critically important to all these outcomes to avoid picking winners, basing plans on projections of future costs and performance, or defining future technologies on the basis of increasingly obsolete concepts and categories of historical technologies.

III. A straw proposal / sketch of such institutional reforms.

In its first two parts, this paper has laid out some of the central features of current institutions that are poorly suited to the cost and performance features of existing and emerging clean energy technologies, along with features that appear needed in new institutions to support those technologies. But is there any reason to think that institution reforms to create those features are even feasible in the power sector? And if so, could they quickly evolve from the current rules and practices, especially in today's fractured and polarized state of public affairs?

There are good reasons to think that the answer to both questions is yes. The previous major institutional changes in the power sector were achieved quickly once their net benefits were clearly established, and both led to massive investments in the new technologies that made them feasible, along with substantial benefits to consumers and the entire US economy. The key changes in the market-based reforms at the federal level, despite their substantial level of innovation, were made without major enabling legislation, and were ultimately upheld by the courts. The potential social benefits of clean energy are arguably even greater than those of either Sam Insull's vertically integrated natural monopolies or replacing them with competitive generation, and are not limited to decarbonization. Indeed, much about both of these reform efforts can, and should, inform this one.

A deeper question is how will we know that any such reforms will be stable and efficient? It is easy to praise the results of early natural monopoly regulation and the more recent move to wholesale competition. But it is harder to learn what went wrong in California's idiosyncratic approach in the late 1990s to restructuring the in-state electric industry, and to avoid such debacles in the future.

To help facilitate both creative and critical thinking about these design and implementation issues, this paper closes with a sketch of one approach to such institutional changes that has been developed with the goals of addressing the key cost and performance characteristics of clean energy technologies outlined above, and of matching the new institutions to all of them.

Figure 6

Principles	New C & PC needs	Core objectives of reform	Basic elements of straw framework
Universally available, safe and reliable electricity services at just and reasonable prices.	Inter-regional co-optimization of resource types, amounts and transmission, new digital technology.	Identify and regularly update efficient configurations of VREs, controllable supply and load resources, transmission.	Configuration market to identify, select and confer cost recovery eligibility on efficient configurations.
Dynamic equilibrium based on recovery of competitive fixed cost for efficient configurations.	Loss of integrated marginal cost equilibrium for energy and balancing technologies.	Expected fixed cost recovery for competitively priced assets that perform and clear conf. market.	PPAs, single market clearing prices, or eligibility for rate-base recovery for assets that clear configuration market.
Strong incentives for efficient development and operation.	Commercial success tied to attributes and performance system values.	Incentives for innovators and asset owners to contribute to less costly, rapidly decarbonizing electricity services customers value.	Operating markets for energy supply, balancing and ancillary service markets. Settlements adjust fixed cost recovery for marginal performance.
Orderly, timely replacement of higher cost, higher emitting assets.	Headroom in configuration market for deployment.	Hasten roll-over of existing assets without confiscation or coercion.	Use of shorter term single price markets for existing assets, allocate "configuration rents" to incent retirement.
Constant identification and nurturing of new technologies to improve decarbonization and lower cost.	Scale, learning by doing, and competitive discipline plus path to market.	Early stage deployment plus products, pathways, performance criteria and efficient prices for new technologies.	Configuration market carve-out for emerging technologies.
Decarbonize quickly if clean energy is least cost; enable efficient climate policies if not.	Convergent, stable climate, regulatory and energy policy without "policy externalities".	Capture all total system cost savings from new technologies, including external costs defined by law	Continually integrate new technologies based on cost and performance, including external costs of emissions as required.
Incremental implementation, no legislative or market operating system overhaul.	Comity and comparability for competitive and regulated assets and business models.	Business-model-neutral configuration market building on current laws and operating systems.	Cleared resources eligible for either ratebase or competitive cost recovery, depending on state approach.

This sketch or straw proposal has four main components: guiding principles for the power sector institutions; the basic clean energy cost and performance characteristics that need to be addressed in a manner consistent with those principles; primary objectives for addressing those characteristics; and basic elements of the proposed institutional framework and their design. These components are summarized in Figure 6 and discussed more fully below.

1. Principles for updating the institutional framework for the 21st sector power sector.

Numerous discussions of the fundamental power market reforms that may be needed start with the price suppressing effects of zero marginal cost energy, and some add the splitting apart of control from energy production. They then jump right into market design reforms that could address those two issues. But if we are looking for fundamental reforms to the sectors key institutions, we would do well to start with several fundamental principles, consistent with those that the institutions already are guided by. These include universally available, safe and reliable service at just and reasonable prices; and both cost based and market based rates as benchmarks for establishing just and reasonable prices.

Market based rates embody the concept of equilibrium prices covering long-run marginal costs of efficient resources when there is neither a shortage or an oversupply relative to the amount needed for reliable and universally available service. For market based rates to be just and reasonable, there needs to be effective mitigation of market power – and, in parallel, for cost-based rates to be just and reasonable, there should be no abuse of political power to force customers to pay prices that are above those that would prevail in an efficient, competitive market. Finally, neither cost-based nor market based rates should require customers to pay less than competitive investors need to induce them to commit capital to the production of goods and services.

FERC has established principles that innovation and competition are to be favored for their ability to improve costs and service quality, leading to lower cost and more valued service over time. An implication of this principle is itself worth underscoring – competition and innovation imply a dynamic equilibrium in electricity markets, where more innovative and efficient resources can displace and even disrupt existing technologies, without creating "stranded costs" or a promise of cost recovery in the event of technological obsolescence. Instead, the benefits of ensuring that developers and investors bear the consequence of their investment decisions, without the ability to saddle captive customers with the costs of their failure, are substantial. If asset developers and owners face the risk of failure, including due to displacement and disruption by new technologies, they will factor it into their capital allocation, resource selection and bidding decisions. Expectations of evolving technologies and dynamic equilibria, along with stable underlying market rules and processes, will help discipline and guide innovators and investors towards efficient investments and highly disciplined execution and operation, instead of making it easier for them to make bad decisions and then continue to throw good money after bad.

To these existing principles, the imperative for rapid decarbonization consistent with the public interest should add several more essential for both decarbonization and innovation. The first is the orderly, timely retirement of higher cost, higher emitting existing assets; coupled with the constant scanning of the horizon for new technologies that have the potential to result in lower cost, higher quality service and continued rapid decarbonization. This continual evaluation and assessment of emerging technologies should be paired with the principle of creating efficient means to allow them to compete for learning by doing and scale benefits, and pathways to allow them to compete in electricity markets.

The next is the ability to foster rapid decarbonization on the basis of cost alone, if clean technology innovation produces low enough costs, or on the basis of efficient climate policies at the state and federal level, if fossil fuels should continue to be more economical. Direct cost advantages for some aspects of a clean energy system are already beginning to show up in VRE costs, and are projected by many observers to materialize in the coming decade for battery technologies and flexible load. To the extent these and related trends lead to overall cost advantages of clean energy systems compared to the continued use of fossil energy generation, the principles for orderly replacement of more costly and higher emitting technology and for the constant identification and nurturing of cleaner, more cost effective clean technologies should be sufficient to drive power sector institutional reform to support decarbonization on cost and performance alone. But if such overall cost advantages are slow to develop, however, successful decarbonization will depend on efficient and well-designed climate policies. In that case, the institutional reforms should be such that they support the effective functioning of such efficient policies. Despite the enthusiasm among economists for a carbon tax, if one is needed for decarbonization, it is unlikely to eliminate the need for the reforms called for in this paper.

For example, a carbon tax would make it less costly, overall, to develop transmission to connect with high quality, less correlated VRE resources and couple them with efficient, scalable DERMs. But the decisions to locate transmission and adopt a decentralized, hierarchical DERMs will require new approaches to regulatory analysis and decision-making that can recognize and prioritize those cost savings. This means a critical principle for the reforms is to support not only the least cost configuration based on direct (out of pocket) costs, but to also support the least cost configuration in light of total costs, including the costs of future economic and environmental damage due to climate change, as required or recognized by state or federal law.

Several additional principals are also likely to be critically important. These power sector reforms should help inform more efficient and effective federal and state energy and climate policies, and to implement them in manners that work in concert with markets rather than at cross purposes. And finally, the entire effort is more likely to succeed if it is based on the principle of incremental reform and implementation that avoids the early need for wholesale rewrites of either statutes or the operating systems and software of current electricity markets.

2. Focus reforms on new clean technology cost and performance characteristics that current institutions did not evolve to support.

As explained in Part II of this paper, the key new cost and performance characteristics that power sector institutions must evolve to support and leverage are: the need for co-optimizing resource types and quantities with diverse locations; the loss of short run and long run marginal cost convergence and the resulting loss of efficient long-run prices for energy production and the partial unbundling of system control from energy production; the orderly roll over of existing assets and the continual development and integration of new and improved clean energy technologies; comity and comparability across regulatory and business models; and convergence of policies and business decisions with regulatory and market objectives.

Focus on enabling and addressing this critical set of clean energy cost and performance characteristics is essential to avoiding and correcting the inefficiencies, needless costs, poor performance and unintended consequences that current institutions are imposing on clean energy deployment. Only by recognizing and incorporating the new cost and performance characteristics can power sector institutions achieve both lower cost, more economically beneficial electricity services and rapid decarbonization, consistent with their guiding principles.

3. Core objectives for power sector institution reform.

To effectively address these critical new cost and performance characteristics of existing and emerging 21st century power technologies, power sector institutional reform must set specific objectives intended to efficiently address each of them. Otherwise, there will be no real changes in the rules and practices that prevent the efficient deployment of these technologies, or any changes that emerge will be a hodge-podge of stakeholder interests, precedent, and ideologies rather than a path to a more efficient power system that supports rapid decarbonization.

The core objectives this straw proposal calls for have each been designed to address the specific, novel clean energy cost and performance characteristics developed in Section II. Since they are relatively high level objectives, and are explained in greater detail in the discussion of the elements of the configuration market framework, below, the reader here is simply referred to the short descriptions in Figure 6.

4. Basic elements of the proposed market framework and related institutional reforms.

The principles, needs due to new cost and performance characteristics, and core objectives identified above – as proposed or as modified and improved -- could be implemented in a variety of ways. The author proposes the following basic framework, intended to be both workable and consistent with those principles, needs and objectives.

a. ***A regional or interregional "configuration market"*** that identifies more and less efficient but feasible incremental configurations of commercially viable resources and infrastructure.[34] If implemented today or in the near future, these resources would include VREs, flexible load and end use optimization, storage, transmission expansion, existing nuclear plants, gas assets and hydro assets. As new technologies – e.g., CCS for existing or new fossil plants, new nuclear technologies, crystalline batteries – emerge, they could participate directly or through the carveouts discussed below. This *configuration market* would be conducted periodically – say every five years – by regional grid authorities, such as RTOs, or aggregated Balancing Authorities, in cooperation with affected state regulators.[35]

The configuration market would use modeling and evaluation processes that evolve from those being used, with increasing sophistication, to analyze renewable integration and system configuration today.[36] But, in a significant departure from the planning and "what-if" scenarios these models and processes are used for today, the inputs to the configuration market would not be based on cost assumptions, engineering estimates or recent observations. Instead, the inputs would be based directly on vendor and developer bids to deploy construct, develop or perform, in accordance with pre-specified criteria. This transition from analytical modeling to bid-based optimization would be comparable to the evolution of power pool dispatch analysis to bid-based security-constrained dispatch by ISOs and RTOs.[37]

Resources that are found to be part of an efficient and feasible configuration of the regional grid, whether they are various VRE types, quantities and locations, transmission enhancements, amounts and locations of storage and flexible load, needed and valuable existing or new generation assets, would be eligible for full cost recovery, provided they meet established performance milestones and criteria. State and federal siting authority and other aspects of market participation could also be conditioned on clearing in the configuration market.

Cost recovery could be carried out in a variety of ways, as appropriate for various types of resources, business models and state regulatory approaches. For example, cleared competitive projects could be compensated through as-bid power purchase agreements, single market clearing prices, or decentralized procurement agreements with load serving entities (LSEs). For resources that participate in the operating and energy market or markets (see below), these instruments could be structured as tolls, contracts for differences (CfD), or swaps to balance earned operating and energy market revenues with the longer term cost recovery mechanisms. Each of these types of instruments would include contractual or contract-like obligations to comply with operating and control requirements from the RTO or aggregated balancing authorities, specific to each resource type, with adjustments to the

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[34] This concept was inspired by a variety of previous work, including the ten-point innovation framework of Lester and Hart (2012); the ongoing evolution of capacity markets; the "investment markets" of Keay (2016); the fundamental insights of Chapter 8 of Baumol and Oates (1988) regarding optimal policy responses to locational non-convexities in production; and Christopher Clack of VCE's approach to co-optimizing resource mix, location and transmission expansion, e.g. in MacDonald et al. (2016).

[35] This new system is conceived of as being workable through an expanded application of the Federal Power Act's current pragmatic Federalism, relying on both a federal role in determining just and reasonable market-based rates and assuring reliable wholesale transmission, along with a deeper and more fruitful cooperation with states exercising their existing authorities.

[36] See the discussion at fn. 29-31 above and the references in those notes.

[37] For a recent proposal of a somewhat similar concept at the distribution level, along with a way to address some of the moral hazard, adverse selection and information asymmetries in such a bidding and procurement environment, see Jenkins and Perez-Arriaga (2014).

contract's payment schedule, outside of the swap or CfD, structure, based on performance. The choice and tenor of these instruments would likely vary by resource type, but would typically need to be long enough, including renewal, re-contracting or refinancing opportunities, to enable efficient debt financing of new projects and resources. The configuration market would settle the net payment obligations for long term and operating market revenues against load.

Cleared regulated utility projects could be treated by the relevant regulatory authority as having prima facie evidence or meeting a condition precedent for state certificate of need and cost recovery determinations. If allowed by states, regulated utilities could also use the configuration market as a procurement device to comply with state clean energy policies, mandates or incentives, and could potentially convert cleared competitive projects to utility ownership, in full or in part, by acquiring cleared projects at their as-bid cost and rolling them into rate-base or a comparable tracking account on that cost basis.

Smaller "carve out" tranches of promising but not fully commercial technologies, such as various forms of CCS and new nuclear technologies, could also be identified and procured through the configuration market. This would provide these technologies with the same kind of opportunities to secure financing, reach scale economies and achieve the benefits of learning by doing under competitive pressure that materially boosted VRE commercial viability in the last decade.

Proposed resources that fail to clear could also be dealt with in several ways, ranging from allowing them to participate as pure merchants in the spot energy or operating market, to putting restrictions on their interconnection and ability to use various classes of transmission service.

Existing resources that fail to clear in the configuration market could likewise be treated in a variety of ways, from being provided with pure merchant status, to receiving a lower tier of payments linked to performance characteristics, to being offered various incentivizing pathways to retirement that would free up headroom for more efficient configurations. To the extent there are economic rents associated with being a resource that cleared in the configuration market, these rents could be allocated on retirement or replacement in ways that would incentivize the orderly and timely rollover of less efficient, higher emitting resources.[38]

b. Operating and energy market layer(s). Generation, flexible load and storage resources that clear in the configuration market would assume pre-specified operating and performance requirements. The dispatch and control of all these assets would take place through a security constrained economic commitment and dispatch process comparable to today's, as modified or extended to allow distributed energy resources to participate.[39] The economic optimization in these approaches may primarily consider losses, balancing and reserve costs in its economics rather than marginal fuel costs during large portions of the year, but with the revenue sufficiency constraint and the incentives to follow dispatch directions resolved by the longer term configuration revenue streams, these control signals should be sufficient for secure and efficient operation.

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[38] Such pathways could be developed around some of the concepts in the ISO-NE "cash for clunkers" concept for freeing up participation space in the current ISO-NE forward market for capacity. Available at https://www.iso-ne.com/committees/key-projects/caspr .

[39] See fn. 27, above.

It may be necessary or desirable to provide two distinct markets or market layers, one for controllable resources and one for energy producing resources, as has been suggested by others.[40] However, appropriately structured cost recovery instruments in the configuration market, which adjust fixed cost recovery on the basis of performance in the operating market, could suffice to provide both revenue assurance and efficient operation for energy production and for separate or integrated balancing and control, and for efficient mixes of these types of resources to co-exist in the broad, dynamic equilibrium defined by the configuration market.

For example, the configuration market should identify the optimal amounts, mix and locations of VREs, together with flexible load, storage and dispatchable generation, to achieve just the efficient amount of curtailment of those VREs. The performance requirement for the VREs to recover their full costs would include them complying with these curtailment levels, i.e., dispatching off or down when required to during times of production. They would not lose money under their CfD by following such dispatch directions, but only by ignoring them. There would thus be no incentive or need for them to bid negatively. However, they would not be penalized for not being able to dispatch on or up when the wind or insolation resource is not available, since those characteristics were already optimized for in the configuration market. Flexible load and storage, by contrast, would be required to perform in both directions and at various times, consistent with their own economic and technical constraints, which would be included in the configuration market's optimization. Hydro and other fully dispatchable resources would be selected by the configuration market in part based on their ability to dispatch up and down on command, and thus would face penalties for not following dispatch directions on and up as well as down and off. Considerations such as these suggest the operating and energy market could be a single market, with "layers" identified by resource-specific performance requirements that are included in the configuration market, rather than being entirely separate markets for energy and controllable resources.

Figure 7

The Configuration Market

What	**Configuration phase** +	**Development phase** +	**Operating phase** =	**Cost recovery opportunity**
Why	Efficient quantity, mix and location of resources	Competitive performance in development	Competitive performance in operation	Expectation of fixed cost recovery
How	Bid-based configuration optimization process	Construction on time and on budget condition precedent for PPA or rate-based cost recovery	Meeting expected performance standards in operating market necessary for full cost recovery	PPA, CfD, single-mkt clearing price, ratebase with performance terms and appropriate tenors to incent investment and efficient finance w/o excessive "lock-in" or isolation from innovation and obsolescence risk
Who	ISO, RTO, regional planning authority w/ state & other stakeholders	Private developers, EPC/OEM combinations sponsored by a bidder	All resources and assets providing or contributing to wholesale service or interstate transmission	Operating market – all operating resources Long term cost market – all resources cleared in configuration market net of other cost recovery modes
Key Out-come	Optimal configuration(s) comprising commercially executable projects	Set of financeable projects comprising an optimized system, with strong incentives for efficient execution	Set of integrated, complementary resources with strong incentives to operate as required for efficient, reliable system	Efficient, compensatory incentives for short run and long run performance and expected cost recovery

[40] E.g., Liebreich (2017) and Keay (2016) each propose such a two-market solution.

The basic elements of the configuration and operating markets can be visualized as three phases which, when each is suitably achieved on the basis of the prior phases, result in the expectation of cost recovery on the part of the developers and owners of all the key elements of the bulk power system, as shown in Figure 7, above.

Note the configuration phase includes the critical element of scanning the horizon for emerging technologies that can increase the benefits of electricity services while hastening decarbonization and making it less costly, and developing ways for those new technologies to benefit from early, critical scale and competitive deployment opportunities, through the carve-outs discussed above. But many new technologies may need products and participation pathways that translate their unique performance and cost characteristics into goods, services or other benefits used in configuring and operating the system. This is important not only to continually increase economic efficiency and related social benefits due to innovation, but also is essential for the configuration and operating markets to actually work as power sector and related technologies evolve.

c. Products and participation pathways. Two basic types of reforms are needed for this to happen. First, market products and protocols must in some cases be modified to be feasible and accessible to resource types, such as batteries and various types of flexible load, that can offer valuable energy production, control and balancing services, but do not meet current product and protocol requirements.[41]

Second, the resources must have a communication protocol that allows them to receive operating requirements, requests or offers from the operating market and to respond appropriately. For some resources, such as batteries connected to the bulk power system, the normal dispatch signal delivery infrastructure is likely to suffice. But for flexible load and other distributed resources connected to the distribution system or behind its meters, there is a more complicated pathway. Many of these resources will interact with the distribution system itself as they respond to wholesale market requirements. Some of these cumulative distribution system interactions, at times, may be inconsistent with safe and reliable distribution operation or may have a variety of more or less beneficial or costly impacts on the distribution system and its configuration. In addition, many forms of flexible load will also be constrained in their time and type of operation by the impacts of that operation on the comfort, productivity or other value they create for their end use customer hosts.

For such resources to reach their full potential and to avoid creating damage or eroding value for the distribution system and their customer – hosts, there needs to be an added layer in the operating market. This DERMS-like layer will clear distributed energy resource (DER) transactions that could benefit their customer - hosts and the bulk power system against their potential for significant negative impacts on the safety, reliability or other key parameters of the distribution system. It would be in everyone's interest to have this layer efficiently screen out DER those transactions that would have such negative impacts, while also identifying other transactions to which the distribution system is indifferent, as well as those which have substantial benefits to the distribution system.

Without a standard, efficient and fair distribution clearing house for DER transactions, neither the configuration market nor the operating market will be able to achieve efficient outcomes, especially if

[41] See FERC's 2016 NOPR on Storage and DER Aggregation and responses for numerous examples. 157 FERC ¶ 61,121 18 CFR Part 35, Docket Nos. RM16-23-000; AD16-20-000. November 17, 2016.

DERs turn out to have the ability to make higher amounts of VRE deployment significantly more cost effective, as seems intuitively likely to be the case. By the same token, early iterations of the configuration market could be very helpful in helping vendors, DER providers and utilities converge on optimal design criteria for the DERMS platform and capabilities.

d. The role of retailers. Such participation pathways for DERs open up new roles for competitive retailers, who could have the potential to dramatically increase the participation of customers in the configuration market through innovation, risk management and accelerated deployment of DERs that are optimized for use in this hierarchical DERMs environment. In effect, retailers would evolve from selling the wholesale market's commodity to selling energy services in a two-sided market – both the wholesale market and the retail customers buy services.

Beyond DERs, the configuration market concept raises deeper questions about the role of the retailer. Should retailers sell only the bundled, optimized output of the configuration market, or should they be able to buy transaction-specific transmission and delivery rights along with system power supply – or, as Michael Liebreich suggests, be required to? Could a system of financial transmission rights supporting such transactions be developed that would enhance the competitive processes underlying the configuration market itself? What roles could transactive energy pricing and distributed ledger-based accounting models play in this market? Though of major importance, these questions are not addressed in this paper.

8. Incremental reforms and a self-reinforcing transition to this configuration + operating market system.

While the overall framework outlined above is substantially different from today's institutional practices – as it should be, if the analysis in Part II is accurate – its key elements could allow it to evolve incrementally from existing practices. Further, it could potentially achieve significant levels of implementation without changing current statutory authority.

For example, the entire process could evolve out of using emerging system co-optimization tools in ISO and RTO transmission expansion planning. FERC Order 1000 and related orders already require public utility transmission owners to participate in a regional planning process with state authorities and other stakeholders within transmission planning areas that are congruent with the boundaries of ISOs and RTOs, where they exist. It requires each of these transmission planning areas to work with neighboring transmission planning areas in developing regional plans. This means pairwise plans already should extend beyond the boundaries of any single ISO, RTO or other transmission planning area. And, while FERC requires those plans to consider transmission needs driven by state and federal public policy requirements, including renewable energy deployment when mandated by states, it allows considerable flexibility for how the plan is developed and what it covers.[42]

[42] For a recent analysis of Order 1000, see Wellinghoff and Cusick (2017). The authors focus primarily on the implications of Order 1000 and preceding orders for regulated cost recovery of DERs that serve a transmission function, rather than the more fundamental implications for efficient system planning discussed here. Also see FERC Order 1000-B, 141 FERC ¶ 61,044, 18 CFR Part 35, Docket No. RM10-23-002, October 18, 2012 for a relatively concise overview and, at p. 24, a clarification regarding regulatory flexibility. Available at https://www.ferc.gov/industries/electric/indus-act/trans-plan/orders.asp .

For these reasons, Order 1000 and related orders should readily support and incorporate the co-optimization tools that provide the basic platform for the configuration market – indeed, several ISOs are already starting to use these tools.[43] The transparent, objective identification of least cost configurations of the system, including least cost ways to achieve state, utility and corporate emission reduction goals, has the potential to provide many of the benefits of the configuration market, under current approaches to fixed cost recovery.

Once such planning use of these co-optimization models is implemented by regional transmission planners, in collaboration with their business sector and regulatory stakeholders, they will offer enhanced ways to address problems facing both capacity markets and energy markets, including revenue sufficiency, resource adequacy and the underlying loss of load standards and metrics, distributed energy resource potential and the design of DER platforms and participation pathways, the integration of state clean energy and carbon reduction goals, optimal transmission expansion and non-wires alternative planning. Even before these tools are used to evaluate bids and select optimal resources, they will be able to help federal and state regulators better understand these issues and identify cost-effective answers to these questions as VRE and DERs proliferate.

At the same time, these tools will help regulated utilities and their regulators gain better insights and more cost-effective outcomes for key state proceedings such as integrated resource planning (IRP), certificate of need proceedings, distribution system planning and DERMs designs, incentive ratemaking and prudence reviews.

Their rapid socialization and the benefits of their insights in both the wholesale and state-level jurisdictions will set the stage for their adoption in reforming both energy-only and capacity markets as falling revenue sufficiency and lack of product specificity, respectively, imperil the stability and effectiveness of both market types. Their initial use in markets may be to clear evolving capacity markets that need to increasingly procure energy and control resources separately, and depend on economic transmission configurations to identify the most economic mix. \But from there, it is only a short step to the full configuration market framework as envisioned here.

Such an incremental process could, conceivably, develop on its own. However, history suggests it would be far more likely if those who believe in and strongly desire to enjoy the benefits of this change gather together – as Sam Insull and the early Midwest business associations did to promote exclusive monopoly service territories in the 1920s, and as ELCON, consumer advocates, economists and independent power producers did to promote open access transmission and wholesale markets in the 1990s – and implement a multi-pronged, thoughtful campaign to make it so.

Of course, before that happens, it would be a good thing to make sure each step of the analysis here – from institutions to cost and performance characteristics, and from principles to objectives to market elements and their individual design – makes sense, is not missing key elements, and does not contain the unwitting seeds of future market failures or melt downs. To that end, this paper is directed

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[43] CAISO has used E3's RESOLVE model to explore ratepayer benefits from an expanded footprint and resulting lower costs for renewables, transmission and energy storage. See https://www.ethree.com/tools/resolve. MISO has used VCE's co-optimization models to explore efficient pathways to achieving 80% CO2 emission reductions by 2050. See *MISO high penetration renewable energy study for 2050* at http://www.vibrantcleanenergy.com/media/reports/ .

primarily to those experts whose practice in institutional and market design will aid in diagnosing the weaknesses and reinforcing any strengths it contains.

IV. Summary and invitation to dialogue.

This paper argues that clean energy technologies essential for decarbonization – both those that are currently commercially viable and those that may become so in the future – have cost and performance characteristics that will require significant changes in the key institutions of today's power sector.

Indeed, due to their mismatch with new technologies, the current forms of these institutions are losing the efficiency-enhancing roles they arose to fulfill. Instead, they are creating their own, institutionally driven inefficiencies, causing both markets and regulation to fail in delivering two critical needs for modern society: decarbonization, and safe, reliable electricity services at competitive and fair prices.[44]

To restore these institutions to their proper roles of ensuring low cost, reliable and essential electricity services, at fair prices for both customers and efficient producers, the institutions must recognize the cost and performance characteristics of emerging clean energy technologies, and support the reconfiguration of the electric grid, including its supply, transmission and distribution resources, into a system that itself is able to optimize its overall cost and performance to meet society's needs – including its need for both a healthy and robust economy and a stable and beneficent climate system.

The proposed configuration market, using emerging power system digital technologies much as today's centrally operated markets use an earlier version of them, would extend combine competitive and entrepreneurial forces to minimize the cost of building and operating the new portfolios of resources needed to provide least cost, reliable, and rapidly decarbonizing electricity services. This is not central planning – the optimal configurations would depend entirely on the costs, as represented by competitive bids to perform, for all of its key components. Further, multiple layers of stakeholder and regulatory participation and oversight would ensure it remains a fair and lawful process.

The opportunity to recover fixed costs – through a variety of market and regulatory structures -- would depend on providing and delivering a competitively priced component of an optimized configuration of the system, and on meeting pre-established and transparent performance requirements. These features would meet a number of important economic and social criteria. They would:

- Support fixed cost recovery for efficient amounts and types of investment needed for reliable, low cost services, despite falling marginal costs and vanishing scarcity conditions.
- Support strong incentives for performance and compliance with operating requirements, even as the incentive power of energy prices diminishes.
- Continually scan the horizon for emerging technologies that could further reduce the costs and improve the performance of the power system, and offer them timely participation pathways.
- Accommodate policy maker desires for a vehicle to enhance early learning by doing and scale economy acquisition by promising new technologies.

[44] This is the profound insight from Baumol and Oates (1988), Chapter 8: the types of non-convexities in production that we usually associate with market failures can, in fact, be caused by inadequate regulatory and government policies. While most economists are familiar with the idea of government policy to correct market failures, here we see the parallel need for old government policies to change in order to correct market failures the old policies cause for new technologies.

- Better harmonize state and federal regulatory, environmental and technology policies and practices without fundamentally altering either.

Finally, the configuration market conceived here should be a good candidate for smooth, incremental adoption by state and federal regulators and the key institutions of the power sector. Many of its elements would serve as incremental improvements, rather than as disruptors, to existing market and regulatory procedures. Indeed, the underlying computing and data analytics technologies are already making their way into use by ISOs, RTOs, utilities and state regulators. Even its full-fledged adoption could happen, one might anticipate, without the need for Congress to alter the Federal Power Act or pass other legislation.

But, perhaps most important of all, the configuration market process should have the powerful benefit of responding to the cost savings and potential synergies of new and emerging clean energy technologies in ways that will increase the stream of benefits and that have historically provided strong incentives for major institutional change in the US power sector.

Whether and how these benefits can really be realized will depend on many factors – initially, at least, the most important of which is an ongoing process of constructively critical thinking and dialogue around this and alternative approaches to achieve a low cost, reliable and innovative pathway to providing critical electricity services without emitting carbon dioxide and other greenhouse gases.

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