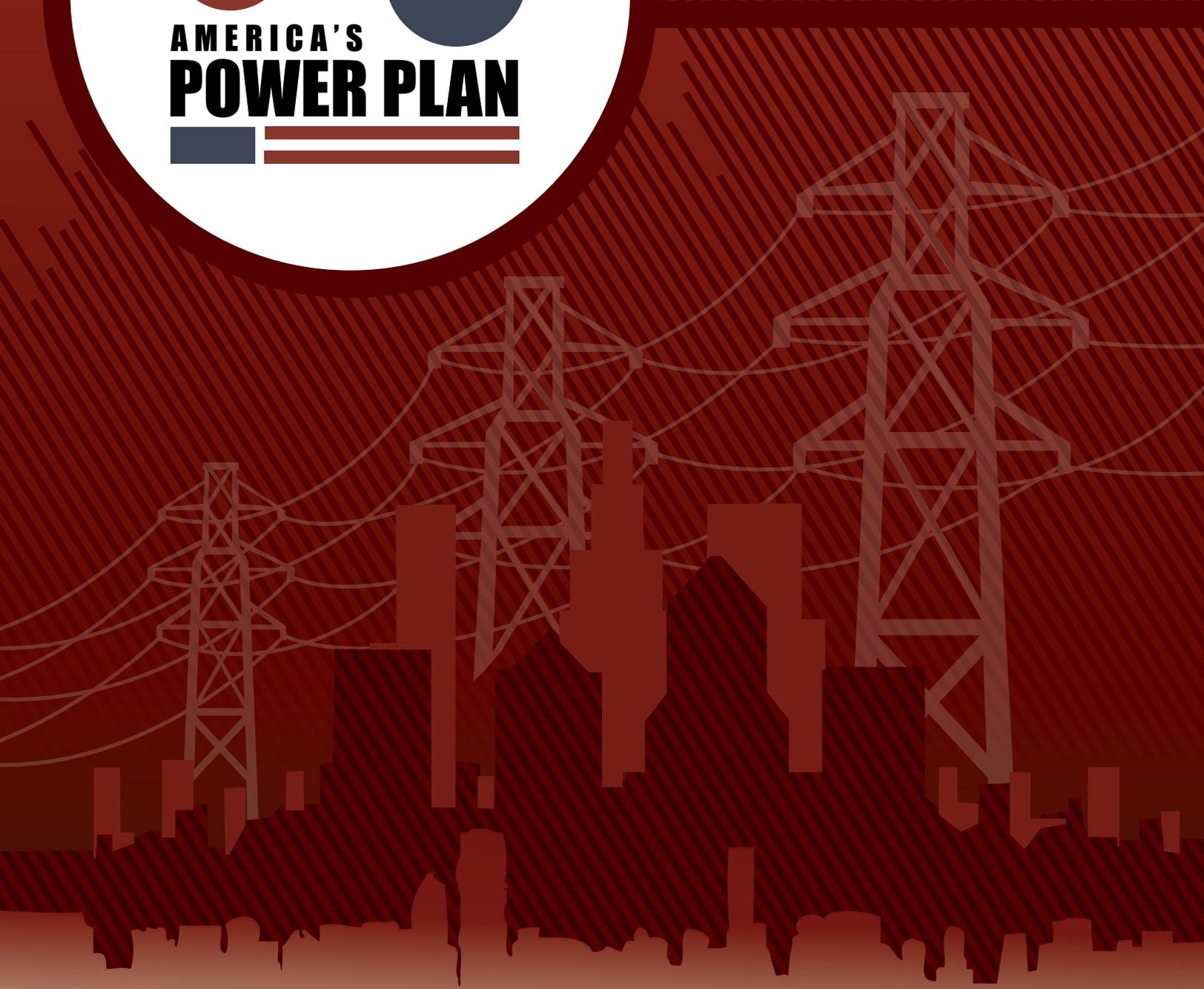




AMERICA'S POWER PLAN



Curated by the ENERGY FOUNDATION in partnership with

building a new energy future

ENERGY INNOVATION

POLICY & TECHNOLOGY, LLC



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America's Power Plan builds on a deep and impressive pool of research on challenges and policy solutions for the nation's energy sector. In addition to the extensive references list in this report, we acknowledge important work that has laid the foundation for this effort. As a sample, we recommend the following materials for further study.

Engineering Feasibility Studies

National Academies

Electricity from Renewable Resources: Status, Prospects, and Impediments

National Renewable Energy Laboratory

Renewable Electricity Futures Study

REN21

Renewables Global Futures Report

Rocky Mountain Institute

Reinventing Fire

Eastern Interconnection Planning Collaborative

Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios

Western Electric Coordinating Council

10-Year Regional Transmission Plan

National Renewable Energy Laboratory

Lessons from Large-Scale Renewable Energy Integration Studies

Policy and Industry Reports

Alliance to Save Energy

Energy 2030 Recommendations

Edison Electric Institute

Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business

Deloitte

Beyond the math: Preparing for disruption and innovation in the US electric power industry

Clean Energy States Alliance

Designing the Right RPS: A Guide to Selecting Goals and Program Options for a Renewable Portfolio Standard

Western Clean Energy Vision Project

Eurelectric

Utilities: Powerhouses of Innovation

Agora Energiewende

Twelve Insights on Germany's Energiewende



TABLE OF CONTENTS

- 1 OVERVIEW: Rethinking Policy to Deliver a Clean Energy Future**
Authors: Hal Harvey and Sonia Aggarwal, Energy Innovation
- 34 POWER MARKETS: Aligning Power Markets to Deliver Value**
Authors: Mike Hogan, The Regulatory Assistance Project
- 55 NEW UTILITY BUSINESS MODELS: Utility and Regulatory Models for the Modern Era**
Authors: Ronald Lehr, former Public Utilities Commissioner
- 88 FINANCE POLICY: Removing Investment Barriers and Managing Risk**
Authors: Todd Foley, ACORE; Uday Varadarajan, Climate Policy Initiative; Richard Caperton, American Progress
- 108 DISTRIBUTED ENERGY RESOURCES: Policy Implications of Decentralization**
Authors: James Newcomb, Virginia Lacy, Lena Hansen, and Mathias Bell with Rocky Mountain Institute
- 152 POLICY FOR DISTRIBUTED GENERATION: Supporting Generation on Both Sides of the Meter**
Authors: Joseph Wiedman, Interstate Renewable Energy Council, Inc; Tom Beach, Crossborder Energy
- 182 TRANSMISSION POLICY: Planning for and Investing in Wires**
Authors: John Jimison, Energy Future Coalition; Bill White, David Gardiner & Associates
- 213 SITING: Finding a Home for Renewable Energy and Transmission**
Authors: Carl Zichella, Natural Resources Defense Council; Johnathan Hladik, Center for Rural Affairs
- 235 REFERENCES**
- 253 APPENDIX A**
- 255 APPENDIX B**



OVERVIEW:

Rethinking Policy to Deliver a Clean Energy Future

Hal Harvey and Sonia Aggarwal *Energy Innovation*

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EXECUTIVE SUMMARY

The electricity system in America, and in many other nations, is in the early days of a radical makeover that will drastically reduce greenhouse gas emissions, increase system flexibility, incorporate new technologies, and shake existing utility business models. This is already underway: it is not speculation. Managed well, this transition will give America a great boost, building a cleaner, more affordable, and more reliable grid, as well as an industry ready to profit from deploying its technologies around the globe.

America has an opportunity to lead the world in a vast power system transformation. As costs of renewable energy technologies decline, experience across the world is demonstrating that it is easier to integrate much higher shares of renewables, more rapidly, than previously thought. But a clear policy signal is required to drive efficiency and then switch to ever-greater proportions of clean power.

America's power system is remarkably diverse, and there will be no one-size-fits-all solution for this transformation. Conversations about the best way to keep costs low, keep the lights on, and deliver a cleaner power system are often plagued by arguments over whether utilities or markets are king, or whether legislators or regulators are driving system evolution. There is no "right" answer to these questions: America's power system is heterogeneous, and will remain so. Change will happen on a regional basis, and innovative partnerships must be forged between previously-siloed decision-makers.

Depending on each region's history and preference, well-designed markets or performance-based regulation can be used to accomplish power system goals of low costs, high reliability, and environmental performance. Top policy recommendations include:

1. Move away from rate-of-return regulation; use performance-based regulation that gives utilities the freedom to innovate or call on others for specific services. Separate the financial health of the utility from the volume of electricity it sells.
2. Create investor certainty and low-cost financing for renewable energy by steadily expanding Renewable Electricity Standards to provide a long-term market signal.
3. Encourage distributed generation by acknowledging customers' right to generate their own energy, by charging them a fair price for grid services, and by paying them a fair price for the grid benefits they create. Set a clear methodology for allocating all costs and benefits.

4. Ensure that all markets (e.g., energy, ancillary services, capacity) and market-makers (e.g., utilities) include both demand- and supply-side options. All options—central and distributed generation, transmission, efficiency, and demand-response—should compete with one another to provide electricity services.
5. Employ electricity markets to align incentives with the desired outcomes, such as rewarding greater operational flexibility. Open long-term markets for new services such as fast-start or fast-ramping
6. Before investing in technical fixes to the grid, first make operational changes that reduce system costs, enable more renewables, and maintain reliability. For example, coordinate between balancing areas, dispatch on shorter intervals and use dynamic line rating to make the most of existing transmission lines
7. Mitigate investor risk by adopting stable, long-term policies and regulations with low impact on the public budget. Financial policies should be predictable, scalable, affordable to public budgets, and efficient for investors.
8. Reduce siting conflicts by using explicit, pre-set criteria; ensuring access to the grid; respecting landowner rights; engaging stakeholders early; coordinating among regulatory bodies; and providing contract clarity.

The U.S. power system is at an inflection point. New technologies offer great promise to increase reliability, reduce fuel costs, minimize capital investment, and reduce environmental damage. Capturing these benefits requires a new approach to utility regulation and business models—no matter if the power system is driven by a vertically integrated monopoly, by a competitive market, or by a hybrid of the two.



INTRODUCTION

The electricity system in America, and in many other nations, is in the early days of a radical makeover that will drastically reduce greenhouse gas emissions, increase system flexibility, incorporate new technologies and shake existing utility business models. This transformation is already underway: It is not speculation. Managed well, this transition will give America a great boost, building a cleaner, more affordable and more reliable grid, as well as an industry ready to profit from deploying its technologies around the globe. Managed badly, we will spend too much time, money and pollution on obsolete power plants, leave our country increasingly exposed to system failure and let our energy technology businesses slip to the back of the pack.

The stakes are high: Every single part of our economy requires reliable, affordable electricity. And the world requires a climate that does not drown our cities, dry up our farms, decimate our planet's biological diversity or leave us vulnerable to mega-storms.

There are three factors driving change in America's power sector. **First**, a large number of new technologies are becoming commercially viable. Power generation technologies like solar (prices down 80 percent in the last five years) and wind (down 30 percent in the same period) are gaining market share.¹ Last year, the United States added more wind than any other kind of generating capacity.² Smart engineers are rethinking the grid, to transform it from a static delivery system for electrons into an intelligent web that can optimize across many variables. New solid state equipment can deliver more functionality to grid operators and replace huge,

expensive, vulnerable and hard-to-monitor transformers and switching systems. And fracking³ has transformed the economics of natural gas in America, making natural gas-fired generation an attractive option, though history has proven the value of a diverse set of power supply and demand-side resources to minimize price volatility.

Second, the advent of competition has challenged the protected and privileged status of America's utilities — catalyzing massive change in the energy industry. For a century, vertically integrated monopolies built power plants, strung transmission and distribution lines, billed customers and were rewarded with a predictable return on investment. That regulatory compact was upended in the last two decades as various parts of the nation's grid were opened to competitive markets, many electric utilities were restructured into multi-state holding companies and regulators increasingly turned to "performance-based regulation," wherein utilities or competitive service providers earn a profit when they, for example, keep costs low, deliver efficiency and keep the lights on. It turns out, however, that building a competitive market is devilishly difficult for a commodity that cannot easily be stored, flows to the nearest load regardless of contract intent, runs along monopoly distribution wires, is a prerequisite for all economic activity and requires real-time coordination across hundreds of power plants and thousands of substations. Well-structured wholesale electricity markets and performance-based regulation have proven effective at reducing costs and bringing important innovation to the fore.

Third, national security, public health, economics and climate change point to the need for clean energy. Society cannot continue to bear the public health and environmental costs caused by unmitigated carbon pollution — and public opinion increasingly demands clean, homegrown electricity for America. As a result (despite federal inaction), a majority of states have adopted policies to encourage greater investment in renewables, energy efficiency, demand-response and grid modernization.

What does this all mean? What opportunities and threats does this conjunction of forces portend? This paper argues that there is no more business-as-usual: These trends will change the power system and utility businesses at their core. Profound opportunity is embedded in that change. Several studies have demonstrated that it is possible to power America's grid using a very high share of renewables in the next 40 years, at very modest cost, and without relying on any technological breakthrough.^{4,5} That kind of transformation means cleaner air, better jobs, a more flexible power system and hope for future generations. It is a very big deal.

These changes require a breakthrough in policy and in business models. We must re-think power system incentives and regulation as well as the relationship of American citizens and their government with the power system. An America powered by 80 percent low-cost, reliable renewables is within our technological reach, but we are not on a path to achieve it quickly or efficiently. To succeed, we need to face head-on the task of modernizing our institutions and lining up the right incentives in the power sector.

Power system planners are well accustomed to figuring out where, when and how to build large, centralized power plants and their transmission lines. They have mostly considered electricity demand to be an uncontrollable variable, to be met by central power plants, which are built based on demand projections, and dispatched to follow load. Today, though, demand-side resources like energy efficiency and demand-response allow system operators and consumers alike to reduce, shape and shift demand — in effect making it dispatchable. At the same time, renewable energy introduces variability in power supply. Utility systems will have more control on the demand side and less on the supply side — which is manageable if, and only if, there are physical systems in place to optimize the whole, and the regulatory structures to reward those who perform well at this optimization.⁶ Utilities and their regulators must re-think system planning, investment, markets and operation to optimize across both demand and supply resources to keep the system in balance. When they do this, they will unleash innovation, drive down prices and increase the resilience of the grid.

The world of electricity regulation is extremely complicated — and it is not likely to get simpler, at least in the near term. In order to capture the benefits of new technology — in cost savings, more reliability and better environmental performance — utility regulators will have to rethink their approach, and will need legislative permission to do so. This paper, building on seven studies organized and reviewed by more than one hundred and fifty of the top experts in the country, is a guide to that rethinking. It is written for state public utility commissioners, power company executives, investors, federal regulators, legislators, grid and market operators and their staffs, considering the demands of their jobs — to supply reliable, clean and affordable power.

A CLEAN ENERGY SYSTEM THAT WORKS

America has an opportunity to lead the world in a vast power system transformation. As costs of renewable energy technologies decline, experience across the world is demonstrating that it is easier to integrate much higher shares of renewables, more rapidly, than previously thought.⁷

Still, none of this happens automatically. Just as today's electric system was built on clear incentives for utilities, tomorrow's system needs direction, and that will come from the way electricity systems operate, power markets are structured, utilities are managed and regulated and new market entrants are supported. Technology, competition and increasing awareness of the dangers of climate change are likely to drive change in the power sector regardless of efforts to preserve the status quo. But without the policy and regulatory drive to facilitate this transition, there is likely to be significant collateral damage and economic hardship.

A clear policy signal is required to drive efficiency and then switch to ever-greater proportions of clean power. Most economists argue that a price on carbon is the most efficient way to do this, and a few states and countries have adopted that approach, though most have done so in conjunction with broader efficiency standards and clean energy policy. Others have employed more targeted tactics: 29 states now require utilities to produce a share of their electricity from renewable sources, under Renewable Electricity Standards.⁸ Many states have increased their targets as renewable energy technology

costs continue to drop.⁹ Other options include feed-in tariffs, production incentives (e.g., production tax credits) or strong emissions standards for power plants. Design may vary, but the most critical point is to have an adequate, clear, stable and long-term policy signal that is economically and politically sustainable.

Each of these approaches has advantages and limitations, but the best have been remarkably effective at increasing the share of renewable energy, delivering efficiency and driving down costs. This series of papers addresses the next generation of policies that can build on the industry's successful growth; policies with the potential to deliver an efficient grid powered by a much higher share of renewable energy.

Regardless of which of these tools a region chooses to use as an overarching signal, supporting policies must be “investment-grade” to make the transition readily affordable, but this factor is often neglected. A policy is investment-grade when it reduces uncertainty, thereby shifting risk to parties that can best manage it, offering

return commensurate with that risk, and driving private investment. The power sector demands large capital investments, but they will not be made unless the potential for return exceeds the risk. Important criteria for an investment grade policy include:

- **Policy certainty that can support investment choices that may have long payback periods.**
- **Long-term certainty about price, or access to markets.**
- **Contract sanctity with credit-worthy utilities (when the utility is the buyer).**
- **Appropriate reduction of other non-price barriers,¹⁰ such as permitting.**
- **Access to the grid.**
- **Reduced time between application and approval (or denial).**

The authors of *Finance Policy: Removing Investment Barriers and Managing Risk* — another paper in this series — lay out ways that policy can remove financing barriers, enable investors to make the most of new assets

they deploy and lower the risk of renewable energy investments. Because the power sector is so capital intensive, reducing risk — and thereby reducing capital costs — is key to keeping consumer costs low.

OUT WITH THE OLD, IN WITH THE NEW...

America's power system received a D+ from the American Society of Civil Engineers (ASCE) on its quadrennial infrastructure report card, saying the nation needs to completely rebuild its grid between now and 2050. This group of professional engineers has been part of the build-out of America's power grid since the first power line was built. Now, the ASCE projects that America must invest \$76 billion annually for generation, transmission and distribution system upgrades by 2020, increasing that annual investment to \$96 billion by 2030. The Department of Energy funded Renewable Electricity Futures Study (RE Futures) projects that reaching 80 percent renewables will require \$50-70 billion of annual investment over the next decade, increasing to \$100-200 billion annually by 2030—arguing, in effect, that we can move toward a renewable energy future based in large part on the size of the investments we have to make anyway.

The scale of outages is already on an upward trend (see figure 1 below). If America fails to invest in updating the power system, the ASCE projects that blackouts and brownouts will cost American homes and businesses \$995 billion by 2040. Unfortunately, progress has been slow, since most of the financial losses from outages are not born by the same people who make decisions about infrastructure improvements.

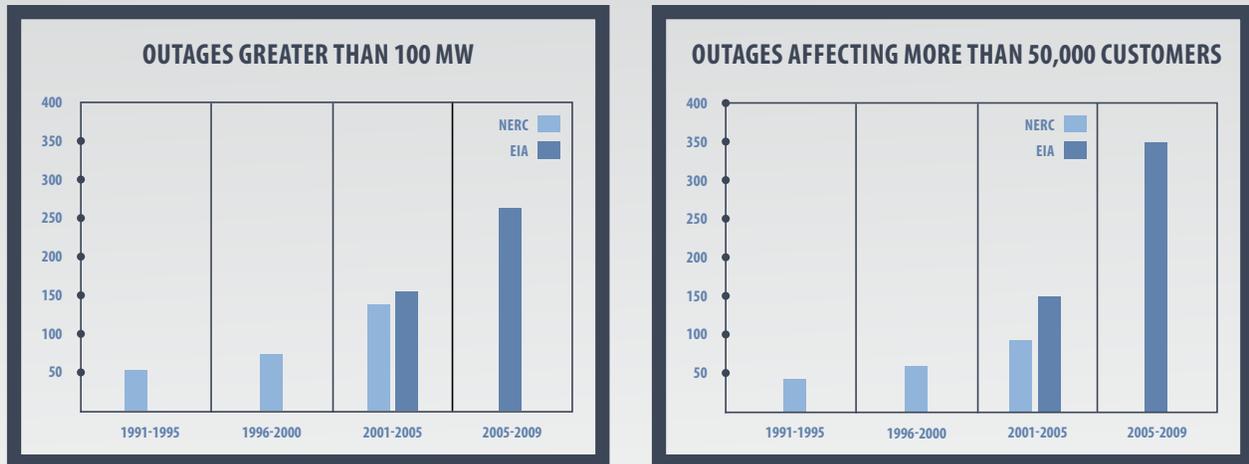


Figure 1. The scale of outages has grown dramatically over the past two decades.

The aging grid badly needs an upgrade in order to maintain reliability and modernize operations, especially as the nation faces ever more frequent extreme weather events. A reliable and resilient power grid may look very different from the one we have today, but nevertheless remains a prerequisite for any economic activity in this country, and investments in the power system should be prioritized accordingly. This natural turnover presents an opportunity for policymakers, utilities, and citizens to make investment choices that guide the country toward a modern clean energy system, rather than locking in old polluting infrastructure.

Sources: American Society for Civil Engineers (2013); National Renewable Energy Laboratory (2012); Amin (2011)

MAXIMIZING AMERICA'S RESOURCES: A FRAMEWORK FOR REGULATORS AND UTILITIES

America's power system is remarkably diverse. It employs a system of high voltage wires more than 200,000 miles long — enough to wrap around the Earth eight times.¹¹ Some parts of the country rely almost entirely on coal-fired electricity, while others already receive a quarter of their electricity from renewables — and the rest of the nation lies somewhere in between.¹² Power generation and demand must be balanced in every instant, all across the grid, to keep America's businesses functioning and homes bright.

Sitting on top of this incredibly complex physical system is an equally complex system of governance. Conversations about the best way to keep costs low, keep the lights on and deliver a cleaner power system are often plagued by arguments over whether utilities or markets are king, as well as whether legislators or regulators are driving system evolution. There is no "right" answer to these questions: America's power system is heterogeneous, and will remain so. Change will happen on a regional basis, and innovative partnerships must be forged between previously-siloed decision-makers. The path to a clean, reliable and affordable energy future must therefore be adaptable to a whole range of regulatory and market structures.

Indeed, no matter what choices each region makes about how to organize power system management, there are five basic roles that must be filled:

- 1. Generation:** Energy must be converted into electricity and fed into the power system. This can be done by utilities or independent power producers — and increasingly, by businesses and homeowners.
- 2. Transmission:** Electricity must be transported from generators to areas where it can be used. This is done by utilities, federal agencies or independent transmission builders and operators.
- 3. Distribution:** Once electricity is delivered via the transmission system, or once it is produced close to where it can be used, it must be conditioned and filtered into the homes and businesses that need it at the end of the line. This can be done by utilities or independent distribution system builders and operators.¹³

- 4. Demand-side management and customer service:** Many smart options exist for reducing the amount of electricity that each home or business needs to function, and customer service is about delivering the best energy services — not the most electrons — for the least cost. Demand-side management can include treating energy efficiency as a resource, higher efficiency appliances or motors or smart controls that ensure electricity is used when it is most needed. Demand-side programs can be administered by utilities or government agencies, but are usually executed by independent service providers.
- 5. System optimization:** Supply- and demand-side resources must be evaluated on equal footing to maximize their value, create a portfolio of options to manage risk and keep the system in balance — both for real-time system operation and longer-term system planning. Advances in intelligent grid technology will underpin this critical task. Properly designed wholesale markets, independent system operators, regional transmission operators or utilities can fill this role.¹⁴

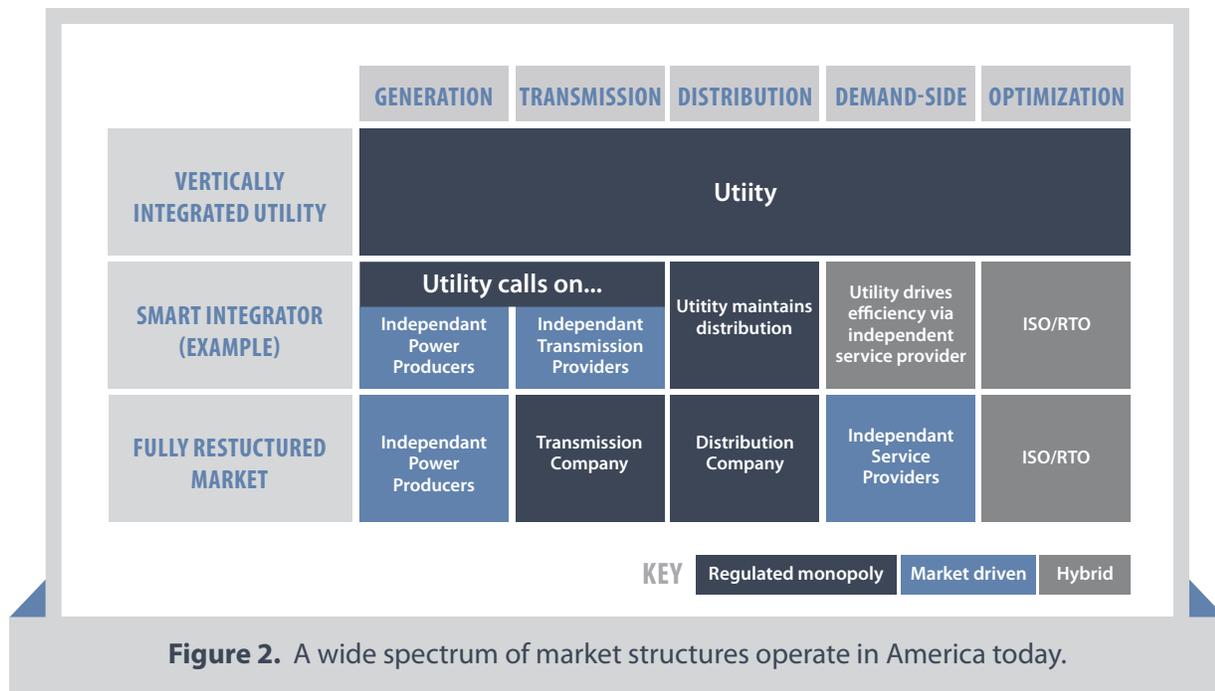
Each region has decided to fill these roles somewhat differently. And the increasing role of consumers in controlling their energy supply and demand will have profound impacts on how these roles evolve — *Distributed Energy Resources: Policy Implications of Decentralization*, another paper in this series, explores the evolving role of distributed energy resources in the power system, as well as the policies that can support them. More than half of all electricity consumed in the U.S. is sold by vertically-integrated utilities. This means that the utility handles at least the first three of these roles, and sometimes the role of demand-side management and system optimization as well. These monopolies are regulated by state and federal governments to ensure they keep prices reasonable for their customers while meeting certain social objectives.¹⁵

“Restructured” electricity markets lay at the other end of the spectrum. Many flavors of restructuring exist because there are many power system “products” or “services” that can be provided through competitive markets. In some regions, customers are allowed to choose their power supplier, or independent companies run the transmission system, or independent system operators use wholesale markets to call on independent service providers and extract maximum value from available resources while keeping the power system in balance. Ancillary services such as voltage support, black-start capability and system balancing can be provided by regulated entities or independent parties competitively bidding for the work. A particular region may choose to restructure the whole system (e.g., the Electric Reliability Council of Texas), or may just restructure one or two of the roles above, leaving the other roles as regulated monopolies.

In markets that lie somewhere between these two ends of the spectrum, a utility might act as a “Smart Integrator.” In this potential scenario, the utility would take advantage of its unique skills and experience as a large-scale social actor, using markets to select the least-cost, most-valuable resources and looking across the whole system to integrate those resources effectively. The Smart Integrator might operate the power grid and its information and control systems, but would not own or sell the power delivered by the grid or by long-term suppliers.¹⁶ This concept relies on new businesses and service providers gaining access to power markets, and suggests a strong imperative to reduce barriers for new market entrants while maintaining service standards.

Done well, this will drive innovation and bring down costs.

Figure 2 (below) lists each of the five roles that must be filled in the power sector, and displays the spectrum of ownership models described here. As the figure illustrates, transmission and distribution are physical monopolies — there is only one set of wires. So even if the system operator runs a contest to determine who should build or operate the lines, and even if they are jointly owned, they will ultimately be operated by just one entity. The other roles in the system can all be handled by competitive markets or by regulated monopolies.



As long as all of these roles are filled, it is up to each state or region to determine where along this range it lands between vertically-integrated utilities and fully restructured markets. Most regions are a hybrid, and the model is likely to fall somewhere between the three

illustrated above. But regardless of the choices made, regulators must ensure that the markets and utility oversight are properly designed, or else costs will rise, while reliability and public health suffer.

THE GOAL AND WAYS TO ACCOMPLISH IT

Regardless of how a region's markets are organized, power system planners must optimize for high **reliability**, reasonable **cost** and strong **environmental performance**. The first two of these objectives have been explicit for as long as the power grid has existed. The third — environmental performance — has gained considerable traction as an equally important objective.¹⁷ Sometimes there can be tension between these three objectives, but emphasis is usually set by policies put in place by the electorate and the legislature with public interest in mind. Striking the right balance between these three objectives is essential to ensure the power system continues to meet America's needs. To keep costs low, power system planners, regulators and market designers must think about how to minimize bills (not rates) for customers, as well as how

to minimize price volatility. They must also make sure that rates are designed to send the right signals to customers about what kind of energy to use, when to use it and how much of it to use. This means that fixed costs cannot be passed through as large fixed charges to consumers. At the same time, maintaining reliability means keeping power system infrastructure up to date (see sidebar), and minimizing the frequency, duration and scale of outages. And finally, environmental performance can be measured via conventional pollutants, greenhouse gas emissions, water use, effluent management and optimal siting for new infrastructure. Figure 3 provides examples of both regulatory and market solutions to each of these challenges — though it is important to note that all market solutions also require regulatory oversight.

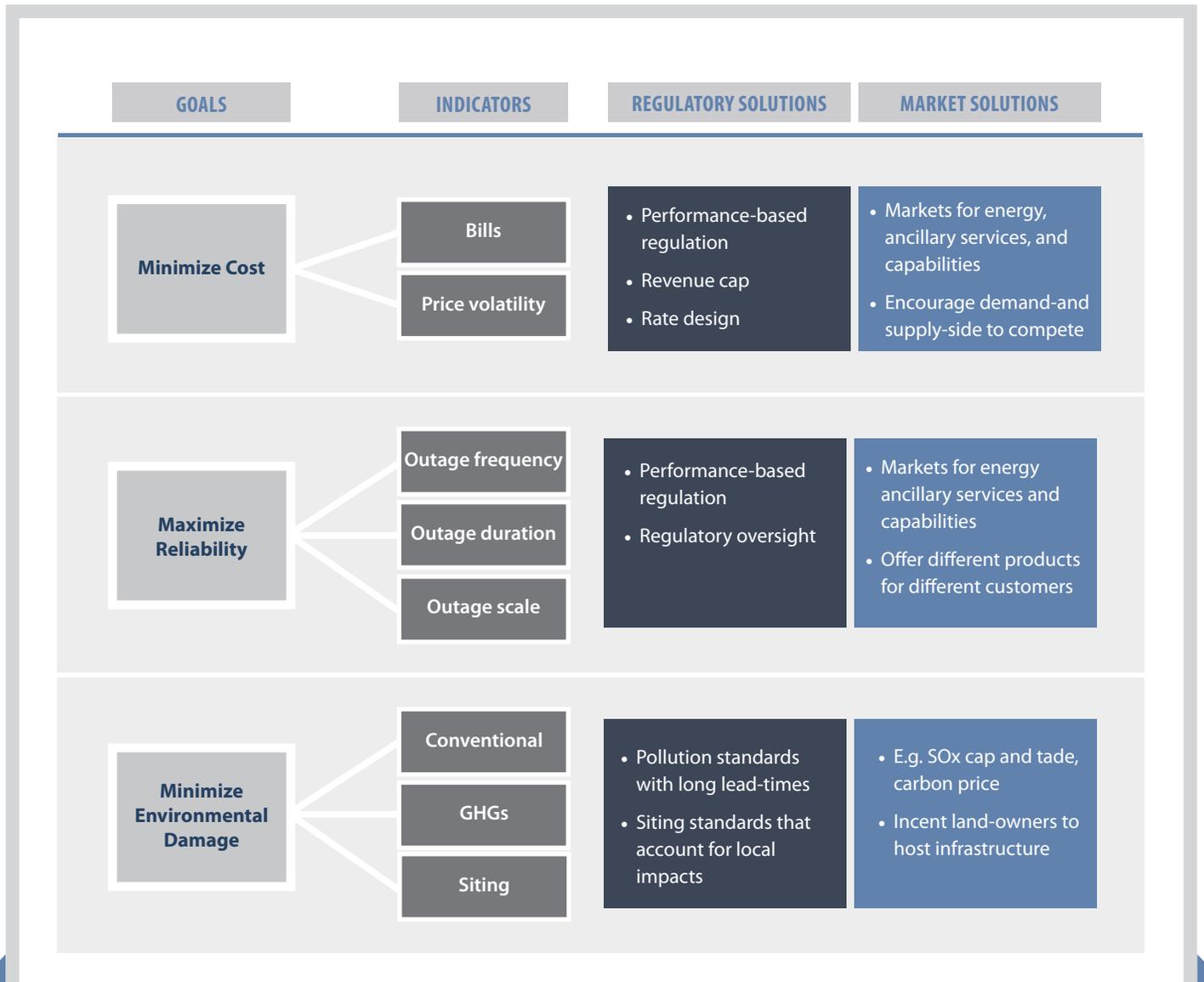


Figure 3. Regulation or markets (or a combination) can be used to optimize cost, reliability, and environmental performance. Still, regulatory oversight is required to ensure well-functioning markets. See further explanation in the following sections.

There are many ways to design markets or regulation badly — and the worst of these can be disastrous. But the right mix of smart regulation and well-designed markets can each be very effective. Five general principles for good power policy design can help increase effectiveness *no matter how a region's markets are structured*:

1. Long-term signals are necessary to give utilities and other investors the confidence they need to get the right resources built and online by the time they are needed. Regulations must be transparent, and must articulate the market failure they address.

2. Innovation and efficiency should be properly incentivized.

3. All resources — both generation and demand-side — should be properly valued for their useful attributes. Supply and demand resources should be compared on an equal footing to determine the right mix of resources for the system. Two other papers in this series, *Distributed Energy Resources: Policy Implications of Decentralization and Distributed Generation*

Policy: Supporting Generation on Both Sides of the Meter, give clear policy recommendations for how to do this, including how to analyze trade-offs between centralized and distributed resources (emphatically including efficiency) as well as “Integrated Distribution Planning.”

4. New ancillary services must be valued (and old ones modified) as the grid modernizes. These non-energy grid services are essential to keeping the system balanced in real-time as well as over the long-term. Many experts are beginning to call these new ancillary services “capabilities,” which include both real-time and forward services.

5. Coordination among agencies — and constructive communication with utilities — is critical.¹⁸

These general principles can be used as preliminary screens to identify the most effective proposals for new markets or regulatory policies. The supporting papers in this series provide many more specific recommendations, but each meets these criteria.

The following two sections lay out best practices for optimizing cost, reliability and environmental performance using these five principles within both competitive markets and regulated utilities.

Best practices: competitive markets

Competition has moved — at varying paces in different parts of the country — into electricity generation, transmission, and demand. Most of the country has introduced competitive generation, and independent power producers own and operate three-quarters of all renewable energy generation.¹⁹ The Federal Energy Regulatory Commission (FERC) now sets rules for these wholesale markets across the nation. Some areas have also introduced competitive transmission, wherein independent transmission companies may compete to build and operate transmission lines, taking bids and negotiating contracts to move electricity (subject to FERC oversight). Some parts of the country have adopted retail choice, where residential and small business customers can choose their own power supplier. As a rule, a system optimizer — such as an Independent System Operator (ISO) or a Regional Transmission Organization (RTO) — is also needed whenever operations are handled by more than one entity. As long as all five roles in the power sector are filled and the barriers to entry into the market are minimized, competitive markets have the potential to lower prices, drive innovation and deliver the energy services that customers need. But it is tricky to design markets that cover all the near- and long-term system needs, so regulators need to act with care and sophistication.

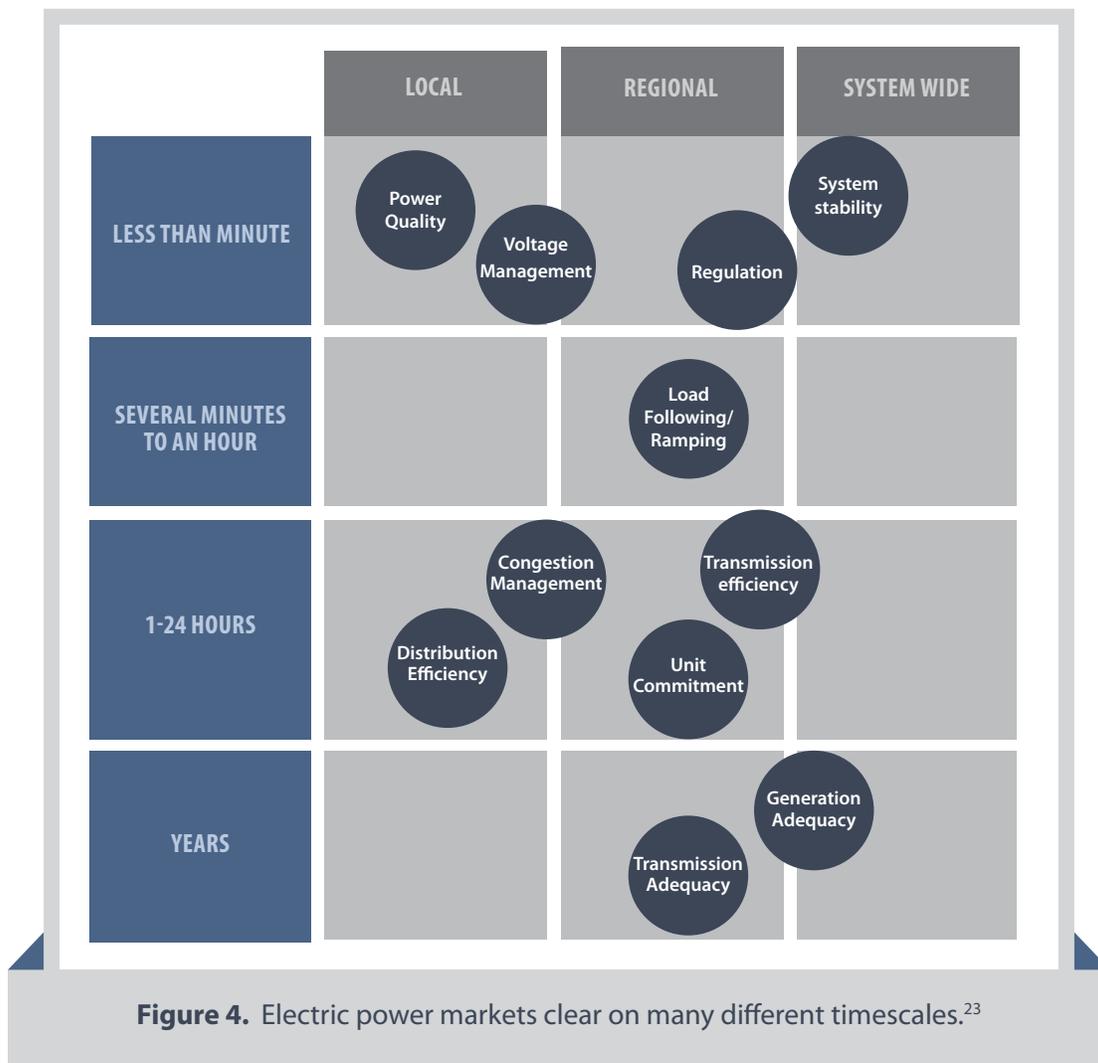
An important step in maximizing the efficiency of competitive markets is consolidating balancing areas — creating more system flexibility and options by enlarging the area over which supply and demand have to be balanced. Consolidating balancing areas helps system operators take advantage of a wider range of resources, which reduces aggregate variability in both generation and demand, decrease the need for costly backup generation or reserves and decrease price volatility.²⁰ When balancing areas cannot be fully consolidated, a second-best approach is to open an organized exchange for grid services between control areas — often called an “energy imbalance market” — coupled with authority for dynamic transfers between regions.^{21,22}

A paper in this series, *Transmission Policy: Planning for and Investing in Wires*, provides clear policy recommendations for getting new transmission lines built to enable balancing area consolidation or energy imbalance markets. Siting of new transmission will remain a challenge, but best practices for streamlining the process are laid out in one of the papers in this series, *Siting: Finding a Home for Renewable Energy and Transmission*.

Each energy market has its own products and services. Within a balancing area, well-designed competitive markets clear on many different timescales for each of these different products and services. To make the most of renewable and demand-side energy resources, markets for energy and short-term ancillary services should clear as often as every five minutes (or less), so as to take advantage of short term fluctuations in demand and variable supply. Examples of these ancillary

services include power quality, voltage management and frequency regulation. At the same time, hour-ahead markets usually ensure that electricity supply and demand are on track to be balanced, and that ample ancillary services (like load following and ramping capabilities) will be available to keep the grid reliable. Markets for access to adequate power generation capacity and ancillary services may also clear a day ahead of when they are needed. In parallel to day-by-day

markets, markets may also clear on a year-by-year basis for access to electricity, capacity, and — in some places — ancillary services. Taken together, it is a huge task to have all these markets built and functioning well, but luckily smart information technology and communications infrastructure can help by automating many of the transactions. All of these shorter-term markets are shown in blue in figure 4.



Even as these complex shorter-term markets operate, system optimizers and grid planners must think about the future. Maintaining the right resources to keep the grid in balance requires long-term certainty for investors and utilities, either through well-functioning markets or long-term contracts, giving them the confidence they need to undertake the multi-year process of gaining reliable access to controllable demand, building new supply and transmission resources or upgrading older ones. Markets for delivery of products or services several years in the future are called “forward markets.”

Some grid regions, such as PJM (the largest wholesale electricity market in the world, located in the Eastern part of the country), have established forward markets for capacity alongside their energy markets. This introduces an explicit value for the ability to call on resources whenever they are needed, and ensures a revenue stream for capacity that may rarely run, but is critical to system reliability. Demand-response is delivering more and more capacity in PJM’s forward market — almost 15 gigawatts of *new* demand-response cleared the market in 2012 for delivery in 2015/16,²⁴ which suggests that demand-side resources could have great potential to deliver low-cost solutions to capacity requirements in other parts of the country. Any new market should take care to ensure that demand-side resources — at least including efficiency,

demand-response, and distributed generation — can participate and bid on equal footing with supply-side resources. Demand-side resources will be an important part of the flexible grid of the future — giving system operators the freedom to call on whichever resource can deliver clean, reliable power at the lowest cost.²⁵

Another paper in this series, *Power Markets: Aligning Power Markets to Deliver Value*, suggests that forward — i.e., future — markets should also be opened for a handful of existing ancillary services, such as the capability to ramp energy production up or down quickly. The paper also suggests that new kinds of ancillary services should be added, such as a service that hedges the price differences between one scheduling interval and another. As generation becomes more variable and demand more controllable, the flexibility characteristics of power generation resources will become more valuable.²⁶ Market designers must develop tools to better forecast net demand, and shed light on the future value of grid flexibility. Valuing the new capabilities that we anticipate needing can make sure the right resources are online when grid operators need them to fill resource adequacy requirements or to minimize costs and keep the grid reliable.

Figure 5 (below) shows the market solutions to meet each of the five principles for good power policy design outlined above. Even if a region relies heavily on competitive markets, there is

still a substantial role for regulators setting policy direction and providing market oversight to minimize gaming.

PRINCIPLE	MARKET SOLUTION
Long-term signals	Work to make short-term markets for energy and services healthy enough to provide long-term signals; ²⁷ open forward markets for energy and services
Value supply-and demand-side resources	Ensure new markets encourage bids from all resources
New ancillary services	Open markets for new ancillary services and capabilities, carefully defined to assure an even playing field for new services, and to reward innovation and performance
Innovation and efficiency	Minimize barrier to entry for new resources and service providers
Coordination among agencies	Consolidate balancing areas, organize frequent meetings between PUCs, ISOs/RTOs, and utilities

Figure 5. Markets can address all of the principles for good power policy design

Best Practices: Performance-based Regulation

To usher in a modern system, regulators must reconsider the very premise upon which utilities have traditionally received compensation. A focus on rate-of-return regulation may no longer make sense for America's power system — partly because of the spread of competitive markets, partly because it is unlikely to adequately compensate utilities if they are building less new infrastructure (as growth in electricity demand slows) and partly because policymakers are increasingly focused on performance, rather than capital investment.²⁸ The power sector increasingly demands a service business, rather than a commodity business. As noted in another paper in this series, *New Utility Business Models: Utility and Regulatory Models for the Modern Era*, rate-of-return regulation suggests a focus on answering “did we pay the correct amount for what we got?” But performance-based regulation shifts more of the focus to, “Did we get what we wanted?” A full departure from rate-of-return regulation is unlikely, but alternatives are worth serious consideration alongside conversations about rate design.

Performance-based regulation rewards the utility based on its achievement of specific performance measurements. “Incentive regulation” is a form of performance-based regulation that provides a means for the utility to earn a higher return over a multi-year period if it is able to reduce expenses associated with providing service.²⁹ Both of these forms of regulation encourage utilities to achieve desired goals by granting them some more freedom to become more innovative and efficient and can encourage new market entrants when they enable utilities to call on third-party service providers.

These forms of regulation also protect energy consumers by ensuring they receive adequate services by exacting penalties on utility shareholders when performance standards are not met. Many states across the nation — as well as some other countries — already employ some form of performance-based regulation. Figure 6 (below) shows a graphical representation of how it works.

Performance-based and incentive regulations have the potential to achieve the goal of minimizing cost, maximizing reliability and maximizing environmental performance more efficiently than historical rate-of-return regulation. To succeed, however, regulatory independence is of great importance — ties between the regulator and regulated entity complicate this regulatory structure and can cost customers. Still, the lines of communication between regulators and utilities must be open and clear in order to find solutions that enable both utilities and customers to thrive amid the changing energy environment.³⁰ Examples of performance-based and incentive regulation include: revenue-per-customer structures, efficiency and demand-side management incentives, portfolio incentives, service quality indices and others.³¹ Well-designed performance-based regulation can accomplish all five of the principles for good power policy design — it can provide long-term signals, value supply- and demand-side resources, integrate new ancillary services, and drive innovation and efficiency. Coordination among agencies — such as between air quality and economic regulators — requires special care and attention in a performance-based system. But if the regime is well-designed, utilities will prosper when they innovate to meet performance standards, energy users will prosper by having energy services met at reasonable cost and citizens will prosper from less pollution.

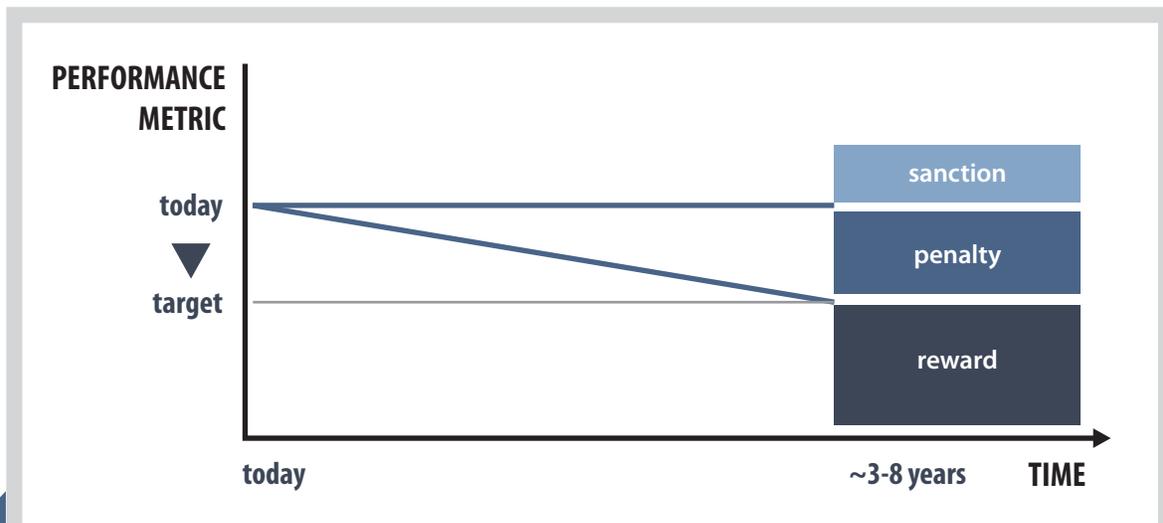


Figure 6. An illustration of performance-based regulation: PUCs set rates or allowed revenues and clear performance standards—such as a CO₂/kWh standard, a power balancing standard, or a total cost per customer standard—for several years in the future, and then give utilities the freedom to innovate in the intervening years. At the end of the compliance period, performance is measured. Utilities receive a reward for meeting or exceeding the standard, a penalty for falling short, or—if the utility completely misses the mark—its monopoly status could come into question.

The concept of performance-based regulation is simple and the theory is clear. But structuring it right is tricky—and can produce perverse effects. In theory, legislators and regulators can set goals for reliability, cost, pollution, greenhouse gas emissions, utility innovation and profitability and whichever other goals are important to them, and utilities (or transmission companies, distribution companies, etc.) will be highly motivated to meet them. In practice, these performance goals can incite gaming, such as data falsification.³² Careful monitoring and adjustment of performance metrics, measurements and outcomes can minimize gaming.

Luckily, there is a good deal of experience from which to draw lessons. Regulators across America have been experimenting with performance-based regulation in the energy sector for almost as long as the sector has existed. Experience with performance-based

regulation in the telecommunications sector provides a helpful set of lessons as well. A survey of 25 experts in performance-based regulation from across the country provided several insights about their experience in both telecommunications and energy regulation.³³

Oregon's Alternative Form of Regulation is an example of a successful case of performance-based regulation with revenue decoupling from the early 2000s. Oregon implemented a well-designed revenue cap for PacifiCorp's distribution service, decoupled profits from electricity sales, measured the utility's service quality and included a safety valve in the form of upper and lower bounds on profit potential – with an obligation to share profit with consumers if it exceeded a certain amount. The result was that PacifiCorp improved service quality and reduced costs by 15 percent, with a commitment to further reduce costs.³⁴

“Revenue decoupling” is an example of performance-based regulation, wherein a utility’s financial health is separated from the volume of electricity or gas that they sell. Decoupling accelerates energy efficiency, distributed generation and demand-response. Decoupling also aligns utility incentives with those of consumers who are generating or controlling their own power. Decoupling can be achieved in several ways, including a revenue-per-customer structure with or without additional incentives. Some form of revenue decoupling has been adopted in 15 states — from New York to Ohio to Oregon, and it is pending in six more. Decoupling has been very successful at removing utility incentives to sell more electricity, giving them the revenue certainty they need to become drivers of energy efficiency and enablers of distributed generation. Because traditional rate-of-return regulation provides a fixed return on capital that a utility would have invested in new power plants and other infrastructure in the absence of energy efficiency, some states have adopted an incentive structure to provide a similar financial reward for achieving real efficiency in the system.

But decoupling plus incentives can produce unintended effects via the process for performance measurement and evaluation. First, regulators, utilities and other stakeholders must work together to establish well-defined outcomes that everyone understands. Next, a clear methodology must be created to determine what would happen in the absence of utility programs

— the “counterfactual.” Without this, it is impossible to determine whether or not a utility performed to its standard, and whether or not it should receive a financial reward. California’s decoupling program — now about 30 years old—has undoubtedly contributed to the state’s per capita energy consumption now being roughly half the national average,³⁵ but California’s Public Utilities Commission continues to wrangle with program design to maximize performance. These lessons from regulatory experience with revenue decoupling (e.g., the need for a clear, quantitative counterfactual) shed light on how to design successful performance-based regulation for renewable energy generation.

Across the Atlantic, the U.K. is also experimenting with a new broad-scale program of performance-based regulation in which the utilities have eight years of certainty in revenues to perform in six categories of outputs (e.g., customer satisfaction, reliability, environmental impact). At the end of those eight years, utility performance will be measured and they will receive an incentive for meeting the goals or a penalty if they do not.³⁶ It will be important to watch the U.K.’s progress to glean lessons for performance-based regulation as the program unfolds. Another paper in this series, *New Utility Business Models: Utility and Regulatory Models for the Modern Era*, provides more information about the U.K.’s program, as well as some other examples of performance-based regulation.

Principles for good performance-based regulation include:³⁷

1. Tie program objectives to regulatory goals and clearly define metrics for performance. This sounds simple, but it is difficult, critically important, and sometimes rushed.
2. Use the mechanism to simplify the regulatory process, improve public understanding and prepare for increased competition.
3. Ensure the performance-based program gives credible certainty over a long enough time period to give utilities and investors the confidence they need to launch new initiatives, invest, build and interconnect.
4. To the extent possible, performance-based mechanisms should cover all of a utility's costs that are not returned by competitive markets — piecemeal programs lead to gaps, perverse incentives and gaming. Simply adding performance-based regulation to existing regulation — without carefully adjusting the terms and conditions of each — will add complexity and undermine both.
5. Performance-based mechanisms should not discourage energy efficiency, demand-response or distributed generation by promoting growth in the volume of electricity sold.
6. Performance-based mechanisms should shift an appropriate amount of performance risk to the utility, in exchange for longer-term certainty (more policy certainty, less exposure to volatile fuel prices and clarity about their role and degrees of freedom) or incentive compensation. Another option may be to allow utilities to recover fixed research and development costs via rates. These options can promote innovation.
7. Progressive revenue-sharing should be included in any program, but structured so that there is enough potential for utility profit to drive innovation.
8. Measurement and evaluation is the most vulnerable part of the system — gaming this process can cost customers greatly. Regulators should be granted appropriate authority and make the right tools available for oversight, adjustments and enforcement.

9. Establish data access and methodology at the start of the program. Prescribe which data sets will be needed, as well as the public process for gathering and reviewing them. In addition, establish a clear methodology for the counterfactual ahead of time.

10. Consider the use of collars (price floors and ceilings) to prevent unintended consequences.

The upshot is that there are many lessons to draw from in the world of performance-based regulation. These ten principles broadly summarize the field, but a reference list for this paper provides a rich set of material for further inquiry.

TOP POLICY RECOMMENDATIONS

Based on the set of seven whitepapers in this series and discussions with more than one hundred and fifty experts in electricity policy, the following represents the set of top recommendations from this series:

1. Move away from rate-of-return regulation; use performance-based regulation that gives utilities the freedom to innovate or call on others for specific services. Separate the financial health of the utility from the volume of electricity it sells. (State legislatures and PUCs)
2. Create investor certainty and low-cost financing for renewable energy by steadily expanding Renewable Electricity Standards to provide a long-term market signal. (State legislatures and PUCs)
3. Encourage distributed generation by acknowledging customers' right to generate their own energy, by charging them a fair price for grid services, and by paying them a fair price for the grid benefits they create. Set a clear methodology for allocating all costs and benefits. (PUCs, utilities, ISOs/RTOs)
4. Ensure that all markets (e.g., energy, ancillary services, capacity) and market-makers (e.g., utilities) include both demand- and supply-side options. All options — central and distributed generation, transmission, efficiency, and demand-response — should compete with one another to provide electricity services. (ISOs/RTOs, PUCs, utilities)
5. Employ electricity markets to align incentives with the desired outcomes, such as rewarding greater operational flexibility. Open long-term markets for new services such as fast-start or fast-ramping. (ISOs/RTOs, utilities, PUCs)
6. Before investing in technical fixes to the grid, first make operational changes that reduce system costs, enable more renewables, and maintain reliability. For example, coordinate between balancing areas, dispatch on shorter intervals and use dynamic line rating to make the most of existing transmission lines. (ISOs/RTOs, utilities, PUCs)

7. Mitigate investor risk by adopting stable, long-term policies and regulations. Financial policies should be predictable, scalable, affordable to public budgets, and efficient for investors. (Congress, state legislatures, PUCs)

8. Reduce siting conflicts by using explicit, pre-set criteria; ensuring access to the grid; respecting landowner rights; engaging stakeholders early; coordinating among regulatory bodies; and providing contract clarity. (Federal land managers, state legislatures, PUCs)

CONCLUSION

The U.S. power system is at an inflection point. New technologies offer great promise to increase reliability, reduce fuel costs, minimize capital investment and reduce environmental damage. Capturing these benefits requires a new approach to utility regulation and business models — no matter if the power system is driven by a vertically integrated monopoly, by a competitive market or by a hybrid of the two.

Legislators and governors, state public utilities commissions (PUCs), the Federal Energy Regulatory Commission (FERC), ISOs, utilities, investors and other decision-makers will need to move deliberately and thoughtfully to create new standards, markets and business models. If they delay, consumers will incur steep, long-term costs, as the investments flowing from today's structure are unlikely to meet tomorrow's needs — and much less take advantage of tomorrow's opportunities. And getting this right the first time is an imperative; it is much more expensive — if not impossible — to go back later and change the course of evolution in the asset-intensive power sector.

This paper argues for clear goals, backed by business decisions and regulations designed to maximize innovation and performance while minimizing costs. We recognize that translating these goals into specific business models and regulations is a big job, and this work will have to be customized for each organization and each region of the country. We are heartened by

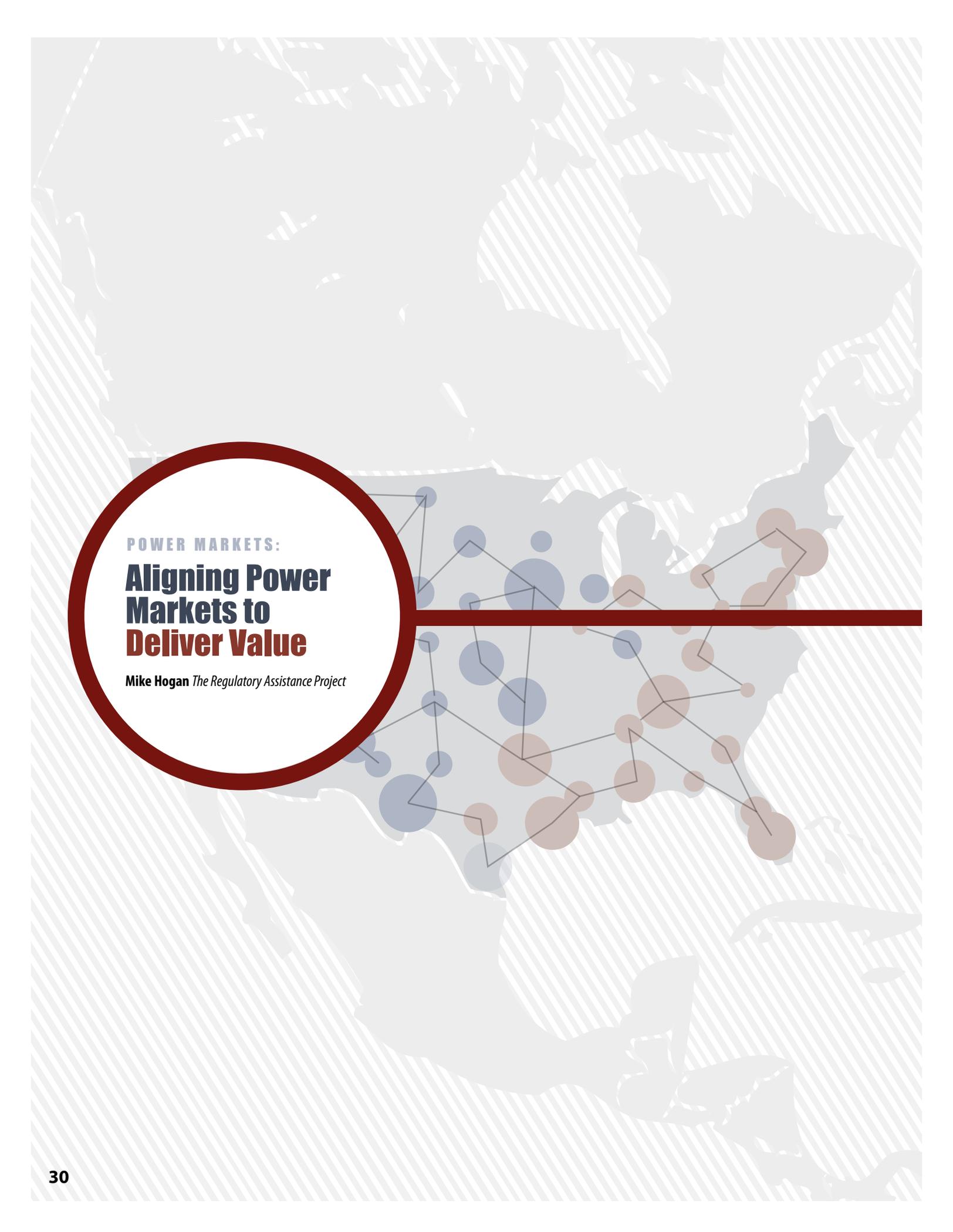
conversations with experts from all realms — PUC commissioners and staff, investors, academic experts, system operators, utility executives and NGOs — who see this challenge and are working hard on new systems.

Our strongest recommendation, then, is for policymakers — governors, legislators, and public utilities commissioners — to face this challenge directly, openly and forthwith. PUCs can open proceedings on how to build the electric system of the 21st century. Ensure that these conversations include experts in new technology, in systems optimization, and on the demand side as well as the supply side. Challenge participants to find solutions that meet all three public goals: minimize costs, increase reliability and reduce environmental damage. Insist that they demonstrate how new proposals bring in innovation. Stress-test recommendations for flaws. Launch and accelerate pilot programs, test markets and more. We can succeed. Now is the time to get going.

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- 11 Based on Edison Electric Institute data for transmission lines above 230 kilovolts. See: <<http://www.eei.org/ourissues/ElectricityTransmission/Pages/default.aspx>>.
- 12 Based on state-by-state data from the U.S. Energy Information Administration.
- 13 Independent distribution system operators are rare in the U.S., but are much more common in Europe.
- 14 Cost-effective storage technologies could fundamentally change the nature of this role, but this paper does not assume their near-term and large-scale deployment.
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POWER MARKETS:

Aligning Power Markets to Deliver Value

Mike Hogan *The Regulatory Assistance Project*

REVIEWERS

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EXECUTIVE SUMMARY

Wholesale markets come in many shapes and sizes but all can be adapted to enable an affordable, reliable transition to a power system with a large share of renewable energy. The paper describes a range of market design measures available to policymakers. It starts by describing how markets can better value energy efficiency and goes on to address those opportunities where market design can more effectively serve consumers' needs as the energy resource portfolio continues to evolve. The overarching goal of these recommendations is to make markets more efficient at valuing the role that resource- and system-flexibility can play to minimize the cost of delivering reliability at all timescales.

Energy efficiency plays a crucial role in reducing the cost of the transition. While cost-effective efficiency faces well-documented market barriers, markets could better capture the value of efficiency as a resource. The ideas presented here can facilitate the value of efficiency in meeting resource adequacy and reducing the need for transmission investment.

Renewable supply has low marginal costs and many renewables have limited dispatchability. It is often said that this will challenge the traditional structure and operation of wholesale energy markets as the share of these resources grows. Fortunately regulators and market operators have a wide range of cost-effective options to smooth the transition. Making markets larger and faster can greatly mitigate the challenge of integrating variable

supply – by consolidating balancing areas, improving the quality of information available to participants about weather and its impacts, and decreasing the intervals between resource commitment and dispatch decisions. Some markets have already demonstrated net benefits from the added *system flexibility* these measures provide. Markets can also become more efficient in recognizing the value of *resource flexibility* and expanding the opportunities for customer loads to respond to market conditions. Measures include sharpening the pricing of operating reserves to more efficiently reflect short-term mismatches between supply and demand, allowing responsive loads to participate in energy and ancillary services markets, and developing new services as warranted to meet the needs of the system.

Resource flexibility is to a great extent determined at the point of initial investment. This ultimately means investing in more flexible resources and shrinking investment in less flexible resources. As the share of renewables grows, the need for adequate resources and the need for a flexible resource portfolio are two sides of the same investment coin. Market administrators should begin by developing tools to gauge the extent to which these issues will emerge within coming investment cycles, including better forecasts of net demand and changes in the demand for critical system services. Where forward markets are adopted to address expected investment needs, mechanisms should include

comparable demand-side resources and incorporate consideration of not just the quantity but also the relevant capabilities of resource investments. New market-based mechanisms should be developed to gauge the value of investment in various forms of energy storage, including end-use energy storage. Finally, The combination of the scale of needed investment and the scope for innovation in areas like demand response makes it more important than ever to encourage new market entry, for instance by third-party load aggregators.

Markets can be harnessed to save consumers and businesses money as the system modernizes. Good market design can help deliver the system and resource attributes that are needed on both operational and planning horizons, at the lowest cost.

INTRODUCTION

The *Renewable Electricity Future Study (RE Futures)* finds that it is feasible to produce 80 percent of America's power from renewables in 2050. This paper begins by summarizing those aspects of the study's findings that have implications for the structure and regulation of wholesale power markets. The paper then lays out an array of measures market authorities can take to enable markets and market institutions to deliver gains in energy efficiency, higher shares of renewable electricity and the system services required to support a modern electricity mix, all while continuing to deliver reliable and affordable electric service.¹ United States power market environments vary considerably, from local, vertically integrated, regulated or publicly owned monopoly utilities to integrated competitive markets stretching across vast regions of the country. Each model has advantages and disadvantages and each can be adapted in a number of ways to readily accommodate a growing share of renewable energy production. Many of the recommendations presented here are already being implemented in competitive market areas, facilitated by the transparency, flexibility and open access that are vital components of well-functioning markets. Some vertically integrated market areas (e.g., Colorado) have illustrated how many of these recommendations can be adapted to fit the unique circumstances presented by more traditionally structured markets.² The paper speaks to both types of market environments.

Many of the ideas in this paper build on experience in today's wholesale markets and others are being piloted in market environments across the U.S. Taken together, the recommendations represent a choice available to policymakers: between a wholesale market structure that is inherently in conflict with a high share of renewables and one that can usher in a high-renewables future.

GETTING MARKET STRUCTURE RIGHT: KEY TO A RENEWABLE ENERGY FUTURE

The National Renewable Energy Laboratory's (NREL) RE Futures Study found that an 80 percent renewable electricity system could meet load in every hour in 2050 across each of 134 grid-balancing areas across the U.S. In NREL's 80 percent scenario, nearly half of overall electricity production would come from variable renewable sources such as solar and wind power. This section highlights those aspects of the findings that are most directly influenced by the design and functioning of wholesale markets. The transition to a much more renewable — and variable — supply portfolio represents a paradigm shift for the sector, one that calls for a transformation of the architecture and operation of the power system and adaptations to wholesale markets. This future can be realized via a combination of administrative mechanisms (e.g., standards and regulations) and market mechanisms. Administrative measures will be essential to setting the U.S. grid on the pathways described in RE Futures. In both competitive and regulated monopoly market areas, however, markets can be aligned with the demands of a more variable supply portfolio to accelerate the transition and minimize the costs. *RE Futures* describes a number of critical success factors that can be facilitated by changes to markets and market institutions.

Increase efficiency

The most cost-effective *RE Futures* scenarios are premised on significant improvements in the efficient use of energy.³ There are at least two key reasons why efficiency plays such an important role: (i) much of the potential for efficiency gains is available at lower cost than supply-side measures, and (ii) a higher level of projected consumption would mean that a higher percentage of renewable supply would come from variable sources because of limits to the sustainable resource base for more dispatchable options such as biomass. Policies and programs will be the primary driver⁴ – markets, and in particular wholesale markets, can play only a limited role in driving the scale of investment in cost-effective efficiency assumed in *RE Futures* – but we will look briefly at how wholesale market practices can help.

Reduce market area fragmentation

While *RE Futures* emphasizes that there are multiple pathways to a high renewable energy future, it clearly demonstrates the benefits of balancing supply and demand over wider regions. Consistent with similar studies, it finds that the benefits of integrating markets over broader areas easily outweigh the costs. The benefits of operating markets over larger geographic footprints include:⁵

- Better access to higher quality — but more distant — sources of renewable energy.
- Less aggregate variability in both supply and demand.
- Lower integration costs due to better use of transmission and sharing of reserves.
- Risk mitigation from both resource and market diversification.

Transmission modernization and expansion can help realize these benefits. Transmission and distribution are each addressed specifically in other papers in this series.⁶

Improve operational flexibility

Because the high renewables future relies on such a large share of variable supply it significantly increases the value of certain modes of system flexibility. System flexibility can reduce the need for backup capacity and transmission expansion and reduce the need to curtail renewable production during periods of low demand and high renewable supply. These attributes of a flexible system can produce substantial benefits for the system as a whole in the form of net cost reductions and improved reliability. We will look at a number of changes system operators can make to market rules and operational practices to increase system flexibility at operational timescales.

Invest in greater resource flexibility

One of the crucial aspects of *RE Futures* was its in-depth analysis of the feasibility of meeting load in every hour in high-renewables futures. The findings illustrate the value of addressing not only traditional resource *adequacy* as an investment challenge, but also the emerging need to address resource flexibility as an investment challenge. Ensuring that resource flexibility is properly valued at the point of investment will reduce the overall amount of investment needed to ensure reliability in a system with a large share of renewable production. The value of, and therefore the investment case for, a conventional generator will increasingly rely as much (if not more so) on its ability to provide balancing services as on its ability to provide energy or even capacity.⁷ We will examine a number of market measures that can drive investment in a sufficiently flexible resource portfolio at least cost.

Make way for continued deployment of renewables

The greatest leverage for success comes from sustained improvement in the cost and performance of a portfolio of commercially available renewable technologies.

This can only come from a steady pace of commercial deployment. Where markets are already fully supplied, and in particular where investments in efficiency keep demand growth to a minimum, many existing thermal generators will come under increasing financial pressure as more renewable generation enters the system. The market challenge is to ensure that it is indeed the least valuable generators that are the ones to retire. As noted above, resource flexibility will become more valuable as the share of renewable production grows. Markets can do their part by ensuring that more flexible plants are fully compensated for their value to the system while properly discounting the value of less flexible plants. In other words, measures for shaping *investment* will be equally valuable in shaping *disinvestment* during this transitional period.⁸

RECOMMENDATIONS FOR MARKET DESIGN ADAPTATIONS

The preceding section identified those dimensions of the *RE Futures* findings that intersect in significant ways with key aspects of wholesale market structure and operations. This section will examine a wide range of cost-effective measures available to market authorities to ensure that wholesale power markets – competitive as well as regulated markets – can continue to deliver reliable, affordable power as the share of renewable production on the system grows. These adaptive measures are organized into three categories:

- Recognize the value of energy efficiency.
- Upgrade grid operations to unlock flexibility in the short-term.
- Upgrade investment incentives to unlock flexibility in the long-term.

Recognize the value of energy efficiency

A well-designed electricity market should drive cost-effective energy efficiency measures. While experience shows that markets alone cannot be relied upon in practice, there are several ways to improve the effectiveness of wholesale markets in driving cost-effective energy efficiency investments. Wholesale markets can drive efficient outcomes by properly rewarding more efficient production and system operations and by factoring transmission losses into delivered prices through, for example, locational marginal pricing.⁹ Beyond these opportunities, however, there are several ways that regulators and market operators

can improve the role of wholesale markets in promoting efficiency:

- Allow energy efficiency to participate in capacity markets.
- Set standard capacity values for a menu of standard efficiency measures.
- Consider location-specific efficiency measures as an alternative to transmission.

In competitive wholesale markets the value of capacity resources is (or should be) embedded in the wholesale clearing price of electricity. In some competitive markets however, certain regions have introduced separate capacity markets to address concerns about whether and to what extent this occurs in practice. In these markets, investments in efficiency measures can represent a comparable alternative to firm production capacity.¹⁰ Market operators should therefore **enable efficiency to participate in markets for capacity** on a comparable basis with firm supply. Whenever a new capacity mechanism is adopted market operators should establish procedures to qualify efficiency measures — they have proven capable of being at least as reliable as supply-side alternatives and are often much cheaper. For example, ISO-New England enables energy efficiency providers to bid into forward capacity markets alongside generation resources. As a result, efficiency constitutes ten percent of all new resources cleared in ISO-New England's forward capacity market since it was first opened in 2008.¹¹

Efficiency as a capacity resource is obviously different from supply resources in important respects, and the challenge of establishing comparability is a barrier to its participation in many market areas. One way to lower the barrier is to seek stakeholder agreement across multiple market areas on **standardized measurement and verification procedures and a schedule of deemed firm capacity values for a menu of common efficiency measures**.¹² This would simplify the process for qualifying efficiency as a resource and would provide more transparency and consistency for investors, particularly third-party aggregators working across market boundaries. If introduced gradually with an iterative review process, the savings in administrative burden and the increase in cost-effective efficiency investments should more than compensate for any residual deviations from standard values.

Energy efficiency investments in specific locations can also compete as an **alternative to transmission**. In both vertically integrated and competitive wholesale markets transmission investment remains largely a regulated monopoly cost-of-service business, and long-term system planning continues to be a critical part of market governance and a driver of market outcomes even in competitive market areas. The particulars of encouraging competition in the transmission sector are covered in another paper in this series,¹³ but it is important to consider transmission as *just one option* to ensure system reliability. Regulators and market operators should therefore ensure that system planning processes actively consider strategic energy efficiency measures as a possible alternative to transmission at the early planning stage.¹⁴ While Federal Energy Regulatory Commission

(FERC) Order 1000 requires that non-wires alternatives — such as efficiency — be considered, no existing entities are obligated to explore or propose them. Furthermore, traditional cost-allocation arrangements have artificially disadvantaged energy efficiency. For balancing areas that span multiple jurisdictions, transmission costs are often allocated across the whole region while efficiency costs are allocated to just one state or locality. This methodology for allocating costs may mean the market chooses a more expensive transmission option over a cheaper efficiency option. Closing these gaps will increase the likelihood that viable strategically targeted efficiency alternatives are actively explored and will increase the likelihood the market selects the most cost effective option.¹⁵

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs, FERC	Create rules, metrics, and standards for allowing efficiency to compete in capacity markets.
FERC, ISOs/RTOs, PUCs	Ensure consistent cost allocation and cost recovery methodologies for comparable demand-side and transmission investments.
FERC, PUCs, siting authorities	Strengthen the obligation to explore non-transmission solutions—such as energy efficiency—that may be more cost effective.

Update grid operations to unlock flexibility in the short term¹⁶

The shift to a high renewables future will have profound consequences for the rest of system resources.

Renewable resources will have near-zero marginal costs, and much of the renewable supply will have limited dispatchability. Thankfully, regulators and market operators have a wide range of cost-effective options to smooth the transition:

- Upgrade scheduling, dispatch and weather forecasting.
- Consolidate balancing areas.
- Promote more dispatchability of variable renewable production.
- Co-optimize energy and reserves to improve the effectiveness of scarcity pricing.
- Expand the role of demand response.
- Open day-ahead markets for existing ancillary services and begin to qualify new ancillary services.¹⁷

Grid operations should be modernized by **upgrading scheduling, dispatch, and weather forecasting**. These measures will allow the grid to respond more efficiently to the operational characteristics of variable renewables. Several recent studies have shown the benefits of scheduling over shorter intervals and improving the use of weather forecasting in grid operations.¹⁸ As the U.S. moves toward the type of resource mix described in *RE Futures*, weather will increasingly influence the power supply, specifically the availability of wind and solar

power. Using high-quality weather forecasting to update commitment, dispatch and transmission schedules more often (e.g., every 2-6 hours) can dramatically reduce the need for operating reserves.

Historical utility practice is to schedule the system at one-hour intervals and many power systems continue to do so. Sub-hourly dispatch and transmission scheduling refers to when market operators clear the markets at intervals of less than an hour — in some markets as often as every five minutes. This kind of scheduling upgrade can reduce costs of day-to-day system operations in markets with high shares of variable production.¹⁹ For example, GE found that sub-hourly dispatch could halve the system’s reliance on fast-ramping natural gas.²⁰ Moving to sub-hourly scheduling – ideally every 15 minutes or less – has consistently been shown to produce net system benefits in lower overall cost and improved reliability particularly in systems with a high share of variable production.²¹ Most of the remaining opportunities to adopt this practice are in regulated monopoly market areas.

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs, utilities	Integrate high-quality weather forecasting into supply and demand forecasts every [2-6] hours, and adjust commitment and dispatch schedules accordingly.
ISOs/RTOs, utilities, PUCs	Transition to sub-hourly dispatch and transmission scheduling. Where needed, specify automatic generation control in new power purchase agreements.

Several recent studies have identified the benefits of balancing supply and demand over a broader geographic region, also known as **consolidating balancing areas**. Benefits include: better use of existing transmission infrastructure, less supply variability, less demand volatility, real-time access to more operating and contingency reserves, less need for backup generation capacity, more use of renewables, and more liquidity and less price volatility in the market due to more competition.²² These benefits increase in value as more of the supply mix becomes variable. Most competitive markets are already in the process of consolidating

control areas under one balancing authority or have done so, though some disconnects remain between ISO regions. In regions where actual consolidation of control areas is not anticipated, there are a number of alternatives available that may offer some of the benefits of actual consolidation: an organized exchange for grid services *between* balancing authorities (an “energy imbalance market”)²³ and dynamic transfers between balancing authorities.²⁴ Dynamic line rating for transmission lines between balancing areas²⁵ can also increase transparency and reduce congestion.

DECISION-MAKER	RECOMMENDATION
FERC, NERC	Update the criteria for approving the creation of new balancing authorities, especially cases of balancing authority consolidation or expansion. ²⁶
ISOs/RTOs, utilities, PUCs, FERC	Open an exchange for grid services across multiple balancing authorities (an “energy imbalance market”).
PUCs, NERC, utilities	Enable dynamic transfers between balancing authorities.
FERC, NERC	Approve dynamic line rating for transmission line owners.
PUCs, state legislatures	Approve consolidation of balance areas.

Promoting more dispatchability in variable renewables has proven beneficial in several systems where variable renewables are a significant share of production. In Xcel Energy’s service territories in Colorado and Minnesota, for instance, 60 percent of wind generation has the option of providing regulating reserves and has, in some instances, provided all of the

frequency regulation required by the system. Exposing the demand for various grid services to competitive procurement from all qualified sources will allow renewable generators to gauge the value of investing in and offering these services, avoiding the tendency to invest in more back-up capacity than would actually be required.

DECISION-MAKER	RECOMMENDATION
PUCs, ISOs/RTOs, FERC	Expose the value of automatic generation control services; make sure market rules enable renewables to provide them.

Improving the effectiveness of scarcity pricing can have a number of beneficial impacts on security of supply, market power mitigation and activation of incremental levels of price-responsive demand. Its immediate benefit here is to more effectively value resource flexibility. The primary measures to accomplish this are more granular locational pricing of supply and

the co-optimization of energy and operating reserves. The objective is to fully reflect the reliability cost in real time of using reserves to provide energy during periods of tight supply. As variable supply increases this will direct more revenue to those resources able to swing easily between providing energy and acting as reserves and less revenue to less flexible resources.

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs, FERC	Adopt operating reserve demand curves.
ISOs/RTOs, FERC	Co-optimize reserves with energy in real-time markets.
ISOs/RTOs, FERC	Allow demand response to participate in price formation.

Expanding the role of demand response is another important way to move to the kind of flexible system described in *RE Futures*. For a century the power system has been structured around the assumption that supply had to follow uncontrollable demand in every instant. The incremental cost of allowing demand free rein was

largely hidden in flat rates and uneven cost allocation across customer classes. These historical practices have presented a challenge for wholesale markets since such markets were first conceived, and as supply becomes less controllable there is greater urgency to revisit them.

Fortunately, as the value of controlling electricity consumption rises, the cost to do so is dropping as the range of options expands. Today demand response refers to far more than just emergency demand reductions. It also means using more electricity when there is a surplus (e.g. storing useful energy by heating water or charging electric vehicles) and using less when there is scarcity (e.g. drawing down energy stored earlier for transport or heating). These responses can be dispatched remotely with no noticeable inconvenience to the consumer, which means their availability to system operators is effectively unlimited. This development has important implications for modern grid management and cost minimization.

As with generation resources, some up-front investment is required to access the demand response potential, and new interventions may be required to overcome market barriers.²⁷ Some wholesale market operators (e.g., PJM) have already begun to tap the potential of demand response, including the kinds of response options described above.²⁸

Demand response can participate in wholesale markets in three ways: as capacity, as energy, and as an ancillary service. First, in markets where forward capacity mechanisms have been deployed, demand response that meets the necessary qualifications should be allowed to compete on an equal footing with supply, as discussed above for efficiency. Several markets have seen tremendous benefits from doing so. For instance, PJM meets approximately 10 percent of its total resource adequacy needs from demand response at significantly less than the cost for comparable new supply resources.²⁹

Second, market operators can allow demand response to bid into day-ahead and intra-day energy markets in the same way that generators bid into those markets. This allows demand to participate in setting the true market value of electricity in daily scheduling intervals, most likely via third-party aggregators or retail providers.

The third way that demand response can participate is via markets for ancillary services, such as regulation and spinning reserves. Market operators should enable demand response to participate as a balancing service on an equal footing with supply-side resources. Some wholesale market operators have already experienced success with this. For example, PJM has successfully enabled demand response to bid into its ancillary service markets to provide regulation services,³⁰ while ERCOT gets half of its spinning reserves from demand response.³¹ The Western Electricity Coordinating Council (WECC), on the other hand, prohibits the provision of spinning reserves by demand response resources.

Where demand response has been successful, third-party aggregators have played a crucial role in innovating new services, attracting new investment, and delivering value to consumers. Some market areas, particularly many regulated monopoly market areas, continue to prohibit or discourage participation by third-party aggregators. As variable renewable production increases, this restricted access (which very likely already has a measurable cost to consumers) will lead to artificially inflated costs of integration. All market areas can and should encourage active participation by third-party aggregators.

Realizing the potential of demand response in each of these roles will require setting standards for determining its cost-effectiveness in relevant timeframes.

DECISION-MAKER	RECOMMENDATION
PUCs, ISOs/RTOs, FERC, NERC	Allow demand response to participate in capacity, energy, and ancillary service markets on equal footing with supply-side resources.
PUCs	Allow third-party aggregators full access to markets.
PUCs, FERC, ISOs/RTOs	Remove tariff barriers to cost-effective demand response (e.g., restrictive demand charges).

All market areas in the U.S. are a mix of central dispatch and bilateral arrangements. Some areas are dominated by bilateral contracts between power producers and utilities, meaning generation is dispatched via contractual obligations rather than via bids submitted to an independent market operator. In these situations, generator owners and their customers choose when to dispatch supply, but grid operators are ultimately responsible for maintaining the balance between supply and demand. In principle there is no reason this arrangement cannot work well, yet there is evidence that current market structures can fail to provide adequate incentives for resources to supply the ancillary services required to keep the grid in balance.³² This market failure — combined with the fact that some market operators rely on cost-based procurement rather than

open markets for certain ancillary services — has driven a decline in the availability of some important services over the past twenty years in the U.S. As renewables become a larger share of the mix, the failure to value these important services properly may lead to an artificial lack of flexibility. Regulators can address this issue in the near-term by **adding day-ahead markets** for ancillary services to value the needed flexibility. For example, the Electricity Reliability Council of Texas (ERCOT) runs a day-ahead market for a range of ancillary services, which has supported the state’s success in wind integration. Regions that already use markets for some services should extend them as needed to encompass additional services. Moreover, **market operators should expand ancillary services markets as appropriate to include new services** such as multi-interval ramping.³³

DECISION-MAKER	RECOMMENDATION
PUCs, ISOs/RTOs	Institute day-ahead markets for ancillary services where they don’t currently exist.
FERC	Expand Order 888 to include additional ancillary services such as load following, frequency response, inertial response, and voltage control.
PUCs, FERC, ISOs/RTOs, NERC	Assess the need for new services that may arise as renewable production grows (e.g., multi-interval ramping service).

Update investment incentives to ensure flexibility in the long run

Competitive wholesale energy markets should be capable of signaling the need for investment in new capacity resources, as well as the value of different levels of operational flexibility available from different types of resources. The question of whether such investment signals are sufficient in practice is the subject of much debate, and in some markets administrative measures such as forward capacity mechanisms have been introduced. This paper does not take a position on whether interventions to value investment in firm resources are necessary or desirable. However, the operational flexibility available from system resources is to a very great extent determined at the point of initial investment. As we transition to a high renewables future, the reality is that the need for adequate resources and the need for a sufficiently flexible resource portfolio are two sides of the same investment coin. Regulators and system operators can address this new reality in a number of ways:

- Develop tools to better forecast net demand and the value of various forms of flexibility.
- In regulated markets, survey existing generators' flexibility and, when it becomes valuable to do so, invest in low cost options to increase the flexibility of existing generation.
- Adapt forward investment mechanisms to capture the value of certain resource capabilities.

- Adopt forward markets for specific system services.
- Create forward markets for a time shifting service.
- Encourage new market entrants wherever possible and consistent with overall market structure.

The first step in ensuring adequate long-term investment in system flexibility is **developing tools to forecast net demand and the value of resource flexibility**. Net demand refers to total customer demand minus total generation from variable, zero-marginal-cost resources.³⁴ Net demand forecasts provide a basis on which to project demand for flexibility services in the future and estimate the price one would be willing to pay for them. Making transparent the value of investments in resource flexibility is essential to establishing a business case for such investment. Several ISOs have recently deployed (or are actively considering) operating reserve demand curves as one way of doing so, and such market mechanisms provide a basis for projecting the value of investment in resource flexibility.

In regulated markets, improved knowledge about expected increases in demand for resource flexibility provides the basis to **survey existing generators' flexibility, determine how to make best use of it and to gauge the value of investing in low-cost options to increase the flexibility of existing generation**. In Colorado, for instance, the state's largest utility has employed these methods that, along with improved forecasting, have helped them cut their wind integration costs by more than half.³⁵

Long-term, or “forward”, capacity markets operate in several parts of the U.S. (e.g., PJM holds annual auctions for capacity three years in advance of the year the capacity is to be delivered)³⁶. These long-term markets are designed to place a future value on firm resources based on the forecasted demand for such resources. Resources that clear in the auction receive a commitment to be paid that value for some period of time (e.g., in PJM the commitment is for one year of payments, while in ISO New England the commitment can be for up to five years). System operators can **adapt capacity mechanisms to capture the value of system service capabilities**. There are several ways to accomplish this,³⁷ but the end result should be that more flexible resources are cleared first in whatever quantity is available at or below their projected value to the system. Less flexible resources would then clear only to the extent that additional resources are needed, and they would also clear only at or below a price reflecting their lower value to the system.

As an alternative, or where forward capacity mechanisms are not used, system operators can **adopt forward markets for specific system services**. These markets would project the future demand for specific critical services and enter into forward commitments specifically for those services. There are several examples of forward system service markets.³⁸ In those markets with both capacity mechanisms and ancillary service markets, however, providers of ancillary services do not yet receive commitments as far forward as do providers of capacity. It will be increasingly important to ensure that investment signals for resource flexibility are at least as compelling as investment signals for the resources themselves. Mechanisms such as operating reserve demand curves gauge the supply of cost-effective flexibility services and, when necessary, the information needed to procure those services forward.

Large-scale energy storage is often cited as a critical requirement for systems with high shares of renewables, but it is more useful to think in terms of the system service that storage technologies provide. *RE Futures* results indicate that demand response will deliver sufficient flexibility through the earlier stages of renewables penetration, while the value of shifting the production of electricity from one time period to another (referred to here as “time shifting”) will grow as the share of renewables on the system reaches very high levels.³⁹ Some large-scale energy storage technologies that have historically been uneconomic may well become profitable, while other approaches to time shifting may prove to be more competitive. The challenge will come in making the emerging value of investments in providers of time shifting services more transparent to potential investors, something that was difficult even when the value of such a service was relatively stable. **Creating forward markets for a time shifting service can help make this happen, not only because they can reveal the value of the service** but also because the range of technology options is expanding to include not only traditional grid-scale storage technologies (primarily pumped storage hydro) and new grid-scale storage technologies like compressed air, but also numerous distributed options such as dispatchable demand response, end-use thermal energy storage and electric vehicle batteries. Some of these options will become economic long before others, and as time shifting services become more valuable the use of market mechanisms can help select the most economic options for providing them, or determine that no cost-effective options are available.⁴⁰

One way to create a time shifting service would be to mimic the success of instruments known as financial transmission rights. These are options traded actively in many wholesale markets that allow widely separated buyers and sellers engaging in energy transactions to hedge forward the risk of congestion arising from time to time on the intervening transmission facilities. Using this as a model, system operators could initiate a market in “financial time-shift rights” by which a seller could hedge the risk of producing in one time interval and selling

at a set price to a customer in a different time interval. In the same way that financial transmission rights markets reveal the value of incremental investment in transmission in a given area, a financial time-shift rights market could reveal the value of incremental investments in time shifting capabilities. The initial demand may be low and the market may clear with only existing options, such as the ability to postpone demand for a given energy service. As the share of variable resources grows, however, the demand for time shifting will grow as well.

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs, PUCs	Develop tools for forecasting net demand and establishing the value of critical services.
FERC, ISOs/RTOs, PUCs, utilities	Adapt capacity markets to capture the value of resource flexibility, or adopt forward markets in specific system services, or both; pilot market mechanisms that would help provide the business case, if any, for investment in either grid-scale or distributed sources of time shifting services.

The scale and capital intensity of the transition envisioned by *RE Futures* presents an enormous opportunity for investors. The investment required to transform the electricity system exceeds the balance sheet capacity of incumbent generators.⁴¹ Given the limited set of alternatives the most promising option is to open the door wide to new entrants. **Encouraging new entrants wherever possible** becomes a critical factor in expanding the pool of available capital and reducing costs. In regulated monopoly market areas the scope for this is obviously more limited, however there are opportunities compatible with the existing governance structure. Actual or virtual consolidation of control areas

can increase liquidity by widening the pool of available buyers and sellers, a critical step in attracting new entrants. Another valuable step is to fully enable third-party aggregators of demand-side resources to bring capital and innovation to the market.⁴² Particularly in competitive market areas, however, there is no substitute for aggressive regulatory oversight and enforcement of the competitive landscape. Concentration of market power in itself is a major barrier to new entry, and concern about abuse of market power in some markets has driven regulators to impose price caps and other measures that create additional barriers to new entry.⁴³

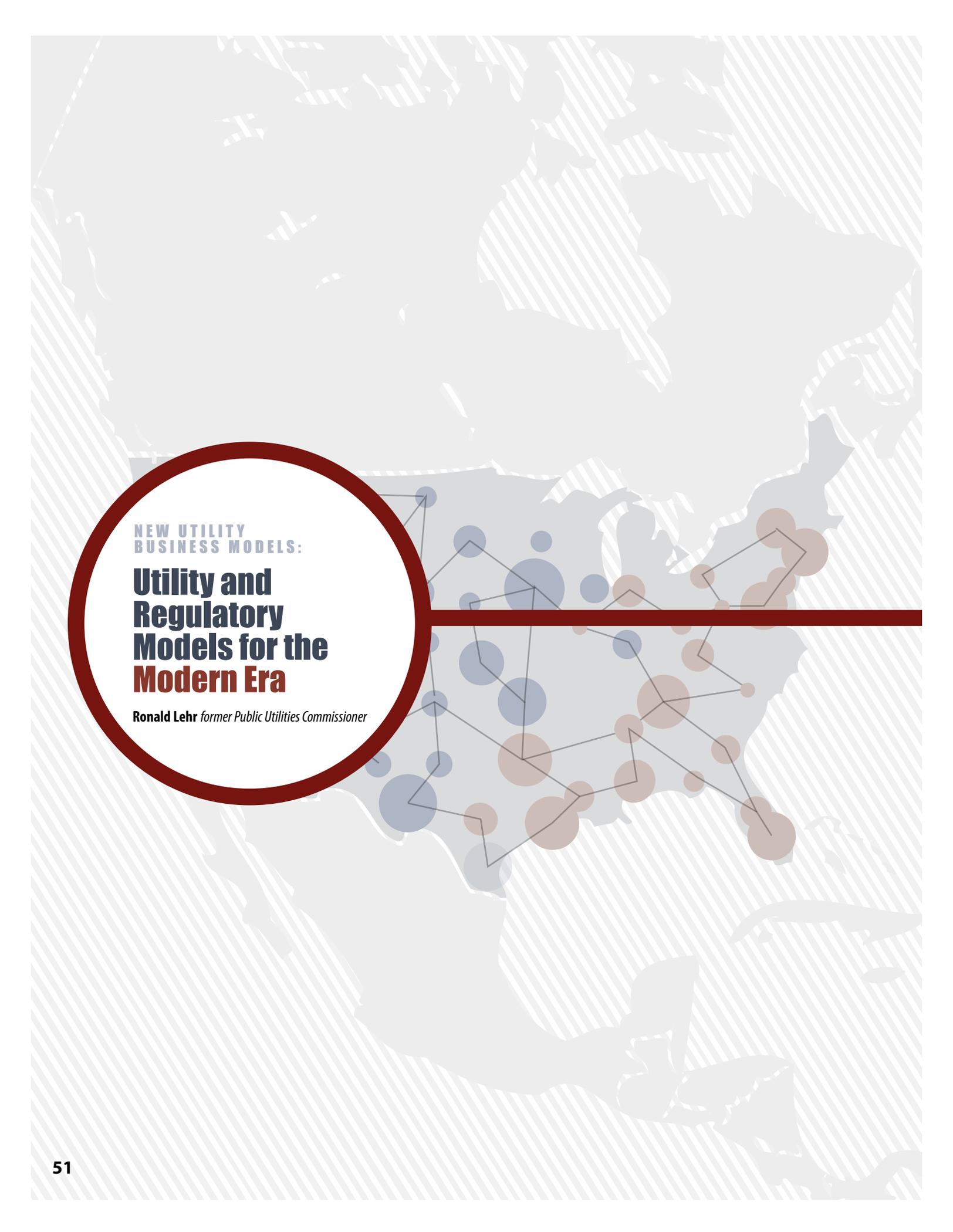
DECISION-MAKER	RECOMMENDATION
PUCs, state legislatures	Enable third party aggregators to bid into all markets.
FERC, PUCs	Closely monitor and aggressively enforce competition in the market.

CONCLUSION

Wholesale power markets can be a powerful force in achieving the transition envisioned by *RE Futures*. Regulators and market operators have a wide range of options available to them to make this happen, both in competitive market areas as well as in regulated monopoly market areas. In most cases policymakers can look to experience with similar measures elsewhere, and in other cases markets can experiment at small scale with innovative approaches. Taken together, these measures will align the operation of wholesale power markets with the goal of a reliable, affordable, renewable energy future.

ENDNOTES

- 1 Many of these points can also be found in Volume 4 of *RE Futures*.
- 2 For a more detailed treatment, see Schwartz et al, 2012. States preferring to retain direct control over their electricity markets assume a number of obligations in doing so. Seizing opportunities such as those identified here and in the WGA report is one of those obligations, and forums such as the Western Interstate Energy Board and the Southern States Energy Board provide existing platforms through which these measures can be implemented.
- 3 *RE Futures* also analyzed a high demand scenario, finding that 80 percent renewables could still meet load in every hour.
- 4 An extensive body of literature focuses on the market barriers and failures affecting the actual rate of investment in cost-effective efficiency measures and the range of administrative programs available to address them. See Prindle et al, 2006, and Joshi, 2012.
- 5 Mills and Wiser, 2010.
- 6 See two of America's Power Plan reports: one by Jimison and White and another by Wiedman and Beach.
- 7 As *RE Futures* states on page xxxviii, "...a high renewable future would reduce the energy-providing role of the conventional fleet and increase its reserve-providing role."
- 8 Particularly in regulated monopoly market areas it will be important to address legitimate claims for compensation where stranded investments were made in good faith in reliance upon prior explicit assurances. Also see America's Power Plan report by Foley, Varadarajan and Caperton.
- 9 Locational marginal pricing refers to factoring transmission congestion in to resource values, based on whether they are providing a service on a specific part of the system that would have otherwise been over- or under-supplied.
- 10 See, for example, page vi of Pfeifenberger et al, 2011.
- 11 Experience with energy efficiency participation in wholesale capacity mechanisms can provide lessons for market design criteria. Specifics about qualifying criteria and procedures for measurement, reporting, and verification are beyond the scope of this paper, but see PJM Capacity Market Operations (2013) for many of these details, and Pfeifenberger et al, 2011, for an assessment of the results.
- 12 See Todd et al, 2012; Schiller et al, 2011; Jayaweera and Haeri, 2013.
- 13 See America's Power Plan report by Jimison and White.
- 14 Cowart, 2012.
- 15 Watson and Colburn, 2013.
- 16 For an extended analysis of the potential benefits available by adopting these and other measures, see GE Energy, 2010.
- 17 "Ancillary services" refers to services the grid operator uses to manage through the intervals in daily schedules for supply and demand or to restore the supply/demand balance when the unexpected happens.
- 18 See Lew et al, 2011, GE Energy, 2010.
- 19 See North American Electric Reliability Corporation, 2011.
- 20 GE Energy, 2010.
- 21 A notable exception at this writing is Spain, where stakeholders in a system with high penetration of variable renewables have concluded that a move to sub-hourly balancing is not yet warranted. It will be useful to better understand what is different about circumstances in the Spanish system.
- 22 See North American Electric Reliability Corporation, 2011, Milligan et al, 2010.
- 23 PacifiCorp and the California Independent System Operator, 2013.
- 24 "Dynamic transfers" refer to virtual transfers of control for specific resources over certain times.
- 25 See America's Power Plan report by Jimison and White for an explanation of dynamic line rating.
- 26 Boucher et al, 2013
- 27 Cappers et al, 2013.
- 28 PJM, 2011.
- 29 PJM, 2012.
- 30 PJM, 2013.
- 31 See North American Electric Reliability Corporation, 2011, pg 50 and 61; also Milligan and Kirby, 2010.
- 32 Martinez et al, 2010.
- 33 Ela et al, 2012.
- 34 Other less controllable sources, such as many industrial cogeneration facilities, are also netted out.
- 35 See Xcel Energy, 2012, for the thirty-minute reserve guidelines and Xcel Energy and EnerNex Corporation, 2011, for the integration costs.
- 36 PJM Capacity Market Operations, 2013.
- 37 One approach — "apportioned forward capacity mechanisms," wherein the capacity market is divided into tranches to meet required grid capabilities in the future — is described in Hogan and Gottstein, 2012. Another approach is to assign points to resources offered based on identified operating capabilities with the price to be paid determined by the score received. ISO New England has proposed adapting their existing forward capacity market so that it will elicit an investment response when the potential combined supply of energy and operating reserves cannot meet demand. See Coutu, 2012.
- 38 For example, ISO New England purchases operating reserves one year forward; National Grid in the U.K. has conducted annual auctions for short-term operating reserves for as far forward as fifteen years.
- 39 Figure ES-7 in *RE Futures* shows the role of storage per se becoming significant once penetration exceeds 30-40 percent; other studies suggest the threshold for cost-effectiveness of grid-level storage options could be much higher.
- 40 The environmental impact of energy storage technologies varies considerably, and must be properly considered as part of the traditional state review process.
- 41 See, for example, European Climate Foundation, 2011.
- 42 See America's Power Plan report by Foley, Varadarajan and Caperton for more detail on how to reduce financing barriers.
- 43 See two of America's Power Plan reports: one by Harvey and Aggarwal and another by Lehr.



NEW UTILITY
BUSINESS MODELS:

Utility and Regulatory Models for the Modern Era

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EXECUTIVE SUMMARY

Much of the U.S. electric power sector has changed little over the past 100 years. But the industry now faces an unfamiliar and uncertain future. Potent new pressures are building that will force fundamental changes in the way that the electric utilities do business. Consumers are demanding a new relationship with the energy they use, and new technologies are proliferating to meet demand. At the same time, innovative new technologies and suppliers have come on the scene, disrupting relationships between traditional utilities, regulators, and customers.

If the U.S. is to meet necessary climate goals with electric utilities remaining healthy contributors to America's energy future, business models used by these familiar institutions must be allowed and encouraged to evolve. This agenda has implications not only for companies themselves, but also for the legal and regulatory structures in which they operate. A new social compact is needed between utilities and those who regulate them, and this paper suggests ways in which this might evolve.

Several motivations exist to move to an electricity system powered by a high share of renewable energy: changing consumer demand and requirements, improved technology, market and policy trends, a smarter grid, weakened utility financial metrics, aging plants, tougher environmental requirements, climate damages, and "de facto" carbon policy. Utilities will respond to these motivations in different ways, which will result in a range

of new utility business models. The minimum utility role may result in a "wires company," which would maintain the part of the grid that is a physical monopoly – the wires and poles – while competitive providers supply the rest. At the other end of the spectrum lies the maximum utility role, or the "energy services utility," which would own and operate all necessary systems to deliver energy services to consumers. Between these two, a "smart integrator" or "orchestrator" role for utilities would entail them forming partnerships with innovative firms to coordinate and integrate energy services without necessarily delivering all services themselves.

Because utilities respond first and foremost to the incentives created by the legal and regulatory regimes in which they operate, this paper focuses its recommendations on how utilities are regulated. Regulators must determine desired societal outcomes, determine the legal and market structures under which utilities will operate, and then develop and implement correct market and regulatory incentives. Three new regulatory options emerge. The UK's RII model is an example of broad-scale performance-based incentive regulation with revenue cap regulation. It focuses on how to pay for what society wants over a sufficiently long time horizon, rather than focusing on whether society paid the correct amount for what it got in the past. The Iowa model stands for a series of settlements entered into by parties and approved by regulators that led to electricity prices that did not change for 17

years. There, the utility and regulators negotiated shared earnings in a less adversarial process than most. The final regulatory model described in the paper is called the “grand bargain,” which combines elements of the RIIO and Iowa models, where a commission would encourage utilities and stakeholders, including commission staff, to negotiate a comprehensive settlement to a range of desired outcomes.

Among the nation’s 3,000 or so electric utilities across 50 states, there are many variations but a fundamental truth: current business models were developed for a different time. A modern electricity grid will require a new social compact between utilities, regulators and the public.

INTRODUCTION

Much of the United States electric power sector has changed little since the early 20th century. But the industry now faces an unfamiliar and uncertain future. Potent new pressures are building that will force fundamental changes in the way that the electric utilities do business. One of the key changes we will focus on here is the potential for a dramatic increase in the amount of renewable energy included in the resource mix of the future.

If the U.S. is to meet necessary climate goals with electric utilities remaining healthy contributors to America's energy future, the business models used by these familiar institutions must be allowed and encouraged to evolve. This agenda has implications not only for the companies themselves, but also for the legal and regulatory structures in which they operate. A new social compact is needed between utilities and those who regulate them, and we will suggest ways in which this might evolve.

A short list of the new pressures on electric utilities includes burgeoning environmental regulation, aging infrastructure, changing fuel and generation economics, cyber security demands and, importantly, reduced or flat load growth. As a result of these forces, utilities will need to deploy capital at an accelerated rate while simultaneously being deprived of the familiar engine of earnings – customer load growth. There is no precedent for this combination of pressures and challenges.

These pressures will be amplified or modified by a dramatic increase in the use of renewable energy. This paper will examine how utilities can adapt to a high-penetration renewable energy future. Assuming that at least 80 percent of energy supplied to consumers comes from renewable resources has implications for utility investment strategies, capital formation, earnings levels, rate structures and even the fundamental question of the roles that electric utilities will play in the U.S. energy market.

IMPLICATIONS OF HIGH PENETRATION OF RENEWABLE ENERGY ON THE GRID

The Renewable Electricity Futures Study (*RE Futures*), conducted by the National Renewable Energy Laboratory (NREL), investigates the extent to which renewable energy can meet the electricity demands of the contiguous U.S. over the next several decades. NREL examined the implications and challenges of various renewable electricity generation levels, with a focus on 80 percent of all U.S. electricity generation from renewable technologies in 2050.

NREL presents its energy modeling analysis in the form of a “prism” or “wedge” graph that shows the fraction of energy requirements that would be met by each major type of energy resource in a baseline 80 percent renewable generation scenario. This type of presentation was pioneered by the Electric Power Research Institute (EPRI) in a series of projections prepared from 2007 to 2009, called the EPRI Prism Analyses.

Here are the major conclusions of *RE Futures*:

- Renewable electricity generation can be more than adequate to supply 80 percent of total U.S. electricity generation in 2050 while meeting electricity demand on an hourly basis in every region of the country.
- Increased electric system flexibility can come from a portfolio of supply-side and demand-side options, including flexible conventional generation, grid storage, new transmission, price responsive loads and changes in power system operations.
- There are multiple paths using renewables that result in deep reductions in electric sector greenhouse gas emissions and water use.
- The direct incremental cost of transitioning to a high penetration of renewable generation is comparable to costs of other clean energy scenarios.

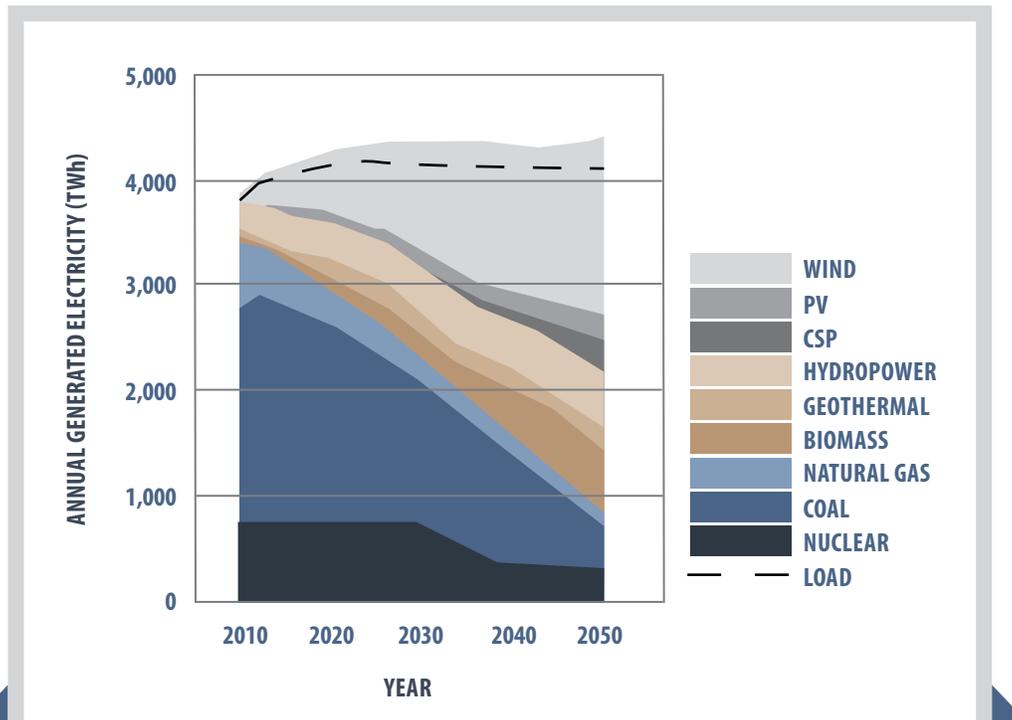


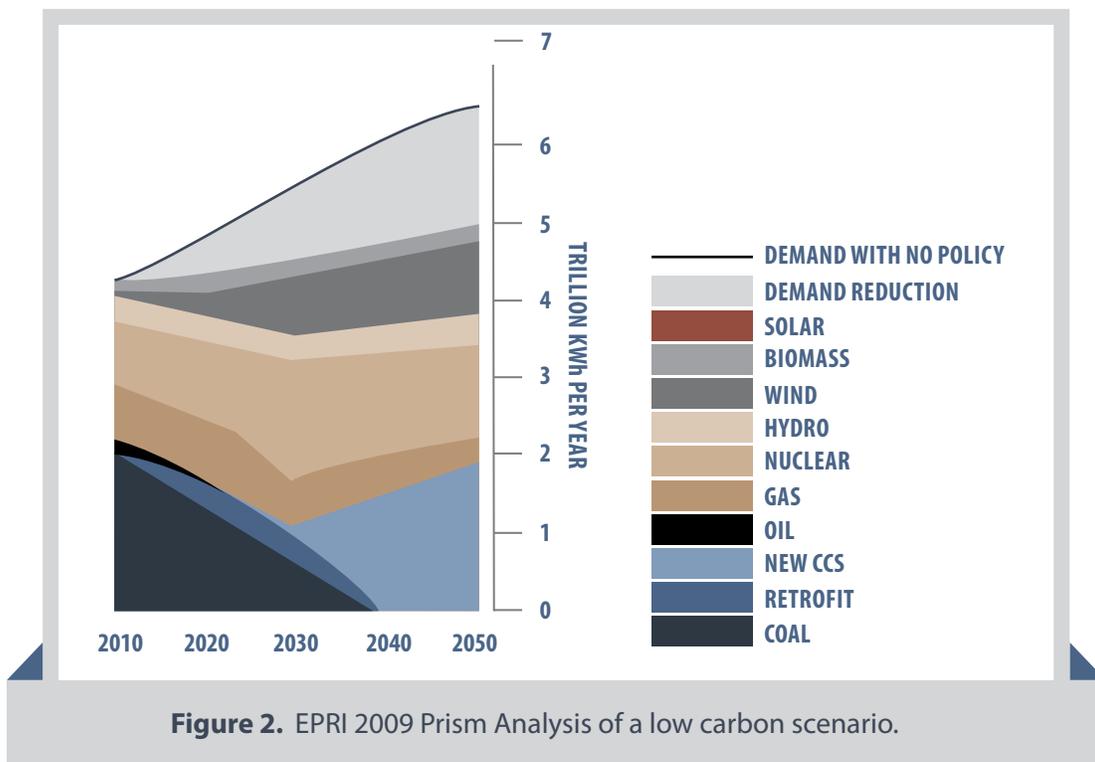
Figure 1. *RE Futures* “Prism” Analysis of baseline scenario

NREL’s baseline scenario in the figure 1 chart shows the energy mix progressing from the actual portfolio in 2010 to a high renewable 2050 scenario. Renewable energy comprises only about 12 percent of the nation’s electric energy in 2010 but makes up 81 percent of the energy mix by 2050. Each contributing resource (wind, photovoltaics, geothermal, biomass, etc.) is shown as a colored wedge in the graph. The fraction of energy supplied by nuclear power and fossil fuels shrinks from a 2010 level of about 88 percent to about 19 percent in 2050.

To understand the significance and context of the *RE Futures* study, consider an earlier “prism” analysis prepared by EPRI in 2009, at about the same time the U.S. Congress was considering climate legislation to limit greenhouse gas emissions from utility generation. EPRI modeled a low-carbon future that relied to a great extent on additional nuclear power and the assumed ability of fossil generators to implement carbon capture and sequestration. Needless to say, both of those assumptions (more nuclear and CCS for coal) have been heavily debated.

Figure 2 shows the results of the EPRI modeling. Two aspects of this chart are important to note:

- Compared to *RE Futures*, the EPRI study assumed greater net energy growth (net of demand reductions) from 2010 to 2050.
- EPRI projected that renewable energy would comprise only about 31 percent of U.S. electricity supply in 2050.



The difference in assumed 2050 total energy use between the two studies is explained by two factors: NREL uses a lower 2010 starting point and assumes a higher level of energy efficiency in its study. The lower starting point is due to the Great Recession of 2008-2010, which actually

lowered U.S. energy use, a fact unavailable to EPRI in 2009. The higher level of assumed energy efficiency is likewise justified by recent increases in the observed level of energy efficiency activities by utilities and their consumers.

The most striking difference between the NREL and EPRI studies is, of course, the mix of energy resources resulting from modeling (which reflect the scenario designs), especially at 2050. Prior to the *RE Futures* study, the common wisdom seemed to be that “intermittent” resources such as wind and solar could not be relied upon to supply a majority of U.S. energy needs, and certainly not 48 percent of those needs as incorporated in the *RE Futures* work. Instead, the EPRI study postulates much less renewable energy and much more “base load” production from nuclear energy and from coal and natural gas with carbon capture and sequestration (CCS). In this context, then, the main contribution of the *RE Futures* study is to demonstrate for the first time the feasibility of supplying the nation’s electricity needs with an 80 percent renewable resource portfolio, at a similar cost as other low-carbon strategies. These renewables would be augmented by an array of flexible conventional resources, grid storage and additional transmission capacity.

By comparing the traditional narrative (exemplified by the EPRI analysis) with the *RE Futures* study, we can identify four major implications of the RE (Renewable Energy) future:

- Much higher levels of variable generation **at the bulk power scale.**
- Greater penetration of distributed energy resources **at the distribution scale.**
- Greater need for flexibility in the grid components, operations, and architecture.
- Higher levels of energy efficiency (sufficient to eliminate load growth).

The *RE Futures* study represents one of the growing pressures on utilities – a change in most of the nation’s generating capacity. Taken seriously, it will affect the types of investments utilities must make, the roles played by utilities in operating the grid, and the way in which utilities make money – in short, the RE future will affect the utility business model.

Utility Market Segments

The variety of utilities and market circumstances in which they serve has resulted in different business models among the roughly 3,000 utilities in the U.S. Investor owned utilities (IOUs) serve the bulk of U.S. electric power and are typically regulated by the federal and state governments. Publicly owned and consumer owned utilities (POUs) serve customers in a wide diversity of circumstances. Nebraska is a wholly public power state while large municipally owned systems serve communities including Los Angeles and Seattle and small city-owned systems are common in some regions. Consumer owned cooperative utilities typically serve electric customers in suburban and rural areas. Boards of directors or municipal officials provide direction and oversight for POUs.

The market structures in which either IOU or POU utilities serve have impacts on what new utility business models might be relevant. In about half of the U.S., markets have been restructured so that traditional utilities have divested their generation assets, and independent power producers compete to provide generation service.

In some states, consumers can choose their power supplier, and utilities provide mainly delivery or “wires” services. In these restructured markets, Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs) dispatch all generation based on competitive bidding and dispatch in order of lowest marginal cost.

Different forms of doing business (shareholders versus owners) and market situations (restructured versus vertically integrated and regulated) shape different utility business models. We see that, in practice, there are five dominant ownership and market structure combinations in the U.S. utility industry:

- 1) Investor-owned Utilities
 - a) Competitive generation markets
 - i) Retail competition (retail choice) ❶
 - ii) No retail competition ❷
 - b) Vertically-integrated and traditional generation arrangements ❸
- 2) Publicly-owned Utilities (Municipal and Cooperative)
 - a) Competitive generation markets ❹
 - b) Vertically-integrated and traditional generation arrangements ❺

Much of our focus in this paper is on vertically integrated and regulated utilities, but most of the analysis applies as well to utilities operating in restructured markets.¹

MOTIVATIONS TO MOVE TO A HIGH SHARE OF RENEWABLE ENERGY GENERATION

Utility industry leaders, consultants, analysts and experts have outlined a number of reasons utilities might be motivated to move in the direction of the high renewables penetration scenarios analyzed in the *RE Futures* study.

Aging plants

Utility investment demographics show large plant investments in previous decades are coming due for high cost repairs and replacement. The Brattle Group estimates \$2 trillion in electric sector investment requirements over the next 20 years, about half of that for generation resources.² Combined with falling costs of renewable generation and growing pressures to reduce greenhouse gas emissions and other traditional pollutants, the required investment could lead in the direction of much more renewable energy choices as described in the *RE Futures* study.

Tougher environmental requirements

Tighter environmental regulations raise questions about how to maintain utility business models that depend on earning equity returns on investments in plants that require major new clean up investments. The advance of these regulations means utilities will face higher operating costs to meet new regulatory requirements as well. Old, depreciated assets may need to be retired early because of new environmental regulatory costs.

Likely EPA regulation of CO₂ emissions for existing fossil units, coal ash disposal, mercury and water issues all compound utility investment decision making. Higher operating costs are likely to follow for existing fossil units. The business question is how to manage these costs while considering clean alternatives such as those found in the *RE Futures* study. A renewable energy future along the lines of the NREL study provides a number of solutions, if the risks can be reduced and rewards increased for investments in new clean equipment – even as write offs and write downs of old investments need to be absorbed.³

Technology costs, market and policy trends

Wind and solar technologies have made very significant gains, leading to much lower costs and rapidly increasing deployment. Distributed technologies, employed in the context of more intelligent grid technologies and operations have drawn attention, especially in the popular imagination and in military circles. Long sought energy efficiency and demand side management programs are spreading among utilities, equipment suppliers and consumers – so much so that many utilities ponder flat or very low load growth going forward. Most states have policies in place requiring minimum amounts of renewable energy and many of them have increased their targets as lower renewable energy costs make the minimums more cost effective to achieve. Technology trends are moving strongly in favor of the RE future.

Smarter grid

As more computer and communications technologies pervade utility operations, and as distributed generation such as solar, Combined Heat and Power and micro turbines become more commonplace, utilities will face more complex issues regarding distribution, investment operations and rate design. The uptake of electric vehicles and their charging requirements, together with their potential to provide grid support, raise related issues. These developments will present new challenges in the areas of reliability, rate equity and recovery of fixed and variable costs of service.

The complexity of a smart grid and the proliferation of potential new services will raise issues of consumer sovereignty, the type and quality of consumer services and issues of consumer costs. The utility could create new revenue streams associated with customer service. Third party disintermediation (new providers getting between a traditional utility and its traditional customers) will challenge utilities to justify and provide services. They may also make partnerships with other providers work to the advantage of customers who wish to avail themselves of these options. Resolution of these trends could spur change in the direction of the RE future – especially at the distributed generation scale – but most of the discussion is about issues at the consumer, rather than the bulk power end of the business.

Changing consumer requirements

Other customers such as companies that operate large computer server locations and military bases have evolving requirements that challenge existing utility business formulae. As providers of clean power compete with utilities to serve customer segments that demand clean power to meet their own goals and standards, utilities are challenged to either offer, or facilitate other providers' offerings, to meet these customer requirements. Utilities that have enjoyed relatively exclusive single provider status may be challenged to provide the levels of consumer options and service that are required. More demand for clean power from large-scale consumers moves strongly in favor of the RE future.

Weakened industry financial metrics

Utility bond ratings have weakened significantly since the sector last faced large-scale investment requirements. Twenty years ago there were many AAA and AA rated utilities, now there are very few. All along the sectors' ratings, declines have far outpaced improvements over the period. Questions relevant to a renewable energy future are the cost of capital for utility investments associated with investors' perception of risks, and managing the transition from fuel cost expense to investment in generation without fuel costs.⁴

Climate damages and recovery, liability costs, fuel risks

A simple computer search on the terms “climate damage litigation” will reveal results that suggest this often mocked issue might emerge as a multi-billion dollar risk to utilities and other emitters. Risks could be at the “bet your company” level if these firms are found to be financially responsible for damages caused by weather extremes, spread of diseases and damage to agriculture and natural systems. In 2010 the SEC issued guidance about disclosure of risks and opportunities related to global climate change in response to concerns that investors and others raised about financial impacts from emerging regulations for addressing it. As contingent risks of liability for climate change damage are better appreciated, the RE future scenario moves closer.

“De facto” carbon policy

While too early to be called a universal trend, some jurisdictions have embarked on policies limiting carbon emissions that could spread more broadly. California, Oregon and Washington all have limited new carbon-emitting electric power generation sources. California has opened its carbon cap and trade market. Boulder, Colorado and British Columbia have small carbon taxes in place. Some utilities’ plans show that they will not consider new coal plants because investment risks attendant on climate issues are too hard to judge. Some have undertaken coal plant retirements that advance planned unit retirement dates. As the retiring CEO of Xcel Energy, Richard Kelly, told a Minneapolis newspaper, “We’ve got to get off of coal. The sooner the better.”

CURRENT TRENDS IN UTILITY BUSINESS MODELS

One CEO observed that utilities organize themselves around standards. In his view, utilities' organizations and efforts are driven by engineering and reliability concerns, those that result in keeping the lights on. Financially, utilities are accountable to their investors, who assess risk based on their views of economics, and particularly on comparisons across firms that assess how capital is employed and what returns result. For utilities, an industry wide standard uniform system of accounting provides the basis for cost-of-service regulation. This supports equity returns on plant investments – the fundamental regulated utility profit incentive, as well as fuel cost and other rate adjustments that support what is essentially a commodity sales business model.

Current examples of utility models changing

There are many examples of utilities that have diversified beyond the basics of the utility business. The traditional utility basics can be summarized as, "invest in plant, earn a return, and turn the meters." Some utilities have subsidiaries that provide clean energy diversification. They are in the business of building wind and solar generation for other utilities. Examples include NextEra, a subsidiary of Florida Power and Light and the nation's largest wind plant owner, and MidAmerican, a subsidiary of the holding company Berkshire Hathaway, the largest utility wind owner and a recent entrant in the wind and solar developer market. Some utilities are engaged in utility consortia that expand member utilities' service

offerings beyond provision of electricity. For example, Touchstone Energy is a cooperative project that provides a variety of services to cooperative customers, from efficiency and other energy services to discounts on hotels and prescription drugs.

Joint construction of generation and transmission projects have a long history in the industry, where the different segments cooperate to finance and build large scale generation and transmission assets and then share in their ownership, operations and benefits. Some utilities have diversified into independent transmission companies, engaged in building transmission in other utilities' service areas. For example, the Sharyland Utility is building part of the Texas ERCOT Competitive Renewable Energy Zone (CREZ) transmission lines.

There have been examples of both successful and unsuccessful utility diversification efforts into a range of enterprises, from drilling for natural gas and building generation plants across the U.S. and the world, to providing appliances and appliance repairs to consumers. So utilities are not strangers in trying different lines of business and a variety of business arrangements that expand their scope and scale beyond the basics of providing customers with power from power plants across lines they own and collecting on a utility bill.

As utilities have tried these expansions and diversifications, regulators have faced very significant challenges policing the line between regulated and unregulated enterprises. A business model where the regulated firm is the low but steady return “cash cow” and subsidizes the unregulated high return “star” enterprise both surcharges monopolized customers and harms competing firms in unregulated sectors. The lessons learned from current utilities’ engagement in businesses related to, but beyond the scope of, their basic utility business will be relevant as a RE future unfolds.

REQUIRED CHANGES TO ENABLE RE FUTURE: NEW BUSINESS MODEL OPTIONS

A spectrum of possible utility roles emerges from Peter Fox-Penner's book "Smart Power" and from discussions within the context of a recent feasibility study of new utility business models and regulatory incentives. These possible roles range from the potential for utilities to be minimally involved in the transition to the RE future, to the potential for utilities' maximum involvement. Since the U.S. is so large, the number and kinds of utilities so various, and the situations so different by region, market, state and locality, the outcomes are likely to vary across the entire spectrum. What we can say with certainty is the one size won't fit all. Nevertheless, discussions are starting to happen about utility roles, and how business plans can reflect them, and we can see the beginnings of how these discussions might usefully lay out some constructive options.⁵

Minimum utility involvement

Those who advocate for minimum utility involvement in transitioning to a renewable energy-dominated future point out that utilities are the last place in business where innovation can rationally be expected to occur. Utilities are creatures of engineering, and financial standards and expectations primarily centered on keeping service reliable, returns steady and costs reasonable. Thus, they have few incentives to understand or take risks that come with rapid rates of change or innovation. As single providers in their markets, these monopoly providers are far less responsive to the motivations for change discussed above than would be other firms that face competitors who will angle for advantage in the face of challenges.

Utilities are also single buyers in their markets for energy supplies (as well as for a number of other specialized inputs from suppliers of specialized power engineering services, grid equipment, etc.) and as "monopsonies" (single buyers in a market) they have strong incentives to prevent market entry by competitors. Those who provide disruptive generation like wind and solar challenge utilities' traditions of reliance on fossil fuel for generation. Because most regulation allows utilities to offload most fuel costs, risks and liabilities onto their customers through fuel cost adjustments, they are further likely to tilt away from new renewable supplies. These are critical issues facing a transition to a high penetration renewable energy future that must be confronted.

There seems to be an assumption among certain economists, many customer segments, and some evidence from the organized RTO/ISO markets, that suggests certain of the utilities' lines of business can be opened to market forces to the benefit of customers. Industrial customers, faced with increased utility costs around 1990, led efforts to restructure the electric industry. Results varied around the country, but left a legacy of more competition within the utility sector.

Competitive entry in generation, for example, is found both in RTO/ISO as well as in markets where regulated utilities are required to obtain generation in response to transparent planning and open bidding. Some states, such as Wisconsin, have moved in the direction of requiring utilities to divest transmission into separate companies, which are then encouraged to compete to provide transmission investments and services.

In support of a minimal utility role, there is continuing discussion of how much the electric industry could be like telecommunications, where new technologies – especially mobile phones – have changed the business realities of traditional regulated telephone companies so entirely that a regulated monopoly structure has nearly disappeared. A lot of customers on the winning side of that equation believe that technology in the electric sector will have the same impacts.⁶

Some of the Silicon Valley investors in clean technology research and development along with start-up firms seem to have this same outlook: they assume Moore's Law applies to the electric sector and will cause the current utilities' business to evaporate as customers find a myriad of new ways to get the services they need outside of current utility technology and business models.

Skeptics of this point of view emphasize that even the best restructured electric markets still struggle to meet public policy requirements for long term supply reliability, to amass capital for long term investment and to meet current minimum renewable energy standards, much less the 80 percent goals discussed in the *RE Futures* study. FERC has recently started enforcement actions against several firms regulators charge have manipulated markets unlawfully, and for many in the West in particular,

the Enron legacy of market manipulation in California still seems like a current threat likely to prevent any discussion of, much less movement toward, expanding markets.

A minimum utility role has both supporters and detractors, but it raises the specter that utilities face a potentially dignified "death spiral" in which their business model is made irrelevant by new technology and customer demands, and they will be forced to raise their prices for their least desirable customers because their best customers depart for more appealing options from other providers.

Middle way: Utility "smart integrator" or "orchestrator"

Along the spectrum of potential utility degree of involvement in a RE future, the middle way option is described in "Smart Power" as providing productive partnerships between utilities and innovator firms. In this model, the utility role is one of facilitating technology and service changes but not necessarily providing all of them. The utility role here brings change along through its business processes. Utilities would maintain their strong engineering and reliability standards, but adapt and apply them to new technologies and service offerings. New standards and changes to existing standards would be needed to incorporate new equipment, simplify and rationalize interconnections between new equipment and utility distribution and transmission grids and integrate new generation into utility operations and markets.

With new standards, pilot and demonstration programs of new technologies and services would present lower risk profiles to both utilities and investors. Consumers might benefit from a rational progression of new approaches as promising ideas grow from research and development, then make their way across what is now a “valley of death” for new ideas into utility pilot and demonstration programs that would prove up developers’ claims. With demonstration project findings in hand, utilities, investors, regulators and developers could turn toward mass deployment and a variety of new technologies, business structures (like community generation ownership) and services would have a clearer path to markets. These outcomes would strongly support a RE future.

The business skills to accomplish these tasks would be analogous to the conductor’s role in orchestral music. In this analogy, policy makers in both government and corporations choose the music for the orchestra’s season, playing the music director’s role. Then the utility, filling the orchestra conductor’s role, trains the players to make a harmonious whole from the music selections and make programs available to the audience, the consumers. Some of the music might be classical, to appeal to those audience members who want to hear familiar tunes played in a traditional manner. These customers might prefer utility-based service offerings with few, if any, innovations and to face the fewest number of choices.

For those who want a more modern flair to their orchestra experience, the conductor would drop his or her baton on more modern scores. Such additional services might include access to a custom generation resource mix, real-time pricing that delivers “prices to devices” or a variety of energy management services.

Some utility customers want yet more choices. They may want solar on their roof, or to own a wind plant and have wind energy delivered by the utility to their computer server farm. They may want to build and live in a net zero energy home, or to have their military base supply its own power when the main grid is down due to a cyber attack. All of these customer options would find a way into the overall music program that the utility conductor would facilitate and be able to present.

The key in the “middle way” role would be for the utility to maintain a series of partnerships with innovative providers that would benefit both partners and the customers they serve. This “Goldilocks” outcome (not too hot, not too cold, just right) probably has the most appeal to utilities, who can find a positive future in it. The middle way also is likely to appeal to many stakeholders as well as most regulators, who would be busy managing the equity and cost of service issues in a much more complex setting. Advocates for a strongly market-oriented approach may find these messy compromises annoying at best or terminally unworkable at worst.

Maximum utility role: “Energy services utility”

While it is easy to imagine a utility role in which the utility is the ultimate enabler that “just makes it happen,” it is harder to suggest how such a maximum utility role squares with the rates and levels of change that are required to get and stay on the path to the RE future. The activist role is particularly challenging to develop given the fundamental critique of utility abilities and incentives: utilities are not change agents.

For a utility to play the central role in a transition to the RE future, a widespread political consensus could lead a state legislature to mandate a structure in which utilities stay in charge, but with new marching orders. In places where utilities have enough political authority to sway legislative policy in their desired direction, this outcome is possible. Perhaps in response to calamity of sufficient magnitude, utilities would be given the direction by public policy makers to take care of rebuilding to solve a crisis. Rebuilding damage to utilities resulting from Hurricane Sandy will be an interesting case study of some of these tensions.

The intersection of the maximum utility role with new technology presents similar conundrums. Perhaps the utility in this setting would control the computer platform for the “smart grid,” allowing innovators to add applications that meet customer requirements. Utilities might be encouraged to expand their business scope and scale by buying up innovator firms, acquiring their competitors and making the most out of their special competence in managing large-scale, complex, engineering construction projects.

These outcomes might be strongly supportive of a rapid move to the RE future, and would be consistent with a social agreement on the need to make a rapid move away from carbon-based electric power.

Maximum role utilities might be expected to diversify their service offerings, as customers segment themselves into groups with different service requirements. For example, a utility could serve military bases and other gated communities with their own solar or other power generation, along with high levels of reliability and resilience against weather damage and cyber interference – and the ability to drop off and rejoin the main grid depending on circumstances (or economics). Such a utility would target distributed generation to the most valuable places in the system.

Other customers might desire absolute least cost service, be willing to sacrifice reliability for lower cost and be unwilling to spend the time or money to add much in the way of their own generation or end use control systems.

A utility serving a variety of evolving and changing customer segments beyond the traditional residential, commercial and industrial categories will be faced with creating additional value propositions to support each offering. Such diversification will also entail more complex equity claims and cross subsidy concerns. Packages of services aimed at particular customer segments might result.

The model might be closest to integrated telecommunications companies such as the telephone and cable companies that can now combine landline phone, wireless, internet and television services in one bill. A bundled services approach could offer new services, define value and convenience for customers, and frame and provide services across a range of offerings and price points.

A utility at the maximum involvement end of the spectrum might be described as an end-to-end aggregator, doing business at the core of change and expanding its scope and scale. Such a utility would be supported by public policy in its central role, and, hopefully, seek continuous improvement of its economic, environmental and financial performance. Some of the offerings the maximum role utility would undertake would vary in degree rather than kind from those described in the moderate utility role. In certain political and policy settings, which are bound to be encountered across the wide variety of utility experience in the U.S., a maximum utility role outcome could be the avenue of choice that leads in the direction of the RE future outcomes.

PUBLIC POLICY RECOMMENDATIONS: NEW REGULATORY OPTIONS

As we have seen, numerous forces are conspiring to change fundamental features of the environment in which the traditional electric utility operates. These forces will alter the role of the utility and will require modifications to utility business models if utilities are to fulfill their new roles while remaining financially viable. These pressures for change are magnified by the assumption of a high-penetration RE future that NREL has shown is possible. Significant changes will be required regardless of whether utilities play a minimal, middle or maximum role in the transition to the RE future.

Consider these implications of the NREL study:

- Much higher levels of variable generation **at the bulk power scale** will require:
 - Greater flexibility in the grid and a successful system integrator at the bulk power level.
 - Significantly more investment in transmission facilities.
 - Investment in grid-level storage and other ancillary grid services.
- Greater penetration of distributed energy resources (DER, both supply-side and demand-side) **at the distribution scale** requires much more sophisticated planning and operation of the distribution grid, and may require significant investment in at least portions of distribution systems.

- In addition to operational considerations, greater penetration of customer-owned renewable energy facilities (DG) means less revenue for utilities and lower load growth.
- NREL's *RE Futures* study core scenarios assume levels of energy efficiency sufficient to eliminate load growth from now until 2050; this likely means much larger and more sophisticated energy efficiency efforts by utilities or other EE providers. In either case, this trend will render the traditional utility "volumetric" rate structure increasingly ineffective as a means to compensate the utility.

Depending on one's assumptions about the essential role of the utility, these implications of the NREL report spawn a host of new requirements for the industry and its regulators in getting to the high penetration renewable future and for operating a reliable electric system once that future has been attained.

Mapping the RE future challenges to structural and regulatory options

We now turn to the question of the impact these RE future-specific challenges will have on utility business models and the implications for the mode of regulation for those portions of the industry that remain regulated by economic regulators.

We examine these RE future-specific impacts across the three basic orientations for utilities described previously:

- Minimum utility involvement.
- Middle way: utility as “smart integrator” or “orchestrator.”
- Maximum utility role: “energy services utility.”

Minimum Utility Involvement Model		
RE FUTURE IMPACT	IMPLICATIONS	RESPONSES
Greater levels of variable resources	Requires improved access to expanding wholesale markets for variable resources; competitor firms provide new, more responsive supply side and demand side resources.	Requires price on GHG emissions; some need for state or federal RPS or tax policy, depending on economics of RE and fossil fuels. Regulators search for and implement opportunities for markets to serve customers and limit utility market power.
More sophisticated grid operations	RTO and ISO markets expand, balancing areas consolidate. Will require more smart grid investment; more sophisticated ISO skills; greater supply of ancillary services.	IT investment in control systems increases. Dynamic pricing is desirable; enhanced ISO ability to accommodate variable resources.
Greater transmission investment	Greater reliance on independent transmission owners; regional transmission planning includes independent projects.	More private market involvement in transmission development, financing. PMA's are privatized.
Higher levels of customer-owned resources	Distributed resources have easy access to wholesale markets.	Retail choice proliferates, competitors enjoy retail open access. Rate structures change.
More sophisticated distribution operations	Retail choice, competitive disintermediation, and rapid technology development and deployment.	IRP-style approach to distribution investment; smart grid performance metrics.
Higher levels of EE	Robust energy service company market required, simple consumer financing.	Distribution wires companies regulated with revenue cap.
Pressure on customer rates	Customer resistance to higher rates.	Communicate climate goals, service value.

Smart Integrator or Orchestrator Model

RE FUTURE IMPACT	IMPLICATIONS	RESPONSES
Greater levels of variable resources	If utility is vertically integrated, likely more reliance on PPAs. Incentives for fair market shares, transparent “make or buy” bids and bid evaluations.	Improved long-term planning; IRP with presumption of prudence; robust competitive bidding regime for PPAs.
More sophisticated grid operations	Enhanced role for system integrator, either ISO or utility. Will require more smart grid investment; development of new operating regimes.	Candidate for reliability incentives. Competitor firms’ satisfaction evaluations determine performance rewards, symmetrical penalties.
Greater transmission investment	Higher capital requirements; upward pressure on rates. Joint projects and more industry partnerships.	Award presumption of prudence tied to planning process. Long term needs met with larger scale projects. Rights of way acquired in advance of need.
Higher levels of customer-owned resources	Heightens need for smart integrator. Reliability, capability requirements change.	Utility identifies preferred distributed generation locations. Rate structures change. Service options expand.
More sophisticated distribution operations	Will require smart grid investments.	IRP-style approach to distribution investment; smart grid performance metrics.
Higher levels of EE	Lowers load growth; demand responsive loads.	Revenue cap regulation with decoupling adjustment.
Pressure on customer rates	Customer resistance to higher rates.	Communicate climate goals; encourage increased firm efficiency; use price cap.

Energy Services Utility Model

RE FUTURE IMPACT	IMPLICATIONS	RESPONSES
Greater levels of variable resources	May require new regulatory approaches to planning and prudence determinations; different approach to portfolios, more PPAs.	May require renewable portfolio or energy standards, depending on renewable energy economics. Reliability incentives; long-term planning; integrated resource planning with presumption of prudence; robust competitive bidding regime for PPAs.
More sophisticated grid operations	Will require more smart grid investment by utility; new operating regimes.	Candidate for output-based incentive regulation; reliability incentives.
Greater transmission investment	Higher capital requirements; upward pressure on rates.	More sophisticated state and regional transmission planning; award presumption of prudence tied to planning process.
Higher levels of customer-owned resources	Lowers utility sales; pressure on rates.	Rate structure changes.
More sophisticated distribution operations	Will require smart grid investments.	IRP-style approach to distribution investment; smart grid performance metric.
Higher levels of EE	Lowers load growth.	Revenue cap regulation with decoupling adjustment.
Pressure on customer rates	Customer resistance to higher rates.	Regulators must communicate climate goals; regulate to encourage increased firm efficiency, using revenue- or price-cap style regulation.

Studying these charts, the implications are clear. Depending on the assumed level of utility involvement, market structures must be improved and, in some cases, created. Regulation must turn its focus towards some new goals for the utilities for those portions of the industry that remain regulated.

Focus on regulation

We might begin this inquiry with the question, “what must a new utility business model look like?” Instead, our analysis and recommendations start from a different place. We know that utilities respond first and foremost to the incentives created by the legal and regulatory regime in which they operate. For that reason, our recommendations focus on how utilities are regulated.

The essential problem of 21st century electric utility regulation is how to compensate utilities fairly while providing incentives to pursue society’s broader policy goals. This contrasts with the economic regulation practiced in the U.S. from the 1930s to the 1990s that focused mainly on overseeing utilities’ profits, servicing growing customer demands and maintaining rate stability and service reliability.

The regulator’s duties today must now become more subtle and complex. Utilities must now be encouraged to decarbonize their fleets, improve both their firms’ overall efficiency and project-level efficiencies and serve customers in new ways. In short, regulation today needs to align regulatory incentives so that healthy utilities can pursue society’s broader policy goals in ways that also benefit customers and shareholders.

A logical approach to designing appropriate regulation will seek to answer the following questions:

- What outcomes does society want from the electric utility industry?
- What role should utilities fulfill in the future?
- What incentives should law and regulation provide?
- How must regulation be modified to provide these incentives?

These questions illustrate the close connection between how utilities operate and make money (their business model) and the incentives provided by the legal structure of the industry and its regulation (the regulatory model). Utility business models should evolve to respond to the outcomes that society wants. Until we adjust regulation to enable and encourage those outcomes from the utilities, adjustments to their business models will be hard to justify.

1. Determine desired societal outcomes.

In this report, we have assumed a high-penetration renewable energy future. This can come about in response to public demand, as evidenced by consistent public polling results over the last few decades that show two or three to one support for more renewable energy. The government, responding to public demand, can mandate a move toward the RE future. The economics of various energy resources and pricing for a low-carbon future can drive us to high-penetration renewable resources, or external causes such as widespread realization of climate damage at unsustainable levels may provide the required motivation. In any case, we may assume that society wants a high penetration of renewable resources. Other desirable societal outcomes include service reliability, equity, sustainability, efficiency, energy diversity, energy 'independence', economic development, risk minimization and environmental results.

2. Determine the legal and market structures under which utilities will operate.

We take this to be a (temporarily) settled matter in most regions of the country, although evolution of market structures continues. Our recommendations for regulatory incentives will be formatted to apply in the case of each of the major market structures (vertically integrated, partially competitive, retail competitive, etc.). Similarly, we assume that the industry segments (investor-owned, publicly-owned or cooperative) are fixed.

3. Develop and implement correct market and regulatory incentives.

This is the main task: modifying regulation to induce regulated utilities to adopt business practices that lead to society's desired outcomes. As regulated IOU firms' experiences build toward new models, we expect best industry practices to move into POUs. They are not regulated in the same way as IOUs, but many of the same principles advocated here will apply in some fashion to municipal utilities and coops. The diversity of market structures means that there will be a spectrum of regulatory arrangements, providing different incentives as appropriate to the market structure.

The late economist Alfred Kahn once observed that, “all regulation is incentive regulation.” By this he meant that the manner of regulation inevitably shapes the behavior of regulated entities. State utility regulation, which might have been adequate for the 1950s through the 1970s, remains rooted in concepts and practices that, while still important, are not adequate to the challenges of the 21st century. Current regulatory structures simply don’t provide the right incentives.

We believe that regulation must shift and broaden its focus from monopoly-era economic issues, to a larger and more generalized set of issues. We believe these issues are best addressed through regulation based on performance so that utilities have incentives to change their ways.

As cost-of-service regulation has evolved in the last three decades, it has shed any realistic claim that it induces regulated companies to be efficient. One of the important roles of regulation, identified by James C. Bonbright in 1966, is to motivate the utility to be efficient as a company. Interviews with utility CEOs confirm that today’s regulatory structure offers few incentives for corporate efficiency throughout a utility. This is significant because increased profitability, derived from eliminating inefficiencies, could be used to offset anticipated cost increases utilities are facing. Utility efficiency could potentially be used to “fund” certain outcomes desired for utilities, such as the movement towards cleaner generation resources and new consumer services.

Other analyses have described alternative regulatory approaches that appear to be appropriate in light of the well-recognized challenges facing utilities.⁷ We now describe those alternatives in a more concise fashion.

New regulatory options

The United Kingdom RIIO model

Electric and gas distribution utilities in the U.K. are regulated under a relatively new, comprehensive structure called RIIO, which stands for “Revue using Incentives to deliver Innovation and Outputs.” The U.K. electric regulator, OFGEM, created RIIO to implement new government policies for the electric sector requiring meeting national climate goals. RIIO builds on the price cap regime that has been used in the U.K. for the past 20 years for energy companies (called “RPI-X”). RIIO adds to price regulation a system of rewards and penalties tied to performance on desired outcomes (or “outputs”) to be achieved by regulated companies. Because RIIO also employs revenue decoupling, it is probably best described as “revenue cap regulation” coupled with “output-based incentive regulation.”

RIIO differs from most U.S. utility regulation by focusing much less on the utilities’ earned rate of return and focusing much more on the utilities’ performance. By its own terms, this new U.K. model seeks “value for money.” Rewards and penalties comprise an incentive system to encourage operational efficiencies, as well as funding for innovation and opportunities for utilities to involve third parties in the delivery of energy services.

Importantly, RIIO contemplates a relatively long period of regulation – the basic price and revenue trajectories for utilities, along with the system of rewards and penalties, will persist for eight years. This means that operational efficiencies achieved by regulated companies can result in higher profitability during the term of regulation, clearly rewarding efficiency.

Under RIIO, utilities are measured for the performance on seven output measures:

- Customer satisfaction.
- Reliability and availability.
- Safe network services.
- Connection terms.
- Environmental impact.
- Social obligations.
- Price.

While some may view the U.K. move to the RIIO model as a partial retrenchment in the U.K.'s march toward electric industry disaggregation, others suggest that it simply builds new goals into a reasonably workable regulatory structure that maintains a prominent reliance on market forces. Seen in the former light, RIIO begins to reassemble aspects of a policy driven, integrated electric system, reinserting additional public policy goals into the regulatory formula. By its own terms, RIIO highlights critical utility functions that include:

- Reliability.
- Environmental stewardship.
- Innovation.
- Price management.
- Efficiency.
- Social responsibility.

Utilities are required to submit new business plans for approval by OFGEM that show how their business models will change, how they propose to provide these critical functions and how they propose metrics and measurements by which their success (or failure) to do so can be judged. By monetizing success in these functions through a system of incentives and penalties, RIIO links financial success for the utilities to achievement of public policy goals. In this way the utilities begin to own the policy outcomes.

By focusing on outputs instead of inputs, RIIO moves from accounting cost regulation to a style of regulation that emphasizes the utility's business plan and measures the firm's ability to deliver on commitments. The RIIO slogan of "value for money" underscores the bottom line, "are we paying for what we wanted?" In contrast, much of U.S. utility regulation seems to answer the opposite question, "have we paid the correct amount for what we've gotten?" RIIO's adoption of an eight-year regulatory term means that the regulated entities have sufficient time to adjust their operations, employ innovative measures and wring out inefficiencies.

U.K. regulation focus:

Did we pay for what we wanted?

U.S. regulation focus:

Did we pay the correct amount for what we got?

Finally, by elevating public policy outcomes to the level they inhabit in RIIO, the U.K. is giving **customers as citizens** equal billing with **customers as consumers**.

At its most basic structural level, the RIIO model appears to address many of the needs we have for reformed utility regulation in the U.S. While the RIIO model might have to be significantly modified for use in the U.S., its basic structure can provide appropriate incentives for utilities to move in the direction that society wishes them to go. Further, the price-cap element provides inducements to firm efficiency, making it possible to “fund” parts of the clean energy investment with higher earnings from efficiency gains.

Performance-based regulation

In the 1990s, the U.S. telecommunications market was remade by changed federal policy, technological innovation and the rise of competition, becoming both more complex and more competitive. Regulators responded (slowly) by moving away from cost of service regulation toward price cap regulation, various flavors of incentive regulation and regulatory forbearance for new market players.

The situation in the electric sector shares some features with the telecommunications sector (disruptive technologies, shrinking of monopoly functions) but there are very big differences as well. In particular, the telecommunications sector has become less capital intensive, is much more nearly “plug and play” and has many fewer negative societal externalities. And yet the regulatory prescription may be very similar: each industry’s evolution will be enabled by a shift towards a type of regulation that focuses on outputs (prices and outcomes) instead of inputs (accounting

costs) and enables the industry to become more efficient, eliminating some of its bad habits. The Federal Communications Commission and many states began to use price cap regulation for telecommunications carriers as competition began to enter their markets. This style of regulation, in both theory and practice, squeezes inefficiencies out of the regulated players in the former monopoly markets.

In short, performance-based regulation (PBR) adds performance outputs by function to basic cost of service regulatory design, values risk management and focuses on the longer term. Ideally, PBR will present utilities with a coherent set of positive and negative incentives, replacing the disjointed and often conflicting set of incentives that has grown up in many regulatory jurisdictions.

Modern 21st century regulation must also come to grips with another neglected outcome: innovation. As practiced today, U.S. utility regulation removes almost all of the upside for utilities that might choose to innovate. There is little incentive for a utility to become more efficient since any financial gains from innovation and improved efficiency are “taken away” in the next rate case. As mentioned earlier, the RIIO regime addresses this situation by creating an eight-year regulatory term, allowing utilities to retain the benefits of improved efficiency, and by creating a separate channel for funding innovation.

Finally, U.S. regulation will profit from moving away from short-term price considerations and toward the practice of developing long-term goals. As discussed in a recent Ceres publication, this strategy is key to managing both risk and costs for a utility.⁸

Two more approaches

We close this discussion with a brief consideration of two additional regulatory models, the “Iowa Model” and what we call the “Grand Bargain.”⁹

The Iowa Model

For seventeen years, from 1995 to 2012, Iowa utility MidAmerican did not change its retail prices; nor did it utilize “adjustment mechanisms” to track costs. Instead, the rates in effect in 1995 were continued without change through a series of settlement agreements involving MidAmerican, the staff of the Iowa Utilities Board, the Office of Consumer Advocate and other interested parties. The terms of the settlement agreements evolved over time but generally provided for a fixed settlement period, a formula for sharing over-earnings and an “escape clause.” It is important to note that MidAmerican continued to add generation resources during this period, including hundreds of megawatts of wind capacity.

The Iowa experience exhibits a system that provides longer-term stability in regulation and incentives for utilities to improve efficiency, while not technically based on a price cap. The Iowa experience relied on a settlement-based process that lessened the transaction costs associated with the adversarial process. This model can be adapted to emphasize clean energy goals by making them part of the periodic negotiations.

The fact that rates did not change over 17 years is an important aspect of the story, but it is not a central lesson about the experience. The particular energy economics in a state will determine whether prices could be kept constant over time. The important lesson from this model is its adaptability to emphasize the goals and incentives that the parties to the negotiation wish to achieve.

A Grand Bargain

Meaningful dialogue among utilities, regulators and other stakeholders is often difficult to achieve. The system of utility regulation has grown to be very confrontational, is often wrapped in judicial processes and usually exists in a charged political setting. This can be a very difficult atmosphere in which to examine fundamental aspects of the way we regulate.

In current practice, state regulatory agencies often treat utility prices and performance in an *ad hoc* fashion: one set of cost recovery mechanisms for this activity, another set for a different activity; one incentive scheme for this goal, another scheme for that goal. An alternative to this fragmented ratemaking process might be called “a grand bargain.”

The Grand Bargain model, as we have termed it, combines aspects of both the RIIO model and the Iowa model. The object would be to produce, through negotiation, a thorough regulatory regime that would address a broad set of issues in a consistent manner. A regulatory commission might, for example, direct a utility to undertake negotiations with a broad set of stakeholders, including the commission’s staff, which would be equipped with guidance from the commission. The direction from the commission would be to negotiate a multi-year agreement concerning rates, cost recovery mechanisms, quality of service goals, environmental performance, energy efficiency goals, incentives, etc.

The commission could supply as much detail and direction to the parties as it prefers. For example, a commission might specify that the eventual agreement must contain certain performance benchmarks for the utility, as well as incentives and penalties to motivate compliance with the agreement. To motivate parties to settle, the commission could indicate from the outset its likely acceptance of a settlement agreed to by a significant group of stakeholders, even if the agreement were not unanimous.

For each of the five essential elements of administrative due process, a less formal but still effective set of procedural processes could be used: notice, a hearing, a fair decision-maker, a record and a chance to appeal. Transparency would need to be maintained, so that outcomes would be reached in open discussions. Where agreements elude such a stakeholder-driven process, the commission could still apply its formal decision making routines, acting on a more limited and better-defined set of remaining issues.

The details of the Grand Bargain model are fluid. It stands principally for the concept that, with appropriate motivation and attention from a regulatory agency, a set of stakeholders might be able to craft a solution that is superior to, and more internally consistent than, a regime that arises out of multiple contested cases at a commission.¹⁰

All three regulatory models discussed in this section – RIIO, Iowa and the Grand Bargain – lead the way to a new utility social compact. Utilities benefit from investment certainty, lower risks and responses to a variety of threats facing the industry. Society benefits from having public interest goals built into utility business models through regulatory incentives.

CONCLUSION

Among the nation's 3,000 or so electric utilities across 50 states we find many variations but a fundamental truth: the business models were developed for a different time. If we agree that it is in the nation's interest to move towards an electricity future dominated by renewable energy, we must realize that a new social compact between utilities, regulators and the public needs to be forged.

Utilities and situations in states vary. In a country the size of the U.S., and in an industry of the magnitude of the electric utility sector, almost any possible model or potential outcome either has been, or will be, attempted. No logical reason suggests that a single, or a small number, of possible outcomes are the only logical or prudent ones to consider. Varying situations call for a variety of outcomes. There are motivations for utilities to consider changing their business models, and options for consideration exist.

Today's constellation of challenges and opportunities recall those that led to restructuring of large portions of the utility industry starting about twenty years ago. If changes at an even greater level are in prospect now, it makes sense to prepare carefully for the discussions that must happen. Across the range of potential outcomes, there are outcomes that support the RE future as well as a regime that meets the broader traditional goals for the utility sector. There are multiple, large scale benefits at stake for consumers. These should provide enough benefits for all contending parties to share, if they are willing to join in the work of gaining those streams of additional benefits.

Utilities need the right incentives to move towards a renewable energy future and regulators and their elected officials need a way to structure public interest goals into regulation. We have seen that utilities can affect the transition towards a renewable energy future at various levels of involvement and that a variety of options have proven workable for changing their business models. But regulation provides a critical incentive in these monopoly businesses and needs to evolve in order to allow the new business models to succeed. We have outlined a series of models that offer some of the required elements. Engaged stakeholders will prove critical in the success of this transition.

Regulation will need to change to support different business models. Both state and federal economic regulators, as well as utility boards of directors, need to consider whether today's goals, objectives, and methods are sufficient given today's challenges and opportunities. Some may decide that what they are doing now is exactly what they should be doing to prepare for the future. But most will consider what needs to change so utilities better serve society's needs. Fortunately, new methods of engagement for all stakeholders are available, through processes to establish performance goals and outcomes, in the analysis and reporting required to support them, and through well planned and facilitated policy dialogues.

ENDNOTES

- 1 See *Aligning Wholesale Power Markets* by Michael Hogan for more detail about how market mechanisms can deliver important signals in restructured markets.
- 2 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008) <http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf>
- 3 Lehr, Ronald, "*Clean Energy Investments and Incentives: Choices for Investors, Utilities and Regulators*" <http://www.cleanenergyvision.org/wp-content/uploads/2013/01/Transition-Plan_Investments.pdf>. And see: See America's Power Plan report by Foley, Varadarajan and Caperton for more detail on how policy can address stranded assets and de-risk investments in new infrastructure.
- 4 See America's Power Plan report by Foley, Varadarajan and Caperton, *op. cit.* for additional detail.
- 5 Several organization have begun to examine and address the subject of the evolving utility model, including the Energy Foundation, the Edison Electric Institute, the Energy Future Coalition, the U.S. Department of Energy, Arizona State University, the Rocky Mountain Institute, and Energy Innovation, among others.
- 6 For more about this point of view, see the electricity chapter of *Reinventing Fire* by Lovins, Amory.
- 7 "Risk-Aware Planning and a New Model for the Utility-Regulator Relationship." Binz, Ron and Mullen, Dan. July 2012. ElectricityPolicy.com. Available at <<http://www.rbinz.com/Binz%20Marritz%20Paper%20071812.pdf>>
- 8 "Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection," Ceres Report, April 2012. Authored by Binz, Ron; Sedano, Richard; Furey, Denise; Mullen, Dan, <<http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation/view>>
- 9 For a fuller discussion of these approaches, see Binz, 2012.
- 10 Although the "Grand Bargain" model is described here as operating in the regulatory arena, it could also be used in the context of state legislation. Indeed, in some states it may be necessary or desirable for the legislature to modify existing laws that specify details of the current regulatory model or to cement the grand bargain.



FINANCE POLICY:

Removing Investment Barriers and Managing Risk

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We would like to offer sincere thanks to our knowledgeable group of reviewers:

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EXECUTIVE SUMMARY

Investing in America’s clean-energy future will create major new economic opportunities, while reducing pollution and improving the security of our domestic power system. Renewable energy power system costs continue to fall. In the transition to this future, driving down the financing cost for capital-intensive energy infrastructure can go a long way to save consumers additional money.

Financing the clean energy transformation will require modernizing electricity regulation, policy and markets, but it can be done – and done efficiently, minimizing the impact on taxpayers and electricity consumers. The private sector will continue to be the primary source of capital for clean energy investment, but public finance also has an important role to play in driving deployment and adoption of innovative technologies, and in reducing the cost of these technologies. This paper describes the size and nature of the investment opportunities and challenges, the basic principles for minimizing financing costs and the ways in which good policies, regulation and market structures can help the money flow.

Minimizing financing costs will require policy, regulatory and market structures that:

- 1. Eliminate barriers to cost-effective financing.** Policy, regulatory or market structures that enable long-term debt and equity financing via liquid and competitive markets can increase the availability and decrease the cost of financing.
- 2. Enable investors to realize the full value of the new assets they deploy.** Currently, markets do not value some of the key benefits provided by renewable electricity, most notably, reductions in greenhouse gas emissions and other pollutants. At the same time, today’s electricity markets are not designed to reflect the value of technologies such as energy storage and flexible electricity supply or demand, partly because these markets tend to be based on a small set of products that don’t fully capture the unique attributes of these technologies. Investors will not finance these assets unless they are confident that markets, policies or regulatory structures are in place that will allow them to get paid for the full range of services they provide.

3. Focus on efficiently managing electric sector risks. Moving to a more capital-intensive electricity system means that financing costs play a more prominent role in determining the cost of electricity services. The cost of financing is closely tied to the risks borne by investors, such as policy, technical, market and system-wide risks. This suggests a greater focus on mitigating and managing risks in market, regulatory and policy design.

Policymakers have many options for achieving low-cost financing for the clean energy technologies consumers are demanding: Since markets, regulatory structures, and utility business models vary across the country, there is no one-size-fits-all approach to good policy. Nevertheless, policymakers everywhere have options that can spur cost-effective renewable energy financing locally.

INTRODUCTION

Financing a renewable future will require modernizing electricity regulation, policy and markets, but it can be done – and done efficiently, minimizing the impact on taxpayers and electricity consumers. This paper describes the size and nature of the investment opportunities and challenges, the basic principles for minimizing financing costs and the ways in which good policies, regulation and market structures can help the money flow. This paper addresses:

1. How much additional investment is needed to get to 80 percent renewables?
2. What are the barriers to scaling up investment at a reasonable cost?
3. What are the conditions necessary to enable low-cost financing of the system?
4. How can policy, regulation and market structures help create such a financing environment?

A RENEWABLE FUTURE REQUIRES SUSTAINED HIGHER LEVELS OF INVESTMENT

Achieving an 80 percent renewable electricity future will provide substantial energy security and resiliency, pollution reduction and climate benefits that far outweigh its costs. However, it requires substantial growth of capital investment in the electricity sector. Specifically, the 80 percent renewable futures scenarios considered by *RE Futures* require (in constant 2009 dollars):¹

- **Adding new renewable generation at two to five times the current rate, \$50-160 billion per year:** In recent years, the United States has spent roughly \$30-40 billion annually on new generation. This will need to increase dramatically. According to *RE Futures*, we will need to add somewhere between 25 and 70 GW per year annually until 2050, which will likely cost between \$50 billion and \$160 billion per year.
- **Greatly expanding energy storage capacity, an average of \$4-5 billion per year:** According to *RE Futures*, 100-152 GW of new storage will be necessary, compared to the 20GW of pumped hydro storage currently in place. Greater storage is needed in scenarios where flexibility resources are constrained; where there are fewer tools designed to manage variable resources, such as active

demand response that adjusts energy demand to match shifts in energy supply and geographically-expanded balancing areas.

- **Expanding transmission capacity over 40 years, \$6-9 billion per year:** The cost optimal scenario without significant transmission constraints, 110-190 million MW-miles of new transmission lines (compared to 150-200 million MW-miles of existing lines) and 47,500–80,000 MW of new intertie capacity across the three interconnections are required.² These additions require annual investment of roughly \$6.4-9 billion per year as compared to \$1.8 billion annually in a low-demand baseline scenario. Some of these transmission investments could also be offset by improved grid operations, which would be enabled by the policies proposed in *Renewing Transmission: Planning and Investing in a Re-wired, High Renewables Future*³. These estimates do not include continuing investment for maintenance or replacement of existing transmission capacity. In 2010, investor owned utilities invested over \$10 billion in all transmission projects including maintenance and replacement.⁴

In total, moving to an 80 percent renewables future will require investing roughly \$50-70 billion per year over the next decade, increasing to between \$100-200 billion per year as we approach 2050.⁵ This is roughly two to five times larger than current levels of investment in new transmission and generation assets in the electricity sector, but still small (0.5-1.5 percent of GDP) relative to the current size of the U.S. economy. Most of the additional investment required is for new renewable generation.

At present, 86 percent of the planned capacity additions as of early 2013 (both renewable and non-renewable) will be built by the private sector, either by shareholder owned utilities or by independent power producers. Though municipal utilities and electric co-operatives play a substantial role as well, the bulk of financing for electric generating capacity sector comes from the private sector. In the case of renewable generation, private investments are enabled in part by federal tax policies such as production and investment tax credits and accelerated depreciation.⁶

BARRIERS TO INVESTMENT

Given the current policy, regulatory and market environment, several challenges hinder investment in renewable generation assets and grid enhancements:

- 1. Markets are designed for financing conventional generation and undervalue renewable energy:** They have been designed to enable the financing of conventional generation with very different risks, benefits and cash flow profiles. Currently, markets do not value some of the key benefits provided by renewable electricity, most notably, the reduction in peak power prices, the hedge against volatile fuel pricing and reductions in carbon and other pollution. Federal tax incentives such as the production and investment tax credits have been critical to providing investors some compensation for these benefits, helping them achieve returns commensurate to the risks associated with wind and solar PV deployment.^{7,8} However, as these incentives have historically been temporary and unpredictable, they do not provide the investor certainty needed to support the level of renewable deployment required for an 80 percent renewable future. As a

result, sufficient financing will not flow to renewable projects unless renewable costs decline rapidly, key risks borne by investors can be mitigated or investors can realize the full value of the services and benefits provided by renewable energy generation in other ways.

- 2. System resources cannot be financed now based on their value in a renewable future:** The significant future system-wide benefits of electricity system resources (such as flexibility resources and energy storage) in 80 percent renewable scenarios will only be realized if we actually do move to more renewables. This creates a chicken and egg problem: we need flexible resources to enable renewables, but flexible resources aren't as valuable without renewables. So, we're trying to finance something today when its value may only be fully realized if we move to a high renewable future. Unless electricity markets, policy or regulation require the consideration of such a high renewable future contingency, investors who must decide whether to invest in grid resources cannot count on getting paid for the services they might

provide. Even if these contingencies are taken into consideration, it is difficult for investors to finance flexibility assets and transmission now on the basis of potential future revenue. For example, the Atlantic Wind Connection is a proposed transmission line that would carry power from offshore wind turbines to cities on the east coast. Offshore wind will be a large part of an 80 percent renewable generation portfolio, but the regional transmission plan only accounts for business-as-usual projections. This line would be much easier to finance and build if planning was based on realistic targets for renewable energy.⁹ Current wholesale markets must be expanded and modified to value these flexibility resources.¹⁰

3. Low energy demand discourages new investment: Many of the low demand growth scenarios studied in *RE Futures* require substantial increases in electricity sector investment during a period of little or no growth in demand. Historically, load growth – and the corresponding growth in electric sector revenues – has been well correlated with electricity sector investment.¹¹ Thus, utilities and other owners of generation assets face the challenge of finding new revenues to support significantly expanding investment in new electricity generation without the

expectation of growth in electricity sales.¹² Unless robust markets or other mechanisms are developed to compensate investors for the full suite of services and benefits of the new assets they build, they will not invest in expansion.

4. Stranded assets may raise financing costs: The risks to current electricity sector investors associated with an increased potential for stranded assets (such as coal or gas infrastructure and generation assets) in an 80 percent renewable scenario may lead to greater sector-wide capital costs. This could drive away investors who are not willing to bear such risks, and increase financing costs for new generation due to the need to offset portfolio losses associated with those old inflexible assets.

INVESTMENT WILL FLOW AT A REASONABLE COST IF RISKS AND REWARDS ARE BALANCED

Achieving a renewable future that minimizes additional costs to ratepayers and electricity consumers is a high priority for regulators and policymakers. An 80 percent renewable electricity system will likely feature much lower operating costs relative to our current system — due to free “fuel” for wind and solar generation — but the new system will be much more capital-intensive. This means that financing costs will play a more prominent role in determining the price of electricity services to consumers. A handful of specific conditions can stimulate the needed investment while minimizing financing costs.

Rational investors make decisions based on finding the right balance of risk and reward.¹³ Projects with higher risk demand higher rewards and projects with lower risk demand lower rewards. Investing in energy is no different. And the cost of financing energy assets – that is, the interest rates lenders require and the earnings that equity investors require – depends on the risks borne by investors. There are three basic strategies for achieving a balance of risks and rewards, which could reduce the cost and increase the availability of financing in an 80 percent renewable future:

1. Eliminate financing barriers – remove financing or other market failures, which reduce available capital and increase its cost for a fixed level of risk.
2. Increase rewards – compensate investors for services their assets provide that are not currently valued by electricity markets.
3. Reduce risks – mitigate or manage risks by allocating them to the actors who can most effectively manage them.

Note that these strategies are more effective when considered holistically – for example, increasing rewards through temporary tax incentives creates additional risk associated with uncertainty regarding the future of the policy, and leads to financing barriers associated with the relatively small market of investors who can use them. The next sections address how each of these strategies can be employed and identify policies that can minimize financing costs.

Eliminate financing barriers

If financial markets are not sufficiently liquid or competitive, investors may demand greater rewards than are commensurate to the risks they bear, resulting in reduced availability and increased cost of financing. For example, at present, financing for renewable generation relies on tax equity – investors who have enough tax liability to make use of federal tax incentives. However, in part due to the lack of political certainty associated with temporary renewable tax incentives, only 20 tax equity investors actively finance renewable projects in the U.S. today. The transactions are generally bilateral agreements that do not have as much transparency on prices or conditions as larger public debt or equity markets. Further, IRS rules require five years of continuous ownership to “vest” the investment tax credit, which restricts the liquidity of these investments.

A direct way to address this issue is to replace tax incentives with taxable cash incentives – this could allow renewable projects to access much larger debt and equity markets. Other mechanisms, such as making renewable energy eligible for master limited partnerships or real estate investment trust treatment, could increase the pool of investors with sufficient need for tax relief and provide liquidity as well – thereby potentially reducing financing costs.

Increase rewards

As we noted above, today’s electricity markets do not adequately compensate investors for the value provided by two critical services in a high renewables future – avoided pollution and system-wide grid flexibility services. Addressing market mechanisms for driving investment in grid flexibility services is a primary focus of another paper on market structures in this series, which contains details about the mechanisms that can be employed to value those services.¹⁴ The paper on market design illuminates the mechanisms available to provide sufficient compensation to enable investment in flexibility and energy storage assets. The related financing costs are tied to the impact of the chosen mechanism on the allocation of risks among market participants (discussed below).

At present, compensation for pollution reduction benefits is primarily addressed by federal tax incentives (including production and investment tax credits) and indirectly through state renewable portfolio standards. The tax incentives also compensate investors for bearing risks associated with the scale-up and deployment of a new technology. They have played a critical role in enabling the scale-up of renewable technologies across the country. Along with global technology improvements and economies of scale, they have helped to drive steep cost reductions over the last few years, making wind and solar increasingly competitive. Many investors expect that with sustained policy to drive continued deployment and cost reductions, wind and solar generation will be cost-competitive with traditional fossil fuel resources without federal support by the end of this decade. To provide investors with more certainty and to help achieve the 80 percent future, these tax credits should be extended for a significant length of time, rather than being allowed to expire every few years.

While existing tax credits have been successful, Congress could consider additional modifications to improve their performance reflecting market progress and value to taxpayers. As an example, these credits could be modified to include built-in adjustments, such as to reduce them as technology costs decline. And, Congress should always keep in mind that it may make sense to invest in clean energy via taxable cash grants, and not just by using the tax code. The key is that any changes be made incrementally, so that investors still have certainty.

Another approach to address this issue is the use of policy or regulation to place an effective price on pollution, and in particular, carbon emissions. The impact of such a price on financing costs is dependent upon how the price setting mechanisms impact the risks borne by investors – the more predictable and politically stable a carbon price is, the lower the risks and the lower the financing costs.

Reduce Risks

Effective management and allocation of risks is critical for reducing financing costs. This section reviews the risks most relevant to renewable projects and policies, and then estimates how much policy can bring down financing costs by reducing those risks.

The risks relevant to investment in renewable generation and related assets can be split into four categories – policy, political and social risks; technical and physical risks; market and commercial risks; and outcome risks.¹⁵

For example:

- Policy, political and social risks: Reliance on public resources (for example, tax credits) to make a project financially viable increases investors' perceptions of policy risks.

- Technical and physical risks: Most renewable energy technologies have been deployed recently and do not have decades of performance data, impacting perceptions about technical risks.
- Market and commercial risks: The long investment horizons, high upfront costs and lack of dedicated investors for renewable assets increase the perception of financing and liquidity risks.
- Outcome risks: Tight budgets and the relatively high cost of renewable support policies increase the public sector's uncertainty around sticking to and achieving public targets.

As a general principle, each of these risks should be borne by actors who have:

- Good information about the risk.
- The financial capacity to withstand or hedge the impacts of an adverse event associated with the risk.
- Operational control or authority that enables them to mitigate the outcome of an adverse risk event.

Based on these criteria, the following table maps these risks, the actors best able to manage them and the kinds of policy, regulatory or market structures that can help to mitigate them:

RISKS	DESCRIPTION	SOURCES OF RISK	BEST MANAGED BY	MITIGATED BY
Political, Policy, and Social	Risks associated with project dependence or exposure to government or societal actions	<ul style="list-style-type: none"> • Reliance on public finance • Investment horizon longer than political cycle • Environmental consequences 	Public sector	Stable, long-term policies and regulations with low budgetary impact
Technical and Physical	Technology or site specific risks such as construction risk, operation risks, and risks associated with variability in natural resource inputs	<ul style="list-style-type: none"> • Unproven technology • Lack of performance data • Lack of resource data 	Private sector, public-private partnership for innovative technologies	Public support for resource and data collection as well as risk pooling for innovative technologies
Market and Commercial	Economic risks such as price volatility in inputs or outputs, cost, liquidity risks, and counterparty risks	<ul style="list-style-type: none"> • High up-front costs • Long payback period • Financial complexity 	Private sector	Functioning markets for electricity services, related derivatives, private-party contracts
Outcome	Uncertain achievement or costs of public goals such as emissions reductions or economic growth	<ul style="list-style-type: none"> • Budgetary constraints • Public and political support for goals 	Public sector, with project-related outcome risk shared with private sector	Clear, long-term public policy goals

Figure 1. Risks related to renewable projects and policies.

How much can the policies to mitigate these risks reduce financing costs? To address this question, the Climate Policy Initiative modeled the impacts of different policies on the financing costs of a few representative renewable projects in developed nations. Policies generally impact

financing costs through seven pathways: duration of revenue support, revenue certainty, risk perception, completion certainty, cost certainty, risk distribution and development risks.¹⁶ The table below discusses these pathways, the risks involved and their relative impacts.

POLICY IMPACT PATHWAY	POTENTIAL IMPACT ON FINANCING COSTS
Duration of Revenue Support (<i>Market and Commercial Risks</i>)	Whether support is concentrated in early years or spread over the life of a project determines how a project is financed and thus the cost. For example, increasing the term of a contract or support policy from 10 to 20 years decreases financing costs by 10-15 percent.
Revenue Certainty (<i>Market and Commercial Risks</i>)	Exposure to price risks of commodity markets can reduce the amount of debt a project can support and the cost of both debt and equity, potentially increasing financing costs by 5-10 percent.
Risk Perception (<i>Policy and Technical Risks</i>)	Higher perceived risks may lead investors to demand higher returns or more security to compensate, increasing financing costs by 2-9 percent.
Completion Certainty (<i>Policy and Technical Risks</i>)	The risk of delayed revenues due to late project completion can reduce achievable leverage and may increase financing costs by less than 5 percent.
Cost Certainty (<i>Policy and Technical Risks</i>)	The risk of unexpected costs – sometimes policy driven – can also increase the costs of financing by less than 5 percent due to the reduced amount of debt providers are willing to commit.
Risk Distribution (<i>Policy and Technical Risks</i>)	The ability to and cost of bearing certain risks will vary among investors, suppliers, consumers, and others. By changing which risks (e.g. commodity prices or inflation) are absorbed by which project stakeholder, policy can reduce or increase the financial cost of projects.
Development Risks (<i>Policy and Technical Risks</i>)	The cost and success rate of developing a project will affect the attractiveness of the industry. A more attractive industry will have more competition, driving costs down.

Figure 2. Policy Impact Pathways and Potential Impact on Financing Costs.

Policies, regulations and market structures can significantly reduce financing costs by enabling long-term supports or contracts (10-15 percent cost reduction), reducing revenue volatility (5-10 percent cost reduction) and reducing investor perceptions of project risks (2-9 percent cost reductions). The large impact of the first two pathways is due to the fact that they reduce market and commercial risks, thereby enabling the project to increase the amount and term of low-cost long-term financing such as project debt. Reductions in investor perceptions of project risk often involve reducing policy,

political and social risks. This can be done by increasing policy certainty, granting pre-approval for siting and interconnection or ensuring that power contracts are not subject to retroactive review by the Public Utilities Commission. Policies can also reduce risk perceptions by reducing technical and physical risks. However, the more direct impact of reducing technical or physical risks is increasing completion and cost certainty and reducing development risks, which have a much smaller impact on financing costs (less than 5 percent cost reduction).

LOW COST FINANCING FOR RENEWABLES IS FEASIBLE

For policymakers, the key is to build a policy environment that effectively addresses the important risks in clean energy development. Broadly speaking, the best policies are those that – in the words of Deutsche Bank – provide “TLC”: transparency, longevity and certainty.¹⁷ Put another way, investors just want to know what the rules of the road will be going forward. As an example, incentives are much more valuable if they have long lives, rather than needing to be renewed every year.

There is one policy that would benefit every renewable project: putting a price on carbon. Both the American Enterprise Institute and the Center for American Progress have proposed doing this via a carbon tax. The President called for a price on carbon in his most recent State of the Union address. And a cap-and-trade system passed the House of Representatives with bipartisan support in 2009. Additionally, national renewable and clean energy standards, which have been proposed in Congress, would establish long-term targets and provide important long-term market signals to investors. Any of these policies would go a long way towards making sure that renewable energy’s qualities are fully valued in the marketplace.

Beyond a price on carbon, smart policies will match the needs (and risks) of specific investments. The research presented here, the *RE Futures* report, and other papers in this series all come to the same conclusion: no single technology, no single business model and no single

market design will dominate the energy future. And, each combination of technology, business model and market design will call for different financing structures, each of which can be enabled by a different set of policy tools.

For example, in an environment where a vertically integrated regulated utility is building large-scale renewables, a significant part of the technological performance risk is borne by ratepayers. If the technology doesn’t perform as expected, the utility will likely be able to recoup some of the costs from their consumers, as approved by the relevant state regulator. On the other hand, when an independent power producer builds a renewable project and sells the power to utilities through a wholesale power market, the investor is bearing the technological performance risk. If this risk is large, then it will add a significant amount to the cost of capital for the independent power producer, but it will make a much smaller difference for the regulated utility. This means that policymakers will need to create tools to manage technological performance risk in deregulated markets, in order to drive more financing. They could do this by offering some type of project performance insurance or warranty.

To dig deeper into this, the renewables market can be broken into three categories:

- Utility-scale, regulated. This market covers large-scale power plants owned by the utilities that serve end-users of electricity. These utilities can have several ownership models: investor-owned, cooperatives and municipally-owned.
- Utility-scale, deregulated. This market covers large-scale power plants owned by independent companies that sell the power to the utilities that serve end-users of electricity.
- Distributed generation. This market covers smaller projects located directly on the distribution grid and typically owned (either directly or through a lease or contract) by businesses or homeowners.

Figure 3. Sources of capital and key policies for low-cost financing, by market segment.

MARKET SEGMENT	TYPICAL SOURCES OF CAPITAL	KEY POLICIES TO ENABLE MORE LOW-COST FINANCING
UTILITY-SCALE, REGULATED	<p>INVESTOR-OWNED UTILITIES</p> <ul style="list-style-type: none"> • Public equity. • Corporate debt via capital markets. • Tax incentives. <p>MUNICIPAL UTILITIES</p> <ul style="list-style-type: none"> • Municipal debt. • Tax-advantaged bonds. • Ratepayers. <p>COOPERATIVE UTILITIES</p> <ul style="list-style-type: none"> • Rural Utilities Service. • Tax-advantaged bonds. • Member equity. 	<p>Continue access to public equity markets through beneficial treatment of dividends. Investors in utility stocks are typically attracted by the dividend yields, which are both stable and tax-advantaged. If dividends were taxed as personal income instead of as capital gains, the cost of raising money via public equity markets would go up. <i>Key actor: Congress.</i></p> <p>Re-authorize Clean Renewable Energy Bonds. Non-profit municipal and cooperative utilities don't benefit from tax incentives. Clean Renewable Energy Bonds carry tax benefits, so that utilities can sell these bonds at a very low rate and investors benefit from the tax benefit and not just the yield. This program should be re-authorized by Congress. <i>Key actor: Congress.</i></p> <p>Direct Rural Utilities Service (RUS) to focus on renewable energy. The RUS provides low-cost financing to cooperatives for a variety of purposes, including building new generation. RUS should focus its generation financing on renewable energy. <i>Key actor: Congress, President, U.S. Department of Agriculture.</i></p>
UTILITY-SCALE, DEREGULATED	<ul style="list-style-type: none"> • Private equity. • Project finance debt. • Public equity markets. • Tax equity. 	<p>Open up public equity. Though important to the success of renewable energy development, private equity is both expensive and relatively rare. Independent power producers would benefit from having better access to public markets as well. One way to do this would be by allowing renewables companies to organize as MLPs or REITs, both of which are currently off-limits to clean energy. These instruments are publicly traded and have a tax benefit, since MLPs don't pay corporate taxes and REIT dividends are tax-deductible. <i>Key actors: Congress, U.S. Treasury Department.</i></p> <p>Make incentives available to more investors by transitioning to refundable tax credits or taxable cash grants. The additional costs of bringing tax equity into a project consume some value of the tax incentives available to a project. The government can get a better "bang for its buck" by instead offering taxable cash or refundable incentives, as described by the Climate Policy Initiative and the Bipartisan Policy Center.^{18,19} <i>Key actor: Congress.</i></p>

MARKET SEGMENT	TYPICAL SOURCES OF CAPITAL	KEY POLICIES TO ENABLE MORE LOW-COST FINANCING
<p>DISTRIBUTED GENERATION</p>	<ul style="list-style-type: none"> • Private equity. • Project finance debt. • Tax equity. • Cash incentives. 	<p>Clarify net metering rules so that they remain stable for the long term.²⁰ Most distributed generation projects rely on net metering as a source of revenue. When net metering rules are open to change over time, the benefit is discounted by investors. States should act now to make sure that net metering policies are financially sustainable far into the future and that any negative impacts from cross-subsidization are avoided. By addressing these challenges early, policymakers can make this revenue stream much more certain. <i>Key actors: utilities, state public utility commissions, state legislatures.</i></p> <p>Allow long-term contracts for distributed generation. Utilities provide long-term, fixed price power purchase agreements for large-scale renewable generation. They could make distributed generation eligible for similar contracts. Such contracts provide the long-term, certain revenues needed to enable low-cost debt financing of distributed generation. <i>Key actors: utilities, state public utility commissions, state legislatures.</i></p> <p>Allow new financing and ownership structures. Third-party ownership of distributed generation has enabled rapid deployment by helping consumers avoid upfront costs. Yet, some states have rules that discourage these business models. Policymakers should make sure that every consumer has access to innovative low-cost financing solutions for distributed generation.²¹ <i>Key actors: state public utility commissions, state legislatures.</i></p> <p>Move from private capital to public capital. Just like in the utility-scale deregulated market, these projects would benefit from access to public equity markets and debt securitization. The same recommendations apply here. <i>Key actors: Congress, U.S. Treasury Department.</i></p> <p>Enable securitization of project debt. The secondary market for project debt is basically non-existent, and securitization could bring this market to life. The government should work with the private sector to encourage standardization of contracts. Any future federal green bank should also work to enable securitization, similar to Fannie Mae’s function in the housing market. <i>Key actors: U.S. Department of Energy, potential future federal green bank, Congress.</i></p> <p>Provide low-cost project debt through state green banks. State green banks can lend money at preferred rates, since states have ready access to low-cost capital. The exact structure of the bank in each state will determine the products they offer, but co-lending and other public/private partnerships are especially promising. State green banks are likely to be relatively small in scale and will want to invest in multiple projects, so they’re uniquely well-suited to the distributed generation market. <i>Key actor: state legislatures.</i></p> <p>Use municipal debt to finance projects through commercial Property Assessed Clean Energy. Cities can lend money to businesses and residents to build clean energy projects, and the borrowers re-pay the loans on their tax bill. This is known as Property Assessed Clean Energy, or PACE. While residential PACE programs have largely been halted due to Federal Housing and Finance Authority (FHFA) policy, commercial PACE does not have the same challenges, and can move forward quickly. Placing debt on the property tax bill adds security and thereby lowers financing cost. <i>Key actor: municipal governments, state legislatures.</i></p> <p>Allow consumers to repay financing for distributed generation on their utility bills. Utility bill-based repayment of distributed generation financing could lower financing costs through increased security and clarify to consumers the economic benefits of distributed generation investments.</p>

SUMMARY OF RECOMMENDATIONS

DECISION-MAKER	RECOMMENDATION
Congress	Continue access to public equity markets through beneficial treatment of dividends as capital gains.
Congress	Re-authorize Clean Renewable Energy Bonds.
Congress, President, U.S. Department of Agriculture	Direct Rural Utilities Service to focus on renewable energy.
Congress, U.S. Treasury	Transition from private to public equity by making renewable energy eligible for new corporate structures, such as Master Limited Partnerships and Real Estate Investment Trusts.
Congress, U.S. Department of Energy, potential federal green bank	Enable securitization of project debt. Any future federal green bank should also work to enable securitization, similar to Fannie Mae's function in the housing market.
Congress	Make permanent or provide long-term extensions of the critical tax credits, and explore possible revisions to the credits such as taxable cash incentives or refundability.
Public Utilities Commissions (PUCs), state legislatures, utilities	Clarify net metering rules so that they remain stable for the long term.
PUCs, state legislatures, utilities	Allow long-term contracts for distributed generation.
PUCs, state legislatures	Allow new financing and ownership structures, including third-party ownership.
State legislatures	Provide low-cost project debt through state green banks.
Municipal governments, state legislatures	Use municipal debt to finance projects through "Commercial PACE."

CONCLUSION

A high-renewable energy future requires substantially expanded investment in the electricity sector, particularly in renewable generation assets. This will require a much more capital-intensive electricity sector, and result in electricity prices, which are much more sensitive to financing costs (although it will also be less fuel intensive and less sensitive to fossil fuel costs). As a result, policy, market and regulatory structures throughout the country face the challenge of increasing investment while reducing financing costs. There are three key strategies for achieving this goal, and a diverse set of policy, regulatory and market structures, which can be used to pursue them:

1. Eliminate barriers to accessing liquid and competitive financing markets.

Enabling access to larger, more liquid financing markets – such as through new partnership structures, public debt or securitization – can help increase the pool of potential investors and decrease financing costs.

2. Enable investors to realize the full value of the new assets they deploy.

A stable price on carbon emissions through one of any number of policy or regulatory mechanisms can help investors in renewable generation monetize the emissions reduction

benefits of their assets. Similarly, several options for driving investment in flexibility and energy storage services through appropriate forward markets that reflect the value of those services have been discussed in the market structures paper.²²

3. Focus on enabling electricity sector stakeholders to efficiently manage risks.

Policy, regulatory and market structures that enable long-term, stable revenues and reduce investor perceptions of risk can substantially reduce financing costs. For example, a stable, increasing carbon price or a renewable electricity standard that uses long-term power purchase agreements or Renewable Energy Credit contracts can enable low-cost financing of renewable generation.

By taking the important steps laid out in this paper, policy, market and regulatory structures throughout the country can adapt to drive sufficient low-cost financing to make a high share of renewables a reality. This is a national imperative: shifting to a renewable future will reduce pollution, enhance our economy, and free us from reliance on finite fossil fuel resources.

ENDNOTES

- 1 Edison Electric Institute, 2012. "2011 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry." <<http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FinancialReview.pdf>>
- 2 Note that NREL considered a scenario with significant constraints on new transmission, including disallowing any new interties or transmission corridors, tripling the cost of new lines and doubling their losses. In this case, less than 30 million MW-miles of new lines were required, but at triple the cost, leading to investment requirements comparable to the low-end of the range. The transmission constraint increased electricity system costs by about 5 percent relative to the 80 percent scenario without it. The America's Power Plan report by Jimison and White discusses in greater detail how the current grid can be optimized to enable reliable operation when faced with such constraints.
- 3 See America's Power Plan report by Jimison and White.
- 4 Edison Electric Institute, 2012.
- 5 On the path to an 80 percent renewable scenario, conventional generation will be relied upon less for the energy it provides and more for its ability to provide operational flexibility to the grid. As a result, there will be a significant decline in the need for inflexible conventional generation. This is likely to include disinvestment in assets, which are not fully depreciated. The exact amount and type of stranded assets will depend on the pathway we take to get to 80 percent renewables. For example, analysis from the Center for American Progress has found that we can likely avoid any uneconomic retirements of natural gas capacity, but only if we just build power plants that are currently in the planning stage and if we retire plants on their 45th birthday, starting in 2023.
- 6 American Public Power Association, 2013. "APPA Report on New Generating Capacity: 2013 Update." <http://www.publicpower.org/files/PDFs/New_plants_analysis_2013.pdf>
- 7 Varadarajan, Uday, et al, 2012. "Supporting Renewables while Saving Taxpayers Money." Climate Policy Initiative. <<http://climatepolicyinitiative.org/wp-content/uploads/2012/09/Supporting-Renewables-while-Saving-Taxpayers-Money.pdf>>
- 8 Federal tax incentives covered roughly half the gap between the cost of wind and solar PV generation in 2010 and expected revenues at market electricity prices. At 2013 costs, wind is nearly competitive with federal incentives alone.
- 9 Wald, Matthew L., 2013. "1st Par of Offshore Wind Power Line Moves Ahead." The New York Times. <http://www.nytimes.com/2013/01/15/business/energy-environment/an-offshore-wind-power-line-moves-ahead.html?_r=2&>
- 10 See America's Power Plan report by Hogan.
- 11 Edison Electric Institute, 2012.
- 12 See America's Power Plan report by Lehr.
- 13 There are non-risk/reward factors that influence decisions, of course. A company with a history of building nuclear power plants and a team of nuclear engineers is likely to invest more in nuclear power, just based on familiarity. Our assumption is that these soft biases against renewable energy will be overwhelmed by the national commitment required to get to 80 percent renewables.
- 14 See America's Power Plan report by Hogan.
- 15 Frisari, Gianleo, et al, 2013. "Risk Gaps: A Map of Risk Mitigation Instruments for Clean Investments." Climate Policy Initiative. <<http://climatepolicyinitiative.org/wp-content/uploads/2013/01/Risk-Gaps-A-Map-of-Risk-Mitigation-Instruments-for-Clean-Investments.pdf>>
- 16 Varadarajan, Uday, et al, 2011. "The Impacts of Policy on the Financing of Renewable Projects: A Case Study Analysis." Climate Policy Initiative. <<http://climatepolicyinitiative.org/wp-content/uploads/2011/12/Policy-Impacts-on-Financing-of-Renewables.pdf>>
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- 19 Mackler, Sasha, 2011. "Reassessing Renewable Energy Subsidies." Bipartisan Policy Center. <http://bipartisanpolicy.org/sites/default/files/BPC_RE%20Issue%20Brief_3-22.pdf>
- 20 See America's Power Plan report by Wiedman and Beach.
- 21 See America's Power Plan report by Wiedman and Beach.
- 22 See America's Power Plan report by Hogan.



DISTRIBUTED
ENERGY RESOURCES:

Policy Implications of Decentralization

James Newcomb, Virginia Lacy,
Lena Hansen, and Mathias Bell
with Rocky Mountain Institute

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EXECUTIVE SUMMARY

With smart thermostats, efficient refrigerators, and solar panels all available at the local hardware store, the role of distributed energy resources is growing. Distributed energy resources can deliver clean electricity on site, reduce electricity demand and provide much-needed grid flexibility. Ensuring that policies and markets adequately support distributed resources to keep costs low, enhance reliability, and support clean energy integration, however, will require special attention to:

1. *Measure the full range of costs and benefits for distributed energy resources.* Consistent and comprehensive methods for measuring the costs and benefits of all available resources will create transparency, help deliver reliability, and provide a foundation for designing effective incentives, pricing structures, and markets.
2. *Analyze tradeoffs between centralized and distributed resource portfolios.* New studies at national, regional, and local levels can help to shed light on how to optimize the mix of centralized and distributed renewables.
3. *Integrate distributed energy resources into resource planning processes.* Planning processes at all levels—federal, regional, state, and utility—can be adapted to provide greater visibility into distributed resource options and their implications.
4. *Create new electric utility business models for a distributed-resource future.* New utility business models can be devised that ensure the stability and health of the grid and incentivize integration of distributed resources.
5. *Adapt wholesale markets to allow distributed resources to compete fully and fairly.* With evolved market rules, all kinds of distributed resources could compete to provide a wide range of energy and ancillary services in competitive markets.

6. *Enable microgrids and virtual power plants to support integration and aggregation of distributed resources.* Microgrid control systems enable better integration of local renewable resources and provide greater capabilities to manage these resources in response to grid conditions.
7. *Drive down “soft costs” for solar by streamlining permitting and interconnection procedures.* Regulators and policymakers can help to reduce the costs of permitting, inspection, and interconnection to significantly reduce the costs of distributed solar.
8. *Encourage smart electric vehicle charging.* Smart charging of electric vehicles can help to support the integration of high levels of variable renewable generation into the grid and provide efficiency and environmental benefits in the transportation sector.

Creating a level playing field for centralized and distributed resources will require significant changes in electric utility business models and electricity markets, as well as other changes in regulation and policy to adapt to rapidly evolving technology.

THE ROLE OF DISTRIBUTED RESOURCES IN A RENEWABLE ENERGY FUTURE

Distributed resources* can play a key role in helping to achieve a renewable electricity future in the United States by: (a) providing direct contributions to renewable electricity supply, (b) reducing electricity demand and (c) providing flexibility resources† that allow integration of high proportions of variable renewable supplies into the electricity supply portfolio. In this paper, we identify key opportunities and make specific recommendations for U.S. policymakers and regulators to shape distributed resource development for greatest overall benefit to the nation in line with achieving a renewable electricity supply goal of 80 percent or greater by 2050.

Distributed resources in *RE Futures*: Lessons and limitations

NREL's *Renewable Electricity Futures Study (RE Futures)* analyzes alternative scenarios for achieving 80percent renewable electricity supply by 2050. The study's analysis is largely focused on devising the least-cost portfolio of investments in large-scale renewable supplies, transmission and storage assets to reliably meet electricity demand over the period 2010–2050. Yet, a complementary portfolio of smaller-scale distributed resources, whose market penetrations are determined

by assumptions rather than optimized by the study's analysis, play important roles in each of the 80 percent renewable scenarios. These resources and their corresponding assumptions include:

- Investments in **energy efficiency** to significantly reduce electricity use in buildings and industry, allowing room for demand growth from electric vehicles while keeping average annual electricity demand growth to just 0.2 percent. Without these measures, the total present value of electricity sector costs to achieve 80 percent renewable electricity supply would be \$844 billion higher, while average retail electricity prices would be 6percent higher (see Table 1).
- Increased **demand-side flexibility**, to reduce the need for grid-scale energy storage and other costly supply-side flexibility resources such as fast-response generation. *RE Futures* assumes demand response reduces peak demand by 16–24 percent in 2050 compared to 1–8 percent today.

* Distributed resources include: energy efficiency, demand response, distributed generation and storage (both thermal and electric), and smart electric vehicle charging.

† Flexibility resources allow electricity supply and demand to be balanced over time. With high penetrations of variable renewable generation, flexibility is especially important. Distributed flexibility resources include demand response, controlled electric vehicle charging, distributed storage and dispatchable distributed generation.

- **Electric vehicle** penetration reaches 154 million vehicles by 2050, with half subject to utility-controlled charging.
- Significantly expanded use of **demand-side thermal energy storage** is assumed to shift load away from critical periods, reducing costs of energy and system capacity.
- **Distributed solar PV** capacity reaches 85 GW by 2050 compared with 4.4 GW installed as of the end of 2012,¹ providing additional renewable electricity supply beyond that provided by grid-scale renewable resources.

	Low-Demand 80% RE	High-Demand 80% RE	Difference
PRESENT VALUE OF SYSTEM COSTS 2011–2050 (BILLION 2009\$)	\$4,860	\$5,704	+17%
AVERAGE RETAIL ELECTRICITY PRICE, 2050 (2009\$/MWH)	\$154	\$163	+6%

Source: NREL, *Renewable Electricity Futures Study* (2012);
Rocky Mountain Institute (RMI) analysis.

Table 1. Comparison of present value system costs and average retail electricity price in low- and high-demand scenarios for 80 percent renewable electricity (*RE Futures*)

The implications for regulators and policymakers are clear: achieving a renewable electricity future is not just a matter of driving new investments in large-scale renewable electricity supplies and transmission assets via supply-oriented policies such as renewable portfolio standards or tax incentives for renewable generation. Distributed resources are key enablers of a high-renewables future in almost any scenario and they may, in fact, provide the engine for a far-reaching transformation of the U.S. electricity sector toward a cleaner, more secure and resilient future.

Indeed, the rapidly falling costs of distributed resources, coupled with shifting customer demands and innovative new business models for delivering distributed resources, could mean that small-scale, local solutions might actually provide a large share of the resources needed to achieve a renewable electricity future. Analysis conducted by RMI using NREL's Regional Energy Deployment System (ReEDS) model suggests that distributed resources could provide half of renewable electricity supply in an 80 percent renewables future, compared with just 3–7 percent in *RE Futures'* core scenarios.

Ensuring that distributed resources are adequately developed to support a high-renewables future will require special attention from regulators and policymakers. In general, existing utility business models typically do not provide a level playing field for investment in distributed versus centralized resources, and distributed resources are only beginning to be allowed to participate in wholesale markets, if at all. Moreover, increased investment in distributed resources could lead to waste or duplication if these investments are not made in ways that integrate with and provide value to both the customer and the electricity grid. Realizing the full opportunity from distributed resources will require new approaches to grid operations and system planning in parallel with new methods for measuring, creating and capturing value. Together, these changes will have significant implications for the electricity value chain, creating new roles and sources of value for customers, utilities and new entrants.

	NREL	Reinventing Fire	
	RE FUTURES	RENEW	TRANSFORM
SHARE OF DISTRIBUTED RESOURCES			
Distributed renewable generation as % of total 2050 generation	2.6–5.2%	3.3%	33.8%
Distributed solar PV as % of total 2050 generation	2.6–5.2%	3.3%	23.7%
Demand response: % of peak load, 2050	16-24%	16-24%	16-24%
NPV OF INVESTMENT REQUIRED 2011–2050 (BILLION 2009\$, 3% DISCOUNT RATE)			
Conventional	\$2,232.49	\$2,714.56	\$2,178.02
Renewable energy	\$2,360.71	\$1,774.41	\$2,659.20
Transmission	\$97.95	\$59.79	\$54.59
Storage	\$168.57	\$166.39	\$103.57
Total	\$4,860	\$4,715	\$4,995
ELECTRIC VEHICLE PENETRATION			
Total number of EVs, 2050 (million)	154	157	157
Average retail electricity price, 2050 (2009\$/MWh)	\$154	\$129	\$134

NREL's *RE Futures* case examines how the U.S. can operate an electricity grid with 80 percent of all generation coming from renewable resources (see *RE Futures*' 80 percent-IT1 core scenario). The "Renew" and "Transform" cases were two of four scenarios RMI evaluated in *Reinventing Fire* (2011). The "Renew" case explores a future U.S. electricity system in which a portfolio composed of largely centralized renewables provides at least 80 percent of 2050 electricity supply. The "Transform" case assumes aggressive energy efficiency adoption, with approximately half of all generation provided by distributed resources, while still meeting an 80 percent renewable supply goal. All three cases used NREL's ReEDS model for the analysis. The *RE Futures* study and *Reinventing Fire* differ in many inputs and assumptions, including energy demand, technology cost reductions and smart grid capabilities.

Source: NREL, *Renewable Electricity Futures Study* (2012); RMI analysis.

Table 2. Comparison of high-renewable-scenario analyses

This paper discusses steps that policymakers can take to unlock the power of distributed resources to support the achievement of a renewable electricity future for greatest societal benefit. These recommendations fall in three major categories:

1. Analyzing the options:

- a. *Measure the full range of costs and benefits for distributed energy resources.* Consistent and comprehensive methods for measuring the costs and benefits of different resources will create greater transparency for all stakeholders and provide a foundation for designing effective incentives, pricing structures and markets.
- b. *Analyze tradeoffs between centralized and distributed resource portfolios.* New studies at national, regional and local levels can help to shed light on how to optimize the mix of centralized and distributed renewables.
- c. *Integrate distributed energy resources into resource planning processes.* Planning processes at all levels—federal, regional, state and utility—can be adapted to provide greater visibility into distributed resource options and implications.

2. Revamping the rules of the game to level the playing field:

- a. *Create new electric utility business models for a distributed resource future.* New utility business models can be devised that ensure the stability and health of the grid and incentivize integration of distributed resources in ways that create greatest value.
- b. *Adapt wholesale markets to allow distributed resources to compete fully and fairly.* The success of demand response aggregation has paved the way for better integration of distributed resources into wholesale markets. In the future, all kinds of distributed resources could compete to provide a wider range of energy and ancillary services in competitive markets.

3. Encouraging innovative technologies and service models to speed adoption and integration of distributed and renewable resources:

- a. *Enable microgrids and virtual power plants to support integration and aggregation of distributed resources.* Microgrid control systems can allow better integration of local renewable resources and provide greater capabilities to manage these resources in response to grid conditions.
- b. *Drive down the “soft costs” for solar PV by streamlining permitting and interconnection procedures.* Regulators and policymakers can help to reduce the costs of permitting, inspection and interconnection by implementing best practices that will significantly reduce the costs of solar PV.
- c. *Encourage smart electric vehicle charging.* Smart charging of electric vehicles can help to support the integration of high levels of variable renewable generation into the grid and provide efficiency and environmental benefits in the transportation sector. An integrated view of distributed resource opportunities can help to achieve both goals.

MEASURE THE FULL RANGE OF COSTS AND BENEFITS FOR DISTRIBUTED RESOURCES

Distributed energy resources are dispersed, modular and small compared to conventional power plants, and these different characteristics mean that they incur different costs and create different benefits not typically accounted for and not reflected in simple busbar costs. The “hidden value” of distributed resources can include avoided line losses, reduced financial risk (including fuel price hedge value and increased optionality in investment timing), deferred or avoided generation and delivery capacity, environmental benefits and local economic development. Some of distributed resources’ costs and benefits do not accrue directly to the utility or to specific customers but rather to society as a whole, such as environmental benefits, creating a mismatch between who pays and who benefits. Regulators and policymakers should drive for comprehensive assessment of all sources of cost and benefit as the basis for creating a level playing field that takes into consideration the factors that matter to customers and to society at large.

Properly measuring and valuing the full range of costs and benefits is a critical step to enabling the efficient and economic deployment of distributed resources. While methods for identifying, assessing and quantifying the costs and benefits of distributed resources are advancing rapidly, important gaps remain to be filled before this type of analysis can provide an adequate foundation for policymakers and regulators engaged in determining levels of incentives, fees and pricing structures for different types of resources. An RMI assessment of 13 studies conducted by national labs, utilities and other organizations between 2005 and 2013 reveals important differences in assumptions and methodologies, driving widely varying results (see figure 1: Costs and Benefits of Distributed PV by Study).²

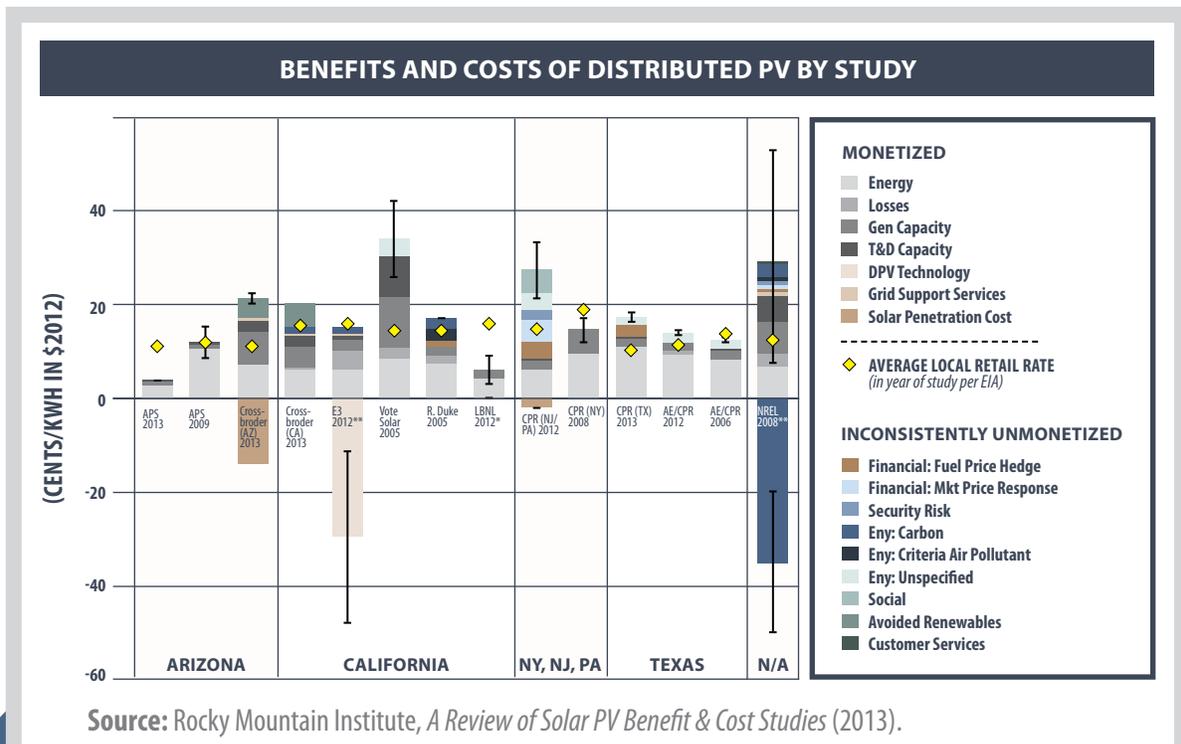


Figure 1. Costs and benefits of distributed PV by study

The wide variation in analytic approaches and quantitative tools used by different parties in various jurisdictions is inconsistent, confusing and frequently lacking transparency. Regulators and policymakers should raise the bar for cost-and-benefit analyses by requiring that these studies:

- **Assess the full spectrum of costs and benefits**, including those related to risk, resilience, reliability, environmental consequences and economic development impacts; identify unmonetized costs and benefits; and evaluate how costs and benefits accrue to various stakeholders.
- **Standardize data collection and analysis methods** to ensure accountability and verifiability of cost and benefit estimates.
- **Use transparent, comprehensive and rigorous analysis approaches, adopt best practices nationally, and allow expert- and stakeholder-review of analysis methods.**

DECISION-MAKER	RECOMMENDATION
PUCs ³	Develop and implement a transparent, consistent framework for the evaluation of distributed resources that encompasses the full range of costs and benefits relevant to these resources.
NARUC and/or DOE	Create a multi-stakeholder taskforce to evaluate and establish best practices and guidelines for the evaluation of distributed resources, to create consistency across regions and provide support to individual PUCs and other stakeholders.

Additionally, policymakers can bring greater visibility to distribution system utilization and costs, creating opportunities for cost reductions in high-renewables systems. Evaluating the impacts of distributed energy technologies on the electricity grid is difficult, due in part to the lack of detailed information about capacity utilization for electricity distribution feeders and the timing and capital costs of system reinforcements and expansions. While detailed distribution feeder information resides with distribution utilities, relatively little, if any, of this information is accessible to the public or researchers.

Several significant efforts are starting to address this need. As part of an effort to streamline the analysis required for a distributed PV interconnection request, a collaboration of Sandia National Laboratory, Electric Power Research Institute (EPRI), NREL and other national labs is developing a method to group and classify distribution feeders in a utility service territory to characterize the capacity of individual feeders to accept new PV projects. These efforts will help to simplify and standardize the analysis needed to evaluate the costs and benefits of distributed energy resources in unique electricity system territories.

DECISION-MAKER	RECOMMENDATION
PUCs	Require access to data on distribution system utilization and marginal costs of expansion to support the evaluation of distributed energy resources.
DOE	Support national laboratories' development of new methods that simplify and streamline analysis of distribution feeders.

ANALYZE TRADEOFFS BETWEEN CENTRALIZED AND DISTRIBUTED RESOURCE PORTFOLIOS

While a growing number of studies exist to describe high-renewables electricity futures for the U.S.,⁴ surprisingly little research is available to evaluate the tradeoffs between different portfolios of centralized and distributed renewable resources. Deeper analysis of the implications of alternative resource portfolios at the national, regional and local level will help to support better regulatory and policy decision-making and help to find the least-cost ways of achieving a renewable electricity future.

Existing national and regional studies describe an extremely wide range of alternative paths to achieve a high-renewables future. For example, the amount of distributed solar PV deployed by 2050 ranges from 85 GW in NREL's *RE Futures* study to 240 GW in the U.S. Department of Energy's *Sunshot Vision Study* to more than 700 GW in Rocky Mountain Institute's *Reinventing Fire* Transform scenario (see table 2). All three scenarios were analyzed using NREL's ReEds model.

Alternative portfolios of centralized and distributed renewable resources have significantly different attributes, not only in cost, but also in environmental impact, implications for economic development, financial risk, security, reliability and resilience. While policymakers and regulators are often mindful of these attributes in making their decisions, the analytic gaps left by existing studies leaves them shooting in the dark in trying to map a path to a renewable electricity future that delivers the greatest benefits to customers and society.

Six states have incorporated carve-outs into their renewable portfolio standard policies, stipulating that a portion of the required renewable supplies be derived from solar resources⁵ and others have created "credit multipliers" that allow distributed resources to earn extra credit toward achieving renewable portfolio requirements. Yet, these approaches are, at best, stopgap measures intended to remedy the lack of a level, competitive playing field, taking into consideration the values that policymakers believe should influence portfolio choices.

Ensuring that centralized and distributed renewable resources compete on a level playing field will be one of the most important challenges facing policymakers, regulators and electric utility planners in the decades ahead. Policymakers at all levels should support the development of better modeling and analysis tools to evaluate tradeoffs between different types of renewable portfolios. In integrated resource planning (IRP)-driven jurisdictions, state PUCs can require that utility planning processes explicitly explore tradeoffs between alternative centralized and distributed portfolios (see recommendations regarding utility resource planning below).

One reason for this important gap in existing analysis is the complexity and difficulty of creating models that can optimize the overall portfolio of distributed and centralized resources. Existing models more easily address utility-scale resources than they do small-scale, heterogeneous, distributed resources. New approaches are now being developed to work through the implications of different combinations of distributed and centralized resources in terms of the needed investments in generation, transmission and distribution grid infrastructure.⁶

But a critical gap still remains: most studies fail to assess the implications of different portfolios for the security and resilience of the grid in the face of natural disasters, physical or cyber attack, solar storms or other threats. *RE Futures* core scenarios for achieving 80percent renewable electricity supply require construction of 110–190 million MW-miles of new transmission capacity and 47,500–80,000 MW of new inertia capacity across the three electricity interconnections that serve the U.S. The average annual investment required for this new infrastructure ranged from \$6.4 to 8.4 billion per year.⁷

The increase in transmission and inertia capacity envisioned by *RE Futures* provides for a national grid infrastructure that can take advantage of dynamic fluctuations in variable resource availability on a regional and national basis. But, at the same time, such a grid could be even more fragile and subject to disruption than the existing system. In the aftermath of Superstorm Sandy, policymakers are increasingly looking for ways to reduce the risk of large-scale blackouts. Increased reliance on local renewable resources, integrated with microgrid control systems, holds the promise of providing new ways to manage the risks of major outages.

DECISION-MAKER	RECOMMENDATION
DOE, state governments, PUCs	Conduct modeling and scenario analysis to assess the implications of different combinations of distributed and centralized renewable resources to achieve a high-renewables electricity future.

INTEGRATE DISTRIBUTED ENERGY RESOURCES INTO RESOURCE PLANNING

Resource planning processes provide a view to the future that can help to reveal tradeoffs between centralized and distributed investments and reduce costs on the path to a high-renewables electricity future. In jurisdictions where organized wholesale markets do not exist, regional transmission planning studies and integrated resource plans conducted by utilities will be critical to assessing how best to utilize such resources as demand response, fast-response storage and other options to provide flexibility to match increasing levels of variable renewable generation. Careful resource planning can also reveal opportunities to reduce transmission and distribution costs through targeted investment in distributed resources.

Improved planning processes that properly consider distributed resource options have already harvested significant savings where these approaches have been rigorously applied. In New York, for example, Con Edison reduced its projected capital expenditures on transmission and distribution by more than \$1 billion by including energy efficiency and demand response in its forecasting. The company achieved additional savings of over \$300 million by utilizing geographically targeted demand resources to defer investments in its distribution system.⁸ Similarly, ISO-New England's energy efficiency forecasting initiative led to revised projections of transmission needs for Vermont and New Hampshire, allowing the deferral of ten proposed transmission upgrades totaling \$260 million.

Nonetheless, important gaps remain to be addressed to provide a consistently level playing field for competition between centralized and distributed resources at both the transmission and distribution system levels. A recent study by Synapse Energy Economics, for example, highlights weaknesses in ISO-New England's forecasting of distributed generation resources and recommends that the ISO establish a Distributed Generation (DG) Forecast Working Group in order to develop a DG forecast that can track existing installations and project future installations.⁹ In New England and elsewhere in the country, critics complain that ISOs and RTOs fail to adequately consider distributed resource alternatives and lack the expertise to do so. ISOs and RTOS, on the other hand, argue that uncertainties about the amount and location of distributed resources that can be expected to be installed, together with the difficulties of anticipating the behavior of variable distributed resources, makes it impossible to rely on them in developing future plans.

Building the capabilities to answer these questions will take better analysis and new institutional alignments. ISOs and RTOs have expertise and vested interest in transmission, but relatively little experience in evaluating diverse portfolios of distributed resources that they are now being asked to evaluate. One way or another, credible, rigorous and independent analysis of distributed resource options will need to support transmission planning processes.

The Federal Energy Regulatory Commission (FERC) Order 1000 requires that all transmission providers develop regional transmission plans that give “comparable consideration” to non-transmission alternatives (NTAs) such as energy efficiency, demand response, distributed generation, storage and microgrid deployment. Despite FERC’s aspirations, however, today’s industry practice often falls short of creating a level playing field for consideration of non-transmission alternatives.¹⁰ Existing rules require only that transmission planners consider NTAs brought forward by participants in transmission planning processes, instead of requiring that transmission providers search for and assess such alternatives even if no other party proposes them. Even where NTAs are estimated to provide the least-cost solution, cost recovery may be a problem:

“If a transmission proposal serves regional needs, the provider can allocate and recover the costs regionally through a FERC-jurisdictional tariff. There is no comparable opportunity for regional cost allocation of an NTA because an NTA, by definition, is not ‘transmission’ subject to FERC jurisdiction.”¹¹

Addressing these problems will require several different actions. At the federal level, FERC could require that regional transmission providers examine all feasible NTAs.

To do so, RTOs will need to develop new capabilities for evaluating NTAs and projecting their potential impact even when there is not a specific transmission project to compete against. At the state level, PUCs can create open competition for NTAs and facilitate cost recovery for these measures and PUCs can require utilities to report distributed-generation interconnections and net-metering activities to increase access to this data for planning purposes.¹² Finally, Congress could amend the Federal Power Act to allow cost recovery for NTAs through a FERC-jurisdictional rate where these measures are found to provide lower-cost alternatives to transmission.¹³

At the distribution level, new planning approaches, known as integrated distribution planning (IDP), hold promise to create more streamlined and coordinated approaches to distribution planning and distributed generation interconnection.¹⁴ Such approaches could provide the foundation for targeted deployment of distributed resources in ways that minimize system costs, manage load shapes and provide valuable ancillary services to the grid. Eventually, greater transparency with respect to marginal capacity costs on the system could support some form of locational marginal pricing targeted incentives for distributed resources within the distribution system (see the New Business Models section of this paper for further discussion of these options).

Improved transparency of the distribution system: The size of the prize

Studies over the last decade have illuminated the potential size of prize when taking a step beyond average distribution rates and examining distribution investments on a more granular scale. For example, a study by the Regulatory Assistance Project included a review of the marginal cost of transformers, substation, lines and feeders for 124 utilities, finding, “On a company-wide basis, the marginal costs are high and variable. For the entire group of 124 utilities, the average marginal cost for transformers, substations, lines and feeders exceeds \$700 per kW.”¹⁵ In another example, cited in *Small is Profitable*, “PG&E found that very locally specific studies often disclosed enormous disparities: marginal transmission and distribution capacity costs across the company’s sprawling system (most of Northern California) were found to vary from zero to \$1,173/kW, averaging \$230/kW. The maximum cost of new grid capacity was thus five times its average cost.”¹⁶

For vertically-integrated utilities, IRP can reveal tradeoffs between centralized and distributed resources. IRP has been used in some parts of the country since the late 1980s, and Congress included a provision in the 1992 Energy Policy Act encouraging state public utility commissions to implement IRP processes.¹⁷ In practice, however, IRP processes across the U.S. are extremely varied. As of 2013, 34 states require that electric utilities conduct integrated resource plans.¹⁸ Where organized markets do not exist, state PUCs could reinvigorate IRP planning

processes, taking them to the next level required for planning a renewable electricity future, by strengthening requirements for these plans to assess distributed resource alternatives to major investments in utility-owned infrastructure. This, coupled with changes in business models that allow utilities to benefit from greater investment in distributed resources (as discussed below), could open the door to a wider range of solutions to meeting future needs for generation, transmission and distribution capacity in a high-renewables future.

Innovative approaches to integrating distributed resources into resource planning

HAWAII'S PROACTIVE APPROACH

In March 2013, the Hawaiian Electric Company (HECO) and several collaborators, including representatives from the solar industry, presented a proposal for consideration by the Hawaii PUC that would integrate HECO's interconnection and annual distribution planning processes. Termed the Proactive Approach, the proposal outlines several steps that HECO would undertake annually to "identify opportunities where infrastructure upgrades can accommodate both DG and load." The process includes: projecting the likely distributed generation growth based on the interconnection queue and other data, evaluating generation production data in comparison to the capacity of the distribution infrastructure, and planning distribution system upgrades accordingly. If approved, HECO plans to start implementing the planning approach in 2013.¹⁹

CONEDISON'S SOLAR EMPOWERMENT ZONES

Since 2010, a partnership task force between ConEdison, New York City's Department of Buildings and New York State Energy Research and Development Authority (NYSERDA) has identified five solar zones that could benefit from solar development. Each zone was selected on the basis of energy use profile coincident with solar production, likely distribution system capacity upgrades needed to meet load growth and available roof space. Within zones, ombudsmen facilitate customer installation of solar PV by helping customers navigate through red tape to receive incentives and permits, provide free data monitoring devices and provide technical assistance.

DECISION-MAKER	RECOMMENDATION
PUCs	Require utilities to implement IDP to provided transparency with respect to planned distribution network costs and allow competition from distributed resources.
PUCs	Require utilities to regularly issue public reports on planned transmission and distribution upgrades. Plans should include cost per kW, the characterization of reductions for deferral and by date.
FERC	Direct RTOs and ISOs to develop capabilities to evaluate NTAs and require that regional transmission planning processes entertain NTAs even when there is not a specific transmission project to compete against.
PUCs	Facilitate cost recovery for NTAs on a coordinated utility, state and regional basis.
Congress	Amend the Federal Power Act to allow cost recovery for NTAs through a FERC-jurisdictional rate where these measures are found to provide lower-cost alternatives to transmission.

CREATE NEW ELECTRIC UTILITY BUSINESS MODELS

Today's electric utility business models reflect the legacy of decades of incremental modifications to structures that were originally designed around technologies, operational strategies and assumptions about customers' needs that are largely outdated today and will become increasingly so in an 80 percent renewable future.

Another paper in this series, *New Utility Business Models: Utility and Regulatory Models for the Modern Era*, explores the question of new utility business models, especially within the vertically integrated environment, in depth. As a complement, this section focuses specifically on business models issues stemming from the growth of distributed resources, which present particular challenges to the current utility business model. Our focus in this discussion is on laying the foundation for taking full advantage of distributed resources over the decades ahead on the path to 80 percent renewable electricity and beyond.

The need for change

Conventional utility business models have evolved based on the control, ownership, scale efficiencies of centralized supply, transmission and distribution. For the better part of a century, generation technologies were primarily limited to supersized thermal power plants with increasing economies of scale: the larger the plant, the more efficient and cheaper the electricity generation. In times of growing demand and passive customer engagement, these conventional utility business models worked well. These traditional approaches, however, are poorly adapted to an environment of up to 80 percent renewable energy predicated on a widening array of distributed energy resource options to meet customer demands and to respond to system conditions in beneficial ways. Many utilities are unable to capture or optimize the value streams associated with distributed energy resources and instead see these resources as threats associated with revenue loss, increased transaction costs and challenges to system operations.

The diversity of utility business models in the U.S.

Over the past century, the electricity industry's characterization as a natural monopoly has evolved to become more nuanced. Technological innovation in thermal-powered electric generation plants that occurred over decades in the 20th century brought down the capital cost and investment hurdles for more (and smaller) players to participate. Today, limited segments of the electricity value chain are considered true natural monopolies, principally the role of delivering electricity via transmission and distribution and the role of balancing supply and demand in real time. There is an open debate as to whether other electricity services — including generation and customer-interfacing services — may be better served with more providers competing and innovating to meet diverse demands more cost effectively.

For the majority of retail customers in the U.S., the same company provides both electricity supply and distribution services. In some jurisdictions, customers can choose their electricity supplier from among competing providers, while receiving distribution services from a regulated distribution monopoly. Additionally, in some parts of the country, the availability of a competitive wholesale electricity market organized by an independent system operator provides another structural layer that delineates the profit opportunities, activities, access and transparency available to electricity sector players. Even with this diversity, key tenets of the traditional utility business model remain largely intact:

- **Limited Electricity Service Providers:** Even in “deregulated” retail markets, competitively generated electricity is treated primarily as a commodity delivered over wires owned and operated by regulated monopoly distribution utilities to retail customers in that area.
- **Centrally Controlled System Operations:** A utility or independent system operator centrally dispatches large generators to meet exacting reliability standards by controlling the output of a generation portfolio to match aggregate customer demand.
- **Regulated Rate of Return and Cost Recovery:** Where the monopoly function remains, the utility's return is earned based on invested capital, often recovered through bundled rates that do not reflect temporal or locational differences in cost or value and which were designed to accommodate services provided by central station resources.

The situation is further complicated by prevalent rate structures and incentive mechanisms that are not easily adapted to the more temporally and geographically diverse value of renewable and distributed resources. For example, a predominant pricing structure for residential and small business customers features a bundled, volumetric charge by which the utility recaptures most of its costs — including both fixed and variable elements — via a single kilowatt-hour-based price. While this approach provides customers with simple bills and an incentive for efficiency, it starts to break down with significant percentages of customer-owned generation. In combination with retail net metering, such bundled, volumetric pricing may not recover the costs of a customer's use of the grid, and conversely, may not compensate the customer for the services they are providing to the system. Further, customers do not receive incentives to invest in technologies that can benefit both them and the larger system, such as smart appliances that can help the system adapt to more variable supply or thermal energy storage that can take advantage of low-cost energy during times of energy surplus. As more investment is made outside of the utility's control, new rate structures, price signals and incentives will be critical for directing that investment for greatest system benefit.

Finally, with a dwindling share of total investment in the electricity sector made by utilities, the decisions and actions of all these interconnected actors — utilities, customers and non-utility providers — will need to be harmonized. Managing the increased complexity of system operations, both technically and transactionally, means that operational management will need to depend less on hierarchical command-and-control and more on responses to signals indicating the state of the system. Successful business models in this environment will transcend the traditional utility versus non-utility framework, creating a conduit of value and service for customers, regardless of supplier.

The path forward

The increasing role of distributed resources in the electricity system will start to shift the fundamental business model paradigm of the industry from a traditional value chain to a highly participatory network or constellation of interconnected business models. In this context, regulators and policymakers should start to consider how the utility's business model could serve as a platform for the economic and operational integration of distributed resources and the ability to make fair tradeoffs between distributed and centralized resources.

Myriad pathways exist toward such a future. In supporting the evolution of new utility business models, regulators and policymakers should consider a set of attributes that the utility platform should be designed to meet. Clearly, it will be necessary to make tradeoffs among some of these attributes and to adapt business models to particular regulatory and market contexts, but a high-level list of desired attributes includes:

- Ensure network efficiency, resilience and reliability. The integration of distributed resources should not just “do no harm” to the efficiency, reliability and resilience of the electricity system, but should actually be deployed to enhance these attributes.
- Create a level playing field for competition between all resources, regardless of their type, technology, size, location, ownership and whether or how they’re regulated.
- Foster innovation in energy services delivery to customers to minimize energy costs. This requires an ability to evolve or adapt the platform structure over time; it points toward modularity, allowing separable services that can be bundled together.
- Provide transparent incentives, where necessary, to promote technologies that result in social benefits such as job creation and local economic development, financial risk mitigation or environmental attributes of different resources.

- Minimize the complexity that customers face in dealing with the electricity system.
- Enable a workable transition from traditional business models to new structures.
- Support the harmonization of business models of regulated and non-regulated service providers.

Business model solutions designed to meet evolving needs on the path to an 80 percent renewable future that optimize distributed resources will not develop under a one-size-fits-all approach. Instead, many different types of models are likely to emerge and evolve in different regulatory and market contexts. Two key factors are likely to influence the types of solutions that are adopted over time in different regions or jurisdictions:

1. The technological capability of the electricity system in question, reflected in the level of adoption of distributed energy resources and the capabilities of the grid to integrate these resources.
2. The regulatory environment, characterized by the degree to which various types of services are considered monopoly functions.

These factors are likely to drive a spectrum of business model options, ranging from incremental approaches, which address discrete problems or opportunities while leaving the fundamental utility model largely unchanged, to transformational ones, which shift the electricity distribution sector towards a more complex value constellation.

Already, various new alternatives are beginning to emerge in the U.S. and around the world that represent solutions to different aspects of the challenge. Some solutions include:

- a. New pricing and incentive approaches.
- b. Opportunities to explore new value creation such as financing through on-bill repayment.
- c. Reducing disincentives and rewarding performance.

The remainder of this section explores some of the options that are or could be considered in vertically integrated and retail competition environments. Since these new models are still nascent, many questions remain about how they might actually be implemented, whether they are practical and workable and what economic impacts they would have on utilities and other stakeholders.

a) Pricing and incentive approaches

Retail rate designs, and the resulting prices that they create, simultaneously reflect the underlying costs of production, indicate the value of services provided between suppliers and customers, serve as signals to communicate the needs of the grid system and directly influence customer behavior. The importance of pricing grows significantly in an 80 percent renewable world, where there is an increasingly dynamic grid that incorporates a high penetration of variable renewable energy and a corresponding need for distributed control and intelligence throughout the system. Today, however, existing rates and policies obscure the costs and benefits of various resources to the grid, limit the ability to add better integration technologies that could add value and restrict signals to customers that would enable them to make mutually beneficial decisions.

In a more highly renewable and distributed future, prices and/or incentives need to provide more accurate signals that reflect the actual costs and values in the electricity system, thereby sending appropriate signals to customers and fairly compensating utility service. At the outset of considering new rate designs, regulators must consider: Can the pricing model pay for operational services, properly capture and promote value to the system and be implemented effectively with the flexibility to accommodate further market changes?

Key approaches include:

- **Itemize and value core service components separately.** By separately measuring service components, costs and value can be more accurately reflected (see, also, the cost and benefit section earlier in this report) enabling the service provider — utility or customer — to be compensated fairly for the value they provide. Overall, mechanisms should be promoted that drive unit prices toward the long-run marginal costs of system operation in order to send correct price signals and promote economic efficiency.
- **Determine the appropriate recovery mechanism for disaggregated components.** While important to transparently quantify the underlying cost drivers and recognize whether they are fixed or variable costs, there is still flexibility in the type of mechanism used to recover that cost in the price to customers. For example, a fixed cost, such as a distribution line expansion, does not necessarily need to be recovered through a fixed charge, such as a straight fixed variable rate structure.
- **Incorporate time- and/or location-varying prices or incentives at the retail level.** While many utilities already have some (often very simple) form of time-varying prices, the widespread implementation of dynamic pricing, supported and enabled by advanced communications and controls, will be a key enabler in allowing distributed and renewable resources to provide needed system flexibility.
- **When appropriate, transparently add policy-driven incentives that are not captured strictly by costs.** Better understanding the utility's avoided costs and determining the difference between the cost of stated policy objectives empowers regulators to achieve policy goals, accurately inform customers and achieve policy goals at a lower societal cost.

“Getting the price right” is not the only consideration. Rate design must also strike a balance between the interests of traditional customers and customers with distributed generation, while remaining simple enough to be understood. There can be significant tension between rate simplicity, the need to support energy efficiency and customer generation and the need for accurately allocating benefits and costs. For example, California has a volumetric tiered rate structure for residential customers with a primary goal of encouraging energy efficiency. Thus, the price of electricity increases as the amount of electricity a customer uses increases over a billing period. Accordingly, reductions in electricity consumption will be valued at the marginal

tiered rate, and higher electricity consumers will have a larger incentive to invest in distributed energy resources. California’s volumetric tiered rate structure and decoupling of rates and sales have helped keep per-capita electricity use flat for the past 30 years and made California the largest energy-efficiency market in the country. However, this rate structure could also contribute to shifting costs to non-participating customers as distributed energy resources and zero-net-energy buildings become more prevalent. Yet wholesale replacement could have the unintended consequence that energy efficiency becomes less attractive for customers. Strict cost-of-service rates and socialization of the “cost shift” must reach an appropriate balance.

Emerging rate design ideas

As part of its General Rate Case in October 2011, San Diego Gas and Electric Company (SDG&E) proposed modifying its residential electric rates to include a “Network Use Charge,” which would bill customers for the costs associated with all network use, including electricity exports. Proponents of the Network Use Charge note that it would allow SDG&E to ensure that net energy metering (NEM) customers contribute to their fair share of distribution system costs when exporting power, while reducing the inequitable cost shifts that result from retail NEM. However, the measure met with fierce opposition from the solar industry, consumer advocates, environmentalists and NEM customers. These groups argue that the Network Use Charge does not account for the benefits that DG systems provide to the network, that it runs contrary to California’s renewable energy goals by discouraging solar, and that it does not send price signals that encourage reduction in coincident peak demand — rather, it pushes PV owners to shift their demand to times when their system is producing, i.e., midday.

In the first of its kind, Austin Energy proposed a residential solar rate to replace conventional net energy metering in its territory, the Value of Solar Tariff.²⁰ Based on the distributed costs and benefits study completed for Austin’s territory in 2006, the rate is designed to include an annually adjusted value for distributed solar energy to the grid, which includes calculations that estimate savings from avoided losses, energy, generation capacity, transmission and distribution capacity and environmental benefits. The approach attempts to address unintended consequences of net energy metering, such as reduced incentives for energy efficiency, by decoupling the customer’s charge for electricity service from the value of solar energy produced.

Outside the U.S., distribution companies in Germany, New Zealand and the United Kingdom use new forms of pricing or incentives to foster deployment of distributed generation in ways that will reduce distribution system costs. For further information see: *New Business Models for the Distribution Edge*, an eLab discussion paper.²¹

The role of aggregators in delivering distributed resource value to the grid

As the electricity system becomes more distributed, millions of devices could be connected to the system with each capable of making a small contribution to respond to system conditions. ISOs and RTOs have enabled many more devices to participate by reducing sizing requirements. Still, minimum size requirements are no smaller than 100 kW. So what is to be done about all of the devices that are much smaller than 100 kW? Should they just be considered noise on the system? Many service providers are trying to find ways to aggregate small, distributed resources in order to maximize their impact.

Take the Nest smart thermostat as an example. The company has been hailed for its hardware design and simple, easy-to-use interface. The smart thermostat has been very effective in providing utility bill savings. Nest though has been ambitious in terms of maximizing the value of its thermostat. Rather than being complacent with only delivering efficiency savings, the company is now starting to work with utilities to reduce peak demand.

In April 2013, Nest announced new partnerships with NRG, National Grid, Austin Energy and Southern California Edison to enable more participation in demand response programs. Rather than calling it a demand response, Nest has cleverly coined its newest feature “Rush Hour Rewards.” As part of the program, Nest raises its customers’ thermostats by up to four degrees during peak hours between 12 and 15 times each summer.²² In Austin, several thousand Nest thermostats delivered average reductions of 40–50 percent in air-conditioner run time when the program was triggered on hot days in June 2013. The utility partners see value in the device, offering customers rebates on the smart thermostats and giving bill credits to customers who participate during “rush hour.” While these partnerships are just pilots for now, both Nest and its partners see sizeable opportunities ahead.

Nest is one of many companies trying to figure out how to aggregate distributed resources. Utilities themselves are bidding electric efficiency program savings into forward capacity markets. Demand response service providers—such as Enernoc, Converge and Viridity—continue to hone their offerings and control rapidly growing portfolios. As the grid transitions to a more distributed one, those that understand the benefits of aggregating distributed resources stand to capture some promising opportunities.

b) Opportunities to explore new value creation such as financing through on-bill repayment

New opportunities to offer new services in these emerging markets could likewise incent utilities to support and encourage this transition. On-bill financing (OBF), in which a utility loans capital to a customer and the customer pays the loan back on the utility bill, has been an effective vehicle for customers to pay for energy-efficiency improvements for decades — usually at a lower cost of capital. More recently, distributed generation has been included within some OBF programs. While some OBF programs have featured bank lending, with the utility as a servicer to its customers, OBF has otherwise been limited in engaging with third-party financiers. OBF has customer acquisition benefits, as the customer does not have to pay a second bill and is familiar with the utility as a reliable electric services provider. The downside of many OBF programs is that they are not well marketed by the utilities, who are not adept at driving new customer uptake and whose business is not heavily predicated on the success of OBF programs.

With on-bill repayment (OBR), the utility enables third-party financiers, as equity and/or debt providers, to provide loans, leases, power purchase agreements and other repayment structures to the customer, with the repayment held on the customer's bill. The OBR solution is particularly valuable with solar PV, as third-party equity can lower the cost of solar below what a homeowner (restricted by inability to monetize solar's accelerated

depreciation), a regulated utility (required to monetize investment tax credit over rate-basing period instead of first year) or a municipal utility (ineligible to receive tax benefits) can otherwise achieve. For all technologies and financing types, however, there is generally stronger business drive to market intelligently and energetically to potential customers and to ensure reasonable transaction costs and customer experiences in OBR than in OBF. In addition, the inherent benefits of OBF (one bill and a reliable, known "face" of the program) are still present.

OBR is most beneficial when there exists a strong relationship between utility and third-party financier. Aligning interests between these parties is essential. Utilities must not see third-party financing as simply diminishment of revenue, weakening investor returns and the safety of creditor obligations. Equally, the third-party financier does not want damaging rate changes or strategic defaults by the utility to disrupt their cash flows. Balancing interests in OBR is a ripe electric regulatory policy opportunity space.

c) Reducing disincentives and rewarding performance

While the steps described above address misalignments in existing institutional and pricing structures, they are not sufficient to provide a long-term, sustainable foundation. The key drivers that are transforming the electricity industry will continue to alter revenue streams, sources of value and operational requirements for electric utilities. This, in turn, will necessitate further evolution and adaptation of utility business models and new thinking about the role of the utility in the future. Should the utility be allowed to own and operate distributed resources on its customer's premises? What incentives should the utility have to ensure that distributed resources are fully deployed to minimize costs for the system as a whole? If the utility is allowed a more expansive role in owning and/or managing distributed energy assets, will this unfairly crowd out other competitors?

No doubt, incremental steps can be taken to start to shift the rules and reward structures to recognize the costs and values of service provision, whether they are met by distributed or conventional resources. Taking a long-term view, however, it is important to recognize that the underlying system architecture — not only physical, but economical — is changing. Localized generation, responsive demand and energy efficiency coupled with distributed communication and coordination can enable the economic optimization of resource use across the entire system that has not been possible before. Equally important, it dramatically opens the potential for demand diversification and the creation of new value.

In the vertically-integrated utility environment, new types of incentive regulation may provide mechanisms to create a more level playing field between centralized and distributed resources. A majority of vertically-integrated utilities and distribution-only utilities in restructured environments are regulated under rate-of-return regulation that determines the amount of the utility’s return based on the amount of capital invested “prudently” to maintain service. Most utilities’ financial health, in turn, depends directly on the volume of retail sales, because their fixed costs are recovered through charges based on how much electricity their customers use. This creates little incentive for utilities to promote distributed energy resources, such as efficiency or distributed generation, or to experiment with new service and price models. Key business model changes could include:

- **Reducing disincentives.** Decoupling the recovery of fixed costs from sales can be an important first step. Decoupling allows automatic adjustments in utility rates so that utilities are ensured the ability to recover their fixed costs regardless of fluctuations in electricity sales. This mechanism addresses some, but not all, of the criticisms lodged

against traditional revenue recovery approaches. For example, it does not protect non-participating customers from cost shifts and does not create the price signals necessary to support long-term distributed resource development and innovation in new technologies.

- **Rewarding performance.** Performance-based regulation could also tie utility revenue growth to a set of performance-related metrics, providing the utility with opportunities to earn greater profits by constraining costs rather than increasing sales.
- **Enabling new value creation.** The utility could continue to maintain its role of: 1) distribution system operations coordinator, 2) provider of reliability/standby and power-quality services for customers that do not self-provide these services and/or 3) integrator of large-scale supply resources, distributed energy resources and storage. The utility could also more actively direct investment and siting for distributed resources.

DECISION-MAKER	RECOMMENDATION
PUCs	Encourage distributed generation by acknowledging customers’ right to generate their own energy, by charging them a fair price for grid services and by paying them a fair price for the grid benefits they create. Use net metering, or set a clear methodology for allocating all costs and benefits.
PUCs	Work with appropriate stakeholders to develop a pathway to more unbundled, time- and location-varying prices that 1) balance needs for simplicity, accuracy and fairness, and 2) collectively send appropriate behavioral and value signals to customers.
PUCs	Actively explore new utility business models that reward desired performance and enable new value creation.

ADAPT WHOLESALE MARKETS TO ALLOW DISTRIBUTED RESOURCES TO COMPETE

RE Futures calls attention to opportunities for improvements in electric system operations that will enhance flexibility in electricity generation and end-use demand to enable more efficient integration of variable-output renewable electricity generation. Organized wholesale markets can provide a crucial link to allow distributed resources to compete to provide energy, capacity and ancillary services in a high-renewables electricity future. Already, organized wholesale markets serve two-thirds of electricity customers in the U.S.²³ Well-structured organized wholesale markets can allow distributed resources to compete with grid-scale energy storage and flexible generation to provide needed flexibility resources to support grid operations. Market mechanisms that allow demand response aggregators to compete in capacity markets have already demonstrated the feasibility of rules that provide for aggregation of distributed resources to the scale needed for wholesale market transactions.

Another paper in this series, *Power Markets: Aligning Power Markets to Deliver Value*, provides details about how wholesale markets can be utilized to accommodate higher levels of renewables. In this section, we focus specifically on how markets can incorporate higher levels of distributed resources to support achievement of a renewable electricity future. Still, we recognize that organized wholesale markets do not serve some regions of the country. For these regions, while they could begin participating in organized wholesale markets

over the next 40 years, other means may be necessary to coordinate and encourage the development of distributed resources.

Today, distributed resources are able to bid into wholesale power markets in some parts of the U.S., including the PJM Interconnection (PJM) and ISO–New England (ISO-NE), to help meet load requirements and support reliability. In PJM, more than 14,000 MW of demand response and energy efficiency have cleared in the forward capacity market auctions over the past five years.²⁴ In ISO-NE, distributed resources are set to defer the need for transmission lines, saving customers over \$260 million.²⁵ FERC’s recent rulings, including Orders 719 and 745, support continued engagement of demand-side resources in organized wholesale markets.²⁶

With continued technological improvements, the ability for distributed resources to provide value will increase. For instance, in a recent PJM vehicle-to-grid (V2G) pilot, electric vehicles were used to provide ancillary services to the grid, including real-time frequency regulation and spinning reserves.²⁷ With proper control and communications capabilities, distributed resources may be used to increase the reliability of the electricity system by providing enhanced flexibility and, in some cases, deferring the need for expensive upgrades to transmission and distribution systems.²⁹

Compensation for the value provided by distributed resources is crucial. Forecasts show increasing levels of adoption of energy efficiency, distributed solar PV and electric vehicles over the decades ahead. If markets provide a price signal for what attributes are most highly valued, technology developers can adapt their technologies to help meet these needs. And if distributed resources are compensated for these attributes, there could be a “virtuous cycle” that improves the economic returns and further increases the adoption of distributed resources.

Although specific rules, requirements and market structures vary among RTOs and ISOs, there are three general types of markets that distributed resources can or could participate in:

- **Energy.** Electricity generators bid into these markets to sell energy. These transactions typically take place in day-ahead and real-time markets, with settlement based on locational marginal prices.²⁹ Already, distributed resources are playing a significant role in energy markets in PJM, ERCOT and New York ISO (NYISO). Electricity is sold to consumers at retail prices that include the costs of transmission and distribution services.
- **Capacity.** There is an ongoing debate whether energy-only markets are sufficient to provide price signals to encourage long-term investments. In order to provide incentives for power plant operators to build new capacity, forward capacity markets have been created in some jurisdictions. Every resource bids into the market at the total cost of operation to provide service at future date, typically three to four years in advance.³⁰ Aggregations of distributed resources can be assigned capacity values and then bid into those markets along with much larger generators.
- **Ancillary Services.** Ancillary services are provided to help ensure the operational stability and reliability of the electricity system. These services include regulation, spinning and contingency reserves, voltage support and system restart capabilities. Like energy markets, ancillary service transactions take place in day-ahead and real-time markets.³¹ Today, market-based mechanisms designed to support ancillary services are the least mature. However, studies and pilots, like the PJM V2G demonstration project, have been promising and distributed resources could start to become an important contributor of ancillary services.³²

Several of the RTOs and ISOs have already begun leveling the playing field and incorporating distributed resources into their markets. The changes to the rules in these markets can serve as a blueprint for beginning to unleash market forces to encourage more development of distributed resources while also staying technology neutral. These changes include:

- **Ensure pricing signals encourage mid- and long-term investments.** Not all ISOs and RTOs employ capacity markets, but some have done so with varying degrees of success. PJM, NYISO and ISO-NE are notable among these. These forward capacity markets have created a clear price signal to direct future investments for both large, utility-scale generators as well as smaller, distributed resources. Some of ISOs and RTOs have debated the need for capacity markets and whether their markets are currently sufficient to encourage future investments.³³ In the move to a high-renewables future, it will be important to make sure that markets adequately compensate the value of all mid- and long-term investments, including investments in demand-side capacity resources.
- **Allow distributed resources (or aggregations thereof) to bid into markets.** Demand-side resources such as energy efficiency and demand response have been able to bid into PJM and ISO-NE for several years. These resources

have reduced the peak demand on the system and prices to consumers. While efficiency acts as a passive resource (it cannot be turned on and off), demand response provides additional value to the system because operators can choose to dispatch it. Furthermore, electric vehicles, distributed storage and solar PV with smart inverters should be able to bid into markets if they are able to meet the necessary technical and physical requirements.

- **Allow smaller resources to compete.** Many markets have rules that only allow large generators to compete (e.g., greater than five MW standard). In order for many distributed resources to bid into these markets, rules will have to be modified to allow these resources to compete. PJM is notable for allowing resources as small as 100 kW to compete.
- **Enable aggregation.** Some resources won't be able compete even at lower sizing requirements. However, service providers can aggregate these resources to provide value to the system. ISO-NE and PJM allow efficiency program administrators to bid their savings into the forward capacity market.

DECISION-MAKER	RECOMMENDATION
PUCs, ISOs/RTOs	Create capacity markets where they are necessary.
PUCs, ISOs/RTOs, NERC	Create a platform for all distributed resources to register and allow participation in capacity, energy and ancillary service markets on the same footing as supply-side resources.
ISOs/RTOs	Allow smaller resources to compete.
PUCs, ISOs/RTOs	Allow third-party aggregators full access to markets.
PUCs, FERC, ISOs/RTOs, NERC	Assess the need for new services that may arise as renewable production grows (e.g., capability markets or alternative dispatch rules).

These are promising first steps that we recommend other RTOs and ISOs begin to adopt. In addition, there are other opportunities on the horizon that no U.S. market has fully implemented.

As the system changes from one in which thousands of devices operate to one where millions could operate, this will create a plethora of new opportunities and challenges. Overall, the intention should be to ensure all resources are recognized for their ability to provide value from a locational and temporal perspective as well as improve reliability. As markets continue to allow more distributed resources to compete, additional considerations will include:

- **Improving responsiveness and visibility.** Having potentially millions of devices on the system responding to price signals will mean that there will be even greater need for responsiveness and visibility. Multi-stakeholder working groups, which should include utilities, service providers, ISO's and others, will have to decide the appropriate response-time and telemetry requirements for resources. These requirements will

have to balance the need to ensure that these resources are providing the services that they are supposed to provide while also minimizing the transaction costs that could prevent service providers from participating.

- **Connecting wholesale markets to retail rates.** Many distributed resources could be on the electricity system in the future without bidding into power markets. In order to maximize the value of these resources, the proper pricing signals will be important, perhaps coupled with customer-choice automation or remote load control. There has already been significant work done piloting and establishing rate structures that more accurately reflect the wholesale market environment, like critical peak pricing and real-time pricing. These rate structures could further incentivize higher levels of adoption of distributed resources by aligning compensation with the value the distributed resources provide.

ENABLE MICROGRIDS AND VIRTUAL POWER PLANTS TO SUPPORT INTEGRATION AND AGGREGATION OF DISTRIBUTED RESOURCES

Microgrids³⁴ and virtual power plants³⁵ can facilitate the achievement of a renewable electricity future by integrating distributed renewable resources locally while providing greater flexibility for managing resources to respond to varying grid conditions. In addition, microgrids can protect customers from outages and support the security and resilience of the larger system by isolating and containing problems, providing ancillary services including black-start services and reducing the risk of cascading outages.

In Denmark, where renewable and distributed resource penetration levels are already among the highest in the world, grid operators have begun to fundamentally shift grid architecture toward a new system of “cellular control” that aggregates distributed resources into blocks of supply that behave like virtual power plants, allowing them to provide grid support services. By design, these “cells” that support the larger grid can isolate from it, withstanding major system disturbances. Meanwhile, market mechanisms, aided by digital communications and real-time feedback, determine the least-cost ways to generate power and provide grid support services.³⁶

Today, the U.S. has nearly 1,500 MW of generation operating in microgrids, but substantial growth is expected. Navigant projects the global microgrid market could surpass \$40 billion by 2020 and over 60 percent of this market resides in the U.S.³⁷ The opportunity for capturing value to the grid and the customer from current and future microgrid deployment will be shaped by the policies and regulations that determine the viable business models.³⁸ In this section, we identify a set of principles for consideration that can help policy makers and other relevant stakeholders navigate the regulatory juggernaut and speed the advance of rational microgrid development.

There are multiple considerations that shape the opportunity for all players and determine whether and how new business models will emerge. These include rate design (e.g., how microgrid costs and benefits are assigned, where the capital comes from, what types of performance incentives exist, how to manage legacy grid costs), provider participation rules (e.g., who is allowed to own the microgrid, what products and services are allowed, how are they governed in the market), customer eligibility (e.g., which customers are allowed to microgrid

in the first place, what rights do they have in secondary markets), how to plan around microgrids (e.g., optimizing parallel investments, role in delivering “smart grid of the future”) and interoperability rules that define the technical aspects of islanding. While this is quite an array of considerations, several guiding principles can help minimize unnecessary friction in the alignment process between stakeholders on all sides of the issue:

- *Define microgrids, and clarify how existing policies apply to them.* Job number one for regulators is to determine a clear definition (or definitions, plural, if a one-size-fits-all approach proves insufficient) for a microgrid. Should a microgrid be categorized as a distributed energy resource, an independent power producer, or something completely different? How big or small can a microgrid get before it ceases to be a microgrid? Only after such questions are answered can the regulator, utility, customer and private developers make sense of how existing rules and regulations inhibit or incent microgrids in places where sound business cases exist. In addition to clarifying how existing rules apply, the regulator must clearly articulate the type of treatment legacy utility assets will receive.
- *Adopt and enforce a grid-wide interoperability standard.* Safe and beneficial linking of micro- to macro-grids requires adoption of standard protocols that ensure physical integrity of the system and allow for joint optimization of the independent and combined system’s economic, environmental or operational performance. IEEE 1547.4 is one promising option for standardization, though there may be additional requirements to be codified in this or other protocols over time.
- *Strive to reasonably value microgrid costs and benefits, and price accordingly.* The foundation for microgrid business models is premised in part on the costs and benefits this technology offers to the grid. These include services such as black-start capability, frequency regulation and an ability to shift from energy sink to source at a moment’s notice. But these services should be weighed against any additional infrastructure or operational costs associated with integrating many semi-autonomous microgrids into the macrogrid. An initial effort at evaluating the size of these costs and benefits and finding ways to monetize them through existing or new pricing approaches is critical to encouraging microgrid development in situations that make the most sense for the grid, while also providing fair compensation for customers investing their own capital in microgrids.

- *Remove the delivery utility's disincentive, and consider performance-based incentives to stimulate development.* As another technology that stands to reduce demand serviced by the distribution utility, there is a potential disincentive for the utility to pursue or support investment in microgrids. However, microgrids present real opportunities to deliver system benefits to customers in the form of cost savings and improved reliability and power quality. Where evaluation and planning reveal these opportunities, the utility should be permitted to pursue and invest in them. Beyond freeing the utility up to invest in microgrids, establishing and strengthening performance-based incentives for cost, reliability and power quality can provide the carrot that some utilities may need to explore microgrid opportunities. And just as the utility is incentivized to make targeted microgrid investments through performance-based incentives, more highly differentiated pricing can signal to customers and developers where microgrid investments will minimize distribution system costs.
- *Allow broad-based microgrid participation in wholesale markets.* In some cases it will make the most sense for microgrids to participate and provide services in the wholesale markets. To facilitate customer participation, clear operational and market-based standards need to

exist without limiting customer access to develop a microgrid. In markets like California, the path to participation for a microgrid connected at the transmission level is clear enough, but the situation grows more complex and nuanced when a microgrid is connected to the distribution system and wants to participate in wholesale markets. In this instance, the customer must navigate between the ISO and the distribution utility. Simplifying and reducing barriers to wholesale market participation for microgrids, both big and small, that are connected at the distribution level increases competition in the markets, improves the economic case for microgrids and provides the grid operator with new resources to balance the system. In Denmark, on the island of Bornholm, the municipal utility is testing a market that encourages participation from many small customers. In this market prices change every five minutes, there is no limit on the size of demand or supply resources that can participate and participants do not need to bid into markets to participate, vastly simplifying the task for small residential and commercial customers.³⁹

- Incorporate microgrids into broader grid-planning processes.* Both distribution and transmission system planning represent important opportunities for evaluating microgrid options and incorporating them into system design. These resource planning processes can provide the foundation for targeted deployment of microgrids in ways that minimize system costs, manage load shapes and provide valuable ancillary services to the grid. Transmission planning processes typically include NTAs, of which microgrids should be included. Although the consideration

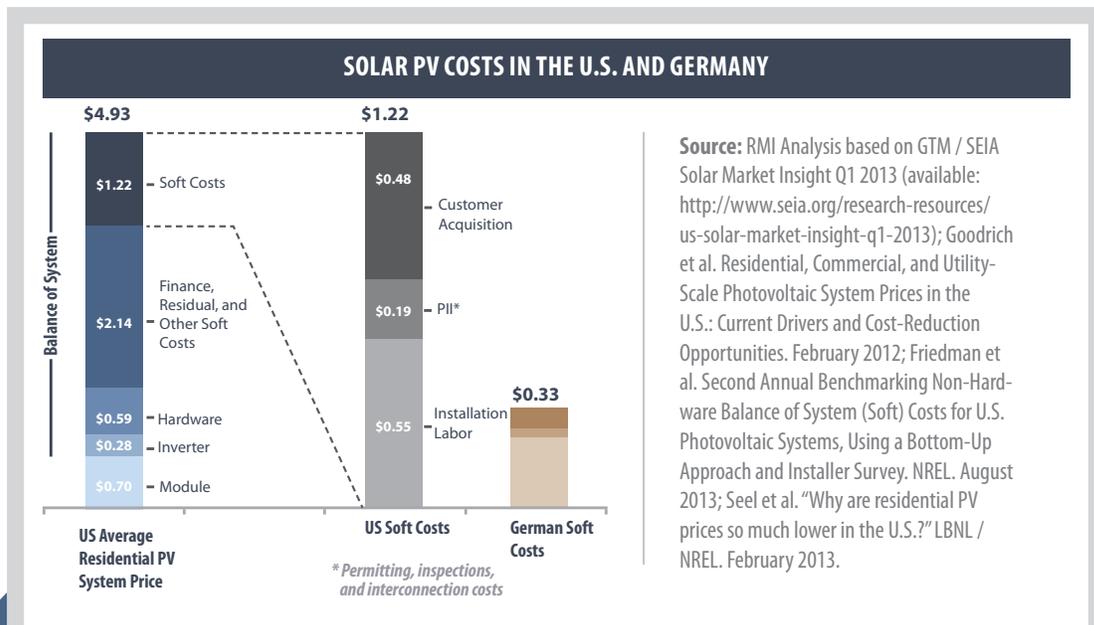
of NTAs is far from perfect, it represents a clear entry point for consideration of microgrids. Incorporating microgrids as potential assets for optimization in other integrated grid-planning exercises (either traditional Integrated Resource Plans done by electric utilities in 34 states,⁴⁰ or alongside the emerging discipline of IDP⁴¹) presents an opportunity to evaluate and implement least-cost distribution alternatives, such as energy efficiency, distributed energy resources and microgrids.

DECISION-MAKER	RECOMMENDATION
PUCs	<p>Ensure interconnection rules allow and conform to intentional islanding standards set per IEEE 1547.4.</p> <p>Enable and encourage delivery utility support and investment in microgrids that offer grid benefits.</p>
PUCs/RTOs/ISOs	<p>Define microgrids, and clarify how existing policies apply to them. Incorporate microgrids into utility and ISO/RTO grid-planning processes.</p> <p>Allow microgrids to transact with wholesale markets and provide services at a single point of interconnection with the microgrid.</p>

DRIVE DOWN “SOFT COSTS” FOR SOLAR PV BY STREAMLINING PERMITTING AND INTERCONNECTION PROCEDURES

Regulators and policymakers can help to reduce the costs of permitting, inspection and interconnection to significantly reduce the total cost of distributed solar PV. Module costs, which have historically dominated the cost of PV systems, declined 80 percent between 2007 and 2012 and are continuing to fall. Given this steep decline, the remaining “balance of system” (BOS) costs — all cost

components *other* than the module —now constitute 80 percent or more of total system cost. “Soft costs” — which include customer acquisition; installation labor; and permitting, inspection and interconnection costs — can be dramatically lower where procedures are streamlined, as evidenced by experience in Germany, where soft costs are 73 percent lower than in the U.S. (figure 2).



Source: RMI Analysis based on GTM / SEIA Solar Market Insight Q1 2013 (available: <http://www.seia.org/research-resources/us-solar-market-insight-q1-2013>); Goodrich et al. Residential, Commercial, and Utility-Scale Photovoltaic System Prices in the U.S.: Current Drivers and Cost-Reduction Opportunities. February 2012; Friedman et al. Second Annual Benchmarking Non-Hardware Balance of System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey. NREL. August 2013; Seel et al. “Why are residential PV prices so much lower in the U.S.?” LBNL / NREL. February 2013.

Figure 2. Residential Solar PV Costs in the U.S. and Germany

Government agencies with responsibilities for permitting solar systems can help to reduce soft costs by streamlining and simplifying permitting procedures consistent with best practices, including adopting the recommendations of the Solar America Board for Codes and Standards' *Expedited Permit Process and Emerging Approaches to Efficient Rooftop Solar Permitting*⁴² and IREC's *Sharing Success: Emerging Approaches to Efficient Rooftop Solar Permitting*. Further, local and state governments can help drive the development of more efficient local installation and support installer training to reduce installation costs.

In permitting, current best practices include:

- Over-the-counter, same-day permit review.
- Clear, well-organized webpages focused on the solar permitting process, including recent changes in codes, where applicable.
- Exempting building permit review altogether for small systems.

Inspection processes can be streamlined with the following approaches:

- Self-inspection (of certain types of systems) by certified PV installers.
- Simplifying requirements for site plans.
- Specifying how much of a project must be complete for interim inspections.
- Providing a tight time window for inspection appointments.
- Providing consistent and current training for inspectors so that installers receive actionable and reliable guidance, including training inspectors on advances in the solar installation hardware and practices and how they relate to permitting codes.
- Combining all required inspections into one onsite visit.

DECISION-MAKER	RECOMMENDATION
Local governments	Streamline permitting procedures to match best practices.
PUCs	Require utilities to simplify and speed inspection and interconnection processes subject to meeting safety requirements.

ENCOURAGE SMART ELECTRIC VEHICLE CHARGING

The electrification of light-duty vehicle transport is an important complement to increasing the share of variable renewable generation in the electricity sector. In *RE Futures'* 80 percent-ITI scenario, 40 percent of the passenger vehicle transportation fleet (about 154 million vehicles) is assumed to be electrified by 2050. Of the assumed 356 TWh of electric vehicle load in 2050, 165 TWh are charged under utility control, which allows vehicle charging to be interrupted by the utility within certain boundaries. In *Reinventing Fire*, the share of the vehicle fleet that is electrified by 2050 is approximately the same (157 million vehicles), with similar shares of utility-controlled charging, but with a total of 26 million vehicles capable of providing active vehicle-to-grid (V2G) services for voltage regulation, ramping and other purposes.⁴³

The proliferation of electric vehicles connected to the grid means that a significant amount of battery storage capacity could be available, if equipped with proper controls and communications capabilities, to help to ride through short-term fluctuations in system conditions and manage load shapes in response to price signals. Electric vehicle manufacturers, electric utilities or other intermediaries could aggregate electric vehicles with charging controls to provide services to the grid. Based on some estimates of the value of grid-control services, the upfront cost of an electric vehicle with full V2G

capabilities could be \$10,000 less than that of an electric vehicle without such capabilities if vehicle manufacturers or other intermediaries were to monetize the lifecycle value of services provided to the grid.⁴⁴ On the other hand, unmanaged electric vehicle loads could present challenges for grid planners and operators if their use contributes to peak period demand and increases burdens on constrained parts of the distribution system.

Regulators and policymakers can help to pave the way toward a high-renewables future by promoting the integration of electric vehicle charging into the grid. This could occur through:

- Encouraging utilities to provide special incentives to customers in return for utility-controlled or V2G charging.
- Allowing aggregators to manage vehicle charging in order to provide services to utilities or directly to wholesale markets. In February 2013, the University of Delaware and NRG Energy began providing frequency regulation services to PJM Interconnection under a pilot program that allows aggregations of as little as 100 kW to provide such services to the grid.

DECISION-MAKER	RECOMMENDATION
PUCs	Encourage utilities to provide special incentives to customers in return for utility-controlled or V2G charging.
RTOs/ISOs	Allow aggregators that manage electric vehicle charging to compete to provide ancillary services to the grid.

CONCLUSION

Distributed resources can play a crucial role in the transition to a renewable electricity future by adding to renewable electricity supply, reducing demand and providing flexibility to integrate variable renewable resources. Creating a level playing field for centralized and distributed resources will require significant changes in electric utility business models and electricity markets, as well as other changes in regulation and policy to adapt to rapidly evolving technology.

ENDNOTES

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POLICY FOR
DISTRIBUTED GENERATION:

Supporting Generation on Both Sides of the Meter

Joseph Wiedman of Interstate Renewable Energy Council, Inc
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EXECUTIVE SUMMARY

In today's era when consumers can buy solar panels at their local hardware store, it's clear that distributed generation is taking off. However, without concerted action, its growth may be hindered by legacy regulations designed for a different era. Clearing a path through this regulatory thicket is critical to ensuring a successful transition to a clean energy future. This report identifies specific actions that decision-makers at the local, state, and federal level can take to promote the continued expansion of distributed generation in both retail and wholesale markets.

The paper's recommendations fall into five major categories:

- **Net Energy Metering (NEM):** Energy consumers need a simple, certain, and transparent method for pricing the power that they supply to the grid. NEM has served this purpose well and should be continued so that the customers and suppliers of distributed generation (DG) systems know that this foundational policy will be available in the long-run. This report recommends that decision-makers address concerns over NEM through the same type of cost-effectiveness analyses that have been used for many years to assess other demand-side resources such as energy efficiency and demand response.
- **Shared Renewables:** Many energy customers do not have a rooftop suitable for the installation of solar panels or a yard large enough to site a wind turbine. Shared renewables programs can address this problem through the development of larger, centralized renewable generation projects, with the power output distributed to subscribers or community members using the existing distribution grid. This report recommends that shared renewables programs be developed so that all energy consumers are able to participate in clean energy markets.
- **Procurement of Wholesale DG.** Utilities can use DG to contribute to meeting their state's Renewable Portfolio Standard goals, to hedge against the risks of developing large-scale generation projects and to respond quickly to load growth. This report recommends that a variety of administrative or market-based pricing mechanisms be used to procure wholesale DG, with long-term contracts essential in order to allow these capital-intensive projects to be financed.

- **Interconnection Standards and Local Permitting.** Unduly burdensome interconnection requirements and poorly designed permitting processes both present major barriers to DG development. This report recommends widespread adoption of interconnection standards (based on best practices) along with improvements in the effectiveness and efficiency of the permitting process for DG as ways to remove these barriers to DG deployment while still ensuring safe and reliable installations.
- **Integrated Distribution Planning (IDP).** DG holds great promise as a means to reduce transmission and distribution costs, but this promise will be realized only if utilities integrate DG into their planning for delivery networks. IDP is a coordinated, forward-looking approach under which utilities plan in advance to upgrade or reconfigure certain circuits that are expected to have DG added in the near future, and make the associated costs known to the market with far more transparency than is common today.

Consumers will continue to demand access to distributed energy, and these policy recommendations can help clear the path.

INTRODUCTION

As part of ongoing efforts to better understand the extent to which renewable energy generation can meet United States energy demand, the U.S. Department of Energy sponsored the development of the Renewable Electricity Futures Study (RE Futures). Under this effort, RE Futures presented a deep analysis of the ability of commercially available renewable technologies - biopower, geothermal, concentrating solar power, photovoltaic solar power (PV), wind power (offshore and onshore) and new hydropower facilities - to meet U.S. energy needs under a wide range of scenarios with an extraordinary level of geographic, temporal and operational detail. The findings of RE Futures are compelling – renewable energy can meet 80 percent of U.S. energy needs by 2050 with technologies that are commercially available today on an hourly basis in every region of the country when these technologies are combined with a more flexible electric grid. Moreover, the cost of reaching this goal is in line with the costs shown in previous studies. RE Futures, thus, provides solid support for ongoing efforts on the policy front to remove barriers standing in the way of a growing penetration of renewable energy technologies.

Unfortunately, due to limitations in the models utilized in the study, RE Futures' analysis included only a fixed contribution of DG in the primary study of how renewable technologies can meet U.S. energy needs in the future.¹ Instead, the RE Futures analysis exogenously analyzed the penetration of distributed PV using the Solar Deployment System (SolarDS) model and then accounted for the results of that modeling within the net load that the RE Futures study analyzes. The RE Futures study did consider a scenario in which transmission deployment was constrained and that scenario resulted in increased utilization of DG. Unfortunately, the limitations of the models did not allow for exploration of future scenarios of the flexibility, opportunities and tradeoffs that DG resources offer in comparison to other, larger-scale options. For example, among its many potential benefits, DG can greatly reduce the need for some of the transmission upgrades modeled in the study. Additional benefits include:

- A shorter and less complex development path to bring new resources on-line.
- A closer match between supply and demand.
- Reduced environmental impacts.
- More resiliency and quicker recovery from outages than large-scale, central station generation.

Distributed generation also can enable customers and communities to invest much more directly in the transition to a renewable energy future. End-use customers can install DG to serve their own loads behind the meter. Companies and communities may be able to develop renewable DG at convenient sites and then deliver the electricity to multiple locations or to community members who subscribe to the output of the DG facility. Distributed generation can complement larger-scale renewable generation by encouraging diversity in resources and scale. Small-scale “micro-grids” can provide greater resiliency and more local control over electric supply without sacrificing the benefits of an interconnected grid. For these reasons and more, this paper lays out careful policies to enable DG to contribute significantly to an 80 percent renewable future, delivering fewer development risks, lower overall cost and greater system reliability.

The costs of renewable technologies continue to drop, particularly for solar photovoltaics (PV). A recent report produced for U.S. investor-owned utilities showed that distributed solar PV is already at grid parity for 16 percent of the U.S. retail electricity market, and that share is growing.² Similar growth has been seen in distributed PV in other countries, and in other DG technologies.³ As a result, DG is becoming an essential and growing component of America’s renewable energy future. Before 2005, only 79 megawatts (MW) of PV had been interconnected to the grid in the U.S. Yet just five years later, in 2010, 878 MW of PV capacity was installed and connected to the grid in just that year alone. Moreover, in 2011, grid-connected PV additions more than doubled again to 1,845 MW, bringing the total amount of PV to 4,000 MW by the end of the year. Collectively, this is a 500-percent increase in seven years.⁴

POLICIES FOR MAKING THE MOST OF DISTRIBUTED GENERATION

Smart policy support for distributed generation can help achieve a renewable energy future as cost-effectively as possible. To unlock DG's potential for growth and related benefits, this paper makes five policy recommendations to facilitate demand-side and wholesale DG deployment in a way that maximizes benefits to consumers:

- 1. Net Energy Metering (NEM)**, which "runs the meter backwards" for utility customers who generate onsite power, has attracted significant retail customer investment in DG. For this reason, state governments should continue to support and expand it. States should address any concerns about NEM's impacts on non-participating ratepayers through the same comprehensive, data-driven cost-effectiveness analyses that are widely used to evaluate energy efficiency and other demand-side programs, as well as through rate design changes that more closely align retail rates with system costs.
- 2. Shared renewables programs** should be developed so that the three-quarters of retail customers who currently cannot participate in on-site renewable energy programs can invest in DG.
- 3. Wholesale procurement programs**, which allow utilities to buy and run DG, should be developed and expanded to provide for stable, cost-effective investment in wholesale DG, with an emphasis on siting DG in locations that can defer transmission and distribution (T&D) system infrastructure costs.
- 4. State-level interconnection standards and procedures and local permitting processes** based on best-practices should be developed and maintained to support cost-effective DG development.
5. States and utilities should **incorporate realistic assumptions regarding DG in their T&D planning processes**, to ensure that the T&D benefits stemming from investment in DG are not lost to utilities and their customers, and to ensure that lower-cost DG opportunities are not ignored in planning the electric grid of the future. When developers, regulators and policymakers have a full sense of the costs and constraints of each option, DG can serve as an effective complement to large-scale renewables and bulk transmission.

1. NET ENERGY METERING

When a customer decides to install and interconnect on-site distributed generation (e.g. solar panels or a small wind turbine), net energy metering (NEM) allows that customer to receive a credit from the utility when on-site generation exceeds the customer's on-site load. Under NEM, the NEM participant earns credits for power exported to the grid, which is typically valued at the serving utility's full retail rate.⁵ Often this is referred to as "running the meter backward" because the customer essentially offsets utility purchases of electricity for all generation produced on-site.

From the perspective of an electricity customer, this framework is simple and easy to understand at a conceptual level.⁶ With respect to power exported to the grid, NEM also avoids the complexity and confusion of separate rates for the import and export of power. Finally, customers interested in distributed generation understand that NEM's design provides a hedge against future increases in their electricity rates because a NEM system will supply some or all of the customer's on-site energy requirements for a known price: either the upfront cost of the system or the known monthly lease or power purchase payments to the solar installer. Because of these factors, NEM has been a foundational element in the growth of behind-the-meter DG. In 2011, ninety-three percent of the grid-connected solar installations in the U.S. were net-metered, accounting for more than 3,000 MW-dc of new generating capacity.⁷ Growth continued in 2012 such that there are now more than 290,000 net-metered systems operating across the U.S.⁸

RE Futures recognizes correctly that the market for distributed PV is highly sensitive to state and local regulatory structures and rate design policies.⁹ Because NEM has supported successful growth of customer-sited DG, and, as discussed in more detail below, concerns about NEM can be addressed using well understood practices, public utilities commissions throughout the U.S. should adopt NEM policies based on best practices.¹⁰

Addressing concerns about net energy metering is vital

Strong growth in net-metered DG systems has raised concerns among some stakeholders, particularly utilities, about whether or not NEM results in a subsidy from non-participating customers to DG owners that participate in NEM programs. Utilities posit that NEM credits at the full retail rate fail to cover the costs for the grid services that NEM customers use, such as standby service or the use of the T&D system to accept exported power, or result in NEM customers avoiding the costs of social programs, such as low-income energy assistance, that other utility customers support. Since 2010, utilities have proposed several alternatives to address these concerns, most commonly advocating for imposing new charges on NEM customers or limiting the growth of NEM systems.

Because NEM plays such a critical role in the development of DG, addressing and resolving subsidy-related concerns is an important near-term policy challenge in the pursuit of continued deployment of behind-the-meter DG. Simply put, energy regulators need to assess the

economic impacts of NEM on both DG customers and other non-participating ratepayers in a comprehensive, transparent and data-driven way. Fortunately, state regulators have years of experience doing this type of cost-effectiveness analysis in support of other demand-side programs (such as energy efficiency), and these analyses can be extended to NEM and to demand-side DG more broadly.^{11, 12} Evaluating the costs and benefits of distributed energy resources, such as energy efficiency, demand response and behind-the-meter generation using the same cost-effectiveness frameworks will help ensure that all of these resource options are evaluated in a fair and consistent manner. See Appendix B and another paper in this series, *The Role of Distributed Resources in a Renewable Energy Future*, for details. These analyses are no less important if regulators decide to consider alternatives to NEM to value the output of DG facilities, as discussed in the next section.

Alternatives to NEM

Concerns about the impacts of NEM on non-participating ratepayers also have stimulated discussion and trials of alternatives to NEM. Discussed below are several alternatives that have received significant attention. While these policies may be viable options in certain circumstances, NEM remains a principal policy choice for the majority of jurisdictions.

- Feed-in tariffs (FITs). Over the last several years, a handful of U.S. utilities have experimented with a variety of “feed-in” tariff arrangements as a means of supporting development of DG resources.¹³ Within these programs,

payments to developers of DG resources have typically been cost-based with an eye towards setting payments at a level sufficient to spur development. FITs have been used widely in Europe, demonstrating clearly that FITs can stimulate development of large amounts of new renewable DG in short periods of time. Yet FITs have also produced significant new costs for other ratepayers.^{14, 15} Perhaps as a result of the European experience, FITs in the U.S. have been limited. At the time of this writing, no state has adopted a FIT as a comprehensive alternative to NEM for behind-the-meter DG. Although a FIT with a long-term assured price can provide stimulus for investments in renewable DG, it does not provide the system owner with the hedge against future increases in utility rates that is available with NEM. Moreover, administratively setting the FIT payment rate can require regulators to make difficult decisions in order to set rates that achieve the right balance between the cost and the amount of renewable development desired. In an effort to streamline this process, some states have moved to establish market-based mechanisms to award FIT contracts to installers or developers who bid the lowest FIT price.¹⁶

- Austin Energy's value-based solar tariff. Since October 2012, Austin Energy, a municipal utility in Texas, has offered residential customers a new solar tariff that is based on a detailed model, developed by Clean Power Research (CPR), which calculates the long-term value of solar energy on Austin Energy's system.¹⁷ The CPR valuation model includes avoided generation energy and capacity costs, fuel-cost hedging value and line loss and T&D capacity savings. The tariff pays a price for all of the customer's solar PV output, while the customer pays separately for power consumed at the standard retail rate. Thus, this structure is more akin to a feed-in tariff than to NEM. It differs from European feed-in tariffs in that it is based on the value of solar output to Austin Energy rather than on an estimate of solar PV costs. The solar tariff rate is revised annually,¹⁸ so some stakeholders have argued that it may not provide an assured revenue stream or hedge value to support a customer's solar investment.

Over the next several years, there will be further tests in the U.S. market of whether these alternatives to NEM can be the basis for sustained growth of solar DG.

NEM in the long-run

Some stakeholders perceive NEM as appropriate only for a period of DG's infancy. Implicit in this perception are the assumptions that NEM provides an incentive for DG customers, and that, once this incentive is no longer necessary and DG penetration grows, NEM will need to be replaced by a more sophisticated valuation of DG. Without a doubt, there are more complex and targeted ways to value DG than NEM's retail rate credit, as illustrated by the Austin Energy value-of-solar tariff and various FIT programs. However, there are trade-offs: for a prospective customer looking to install a DG system to offset their load, these structures may not be viewed as simple or as certain as NEM. For example, requiring a DG customer to accept different prices for power exported to the grid and power consumed on-site could be a tough sell if the price offered for exported energy is viewed as arbitrarily low or transferring value of the investment to other utility customers. Moreover, alternatives have yet to demonstrate the same wide customer acceptance that NEM has achieved.

Most importantly, exploration of rate designs that better align rates with long-run costs can address cross-subsidy concerns while preserving the signal virtues of NEM for the DG industry and customers. Rate designs that are more closely linked to costs are likely to be desirable for other reasons, including providing accurate price signals to encourage energy conservation and to shift power use away from high-demand periods, both of which often are lower-cost steps that consumers should take before investing in DG. The central focus of NEM programs could also evolve in ways that address cross-subsidy concerns but still maintain the simplicity of NEM from the potential customer's perspective. For example, shorter netting periods – such as monthly or hourly

instead of yearly – could be coupled with a payment for net excess generation at the end of the netting period. That payment could be set at a level that provides compensation to customers for the value of their energy investment to the grid. However, such a framework would require that compensation levels carefully and fully value the long run benefits that these demand-side systems bring to the grid, which is often not the case today. This outcome is important so that customers installing DG systems are fairly compensated for the value provided while non-participating customers are not paying for more than the value received. Such a framework would still allow a customer to avoid utility-purchased energy by consuming energy produced on-site which would leave NEM open to criticism that it is burdening non-participating customers due to this reduction in sales. However, this concern is more a function of current utility business models that rely on increased sales or infrastructure investments for revenue growth than a function of NEM policy. Evolution in utility business models to move away from the link between increasing sales and profitability will better align utility incentives with society's changing needs and preferences will be necessary to fully address this criticism.

It is also important to recognize that elimination of all cross-subsidies may not be feasible politically or desirable socially. It is commonly understood that retail rates are set based on social goals that may be more compelling to regulators than simple economic efficiency and cost causation. In many states, wealthy energy consumers typically subsidize their less wealthy neighbors, urban energy consumers subsidize rural consumers, residential energy customers are subsidized by commercial/ industrial customers (or vice versa) and, in the case of California, coastal users subsidize users in the warmer central regions of the state. Increasing block rate design

in California and other states to encourage reductions in consumption also can lead to cross-subsidies from higher energy users to lower energy users. Each of the cross-subsidies that result from rates being set with underlying social goals in mind is not indicative of a problem with NEM, but rather a function of the social policies set by each state. This last point is important to remember: as customers are presented with more options and more freedom to manage their energy use and supply, all cross-subsidies will need to be carefully examined to ensure they continue to result in the outcomes desired by society, which can often be in conflict.

Recently there has been significant attention to the possibility that the value of solar will decline at higher solar penetrations. Growth in solar DG, including behind-the-meter DG, will shift the electricity system's aggregate peak power demand to later in the afternoon or into the early evening, and wholesale solar will lower the market value of power on summer afternoons.¹⁹ However, these studies have focused on achieving high renewable penetrations through adding only solar, such that there is a significant oversupply of resources to serve load in the daylight hours.²⁰ As a result, caution is advised on extrapolating these results to the RE Futures scenario of an 80 percent renewables penetration, which

requires high penetrations of a wide range of renewable technologies, including significant amounts of resources other than solar, to meet the afternoon peak.

Undoubtedly, the value of solar and of other types of DG at high penetrations of renewables will be different than today, and will require rates to be revised periodically to align with changes in the value of power across the day, the week and the seasons. As rates change to reflect the evolving resource mix, customers seeking to invest in DG will adjust their investments in a way that continues to align costs with the benefits they receive from their investment. Ultimately, the game-changer in this regard is on-site storage. Even the availability of a few hours of storage per day would enable intermittent DG resources to focus their output on those hours when power is most valuable, even if those occur after sunset or when the wind is still. In addition, even modest amounts of storage will help to unlock the reliability and resiliency benefits of DG, by providing the ability to serve critical loads if a major storm disrupts grid service for an extended period. This will help to avoid experiences such as Hurricane Sandy, after which almost 1 GW of installed PV capacity in New Jersey could not operate because the grid was down.

DECISION-MAKER	RECOMMENDATION
PUCs	Adopt Net Energy Metering (NEM) based on best-practice policies identified in Freeing the Grid. ²¹
PUCs, ISOs/RTOs, utilities	Evaluate NEM and distributed generation using the same cost-effectiveness framework used for other demand-side resources such as energy efficiency and demand-response. (See Appendix B for methodological suggestions.)
PUCs	Design retail electricity rates to align more closely with long-run marginal costs, including time-varying costs over the course of the day.

2. SHARED RENEWABLES

As described above, demand-side renewable energy programs, in particular NEM, have facilitated customer investment in renewable energy across the U.S., allowing homeowners and businesses to install on-site renewable energy systems and to generate their own electricity. Nevertheless, many residential and commercial consumers who are interested in supporting renewable energy cannot participate in NEM and other renewable energy programs that require a system to be located on-site. This may be because these consumers are renters, live or work in multi-tenant buildings and/or do not have adequate or appropriate roof space. In addition, some homeowners and businesses simply may not want to install renewable energy systems on-site. For example, a homeowner may live in an historic district where PV panels would be considered visually out of place. For these reasons, a recent report from the National Renewable Energy Laboratory (NREL) has estimated that only about one-quarter of U.S. households are able to install solar on their roofs.²²

Shared renewables programs solve this issue by allowing a centralized system to serve these parties. By increasing the flexibility in the siting of a system, shared renewables programs allow new customers to participate in ownership of a renewable energy system and to receive the benefits from their investment. Such programs also allow renewable energy developers to tap a huge potential market. For example, if just 5 percent

of U.S. households were to invest in a 3-kW share of a shared solar system — the size of a typical rooftop solar installation — it would result in more than 17,000 MW of additional solar capacity.²³ While still considered DG, shared solar systems often are larger than a typical rooftop system, and can benefit in lower installation costs due to economies of scale. Because well-designed shared renewables programs represent an opportunity to remove barriers to renewable energy growth, these programs should be expanded.

Defining shared renewables

Shared renewables programs refer to programs in which participants either own or lease panels, or purchase kilowatt-hour (kWh) blocks of generation from a particular system.²⁴ That is, participants have some sort of “interest” in a renewable generation facility or program from which they receive benefits via a check or a credit on their electricity bills. Because shared renewables programs provide participants with a direct benefit similar to what they might experience through NEM or other demand-side programs, these programs have proven to be popular where implemented. Solar installations power most shared renewables programs, but other types of renewable generation, such as wind, have made more sense for certain communities.²⁵

Conversely, community-based renewables programs cover a relatively wider range of programs that facilitate investment in a DG facility located in or near a community — such as on a community center, a municipal property or a non-profit — if the facility is seen as benefiting the community. For example, Mosaic, a new company launched in 2011, relies on a crowd-funding model to finance community systems, and investors benefit through interest on their investment.²⁶ Other community-based programs have relied on a donation model, such as RE-volv (also founded in 2011), where interested participants donate to the construction of a renewable energy system in their community, sometimes receiving a tax deduction or a gift.²⁷ Community-based renewables programs have a long track record, especially in facilitating local investment in wind projects.²⁸

Critical issues in developing shared renewables programs

Shared renewables programs tend to be developed in ways that respond to the particular needs and interests of their administrators and participants.²⁹ Thus, these programs are especially dependent on policy decisions by legislatures, state-level regulatory entities (such as public utility commissions), local governments and utilities’ own governing bodies, such as a cooperative utility board. Each must address certain key issues, including the ownership of a system and the distribution of the benefits of participation.³⁰

Ownership of the system: In some cases, the utility administering the program owns the community generation system.³¹ In other cases, an individual or community organization may own the system. In still other cases, a program may allow for a third-party developer or multiple developers to own the systems. Finally, some programs provide for multiple ownership models. Flexibility in ownership models allows for innovative financing that can result in the lowest cost and most benefit to participants. Even so, at this writing, only 22 states and Washington D.C. allow third-party ownership of self-generation systems.³² Prohibition of, or lack of clarity in, third-party ownership can serve as a barrier by limiting financing options.

Distributing the benefits of participation: For most programs, it makes sense to structure shared renewables programs in a form similar to familiar DG programs, distributing benefits via bill credits on participants' electricity bills. This method of distributing benefits is sometimes referred to as "virtual net metering" because the participant receives a credit on his or her utility bill, but the renewable energy system is not directly connected to the participant's meter. According to research from the Interstate Renewable Energy Council (IREC), about 80 percent of shared solar programs function this way. As with NEM, the most complex element of distributing shared solar credits is how to determine the appropriate value for the credit. Most programs today value the bill credit based on the

utility's retail rate, similar to NEM bill credits. Some programs provide a modified retail rate-based credit that compensates the utility for certain things, like the use of its distribution grid and administration of the program. Recently, however, more utilities are considering bill credits based on the "value of solar" and other methodologies, as described above with respect to NEM.

Despite the implementation and policy challenges discussed above, shared renewables programs are emerging throughout the U.S., with more than thirty shared renewables programs operating as of 2012.³³ These programs can serve as models and useful resources for communities interested in developing their own programs.

DECISION-MAKER	RECOMMENDATION
PUCs, cities, counties, utilities	Adopt Shared Renewables programs using a bill credit mechanism. Enable flexible ownership models for shared renewables, including third-party ownership.

3. WHOLESALE PROCUREMENT PROGRAMS

Wholesale procurement programs allow utilities and system operators to buy DG directly, providing another means to accelerate a high-renewable electricity future and complementing retail programs including NEM and shared renewables.³⁴ Wholesale procurement policies are often part of a Renewable Portfolio Standard (RPS) implementation strategy. In some cases, RPS carve-outs for DG and/or solar inform the development of wholesale procurement programs; that is, wholesale programs can be designed to target particular distributed technologies or DG generally.³⁵ If implemented carefully, wholesale policies can create opportunities to locate DG projects where they maximize benefits to ratepayers while minimizing cost.

Existing wholesale procurement programs

States and utilities have a range of wholesale procurement mechanisms to use in implementing renewable procurement policies, each with its own set of challenges and benefits. Options include avoided-cost pricing, feed-in tariffs (FITs) and market-based procurement mechanisms, such as auctions and requests for proposals (RFPs). Each mechanism may be more or less attractive depending on the policy climate and the goals it is intended to achieve, but each can serve as a mechanism to support deployment of wholesale renewable DG.

- **Avoided-Cost Pricing** sets prices based on the energy and system costs that are saved when DG generation is added. The Public Utilities Regulatory Policies Act of 1978 (PURPA) first introduced the avoided-cost pricing mechanism.³⁶ PURPA originally required utilities to purchase electric generation from small power-production facilities, which include renewable energy facilities smaller than 80 MW, and cogeneration qualifying facilities (QFs) at a price equal to a utility's avoided cost. While PURPA's requirements have evolved over the years, many utilities continue to purchase QF output at avoided cost. For example, under its Small Customer Generator (SCG) Tariff, Duke Energy in North Carolina purchases the excess generation of certain eligible solar systems at avoided cost, as set by the state regulatory commission every two years.³⁷ Avoided cost-based prices have historically been too low to incentivize significant program participation, but several policy initiatives could change this. The first is that states could take advantage of a FERC decision from October 2010, which clarified that states may set technology-specific, "multi-tiered" avoided costs in cases where the state has a specific procurement goal for each technology.³⁸ The second is that the

scope of avoided cost-pricing for DG QFs could be extended to include the avoided transmission and distribution capacity costs that result from using DG resources. QF pricing historically has been limited to avoided generation costs, even though many utilities calculate marginal transmission and distribution costs for use in rate design, and states such as California use avoided T&D costs in cost-effectiveness evaluations of DG and other demand-side programs.

- **Feed-In Tariffs** set prices based on the cost to the developer. FITs are similar to avoided cost mechanisms in that they obligate a utility to purchase power from eligible generators at administratively predetermined prices. In contrast to avoided cost prices, FIT pricing is intended to reflect a payment level that is viewed as necessary and sufficient to ensure that developers can build and operate a project with a reasonable profit. Thus, the price may be well above the cost of alternative resources. For this reason, U.S. jurisdictions that have established FITs have all imposed caps that limit FIT system deployment on the basis of installed capacity, total cost or allowable rate impacts. For example, Hawaii has a FIT for certain eligible renewable energy technologies, which is offered by the state's three investor-owned utilities: HECO, MECO and HECO.³⁹ Qualified projects receive a fixed rate, depending on technology and system size, over a 20-year contract. The program is capped at five

percent of 2008 peak demand for each utility. Similarly, California has a FIT program for DG projects of three MW of smaller, which the California Public Utilities Commission (CPUC) recently modified in response to various pieces of legislation, although the new program is not yet in effect.⁴⁰ The FIT price under the California program will no longer be based on the all-in costs of a new gas-fired combined-cycle plant (as determined administratively by the CPUC), but instead will be set using an innovative market-based pricing mechanism called the renewable market-adjusting tariff (Re-MAT). The Re-MAT price will adjust up or down depending on the market demand for FIT contracts.⁴¹ In addition, the FIT cap will increase to 750 MW statewide, split across investor-owned and publicly owned utilities.

- **Market-Based Procurement Mechanisms:** Unlike avoided-cost pricing and most FIT programs, market-based procurement uses competitive means, such as auctions and RFPs, to determine price levels. In short, a contract or contracts are selected largely based on best-available price, so long as the project meets the eligibility criteria of a program, which could include size, technology type or location and developer experience. Market-based programs may place smaller systems and emerging technologies at a disadvantage because administrative costs, such as the cost of submitting a bid, represent a larger

percentage of project revenue than for larger PV projects. Nonetheless, there are some successful market-based programs that target DG procurement. For example, California's Renewable Auction Mechanism (RAM) covers renewable energy systems between three and 20 MW located anywhere within the three largest investor-owned utilities' service territories.⁴² To date, California utilities have successfully implemented two of the four RAM auctions allowed by the CPUC, and are in the process of administering the third. The CPUC has not yet determined whether or not it will extend the RAM program after the fourth auction. California's investor-owned utilities also each have solar PV programs, which target solar DG through competitive solicitations.⁴³ Similarly, in Oregon, the Public Utilities Commission approved a market-based procurement pilot program for solar PV systems between 100 and 500 kW in capacity.⁴⁴ To date, two Oregon utilities, Pacific Power and Portland General Electric, have undertaken three rounds of RFPs as part of this program.

- **Renewable Energy Credits (RECs) as part of a Renewable Electricity Standard:**⁴⁵

Treatment of renewable energy credits produced by wholesale DG facilities is a complex, but important, consideration in designing successful wholesale DG programs. States have taken different approaches to using RECs to facilitate deployment of DG resources. Some states (e.g., Arizona, Colorado and New Jersey) allow DG facilities participating in their wholesale renewable energy programs to sell their RECs to a utility to meet identified solar and distributed generation requirements within their state-mandated RPS programs. Other states (e.g., California) require DG facilities to transfer RECs at no cost to a utility as a condition for participation in the state FIT program.

Critical components of wholesale procurement programs

Experience with existing wholesale procurement programs has demonstrated the importance of two critical program components: long-term program design and incentivizing location in higher-value areas. These two components can be integrated into a program using any of the mechanisms described above. When a wholesale program incorporates both of these components, it can facilitate a highly reliable, decentralized grid and allow for the avoidance of new transmission infrastructure.

Long-term program design

Wholesale procurement programs should provide for long-term investments, which are necessary to promote a stable market for capital-intensive renewable technologies. Successful wholesale procurement programs, such as California's Renewable Auction Mechanism, offer 10-, 15- or 20-year contracts to align payments with system lifetimes, making it easier for developers to finance and build renewable energy projects.⁴⁶

Similarly, wholesale procurement policies should establish multi-year programs in order to avoid the regulatory uncertainty that can stymie investment by renewable energy businesses.⁴⁷ For example, Oregon's market-based procurement mechanism, even though it was considered a pilot project, was authorized for five years, from 2010 to 2015, at which point the Commission will reassess it. Assurance of stable policy support for renewable energy — in particular, the continued viability of wholesale procurement policies — sends an important market signal that supports investment in renewable DG resources.

Offering incentives to locate in higher-value areas

In addition to providing long-term support for wholesale renewable procurement, program designers should ensure that wholesale procurement programs prioritize higher-value DG. Distributed generation increases in value the closer it is to load, especially if it is sited on the same distribution system as the load it is intended to serve. It is critical to locate DG in this manner, as many of DG's benefits are location-specific and therefore are maximized when DG is near to the customers it serves.⁴⁸ When DG is sited strategically — such as on rooftops, parking lots and other hardscape areas or brownfield sites — it can put existing land and infrastructure to more productive use. At the same time, it can minimize the amount of virgin land and habitat that would otherwise be needed for power generation. On the retail side, NEM facilitates high-value on-site generation, and shared renewables programs can be designed to maximize locational value;⁴⁹ wholesale procurement policies should do the same.

Currently, most wholesale procurement programs do not prioritize development in higher-value locations because they typically allow participants to interconnect anywhere on the distribution or transmission systems. As a result, renewable energy developers do not take into account the costs of connecting in sub-optimal locations far from load, which may appear less expensive for other reasons (e.g., low land costs); instead, these costs are born, at least in part, by ratepayers. There are a variety of ways that a procurement program could realign incentives to encourage development in higher-value areas. For example, a program might provide an incentive payment for projects that locate in higher-value areas to reflect the added benefit of strategic siting. Interconnection policies also can incentivize wholesale projects to locate in higher-value areas, as described in more detail below.

Ensuring that wholesale procurement policies support higher-value DG would have the effect of creating DG “hot spots” in strategic locations that maximize the benefits of DG. As DG development increases and concentrates, it may put pressure on local DG permitting processes, which can sometimes be difficult to navigate or can become overwhelmed by high numbers of applications. Nevertheless, these “hot spots” may also be beneficial to utilities, enabling them to adjust their planning efforts to take advantage of concentrated DG. In addition, utilities could integrate energy storage or focus on demand-response programs in these higher-value DG areas to firm generation capacity.

DECISION-MAKER	RECOMMENDATION
PUCs	Set technology-specific, “multi-tiered” avoided costs to stimulate the DG market.
PUCs	Expand the scope of avoided cost pricing for qualified facilities to include avoided transmission and distribution capacity costs.
PUCs	Streamline bid processes for market-based procurement.
PUCs	Where there is a Renewable Portfolio Standard but no Feed-in Tariff, allow developers of DG facilities to sell Renewable Energy Credits to utilities.
PUCs	Design wholesale procurement mechanisms with long time frames (5-20 years), to support procurement of the output of new DG facilities.
PUCs	Incorporate locational value into wholesale procurement assessments via a locational marginal price adder or a location-specific interconnection incentive.

4. INTERCONNECTION STANDARDS AND LOCAL PERMITTING

The existing distribution system was built for a one-way power flow. As more on-site generation comes online, well-designed interconnection procedures are crucial to ensure safe and reliable operation of the distribution grid. However, the decision to study each individual generation system in depth must be balanced with the cost for utility staff time to review each application, the challenge of studying projects in series on a dynamic system, and the need for DG developers to have predictability, certainty and speed in interconnection. For these reasons, unduly burdensome study requirements and associated timeframes can pose significant hurdles to DG systems, particularly those in the 25 kW or smaller size range, and could present unacceptable costs to utilities and their customers with minimal safety or reliability benefits. To address these concerns, the Federal Energy Regulatory Commission (FERC) and many states have moved to adopt standards to govern the review of requests for interconnection that balance these concerns while removing barriers to DG deployment.

Adoption of best-practice interconnection procedures has been slower than adoption of net metering. Since 2000, FERC has adopted the Small Generator Interconnection Procedures (SGIP), and 32 states and Washington D.C. have adopted state jurisdictional interconnection procedures. Yet, according to state interconnection procedure ratings in *Freeing the Grid*, only eight states have earned an A for their interconnection procedures, and more than half have

adopted interconnection procedures that grade at a C or below, or have not adopted statewide interconnection procedures.⁵⁰ This situation represents a serious barrier to continued deployment of DG. In addition, as discussed more fully below, even those states that currently achieve high grades will need improvements to ensure that the interconnection process is equipped to support higher penetrations of DG, particularly as the ratio of generation to load on distribution circuits increases.

Moreover, while much of the focus on removing barriers to DG deployment have focused on state-level efforts and activities at public utilities commissions, local jurisdictions have a crucial role to play in the deployment of DG within their permitting processes. Plan checks and inspections are an important part of ensuring safety and reliability of DG systems. However, there is a strong need to update permitting processes to ensure they are effective and efficient.

Reassessing the penetration screen for distributed generation

Most U.S. interconnection procedures use a set of technical screens, including a penetration screen, to identify which projects require an interconnection study and which can proceed on a faster track. As an increasing number of circuits in the country reach high penetrations of DG, more and more DG projects are failing the penetration screen. Thus, fewer projects are able to proceed quickly and more utility resources are tied up in the study process. In the near term, an update of the penetration screen to continue to allow for expedited review of small systems, while still maintaining a high level of safety and reliability, is important to keeping the interconnection process moving.

As the capacity of installed DG on a line increases, the possibility of unintentional islanding, voltage deviations, protection failures and other negative system impacts may increase.⁵¹ To account for this possibility, most interconnection procedures apply a penetration screen that requires further study of a project if the new project would cause total generation to exceed 15 percent of the line section peak load. At the time this screen was originally drafted, few utilities were regularly collecting minimum load data, thus the 15 percent of peak load measurement was identified “as a surrogate for knowing the actual minimum load on a line section.”⁵² The screen is intended to approximate a limit of roughly 50 percent of minimum load.⁵³ In many cases, however,

a full interconnection study is not required until the generation on a line exceeds 100 percent of minimum load. Thus, some states, including California and Hawaii, have adopted a modification to their penetration screen that allows projects that fail the 15 percent of peak load initial screen, but are below either 75 or 100 percent of minimum load, to interconnect without detailed study as long as they pass two supplemental screens that examine whether the interconnection raises potential power quality, voltage, safety or reliability concerns.⁵⁴ Two recently released studies from NREL support the viability of these approaches.⁵⁵ FERC, Massachusetts and Hawaii are considering a similar change. As other states experience higher DG penetration levels, it will be essential to consider this or a similar modification to their interconnection procedures.

Coordinate changes to interconnection and procurement

An update of the penetration screening method is the most critical near-term change for interconnection procedures, but a deeper evaluation of the role of the interconnection process as a whole will likely be needed, as the popularity of DG in certain markets is already resulting in penetrations that exceed minimum load on circuits in the U.S.⁵⁶ In particular, coordinated changes to the interconnection and wholesale procurement process can help maximize use of the existing infrastructure and result in greater system-wide benefits.

Increasing the transparency of the interconnection process can help to smooth the flow for both project developers and utilities. Creating system mapping tools and pre-application reports can provide valuable information to applicants, enabling them to select project sites with fewer potential interconnection issues and obtain a better understanding of the likely costs and interconnection time frames associated with chosen sites. This improvement should come in tandem with similar improvements to wholesale procurement programs, described above, that can drive projects to the lowest-cost, highest-value locations. These two policies in combination can reduce the number of applications for unviable projects, and can also help to maximize existing system capacity. In considering how to implement such changes, however, it is important to recognize the difference between rooftop solar projects designed largely to serve local load, and wholesale or shared renewables projects. Wholesale and shared renewables projects have greater flexibility in selecting sites, while rooftop customers have no choice in location. In addition, increasing transparency within the process itself, by adding clearly defined timeframes for each step in the process and an explanation of what the utility's analysis will include, can also help prevent backlogs in the interconnection queue.

While efforts to develop best-practice interconnection procedures have facilitated growth in DG to date, more needs to be done to ensure interconnection procedures are standardized nationally in order to further facilitate interconnection in a fair, safe and effective manner. Moreover, current procedures are not equipped to smoothly handle the volume of applications that could be submitted in high DG growth scenarios, nor are current interconnection procedures prepared to address the increasing number of technical issues that

arise as higher penetrations of DG are reached. If the higher penetrations of DG shown to be feasible in RE Futures are to be undertaken, continued examination of interconnection standards will be necessary.

Enhancing and streamlining local permit processing

Much of the focus on enabling greater amounts of DG is centered on the actions of the public utilities commissions and the utilities. However, local governments and environmental regulatory agencies can also play a significant role in facilitating greater uptake of distributed generation by increasing the ease with which properly sited DG can obtain necessary permits for construction. Local governments, in particular, play a critical role in ensuring the safety and quality of solar installations on homes and businesses in the U.S. Without plan checks and inspections, it is possible that a number of faulty installations, which cause personal injury or property damage, could impair customer interest in renewable energy. Similarly, while ground-mounted DG creates fewer impacts than utility-scale installations, poor siting choices can also have significant land use and environmental impacts on communities.

With the importance of the review process in mind, there is a need for an update to the procedures for obtaining permitting review and approval to make them more effective and efficient. The most recent figures from the Department of Energy's SunShot Initiative indicate that improving permit review efficiency can result in system costs that are between 4 and 12 percent lower than in jurisdictions that have not adopted similar streamlining.⁵⁷ Tackling this issue is particularly challenging due to the sheer number of different permitting authorities that exist in the U.S. In addition to the public utilities

commission in each state, there are over 20,000 municipalities and other authorities responsible for issuing permits to enable DG facility construction. Thus, the strategic approach has to involve widespread dissemination of well-developed models that can be easily adopted by other municipalities.

As the volume of DG increases, so will the number of permit applications that municipalities have to process. For example, the City and County of Honolulu processed an astonishing 16,715 PV permits in 2012, reviewing an average of 80 permit applications a day.⁵⁸ Even a small portion of this volume would easily overwhelm most jurisdictions. Thus, finding more efficient methods of review that do not undermine safety and quality can be in the municipality's interest. Approaches to permitting reform that can benefit both the municipal government and the installation community are most likely to be immediately appealing and successful.

Improved access to clear information about the permitting process and its requirements can enhance the quality of applications, and thereby reduce the back and forth that has burdened both installers and permit officials. Internal improvements in permit processing can include adopting expedited review for applications that meet pre-determined design criteria and new methods of scheduling permitting staff to enable faster application review and inspection. Moving the permitting process online can result in significant efficiency improvements but can require an upfront investment for cash-strapped municipalities. Finally, ensuring that inspectors and permitting staff, as well as the installation community, have sufficient training in DG technologies can enable more efficient review with high safety standards.⁵⁹

DECISION-MAKER	RECOMMENDATION
FERC	Define a standard interconnection procedure.
PUCs	Adopt best-practice interconnection procedures.
FERC, PUCs	Enable systems that fail the penetration screen to interconnect without in-depth study if they pass additional screens examining their effect on power quality, voltage, safety, and reliability.
PUCs, Utilities	Create system mapping tools and pre-application reports to highlight the lowest-cost and highest-value locations for DG projects. Publish clear timelines for project development.
Municipal and local authorities	Improve and streamline permitting review and approval with the adoption of best practices

5. MOVING TOWARD INTEGRATED DISTRIBUTION PLANNING (IDP)

A central benefit of DG is the ability to avoid or defer the need for costly expansions of transmission and distribution infrastructure, but current utility business models tend to discourage planning that analyzes distributed generation's ability to defer T&D. Utility T&D planners alone have the information needed to make the decisions about whether DG can avoid T&D investments. But under the traditional U.S. model of utility ratemaking, utility profits are based on how much capital the utility has invested. This inevitably places pressure on the utility to minimize the potential for DG to reduce its spending program on T&D infrastructure. The utility's incentives are understandable, given a ratemaking structure that ties profits to the magnitude of T&D investments. Utility business models and regulatory frameworks will need to be reexamined in order to properly align utility incentives to take advantage of distributed generation's ability to defer or avoid T&D expansions or upgrades.⁶⁰

Historically, utilities have planned for distribution system upgrades that accommodate growing or changing energy and power demand. Utility planners typically prioritize distribution system upgrades based on extrapolations of historical loads that may or may not include very small amounts of DG in the local area under study. But DG's exponential growth in some U.S. markets suggests that trending historical loads may not continue to provide a reliable picture of demand even a few years into the future.

Furthermore, under today's procedures, utilities study only pending interconnections, and circuits are upgraded to accommodate generation on a project-by-project basis. This approach has a number of potential downsides. First, it means the first project to trigger an upgrade pays the full cost, even if later generators also benefit. It also results in a slower interconnection review process because each project must be studied in sequence, and if a developer chooses not to proceed with an upgrade, it can sometimes result in a need to re-study projects further down in the queue.⁶¹ This reactive approach also undermines the ability of the utility to provide incentives to DG to locate in the highest-value parts of the grid. It makes it very difficult, if not impossible, for utilities to pursue cost-effective upgrades to the distribution system to support anticipated levels of DG. In short, this approach provides no incentive for utilities to undertake system planning that can benefit both load and generation.

These historical inefficiencies in the treatment of DG can be addressed through more streamlined and coordinated approaches to distribution system planning and DG interconnection. One approach is for utilities to conduct forward-looking studies, and possibly even upgrades, for certain circuits that are expected to have generation added in the near future. This coordinated approach is known as “Integrated Distribution Planning” (IDP).⁶² IDP requires a reconsideration of the traditional methods for financing interconnection studies and upgrades, but it makes more efficient upgrades and increased transparency possible. Hawaii and New Jersey have begun to implement this method as they see increasing pressure from high circuit penetrations.⁶³

Emerging IDP methods under development generally use a two-step process to determine a circuit’s capacity to host DG prior to a request for interconnection. The first step involves modeling to determine the ability of a distribution circuit to host DG. The second step coordinates distribution system planning with anticipated DG growth. In situations where anticipated DG growth exceeds a distribution circuit’s hosting capacity, utility planners can identify additional infrastructure that may be necessary to accommodate the coming growth. The results of these proactive studies can be used to inform subsequent interconnection requests by determining, in advance, the precise level of DG penetration that can be accommodated without system impacts. At higher levels of penetration, utilities will have foreknowledge of any upgrades that may be required to maintain safety, reliability and power quality standards.

DECISION-MAKER	RECOMMENDATION
Utilities, ISOs/RTOs	Conduct forward-looking studies for circuits likely to achieve high penetrations of DG.
Utilities, ISOs/RTOs	Adopt Integrated Distribution Planning to compare DG and distribution system upgrades on an equal footing with each other, and with other demand- and supply-side options.

CONCLUSION

There is unlikely to be a single path to reach the goal of a U.S. electric grid that obtains 80 percent of its power from renewable resources. Distributed generation provides an essential piece of the puzzle, in conjunction with larger-scale renewable energy resources in remote areas where wind and solar resources are plentiful and there is adequate transmission capacity to bring energy from these facilities to load. In cases where land use concerns limit the ability of the renewables industry to site central station plants and the associated transmission in the remote areas, DG can and should be the primary alternative examined.

Individuals, communities and businesses are increasingly demanding DG. Harnessing this interest will require the development of smart, customer-focused policies that provide a stable and certain environment in which customers can make informed investments in DG systems, and incentives to encourage utilities to integrate DG resources into their planning on the same basis as investments in large-scale generation or the delivery infrastructure. Most importantly for the future, it will be easier to maintain momentum toward a high renewables future if a significant segment of electricity consumers have had the direct experience of procuring and producing their own renewable energy on their home, at work or in their local community.

On the wholesale side of the equation, stable, long-term policies are also necessary to incentivize participation by developers in utility DG procurement programs. Smaller-scale DG may compete with remote central station plants when avoided transmission and distribution costs are considered, and programs should be designed to offer the best solution over the long term, taking into account all the benefits DG can provide.

Adapting today's processes to accommodate DG growth will require both simple changes, such as the reassessment of penetration screens, and more fundamental reforms, such as a movement toward integrated distribution planning, and even a fundamental re-thinking of the role of the utility and the business models under which they operate. Making these changes requires recognizing that energy production is being fundamentally transformed and grid management will have to evolve along with it in order to maintain safety and reliability, provide DG systems with access to the grid and ensure that costs and benefits are fairly distributed amongst customers.

ENDNOTES

- 1 DG is commonly understood to mean energy production facilities located within the distribution system with capacities of 20 megawatts (MW) or less. NREL did publish complementary analysis of the Sunshot Vision goals, which explore scenarios with higher contributions from DG. See Denholm et al (2013).
- 2 Kind, Peter, 2013. "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business." Edison Electric Institute. <<http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf>>
- 3 American Wind Energy Association, 2012. "2011 U.S. Small Wind Turbine Market Report." <http://www.awea.org/learnabout/smallwind/upload/AWEA_Small-WindReport-YE-2011.pdf>
- 4 Sherwood, Larry, 2012. "U.S. Solar Market Trends 2011." Interstate Renewable Energy Council. <<http://www.irecusa.org/wp-content/uploads/IRECSolarMarketTrends-2012-web.pdf>>
- 5 In some states, the export price under NEM is set explicitly at the utility's avoided cost, not at the retail rate; and in many states, avoided costs instead of retail rates are used to compensate DG customers if their production exceeds their on-site use.
- 6 The complexity associated with billing for net metering and how net metering credits are presented on customer bills can lead to confusion for participants in net metering programs. Billing simplification could help ameliorate these issues, but further research is needed to develop best practices in support of such simplification.
- 7 Sherwood, 2012. Figs. 2 & 6. Most NEM programs allow for a variety of renewable energy technologies. Solar PV generation today is the most prevalent DG technology, because PV is inherently modular and the broad availability of solar resources means that property owners may install distributed, behind-the-meter PV wherever there is a load and available sunny rooftop or open space.
- 8 Author correspondence with Larry Sherwood, Interstate Renewable Energy Council, April 15, 2013.
- 9 National Renewable Energy Laboratory, 2012. "Renewable Electricity Futures Study." Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek M.; Sandor, D. eds. 4 vols. NREL/TP-6A20-52409. National Renewable Energy Laboratory. <http://www.nrel.gov/analysis/re_futures/>
- 10 Freeing the Grid, 2012. "Freeing the Grid 2013: Best Practices in State Net Metering Policies and Interconnection Procedures." Vote Solar; Interstate Renewable Energy Council. <<http://freeingthegrid.org/>> assigns letter grades to each state's net metering program, as assessed against NEM best practices. In 2012, sixteen states had adopted net metering programs that earned an A based on the design of their programs. However, eighteen states show low grades of a C or below, meaning those states' programs have program elements that represent serious departures from best practices, or they received no grade meaning they have no statewide net metering program or participation in the program by utilities within the state is voluntary.
- 11 For example, IREC has devoted significant attention to establishing a consistent and thorough approach to evaluating the costs and benefits of NEM. With the support of the Solar America Boards for Codes and Standards, IREC published A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering.
- 12 Keyes, Jason B.; Wiedman, Joseph F., 2012. "A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering." Interstate Renewable Energy Council. <http://www.solarabcs.org/about/publications/reports/rateimpact/pdfs/rateimpact_full.pdf>
- 13 Couture, Toby; Cory, Karlynn, 2009. "State Clean Energy Policies Analysis (SCEPA) Project: An Analysis of Renewable Energy Feed-in Tariffs in the U.S." NREL/TP-6A2-45551. National Renewable Energy Laboratory. <<http://www.nrel.gov/docs/fy09osti/45551.pdf>>
- 14 The German EEG charge that principally recovers the costs of the German renewable FITs now constitutes about 14 percent of the average residential electric rate in Germany.
- 15 Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, 2013. "Development of renewable energy source in Germany 2011." Working Group on Renewable Energy-Statistics (AGEE-Stat). <http://www.erneuerbare-energien.de/fileadmin/Daten_EE/Bilder_Startseite/Bilder_Datenservice/PDFs/XLS/20130110_EEZIU_E_PPT_2011_FIN.pdf>
- 16 "Renewable Auction Mechanism" California Public Utilities Commission, 2007. <<http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm>>
- 17 Rábago, Karl R., et al., 2011. "Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator." Austin Energy; Clean Power Research. <http://www.cleanpower.com/wp-content/uploads/090_DesigningAustinEnergySolarTariff.pdf>
- 18 The Austin Energy solar tariff provides that "[t]he Value-of-Solar Factor shall initially be \$0.128 per kWh, and shall be administratively adjusted annually, beginning with each year's January billing month, based upon the marginal cost of displaced energy, avoided capital costs, line loss savings, and environmental benefits." For more detail, see <<http://www.austinenergy.com/About%20Us/Rates/pdfs/Residential/Residential.pdf>>.

- 19 Mills, Andrew; Wiser, Ryan, 2012. "Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California." LBNL-5445E. Environmental Energy Technologies Division; Lawrence Berkeley National Laboratory. <<http://eetd.lbl.gov/ea/emp/reports/lbnl-5445e.pdf>>
- 20 The authors of the LBNL Report explicitly caution against drawing conclusions about the value of combinations of renewable technologies, which they plan to examine in a future study. LBNL Report, at 3 and 8.
- 21 The Vote Solar Initiative, et. al., Freeing the Grid, 7-8, Nov. 2012, available at <<http://freeingthegrid.org>>.
- 22 Denholm, Paul; Margolis, Robert, 2008. "Supply Curves for Rooftop Solar PV-Generated Electricity for the U.S." NREL/TP-6A0-44073. National Renewable Energy Laboratory. <<http://www.nrel.gov/docs/fy09osti/44073.pdf>>
- 23 "State and County Quick Facts." U.S. Census Bureau, 2013. <<http://quickfacts.census.gov/qfd/states/00000.html>>
- 24 In previous reports, IREC and other stakeholders have referred to shared renewables as community renewables or community-shared renewables. However, as the concept has matured, consensus has developed among stakeholders that use of "community" in describing the programs can create confusion, as stakeholders' perceptions of "community" are highly diverse. IREC has supported the move to describing programs as shared renewables and is adjusting references in documents it produces, including the ones cited in this paper, to that new nomenclature over time.
- 25 See <www.windustry.org>.
- 26 See <<https://joinmosaic.com>>.
- 27 See <<http://www.re-volv.org>>.
- 28 See <<http://www.windustry.org>>.
- 29 According to IREC's research, roughly half of the programs identified above are run by electric cooperatives, with the other half split between municipal utilities and investor-owned utilities.
- 30 IREC's Community Renewables Model Program Rules provide a good starting point for understanding issues relevant to community-shared solar. See <<http://www.irecusa.org/2010/11/irec-releases-first-model-program-rules-for-community-renewables>>. IREC also offers direct assistance to individuals and organizations looking to establish shared renewables programs. In addition, the U.S. Department of Energy has a useful Guide to Community Shared Solar for individuals and communities interested in establishing programs. See <<http://www.nrel.gov/docs/fy12osti/54570.pdf>>.
- 31 In the case of utility ownership, it is important that all system purchase costs, operation and maintenance costs, necessary investment returns, and other costs related to a utility-owned system are recovered from participants enrolled in the program and not non-participating ratepayers. This requirement ensures that non-participants do not bear costs for which they do not receive any benefits, and keeps a level playing field between utility offerings and offerings of other providers.
- 32 "3rd-Party Solar PV Power Purchase Agreements (PPAs)." DSIRE, 2013. <http://www.dsireusa.org/documents/summarymaps/3rd_Party_PPA_map.pdf>.
- 33 Information on shared solar programs can be found at <http://sharedsolarHQ.org>. The U.S. DOE also provides a list of programs at <http://apps3.eere.energy.gov/greenpower/markets/community_re.shtml>.
- 34 Fox, Kevin T.; Varnado, Laurel, 2010. "Sustainable Multi-Segment Market Design for Distributed Solar Photovoltaics." Interstate Renewable Energy Council. <http://www.solarabcs.org/about/publications/reports/market-design/pdfs/ABCS-17_studyreport.pdf>
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TRANSMISSION POLICY:

Planning for and Investing in Wires

John Jimison, *Energy Future Coalition* and
Bill White, *David Gardiner & Associates*

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We would like to offer sincere thanks to our knowledgeable group of reviewers:

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EXECUTIVE SUMMARY

America's power transmission network is critical to society, bringing the electricity needed to run homes, factories and businesses. Yet regardless of the energy mix involved – fossil fuels or renewables – the cost of moving power from here to there remains the smallest part of the typical consumer electric bill – about 11% on average¹ – compared with two-thirds of the bill for generation and a quarter for distribution. Needed investments in transmission can frequently be more than paid for by savings in energy costs the new capacity makes possible.

The primary barriers to building new high voltage lines and optimizing the grid aren't so much technical or economic but rather bureaucratic. Inefficient *institutions* and insufficient *policies* are the key factors preventing the United States from accessing its rich resources of clean energy, and spreading that wealth throughout the economy. This paper describes how to overcome these institutional and policy barriers, providing policymakers with clear guidance for planning and allocating the costs of badly-needed transmission upgrades.

As clean energy grows and modernizes America's power system, transmission can be either a strong enabler or the dominant constraint. Easing this constraint will require actions that sort into five categories:

1. Assess and communicate the benefits of transmission expansion.
2. Prioritize inter-regional lines that link balancing areas.
3. Harmonize grid operations and increase competition in electricity markets.
4. Slash the timeline for planning, building, and siting transmission.
5. Then, make the most of the lines once they are built.

¹ *Transmission Projects: At a Glance*, Edison Electric Institute, March, 2013.

Transmission upgrades and expansion are a critical part of any long-term investment plan for America's future. In fact, there is a growing body of reports indicating that transmission investments deliver benefits far exceeding their costs, and they are essential to delivering higher levels of renewable energy to consumers at least cost. Fortunately, there are specific actions that policymakers can take today to accelerate the grid modernizations that would enable electricity customers to access the most valuable renewable energy resources. From making the most of what we have, to opening up more competition in the electricity sector, to linking together new regions of the country, the next steps are clear. America's policymakers can enable a grid that will maximize the value of the country's energy resources by delivering clean power to the homes and businesses that need it.

INTRODUCTION: ENERGY ON THE MOVE

America's power transmission network is critical to society, bringing the electricity needed to run homes, factories, and businesses. Yet regardless of the energy mix involved – fossil fuels or renewables – the cost of moving power from here to there remains the smallest part of the typical consumer electric bill – about 11 percent on average¹ – compared with two-thirds of the bill for generation and a quarter for distribution. Importantly, needed investments in transmission can frequently be more than paid for by savings in energy costs the new capacity makes possible.

High-voltage transmission lines make the grid more efficient and reliable by alleviating congestion, promoting bulk-power competition, reducing generation costs and allowing grid operators to balance supply and demand over larger regions. And these considerations will be ever more important in a high-renewable energy scenario. Solar, geothermal and wind energy can't be shipped in rail cars or pipelines like traditional fuels, but rather must be converted to electricity on-site and then transmitted to consumers. High-voltage transmission is essential for keeping these costs as low as possible, considering that many high value renewable resources are richest in remote regions far from population centers, where most energy is used.

The National Renewable Energy Laboratory's *Renewable Electricity Futures Study (NREL RE Futures)* concluded that building additional transmission and taking full advantage of the flexibility it affords would enable grid operators to balance supply and demand at the hourly level with very high levels of renewable energy – 80 percent or more.² When combined with the growing body of evidence that high voltage interstate transmission lines produce economic benefits far exceeding their costs – NREL's conclusion strongly suggests that there are few – if any – remaining technical or economic hurdles to a high renewable electricity future and the infrastructure to support it. What's more, NREL concluded that the incremental transmission investments needed to achieve an 80 percent renewable future are well within the recent historical range of utility transmission outlays, and thus would likely have minimal impacts on average electric rates.

The primary barriers to building new high voltage lines and optimizing the grid aren't so much technical or economic but rather bureaucratic. Inefficient *institutions* and insufficient *policies* are the key factors preventing the United States from accessing its rich resources of clean energy, and spreading that wealth throughout the economy. Currently, the main obstacles include:

- Disputes over how to allocate or share costs for new lines among ratepayers in different sub-regions of the electric grid.
- Concerns over whether the costs of new high-voltage transmission lines will outweigh benefits for ratepayers, and whether the cost of new lines will unfairly be allocated to customers who will not benefit from them.
- Concerns related to impact of siting the lines, including environmental and cultural impacts, and compensation to landowners, as well as inconsistent and uncoordinated state policies on transmission line siting.³ (A separate paper in this series addresses siting concerns.⁴)
- Failure to accord proper weight to the clean nature of renewable energy in much of the country, a failure that the falling cost of renewable energy is beginning to remedy, with major recent purchases of renewable energy requiring long-distance transmission by utilities motivated by economic considerations, not mandated by public policy.⁵

This paper describes how to overcome these institutional and policy barriers, providing policymakers with clear guidance for planning and allocating the costs of badly-needed transmission upgrades.

CROSSING BOUNDARIES

America's aging electric power system badly needs new and improved high-voltage lines to deliver renewable power from remote areas to population centers, and to link fragmented balancing areas and markets. Developers are naturally motivated: investments in transmission are usually profitable. High-voltage transmission projects are expensive, but can be built for profit because they cost less than the savings they create in lower costs for delivered energy and avoided congestion.

The challenge is that the most essential lines for a high-penetration renewable electricity future are often the most difficult ones to build. These transmission facilities typically must span hundreds of miles, carry price tags of hundreds of millions of dollars,⁶ and most significantly, cross many boundaries of a balkanized regulatory framework that emerged almost a century ago⁷ for local monopolies organized around central power plants serving retail markets. This institutional structure is fundamentally unsuited to the task of planning and building modern, efficient, regional and interregional transmission.

Due to these archaic institutional and political structures, some incumbent utilities and power plant owners benefit from the inefficiencies of the current system. By blocking new transmission, these power plant owners may protect themselves from competition from renewable energy that is priced below the marginal cost of their own fossil-fired power. Incumbents can use the outdated institutional structure to block grid modernization that would threaten the economic advantages they reap from today's inefficient transmission system.

EASIER THAN IT LOOKS

The *RE Futures Study* reaches a striking conclusion about the feasibility of a clean energy future for the U.S.: an 80 percent clean energy economy by 2050 is both technically achievable and affordable, and that the most efficient means of reaching that goal include major investments in the expansion and improvement of the nation’s high-voltage electric grid. The NREL study made several assumptions to facilitate the evaluation of various high-renewable energy futures, notably:

- No new laws, such as carbon pricing, cap-and-trade policies, or additional state renewable portfolio standards, were assumed to take effect during the study period beyond the provisions of existing laws. (See RE Futures Study pages 1-13)
- Distribution-level upgrades were not considered.⁸ (1-12)
- Renewable electricity that was not delivered due to system management curtailment and transmission losses was not counted toward the 80 percent renewable electricity level. (1-12)
- Pre-existing transmission infrastructure was assumed to continue operation throughout the study period, and existing line capacity was assumed to be usable by both conventional and renewable generation sources. (1-32)
- Transmission cost assumptions spanned a wide range as is shown in table A-6 below, and transmission losses were assumed to reflect current experience, despite likely improvement from new technologies and production economies, as well as increased use of direct-current lines.

Table A-6. Assumptions for Transmission and Interconnection

CATEGORY	RANGE
Inter-BA line costs (\$/MW-mile)	\$1,200-\$5,340
Substation costs (\$/MW)	\$10,700-\$24,000
Intertie (AC-DC-AC) costs (\$/MW)	\$230,000
Base grid interconnection costs (\$/MW)	\$110,000
Intra-BA line costs (\$/MW-mile)	\$2,400-\$10,680
Transmission losses	1% per 100 miles

Grid and market operators around the country are rapidly gaining experience managing ever-larger amounts of renewable energy on their systems. This real-world experience is challenging long-held assumptions about the cost and difficulty of integrating large amounts of renewable energy into the electric system. Almost uniformly, experience suggests that common assumptions overestimate – perhaps dramatically – the cost and technical difficulty of integrating large amounts of renewable energy, specifically the need for balancing generation and curtailment of variable renewable resources.

How MISO Got it Done

Joe Gardner, Executive Director of Real-Time Operations for the Midwest Independent System Operator (MISO), told his Board of Directors in February of 2012 why integrating more than 12,000 MW of wind generation, about ten percent of MISO’s total generating capacity, has been relatively painless:

- **Geographic diversity.** The wind blows at different times in different places across MISO’s twelve state footprint – smoothing out the variation at any single location.
- **Better forecasting tools** make it easier to accurately predict wind turbine output.
- **Transmission expansions and upgrades** are being approved and constructed, giving operators greater flexibility to manage all resources, and giving consumers more choices via competition.
- **Grid operators around the country and the globe are learning from each other** as they successfully integrate ever larger shares of renewable energy on their systems.

Another presentation by MISO confirms that they have seen very little increase in their need for operating reserves, even as they successfully integrate ever larger shares of renewable energy on their systems.

Transmission Projects: At a Glance, Edison Electric Institute, March 2013. <https://docs.google.com/viewer?url=http%3A%2F%2Fwww.eei.org%2Fourissues%2FElectricityTransmission%2FDocuments%2FTrans_Project_lowres.pdf>

A study of lessons learned by the Midwest Independent System Operator (MISO) identified larger balancing areas and shorter dispatch periods as critical factors in MISO’s success at integrating large amounts of variable wind generation at minimal cost.⁹ A more recent presentation by MISO confirms that they have seen very little increase in their need for operating reserves, even with this large amount of wind energy on their system.¹⁰

If the recommendations in *New Utility Business Models: Implications of a High-Penetration Renewable Future* and *Renewable Energy and Transmission Siting* are taken to heart, new transmission will play an accelerating role in the electric sector ecosystem of the future, delivering benefits to grid operators, utilities and electricity customers alike.

In fact, throughout the U.S., other recent developments have favored the rapid growth of new transmission investments that are easing the transition to a higher renewable energy scenario:

- Renewable energy sources such as solar and wind are rapidly falling in price.
- Recent federal actions (described below) and the growth in the number of independent system operators mean more competition and less risk in the market for new transmission, stimulating new investments.

- More industry actors are recognizing the multiple benefits of planning and sharing transmission over larger regions, reducing the number of separate “balancing areas” where utilities are required to balance internal generation with internal demand at all times.

Transmission planners must also account for the rapid growth of demand-side resources, such as demand-response, energy efficiency, distributed generation, storage and “smart grid” technologies that have reduced the required new transmission capacity from the massive amounts that would be necessary if such demand-side resources were not available. Transmission planners must evaluate how these resources may affect the need for specific transmission investments, their timing and the capacity of the grid to reliably and cost-effectively achieve high levels of renewable integration. While demand side resources are unlikely to substitute for transmission investments needed to access remote high quality renewable resources, serve high-voltage loads, maintain regional power quality or expand balancing areas, they are likely to mitigate variability and reduce the need for balancing generation. Moreover, a planning process that fully considers demand side resources will build confidence in and broaden support for any new transmission investments, which are identified. Planning that fully accounts for demand-side options as they evolve will offer a net benefit to the ability to gauge and meet transmission needs appropriately.

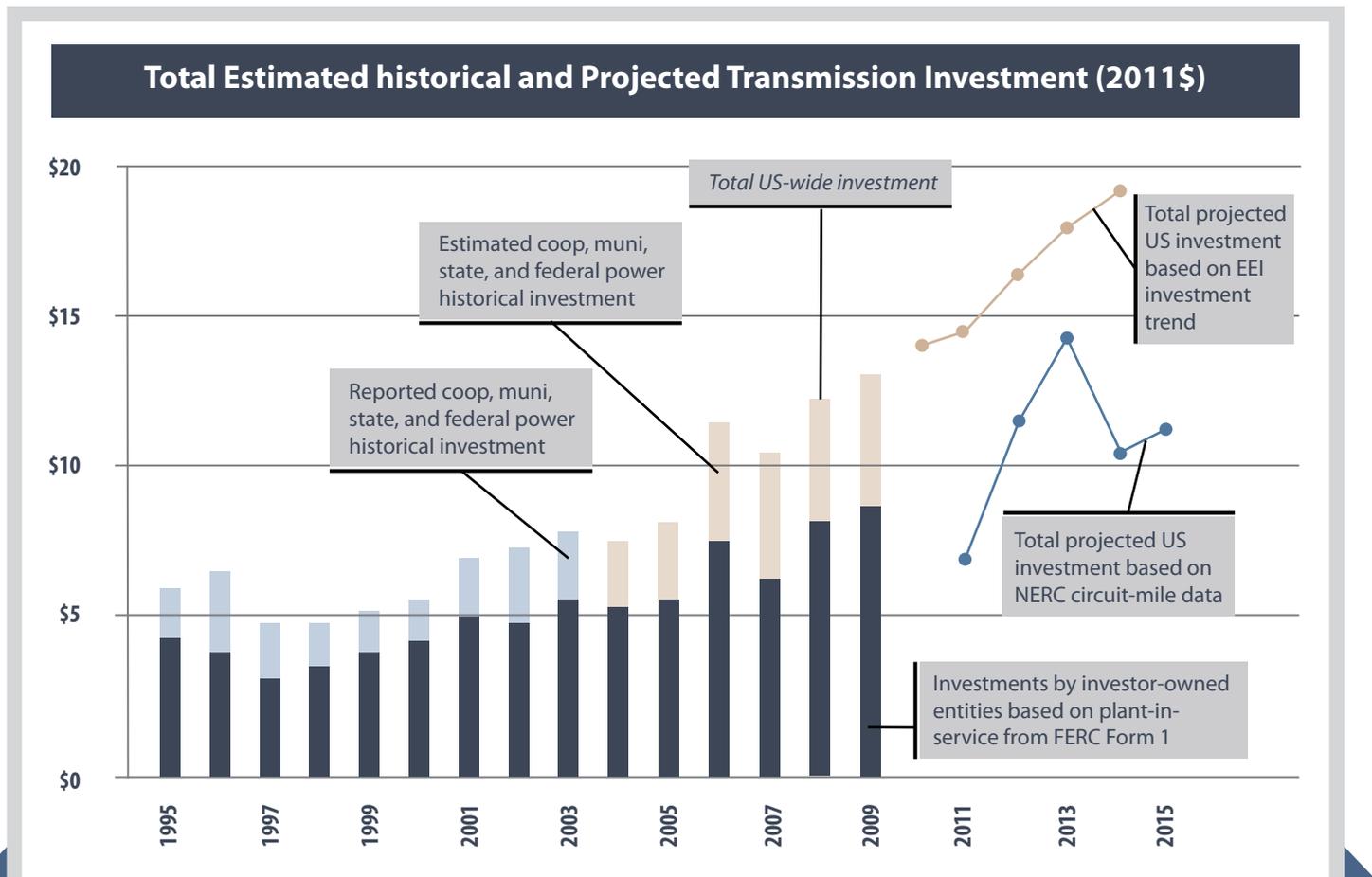


Figure 1. Recent and projected transmission investment.¹¹

Figure 1 shows that investment in high voltage transmission has increased in every region of the country over the past decade, most rapidly in regions with linked planning and cost allocation processes operating across large geographic regions (e.g., Midwest Independent System Operator and Southwest Power Pool). The Edison Electric Institute projects that transmission investments will peak in 2013, and then gradually decline in subsequent years.¹² Transmission policy reforms and adoption of aggressive renewable energy standards or greenhouse gas targets would likely change those projections.

Now, let's take a closer look at each of the trends listed above, all of which are encouraging new investments in both renewable energy and transmission.

REASONS FOR OPTIMISM

Renewable energy grows as prices fall

Wind has become cost-competitive with wholesale electricity generation in many parts of the country. In 2012, private investors poured \$25 billion into the industry, adding a record 13 gigawatts of new generating capacity, and bringing total installed wind in the U.S. to more than 60 gigawatts – a five-fold increase since 2007.¹³ Solar power also had a record year in 2012, with more than three gigawatts installed, employing about 120,000 people across the industry.^{14,15} Cost parity has already been achieved for utility-scale renewable energy in many regions – infrastructure is a chief barrier to further development.

The growth of renewable energy generation (combined with retirement of old, fossil fueled electric-generating plants) is already driving increased investment into the transmission industry. The vast transmission market opportunity is attracting new entrants to the business; merchant developers, utility spin-offs, and smaller operators are taking advantage of the opportunities to make long-term, stable and remunerative investments.

Demand-side options are helping

Regional transmission planning increasingly requires consideration of a vast array of alternative resources that can reduce or even eliminate the need for some transmission investments. Demand-side resources are increasingly available to meet reliability and economic goals that automatically prompted proposals for increased central generation and accompanying transmission from traditional utility planners. These options should thus allow the capital available for new transmission to be better focused on capacity to provide access to clean energy that would otherwise remain undeliverable. Smart planners and markets will weigh new transmission against alternative resources such as distributed generation, demand-response, energy efficiency, storage and “smart grid” technologies. This process can deliver a portfolio of investments – including transmission – that achieve grid operators’ goals while delivering the best long-term value to customers. Consistently and comprehensively considering alternatives in the planning process will ensure that new investments in transmission are focused on the highest value opportunities.

Regulatory moves have increased competition

At the regional level, Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) have grown to cover large swaths of the country's electric systems in the past decade. The expansion of RTOs has resulted in more open, competitive wholesale electric markets. Today, nearly two thirds of the U.S. population is served by competitive transmission markets and organized wholesale electricity markets run by ISOs and RTOs.¹⁶ And RTOs are expected to expand further in coming years. Transmission delivers the greatest value in regions with RTOs and open markets because coordinated planning and cost allocation prioritizes the most cost-effective transmission investments, while electricity markets ensure that cost savings enabled by new transmission are realized.

At the national level, three recent actions are likely to accelerate competition and investment in transmission:

- A recent federal requirement that opens markets and reduces risks for independent transmission developers (FERC Order 1000).
- Reform of policies governing Federal Power Marketing Administrations.
- Clarification of guidance for incentive rates of return.

The Federal Energy Regulatory Commission's (FERC) Order 1000 went beyond basic guidance for transmission planning and cost allocation to include a requirement that incumbent utilities surrender their right of first refusal to build transmission projects in their service area, as long as the proposed new projects result from the Order 1000 planning process. If this is sustained in FERC's implementation processes and in the Court of Appeals where it has been challenged, this aspect of Order 1000 increases market competition in the transmission industry. First, it allows independent developers to compete directly with incumbent utilities from the start. Second, and less obvious, it prohibits incumbent utilities from taking over projects initiated by independent developers in which the utilities hadn't properly exercised their first right of refusal. This change helps drive down risks for transmission investors, who have previously had to weigh the possibility that a new project could be taken over after considerable time and investment.

Modernizing the policies governing Federal Power Marketing Administrations (PMAs) holds additional promise for increasing investments in transmission and promoting competition in the electric sector. Specifically, the PMAs can expand transmission infrastructure by implementing authorities already on the books; operating existing transmission more openly and efficiently; and coordinating investments and operations with other utilities, regional transmission organizations and balancing authorities. As initiated in March 2012 (by then-Energy Secretary Steven Chu), these changes in PMA operations would open access to underutilized transmission resources and stimulate new transmission investment. Despite vocal opposition from

PMA customers,¹⁷ these reforms would accelerate efforts to expand, modernize and more efficiently operate of the grid in the most renewable energy-rich regions of the country – with potentially huge benefits for customers and local economies of those regions and beyond. There is no necessary incompatibility between a modern, integrated and competitive regional grid in the PMA areas and the preservation of historic economic benefits the PMA customers in those regions have enjoyed, but without such improvements to the grid and its operations, it is clear that the rich resources of renewable energy in that region will not achieve their potential to offer clean energy economically to broad regional and interregional markets.

The scope of transmission planning is expanding

As mentioned above, FERC finalized Order 1000 in 2012. Among other changes, this new order requires that all utilities participate in a regional transmission planning and cost-allocation process; that planners account for public policies like state renewable portfolio standards (RPS), federal environmental regulations and other laws and regulations that could affect the electric industry; and that they coordinate with neighboring regions. Early indications suggest that Order 1000 is having the intended effect of expanding the scale and scope of regional transmission planning. Specifically, Order 1000 is forcing planners to work together over larger areas to consider the benefits to ratepayers of region-

wide transmission investments that expand balancing areas, deliver remote renewable resources to customers and allow the electric system to meet public policy requirements at least cost. Separately, but also significant, the Department of Energy has funded even larger scale planning and analysis activities – at the interconnection level – which have laid important analytical and process groundwork for inter-regional coordination yet to come under Order 1000.

Meanwhile, RTOs are increasingly recognizing the benefits of coordinated planning, cost allocation and market operations at the regional scale. ISOs and RTOs in regions with strong renewable energy resources and state policies driving the development of those resources are implementing regional transmission plans with clear methods for cost allocation. Recent experience suggests new lines will be able to facilitate larger balancing areas:

- The Midwest Independent System Operator (MISO) used a broad-based, stakeholder-driven planning process over 18 months to secure agreement to share the costs of 17 high-voltage transmission lines addressing critical constraints throughout a twelve-state region. According to MISO, the transmission investments were driven by the need to deliver renewable resources from remote areas to population centers. MISO estimates that the 17 Multi-Value Projects (MVPs) will create \$15.5 to \$49.2 billion in net present value economic benefits over a 20 to 40-year timeframe, which means they will deliver benefits 1.8 to 3.0 times their costs. For retail customers, that translates to \$23 in annualized benefits from lowered delivered energy costs for about \$11 a year in investment - a 109 percent return.¹⁸
- The Southwest Power Pool (SPP) completed its first 20-Year Integrated Transmission Plan Assessment in January, 2011, and estimates that the nearly 1500 miles of 345 kV lines and 11 transformers in the plan will reduce the cost of generating and supplying energy by more than five times their \$1.8 billion engineering and construction cost, while simultaneously giving the region the flexibility to respond to potential policy initiatives such as carbon regulation.¹⁹ SPP's "Highway-Byway" cost-allocation methodology, approved by FERC in 2010, allocates transmission facility costs based on facility voltage. For projects of 300kV and above, all costs are allocated on a uniform (i.e., "postage stamp") basis equally across the entire SPP region. For projects below 300kV but above 100kV, one-third of the cost is allocated on a regional basis, and the remaining two-thirds of the cost are allocated to the SPP zone where the facilities are located. For projects of 100kV or less, all costs are allocated to the zone where the facilities are located.
- In January of 2013, the Nevada-based Valley Electric Association became the first out-of-state utility to join the California Independent System Operator (Cal-ISO). The partnership gives California additional capability to import inexpensive and abundant out-of-state renewable resources to help meet its goal of 33 percent renewable energy by 2020. This move is part of a larger Cal-ISO effort to work with neighboring states to achieve the efficiencies offered by regional collaboration.²⁰

- In February of 2013, PacifiCorp and the California ISO announced their plans for a real-time imbalance market to be operation in 2014.²¹
- Entergy recently gained approval from federal and state regulators to integrate its high-voltage transmission system into MISO by the end of 2013. The transaction will not only add 15,800 circuit-miles of high voltage lines in Louisiana, Arkansas, Mississippi and Texas to MISO, it will extend MISO's groundbreaking markets, transmission planning processes and cost allocation procedures to the Southeast.

Although the trends described above are well underway, several wildcards could have important impacts on transmission planning and build-out in the coming years:

- Dramatic cost reductions in offshore wind, distributed generation or bulk electricity storage.
- Development of cost-effective DC circuit breakers.
- Broad adoption new technologies that allow the transmission system to be operated more efficiently, such as synchrophasors and “Dynamic Line Rating.”
- Accelerated use of cost-effective and efficient grid operational practices, such as intra-hour transmission scheduling, improved wind and solar forecasting, dynamic transfers of variability between balancing areas, real-time path ratings and improved reserve sharing.
- Dismantling state and local barriers to a more integrated, competitive and cost-effective transmission system.

Big changes in any of these areas could significantly alter the actions that America takes to update and expand its power system.

Dramatic reductions in the cost of offshore wind, distributed resources or storage

Technological breakthroughs reducing costs in any of these areas could essentially re-draw the clean energy resource map in ways that would significantly affect both the value and nature of on-shore transmission investments. For example, a large drop in the cost of offshore wind would open development of very large renewable resources close to eastern population centers, and reduce the value of new capacity transmitting on-shore wind from the Midwest to the East coast. Further price drops in distributed renewable generation and/or electricity storage technologies could allow more generation to be located closer to load, potentially reducing the value of inter-regional transmission investments.

Practical high-voltage DC circuit breakers

Global electronics giant ABB announced last year that it had developed “a fast and efficient circuit breaker for high-voltage direct-current (DC) power lines, a device that has eluded technologists for 100 years.”²² If the technology proves cost-effective, it could make possible a resilient high-voltage DC transmission grid; could help make possible the cost-effective undergrounding of long distance, high-voltage DC lines; could reduce line losses over long distances and drastically reduce siting concerns in sensitive areas.

DC transmission is especially well suited to connecting inter-regional electricity markets due its ability to schedule power flows that precisely match market signals. Customers on the receiving end get lower prices, while generators get increased revenue. When designed as integrated elements of the AC systems, DC lines have the potential to tie RTOs and interconnections together in an extremely cost effective manner.

Broad deployment of technologies that make grid operations more efficient

Many technologies now exist which would allow the high voltage transmission system to be operated much more efficiently – at very low costs compared with building new lines. While these technologies will never substitute for some new investments, such as lines to increase transfer capacity between RTOs or lines to access large remote renewable resources, they can allow grid operators to get the most out of every existing line, every new line, and the transmission network as a whole. Two good examples of these types of technologies now in limited deployment around the country are synchrophasors and dynamic line rating systems.

Synchrophasors monitor electrical conditions hundreds of times faster than current technologies – 30 to 120 times per second – and time-stamp every measurement to synchronize data across large regions of the high voltage transmission system. Grid operators can use this information to detect disturbances that would have been impossible to see in the past, and to take actions to address them before they lead to much more serious and costly problems, like severe congestion, voltage reductions or widespread loss of power. Broad deployment of synchrophasors would allow grid operators to contain or even prevent catastrophic

outages like the “Northeast Blackout of 2003,” which affected 55 million people, cost billions of dollars and contributed to six deaths in New York City.²³

With support from the Department of Energy’s \$3.4 billion Smart Grid Investment Grant (SGIG) program, the Western Electricity Coordinating Council (WECC) is installing more than 300 phasor measurement units across the Western Interconnection – providing 100 percent coverage for the Western Interconnection. The technologies are expected to enable an additional 100 MW of operational capacity on the California-Oregon Intertie. Similar system benefits are possible in other parts of the system.

Most existing high voltage transmission lines have conservative voltage ratings, set low to make sure the lines work under worst case conditions. Under normal weather conditions, that means that substantial transfer capacity is left on the table. Some weather conditions (i.e., cold temperatures or high wind conditions) may actually increase the transfer capacity further, since the line is better able to shed resistance heat. Dynamic Line Rating, a.k.a. “automated transfer capacity evaluation,” can much more precisely match the transfer capacity of high voltage lines to their actual operating environment in real time, increasing their transfer capacity by 10-20 percent or more in most cases. Broad deployment of Dynamic Line Rating – already required in Europe – would increase transmission capacity at extremely low cost, change our understanding of existing transmission capacity and constraints, and potentially increase the capacity – and value – of transmission expansions and upgrades. Moreover, when wind conditions permit stronger than average generation of wind-powered electricity, those same conditions could potentially permit above-normal use of the transmission lines that deliver that power.

More efficient grid operational practices

Even the most technologically advanced transmission system will fail to benefit ratepayers and advance clean energy unless it is operated efficiently. Significant parts of the U.S. have yet to implement proven practices that make the transmission system more efficient and more friendly to renewable energy, including: intra-hour transmission scheduling, improved wind and solar forecasting, dynamic transfers of variability between balancing areas, real-time path ratings and improved reserve sharing. Uniform implementation of these and other efficient grid operational practices would accelerate transmission development and development of renewable energy resources by expanding the regions with the most favorable conditions for both types of investments.

State and local policy barriers to a more integrated transmission system

A powerful but under-appreciated group of barriers to a more efficient and integrated transmission system are provisions of state RPS's which give preferential treatment to in-state resources or even exclude out-of-state resources entirely. These provisions are generally aimed at spurring development of local renewable resources and related economic activity, a laudable goal. For modest RPS goals, the cost to ratepayers of excluding higher quality and cheaper out-of-state resources may be small. But for high levels of renewable energy, such as those examined in the RE Futures study, the costs to ratepayers of these market barriers is likely to be high. If states maintain or strengthen preferences for in-state renewable resources, or if the courts do not invalidate them as unconstitutional under the Commerce Clause of the U.S. Constitution, consumers may be forced to pay dramatically higher costs for clean energy, accept greater local impacts from producing and transmitting that energy and lose the geographic-diversity benefits of broader regional access to locally variable resources. In this case, potentially cost-effective interstate transmission lines would also be excluded from regional plans.

POLICY RECOMMENDATIONS

To achieve low levels of renewable energy penetration within certain regions – such as the ten percent of capacity already achieved in MISO – incremental changes in transmission planning and markets would be sufficient. Yet for the very high levels of renewable electricity penetration described in the *RE Futures Study*, there are no alternatives to major new transmission capacity investments.

As the U.S. moves toward much higher levels of renewable penetration, transmission can be either a strong enabler or the dominant constraint. Easing this constraint will require actions that sort into five categories:

1. Assess and communicate the benefits of transmission expansion.
2. Prioritize inter-regional lines that link balancing areas.
3. Harmonize grid operations and increase competition in electricity markets.
4. Slash the timeline for planning, building and siting transmission.
5. Then, make the most of the lines once they are built.

Assess and communicate the benefits of transmission expansion

As described in the examples above, careful analysis shows that the economic benefits of transmission consistently exceed their costs – often by a wide margin. But the complexity of the grid makes it difficult to impossible to calculate with any precision how those benefits accrue to specific groups of ratepayers in different regions over time. Despite these inherent limitations, enhanced analysis and communication of transmission benefits can help policymakers arrive at better decisions about planning and cost allocation. A comprehensive recent study for the WIRES Group of transmission companies by the Brattle Group²⁴ laid out the many benefits that can be attributed to a transmission system investment and provides explicit guidance to regulators, utilities and customers on evaluating those benefits for purposes of planning and cost allocation. It remains to be seen whether the stakeholders will embrace the broader view of transmission benefits the report proves appropriate, and whether regulators will modify their traditional formulas for approval and ratemaking to reflect them. FERC and DOE should also explore methods for financing the relatively small cost of analytically robust, accessible and transparent planning processes. Such planning (if continued as it is being conducted at present) should pay off in a few years with much greater consensus about the costs and benefits of new transmission, and better agreement about allocating those costs and benefits.

Traditional justifications for new transmission lines have been limited to narrowly-defined economic and reliability benefits – leading both planners and ratepayers to underinvest in them. Analysis such as that performed by Brattle for WIRES can begin to account for the full scope of benefits from transmission investments to help planners make better decisions about how much to invest and when and where to do it. Specifically, regulators should quantify benefits from:

- Meeting public policy goals.
- Linking and consolidating balancing areas.
- Increasing reserve sharing.
- Reducing the total variability of renewable resources, loads and conventional generators by aggregating larger areas.
- Accessing higher quality renewable resources.
- Enabling the price-suppression effect from renewable resources with marginal costs verging on zero that reduce generation by more expensive resources.

Better analysis of the benefits of transmission will accelerate investments only if it is trusted by stakeholders can be effectively communicated to diverse and non-technical audiences. Education and outreach are crucial to building support for new investments. In many regions of the country, customers simply do not understand the financial benefits they could realize from new transmission, competitive electricity markets and high

levels of renewable energy. The MISO MVP process²⁵ is an excellent example of how robust analysis; stakeholder engagement and communication can be combined to reach broad agreement on transmission investments that deliver enormous net benefits to customers.

Transmission planners frequently have difficulty overcoming resistance to new transmission investments even when the aggregate benefits of those lines exceed their costs by wide margins. In many cases, regulations prevent planners from allocating costs to ratepayers in neighboring regions, even when they benefit from the lines, unless those ratepayers voluntarily agree to chip in. Sharing the costs of groups of lines over large regions with competitive markets solves this problem by ensuring that everyone who benefits from *any* of the lines helps to pay for *all* of them. The benefits of the lines are then shared by everyone who participates in the competitive market.

Transmission lines are vulnerable to political opposition when their costs and benefits are evaluated on an individual basis. New lines can expose previously protected power plants to competition, reduce electricity prices or threaten long-standing arrangements that give subsidized electric rates to select groups – galvanizing constituencies who stand to lose if the line is built. Meanwhile, the more numerous and dispersed beneficiaries of new lines are less motivated because they anticipate a modest benefit, rather than a significant threat. Aggregating lines over large areas can smooth out uneven impacts, but policy makers should also explore options for compensating groups who end up worse off even after costs are widely shared, rather than allowing them to hold up projects with broad benefits.

Smoothing out uneven costs and benefits is easiest to accomplish in regions where competitive markets automatically distribute the benefits of new transmission investments fairly to ratepayers via lower prices. The greatest promise for broadening support for transmission investments needed for a high renewable energy future lies in strategies to even out cost and benefits – like aggregation – and, where necessary and feasible, approaches which directly address the more stubborn distributional impacts of an integrated transmission system.

DECISION-MAKER	RECOMMENDATION
DOE, NARUC, ISOs/RTO ²⁶	Embrace updated scope and analysis of transmission benefits.
ISOs/RTOs/RPEs, DOE/EIA	Improve cost and benefit estimates for new lines (see LBNL ²⁷ , others). Deliver estimates to FERC and PUCs.
PUCs, FERC	Take care of distributional effects via clear procedures for allocating costs and comprehensive evaluation of benefits.

Prioritize inter-regional lines that link balancing areas

To enhance reliability and resilience, it will be important to build new inter-regional lines that link balancing areas and authorities, increase transfer capacity between interconnections, deliver high quality renewable resources from remote areas to population centers and allow for sharing and balancing of variable and dispatchable resources with complementary characteristics. To accelerate this process, FERC could provide incentive rates for transmission lines that deliver on these goals.

FERC’s existing legislative authority allows it to adopt rates for interstate transmission and interstate sales of power. This authority requires a determination that the rates adopted are “just and reasonable” and “not unduly discriminatory,” and should permit FERC to offer rate incentives for any new transmission that is judged to face higher business risks than other transmission (perhaps as a function of distance, variability of power sources or costs of construction) that delivers consumer benefits (from clean energy access) that pay back more than the incentive costs over the lifetime of the project. FERC could propose such a policy, and adopt it — after appropriate administrative procedures and input from stakeholders — within a few months.²⁸

DECISION-MAKER	RECOMMENDATION
FERC, NERC, PMA, PUCs	Prioritize inter-regional lines that connect balancing areas.
FERC, NERC	Update the criteria for approving the creation of new balancing authorities, especially cases of balancing authority consolidation or expansion. ²⁹
FERC	Consider whether transmission providers have taken steps to minimize integration costs (e.g., cooperating with other balancing areas, using dynamic scheduling, or opening energy imbalance markets) before deciding how much ancillary service cost should be assigned to new variable resources.
FERC	Build on Order 1000 to prioritize transmission that delivers renewable energy and to further mitigate risks for inter-regional projects.
ISOs/RTOs/RPEs	Seek good faith collaboration on inter-regional lines.

Harmonize grid operations and increase competition in electricity markets

Competitive, open and efficient wholesale electricity markets are ideal, almost necessary, structures to broadly distribute the benefits of market-enabling transmission investments. Policies that provide and enhance incentives for utilities to join competitive markets and the RTOs that run them will help deliver the full benefits of urgently needed transmission investments. Consumers in competitive markets will become the most vigorous advocates of new transmission, as they benefit from the transmission's role in providing access to the cleanest, most reliable and least cost generation resources. At the same time, some incumbents may see competitive markets as threats to their profit margins, even when competitive markets clearly benefit their customers. More than two thirds of U.S. electric customers are now served by RTOs operating competitive markets, a number that

will continue to grow in coming years. Regions outside RTOs that resist reforms will increasingly find themselves competitively disadvantaged relative to those that experience the enormous economic, reliability and clean energy benefits of large, efficient and competitive electric markets.

Transmission lines are even more valuable in competitive electric markets that are scheduled and cleared on short intervals. Many regional electric systems are not operated with sufficiently short dispatch intervals to reap the full benefits of transmission investments. In fact, transmission opponents are often motivated by the antiquated and inefficient market rules and operational practices in their regions that *prevent* ratepayers from benefiting from transmission upgrades and improved grid operations. Modernizing grid operations and making electricity markets more open and competitive are proven ways to benefit electricity customers and to improve the efficiency and reliability of the electric system.³⁰

There is no remaining doubt that region-wide wholesale electricity markets work well under existing FERC principles and standards and also that they enable the efficient use of transmission. We also know that renewable energy thrives in environments where both competitive markets and robust transmission infrastructure are present (e.g. MISO). FERC or RTOs themselves could offer incentives to attract more transmission owners to join competitive markets with large scale regional planning and cost allocation processes. Transmission owners who operate in competitive markets could receive higher rates of return to reflect the risks they bear by operating without the traditional protection granted to vertically-integrated monopoly utilities by regulators. RTOs might be able to offer supplemental or attractively-priced energy from their demand-response or integrated multi-state markets to utilities outside their markets, but only on the condition that those utilities join a similarly competitive market to ensure that prices remain a fair reflection of the value.

To alleviate resistance from stakeholders who believe that market efficiencies would reduce their current advantages, FERC and policy-makers could – if necessary – design temporary or permanent economic offsets to mitigate their losses. This type of payment could be more than covered by the large financial benefits of transmission, and would still allow utilities and customers to capture other benefits of the new technology, new capacity and new access to lower-cost resources. This type of payment would help reduce any disincentives to transition to competitive regional power markets.

Beyond competitive markets for electricity and grid services, opening competition for building the transmission lines themselves will improve the cost-effectiveness of transmission solutions. Under Order 1000, the FERC removed the federal “right of first refusal” for the regional and interstate transmission lines most critical to renewable energy development. Forcing these lines into an open, competitive process will allow planners to evaluate a full range of transmission solutions proposed by incumbents and independents, and to choose the most cost-effective investments for ratepayers.

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs, PUCs, IPPs, utility associations, customers	Continue progress toward open competition and generation dispatch at short intervals.
ISOs/RTOs, FERC, PUCs	Offer grid services (demand-response, linked balancing areas) to others in competitive markets.
FERC	Maintain incentive rates for new lines in competitive markets.

Slash the timeline for planning, building and siting transmission

The average time it takes to build a new high voltage transmission line – from the time it becomes part of a plan to the time it is placed in service – is in the range of decade or longer for most planning regions. This timing data is almost exclusively based on transmission lines that are built entirely within one planning region – e.g. MISO, SPP, ISONE, CAISO, etc. For the lines most important to high renewable electricity futures – those crossing multiple planning regions, balancing areas, RTOs, markets, state borders or even interconnections – the time to construction is expected to be longer, since there is no established process for deciding how to plan and allocate costs for these lines.

In contrast, renewable energy generation facilities can be built quickly – typically in less than two years. The actual construction time required to build high-voltage transmission lines (depending on their length and size) is actually much closer to the timeline for building renewable energy generation. What this means is that speed and scale of renewable resource deployment depends critically on the speed of transmission deployment. If the time for planning, cost allocation and siting transmission can be reduced, renewable resources can ramp up quickly. If the transmission building process remains stuck, renewable resources will hit a wall, and isolated parts of the grid will be forced to rely on more expensive and dirtier alternatives.

A relatively painless first step for accelerating transmission siting would be to maximize the potential for joint use of existing rights-of-way for other transportation and transmission functions. The U.S. is crisscrossed by railroads, highways and other infrastructure that already take up land. These existing rights-of-way could provide dual service as routes for new bulk-power transmission lines. Such dual usage could not only offer additional revenues to the land-owners, but could offer potential benefits for electrification of railroads or electric vehicle charging stations along interstate highways. Since land-owner objections are a main driver in the slowness of transmission-line approval, concentrating on routes that are already in use could speed approvals. The first step will be to study the potential for joint-use of rights-of-way, with actual development to follow as appropriate.

Another way that state and federal authorities can accelerate new transmission is to designate and study potential transmission corridors in advance of any specific project proposals. The locations of the highest-value renewable resources are well known, right down to local micro-climate conditions. Transmission should be planned and routes put into the approval process to connect such areas to the grid and the major load centers. This would help in three ways. First, it would lower up-front costs and risk to potential project developers. Second, it would directly cut down on the time to construct an approved line — right now, the regulatory approval for land-use take about four times longer on average than the construction of the actual line. And third, it would stimulate competition from renewable project developers to build in approved locations so that they could access the new transmission.

Finally, developers could be required to incorporate costs of mitigating significant environmental, physical or visual impacts into their bids — these would include funds for strategies such as re-routing around sensitive areas, undergrounding, landowner compensation and other actions to minimize physical impacts and expedite siting of new lines. This would incentivize them to minimize these impacts. Such mitigation of line impacts

must be accomplished via siting processes, and are therefore covered in more detail in *Renewable Energy and Transmission Siting*, another paper in this series. From the overall perspective of transmission planning and development, however, any progress in solving siting issues will drive improvement in the economics of new transmission additions.

DECISION-MAKER	RECOMMENDATION
DOT, state/federal highway regulators, railroad regulators	Use existing rights of way.
PMA's, DOI, state/federal authorities with right to approve	Get a head start on approving likely corridors before a specific project applies.
State authorities with right to approve	Accelerate line permitting and approval. Allow federal backstop for lines over 765KV or direct current lines.
Developers	Include payments for siting (overcoming environmental and cultural impacts) in transmission costs.
FERC, NERC	Approve dynamic line rating for transmission line owners, making clear that capacity will be limited under peak demand conditions.

Make the most of lines once they are built

Given the enormous effort and time required to put new transmission lines into service, their extremely long lifetimes (40 years or more), and the similar time frame for achieving high-renewable energy penetration, a bias toward larger lines makes more sense than the current bias toward minimizing the size of new lines. High voltage transmission lines are almost never taken out

of service due to under-use, and are almost always used at full rated capacity. In fact, the *RE Futures Study* is one of a growing body of research that indicates *increased* congestion on the high voltage system in the future, even after the addition of thousands of miles of high voltage transmission to access renewables and link fragmented regions. That means it is important to take advantage of new lines being built now, so that their additional capacity can be used in the future.

Another way to make the most out of existing and new lines is to implement dynamic line rating (described in the wildcards section above). With approval from FERC and the North American Electric Reliability Corporation (NERC), transmission line owners could increase the capacity of America’s transmission system today, without needing to build anything new. Dynamic line rating

would increase transmission capacity at all times except under peaking conditions, rather than capping the throughput based on worst case conditions of a hot, wind-less summer day. Once approved, transmission owners should be eager to install dynamic line rating technology to get the most out of their investments.

DECISION-MAKER	RECOMMENDATION
Developers, FERC, PMAs	Make sure lines being built have the right capacity—“right size” them to enable more capacity in the future.
FERC	Clarify that regional transmission expansion plans may allocate costs for projects that will not be used immediately, if the projects use scarce rights of way or serve location-constrained generation.
FERC, State PUCs	Allow incentive rates of return on investments in advanced grid management technologies, such as: synchrophasers, automated grid operations, transfer capacity rating systems, and strategically placed hardware (e.g., flywheels, capacitors) that cost-effectively addresses voltage fluctuations throughout an interconnection.

CONCLUSION

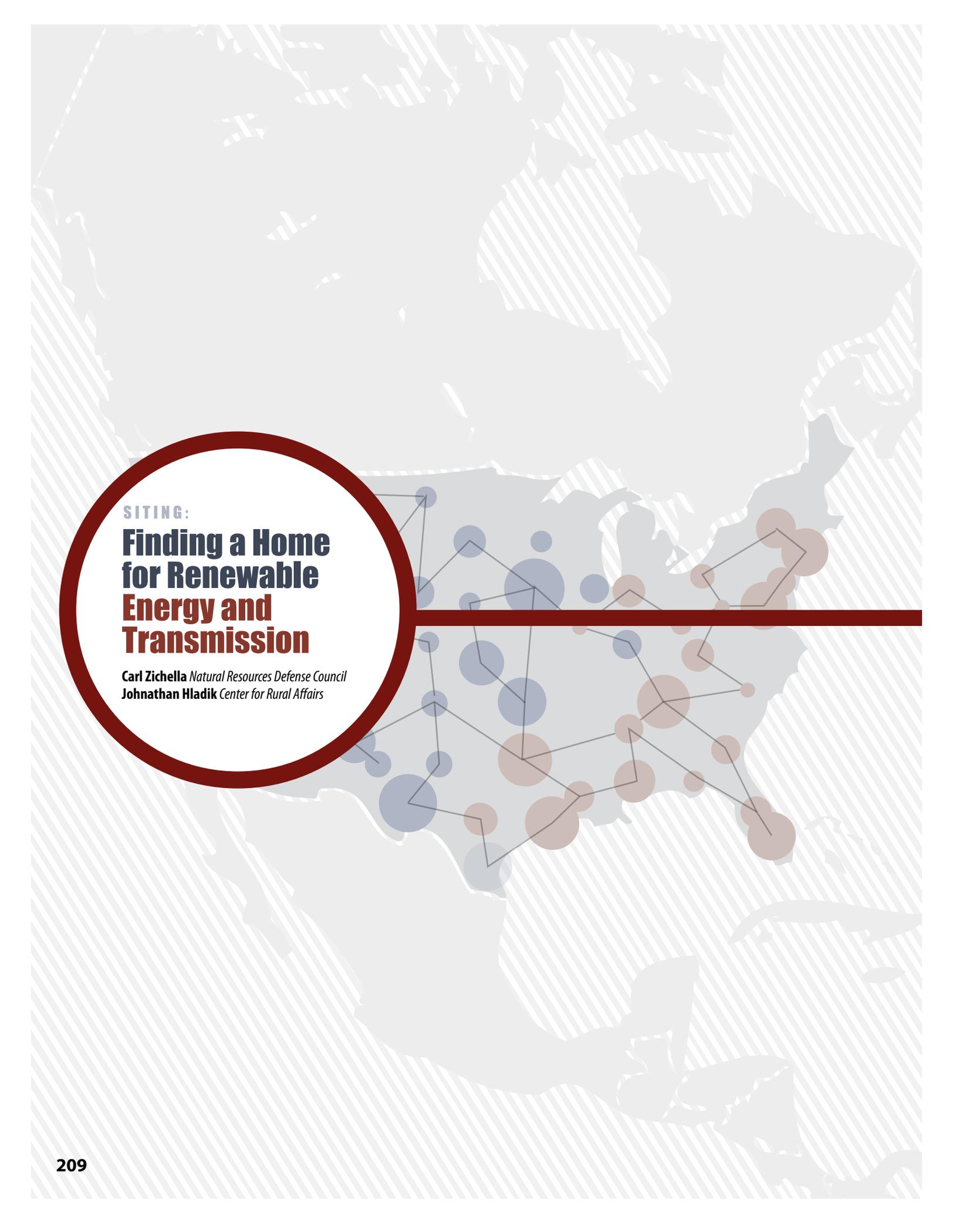
Transmission upgrades and expansion are a critical part of any long-term investment plan for America's future. The barriers to making these urgently needed investments are institutional – and not due to costs or technical issues. In fact, the *RE Futures Study* is the latest in a growing body of reports indicating that transmission investments deliver benefits far exceeding their costs, and they are essential to delivering high levels of renewable energy to consumers at least cost. Fortunately, there are specific actions that policymakers can take today to accelerate the grid modernizations that would enable electricity customers to access the most valuable renewable energy resources. From making the most of what we have, to opening up more competition in the electricity sector, to linking together new regions of the country, the next steps are clear. America's policymakers can enable a grid that will maximize the value of the country's energy resources by delivering them to the homes and businesses that need them.

DECISION-MAKER	RECOMMENDATION
DOE, NARUC, ISOs/RTOs ³¹	Embrace updated scope and analysis of transmission benefits.
ISOs/RTOs/RPEs, DOE/EIA	Improve cost and benefit estimates for new lines (see LBNL , others). ²⁷ Deliver estimates to FERC and PUCs.
PUCs, FERC	Take care of distributional effects via clear procedures for allocating costs and comprehensive evaluation of benefits.
FERC, NERC, PMAs, PUCs	Prioritize inter-regional lines that connect balancing areas.
FERC, NERC	Update the criteria for approving the creation of new balancing authorities, especially cases of balancing authority consolidation or expansion. ²⁹
FERC	Consider whether transmission providers have taken steps to minimize integration costs (e.g., cooperating with other balancing areas, using dynamic scheduling or opening energy imbalance markets) before deciding how much ancillary service cost should be assigned to new variable resources.
FERC	Build on Order 1000 to prioritize transmission that delivers renewable energy and to further mitigate risks for inter-regional projects.
ISOs/RTOs/RPEs	Seek good faith collaboration on inter-regional lines.
ISOs/RTOs, PUCs, IPPs, utility associations, customers	Continue progress toward open competition and generation dispatch at short intervals.
ISOs/RTOs, FERC, PUCs	Offer grid services (demand-response, linked balancing areas) to others in competitive markets.
FERC	Maintain incentive rates for new lines in competitive markets.
DOT, state/federal highway regulators, railroad regulators	Use existing rights of way.
PMAs, DOI, state/federal authorities with right to approve	Get a head start on approving likely corridors before a specific project applies.
State authorities with right to approve	Accelerate line permitting and approval. Allow federal backstop for lines over 765KV or direct current lines.
Developers	Include payments for siting (overcoming environmental and cultural impacts) in transmission costs.
FERC, NERC	Approve dynamic line rating for transmission line owners, making clear that capacity will be limited under peak demand conditions.
Developers, FERC, PMAs	Make sure lines being built have the right capacity – “right size” them to enable more capacity in the future.
FERC	Clarify that regional transmission expansion plans may allocate costs for projects that will not be used immediately, if the projects use scarce rights of way or serve location-constrained generation.
FERC, State PUCs	Allow incentive rates of return on investments in advanced grid management technologies, such as: synchrophasers, automated grid operations, transfer capacity rating systems, and strategically placed hardware (e.g., flywheels, capacitors) that cost-effectively addresses voltage fluctuations throughout an interconnection.

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SITING:

Finding a Home for Renewable Energy and Transmission

Carl Zichella *Natural Resources Defense Council*
Johnathan Hladik *Center for Rural Affairs*

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We would like to offer sincere thanks to our knowledgeable group of reviewers:

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EXECUTIVE SUMMARY

The power plants, poles and wires that generate and deliver electricity to consumers and businesses are a hallmark of modern society. An efficient system requires wires to transmit and distribute electricity where it is most needed to keep the system in balance. But the grid is aging and consumers are increasingly demanding efficiency and clean energy. This paper focuses on the institutional innovations that can help modernize America's grid—by making changes to the way we plan for, site and permit clean power generation and transmission infrastructure.

Today's siting process starts with a series of applications to each governmental agency with jurisdiction in a particular area, with different agencies often requiring different assessments of land-use. This can be a particular challenge for transmission line projects that cross many different jurisdictions. Several changes to today's process can help accelerate smart siting.

Policymakers have many options to accelerate siting for new generation and transmission needs. First, system operators must manage demand for energy, and take advantage of America's existing grid. This paper then focuses on the reforms needed to locate, coordinate and expedite any new generation or transmission that the grid system requires. In short, policymakers should:

- Optimize the existing grid infrastructure.
- Fully use available planning processes.
- Employ "Smart from the Start" criteria.
- Improve interagency, federal-state and interstate coordination.
- Work with landowners to develop new options for private lands, including innovative compensation measures.
- Refine the process to support siting offshore wind developments.

New approaches will require engaging stakeholders early, accelerating innovative policy and business models, coordinating among regulatory bodies, employing smart strategies to avoid the risk of environmental and cultural-resource conflicts and improving grid planning and operations to take better advantage of existing infrastructure and reduce costs of integrating more renewable energy.

This paper provides detailed recommendations for how to accomplish this. Modernizing the grid and transitioning to clean power sources need not cause harm to landowners, cultural sites or wildlife. On the contrary, taking action today will provide long lasting benefits.

INTRODUCTION

The National Renewable Energy Laboratory's *Renewable Electricity Futures Study*¹ (*RE Futures*) finds that it's feasible to produce 80 percent of America's power from renewables by 2050. Yet doing so would require enormous changes in the way we plan for, site, permit, generate, transmit and consume renewable electricity. Innovation — both technological and institutional — will be the cornerstone of this effort. Beyond more efficient solar cells and bigger wind turbines, American *businesses and institutions* will need to find innovative solutions for locating new generation and transmission.

The need to site and build a new generation of transmission infrastructure continues to increase. Current and expected investment trends suggest now is the time to act. Between 2000 and 2008, only 668 miles of interstate transmission lines were built in the United States. The past four years have seen a greater commitment to infrastructure improvement, but the nation continues to fall short. Annual investments during 2009 to 2018 are expected to reach three times the level of annual transmission additions in the previous three years. More than one quarter of transmission projects currently planned through 2019 are designed to carry power generated by new, non-hydro renewable resources. The Midwest Independent System Operator (MISO) estimates that up to \$6.5 billion in transmission expansion investment will be needed by 2021 in that region alone. In the West, estimates range as high as \$200 billion over the next 20 years.²

It will be critical to implement reform ahead of the next wave of expected projects. America needs a new paradigm, one that removes barriers to new projects and takes into account lessons learned over the past 10 years. Reform must reflect a new approach to siting — one that recognizes the effect wholesale power markets have on transmission planning, and one that meets the needs of landowners, wildlife and society as well as project sponsors and investors.

FINDING THE SWEET SPOTS FOR RENEWABLE ENERGY

Modernizing America's electric grid will be a monumental job. While distributed generation will play a big role in America's clean energy future, on-site power alone cannot bring us to 80 percent renewables. The amount of energy needed is too vast, especially as the economy rebounds and economic growth continues. We will need major additions of centralized renewable energy generation, and some of the very best renewable energy resources are far from population and energy demand centers.

NREL calculates that a gross estimate of land needed for an 80 percent national renewable electricity future would be equivalent to less than about 3 percent of the U.S. land base, up to 200,000 square kilometers. Such large-scale developments must be located with extreme care for culturally rich areas, species protection and wildlife habitat.

Land-Use Implications of Low-Demand Core 80% RE Scenarios and the High-Demand 80% RE Scenario*

Total Land Use (000s of km²)

RENEWABLE TECHNOLOGY	LAND USE FACTOR	LOW-DEMAND CORE 80% RE SCENARIOS	HIGH-DEMAND 80% RE SCENARIOS	DESCRIPTION
Biopower	25,800 GJ/km ² /yr	44-88	87	Land-use factor uses the midrange estimate for switchgrass in Chapter 6 (Volume 2). Other waste and residue feedstocks are assumed to have no incremental land use demands.
Hydropower	1,000 MW/km ²	0.002-0.10	0.06	Assumed only run-of-river facilities, with land use based only on facility civil works with no flooded area. Although not evaluated here, inundated area associated with run-of-river facilities would increase these values.
Wind (onshore)	5 MW/km ²	48-81 (total) 2.4-4 (disrupted)	85 (total) 4.2 (distributed)	Most of the land occupied by onshore wind power plants can continue to be used for other purposes; actual physical disruption for all related infrastructure for onshore projects is approximately 5% of total.
Utility-scale PV	50 MW/km ²	0.1-2.5	5.9	Direct land use of modules and inverters.
Distributed rooftop PV	0	0	0	Systems installed on rooftops do not compete with other land uses and no incremental land use is assumed here.
CSP	31 MW/km ²	0.02-4.8	2.9	Overall land occupied by CSP solar collection fields (excluding turbine, storage, and other site works beyond mirrors).
Geothermal	500 MW/km ²	0.02-0.04	0.04	Direct land use of plant, wells, and pipelines.
Transmission	See Description	3.1-18.6	18.1	Assuming an average new transmission capacity of 1,000 MW and a 50-m right-of-way.
Storage	See Description	0.017-0.030	0.025	Land-use factors of 1,100 m ² /MW, 500 m ² /MW, and 149 m ² /MW were assumed for PSH, batteries, and CAES, respectively. See Chapter 12 (Volume 2) for details.

Renewable Electricity Futures Study

Volume 1: Exploration of High-Penetration Renewable Electricity Futures

* National Renewable Energy Laboratory (2012). "Renewable Electricity Futures Study." Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek M.; Sandor, D. eds. 4 vols. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/re_futures/

Table 1. RE Futures land-use estimates

Given the scale of these projects, several important considerations can help guide developers, policymakers and grid planners as they make decisions about where and how to locate new generation and transmission. These considerations include:

- Location of high-quality renewable resources.
- Generation profiles of the resources (i.e., when during the day does the wind blow).
- Impact on landscape, including both natural and cultural resources.
- New options for siting on private lands.

The first consideration in siting generation and transmission is the presence of high quality renewable resources. Planners and developers can use some key questions to identify such sites: what is the solar insolation per square meter? What is the wind speed at 80 meters above the ground? How many hours per year is the wind blowing at the right speed to drive a turbine efficiently? These are extremely important questions; developing optimal sites means that fewer acres of land or nautical miles of ocean need be developed to produce the energy we require. But the location of these high-quality resources is just one piece of the puzzle.

The kind of centralized projects³ we are talking about are very large, and can sometimes span several square miles (see figure 1). Large developments mean substantial physical impacts on the landscape, as well as impacts on valued natural and cultural resources. Wildlife habitat will be destroyed in the process, at a time when many species are already under stress from overdevelopment and a changing climate. Decision-makers must factor these impacts into location selection.

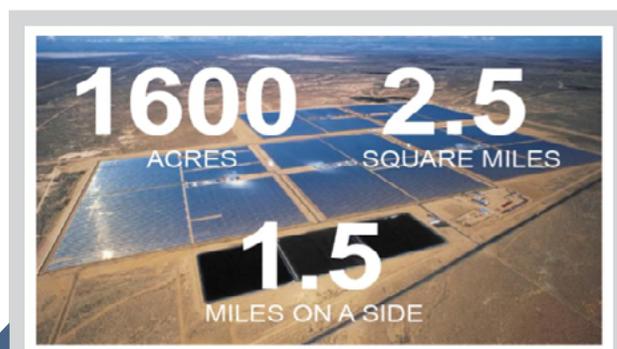


Figure 1. 354 MW Solar Energy Generating Station, California desert⁴

Additionally, decision-makers must pay special consideration to private land owners. Private landowners play an invaluable though often overlooked role in the siting and construction of both generation and transmission infrastructure. Particularly in the Eastern Interconnection, transmission projects are built almost exclusively on private land. How landowners are treated throughout this process can determine whether projects are more rapidly approved and developed or delayed and even halted.

Today's process

To begin any discussion of how to improve siting practices in the U. S., one must first consider today's approach. When a new transmission project is conceived and drawings begin, developers first apply to each state's own Public Utility Commission — or relevant siting authority — for a "Certificate of Need" and a route permit. The same process is used whether the project is being proposed by an investor-owned utility, a private investor, a public power district or a rural cooperative. A typical application includes an estimate of costs, a justification of need and at least one proposed route to study. If the proposed project crosses federal lands, as is typical in the Western Interconnection, it triggers the National Environmental Policy Act (NEPA) process. In most instances, the independent transmission developer will first pursue and complete NEPA on his project, at least through the Final Environmental Impact Statement (EIS) stage (or Record of Decision, in some cases) prior to initiating serious permitting activity in state jurisdictions. This is normally done to allow incorporation of the NEPA record by references in the state siting hearings and application process. California has a siting process under the California Environmental Quality Act (CEQA) that allows for more formal parallel activity with NEPA.

In deciding whether to grant a "Certificate of Need," state Public Utility Commissions overwhelmingly focus on two distinct sets of issues: 1) operational and economic need for the proposed project and 2) environmental impact of the proposed project.

Operational and Economic Need considers whether the line has significant market value, how it would fit into the state's integrated resource plans, whether new generation sources need it to deliver their power and whether it is needed to ensure reliability or meet new demand.

Environmental Impact generally involves a full evaluation of the line's environmental impact, whether the construction will affect endangered species, open new areas to development, involve sensitive ecological areas or give rise to visual or aesthetic concerns.

The Commission's final decision prioritizes benefits to in-state ratepayers. A Certificate of Need is granted once the project has been reviewed, tradeoffs have been evaluated and the Commission has determined that the proposed line is in the public interest. This designation allows the applicant to begin building on public lands and negotiating easement terms with affected landowners. In most cases, it allows developers to exercise eminent domain authority if private land negotiations fail.

Several changes to today's process can help accelerate smart siting.

RECOMMENDATIONS FOR POLICYMAKERS

Policymakers have several options to accelerate siting for new generation and transmission needs. First, system operators must manage demand for energy and take advantage of America’s existing grid — these topics are touched on here, but covered in more detail in other papers in this series.⁵ This paper focuses on the reforms needed to locate, coordinate and expedite any new generation or transmission that the grid system requires.

In short, policymakers should:

- Optimize the existing grid infrastructure.
- Fully use available planning processes.
- Employ “Smart from the Start” criteria.
- Improve interagency, federal-state, and interstate coordination.
- Work with landowners to develop new options for private lands.
- Refine the process to support siting offshore wind developments.

The following sections describe how policymakers can do each of these things.

Optimize the existing grid infrastructure

Any siting discussion should start with the idea of getting more out of infrastructure that has already been built. Optimizing grid management practices can save enormous amounts of time and capital, while reducing the footprint of development. Operating efficient markets for generation and other grid services can help,⁶ as can adopting dynamic transmission line rating.⁷ Another optimization tool is considering the generation profiles of resources in different locations. Variable resources that operate at different times of day can reduce integration challenges, prevent the construction of unnecessary reserves and more completely utilize existing transmission lines. Grid optimization is the most efficient way to reduce the need for new generation and transmission lines. A next-best option is to site new renewable energy generation in places with feasible access to existing transmission. Once existing infrastructure is maximized, decision-makers should begin to consider the actions outlined in the following sections.

DECISION-MAKER	RECOMMENDATION
ISOs/RTOs ⁸ , DOI, WECC, state authorities	Add grid optimization to siting criteria or the renewable zone formation process.

Fully Use Available Planning Processes

While the focus of this paper is siting, it is critical to fully consider the *planning* process as a precursor to siting. Many organizations, notably the Western Electricity Coordinating Council (WECC) in the western U.S., western Canada and Mexico, perform a variety of studies that attempt to understand infrastructure needs 10 or 20 years in the future. This process does not attempt to predict the future. Rather, it seeks to identify strategic choices that will guide infrastructure development needs. The planning process also does not attempt to supersede the siting process. Rather, it seeks to identify issues that will need to be addressed when a project enters siting consideration. One of the goals of the planning process is to expedite the siting process. By understanding and mitigating issues early, detailed siting analyses should proceed more quickly.

Specific issues that can be addressed in the planning process include:

- Transmission expansion needed to facilitate meeting expected load with available resources.
- Policy initiatives such as Renewable Portfolio Standards (RPS).
- Environmental and cultural risks.
- Economic variables such as fuel prices and emission costs and their effects on resource choices.
- Resource and transmission capital costs.

Employ “smart from the start” criteria

Locating new generation carefully and strategically can avoid most conflicts. This approach has become known as “Smart from the Start.” The Interior Department has adopted many of the concepts inherent in this approach to guide both onshore and offshore renewable energy development. Originally introduced in 2005, many Smart from the Start criteria have been put into practice in federal, state and regional generation and transmission siting processes in recent years. Projects and organizations using these criteria include: the Department of the Interior’s Solar Program, the Department of Energy Regional Transmission Expansion Policy Project, the Western Governors Association, the Bureau of Land Management’s Arizona Restoration Design Energy Project, the Bureau of Ocean Energy Management’s offshore wind Smart from the Start program and the WECC’s Transmission Planning and Policy Committee.

Smart from the Start Siting Policies and Criteria

- Consult stakeholders early and involve them in planning, zoning and siting.
- Collect and use geospatial information to categorize the risk of resource conflicts.
- Avoid land and wildlife conservation conflicts (including national parks and other protected areas) and prioritize development in previously disturbed areas.
- Avoid cultural resource conflicts (historic sites, tribal resources, etc.).
- Identify excellent renewable energy resource values.
- Establish, when possible, pre-screened resource zones for development .
- Incentivize resource zone development with priority approvals and access to transmission.
- Consider renewable energy zones or development sites that optimize the use of the grid.
- Maximize the use of existing infrastructure, including transmission and roads.
- “Mitigation that matters” (durable and planned conservation improvements at larger scales).
- Where zoning is not feasible (as in much of the Eastern Interconnection), use siting criteria based on the above principles.

The Smart from the Start approach is valuable for siting both generation and transmission, but is most effective when used for both at the same time. It can also be helpful in delivering efficient use of existing transmission resources.

Two of the Smart from the Start principles are particularly important for accelerating renewables:

- Establish, when possible, pre-screened resource zones for development.
- Where zoning is not feasible (as in much of the Eastern Interconnection), use siting criteria based on the above principles.

Establish renewable energy zones

Pre-screened zones for renewable energy can dramatically accelerate time to market for new generation. This streamlines siting hurdles for all projects involved, and can help government agencies prioritize projects and work together to assess impacts efficiently and bring new infrastructure online more quickly.

Texas pioneered renewable energy resource zoning in 2005 to develop transmission for remote wind energy projects. Today, nearly 11,000 megawatts of wind capacity have already been constructed in Texas, and the state expects to add at least 18,500 megawatts more. The Electricity Reliability Council of Texas (ERCOT) is responsible for developing the transmission, and has estimated that up to 3,500 miles of new lines are needed to bring the new wind capacity to the state’s load centers. Texas’ proven renewable energy zones will be critical to making this happen.

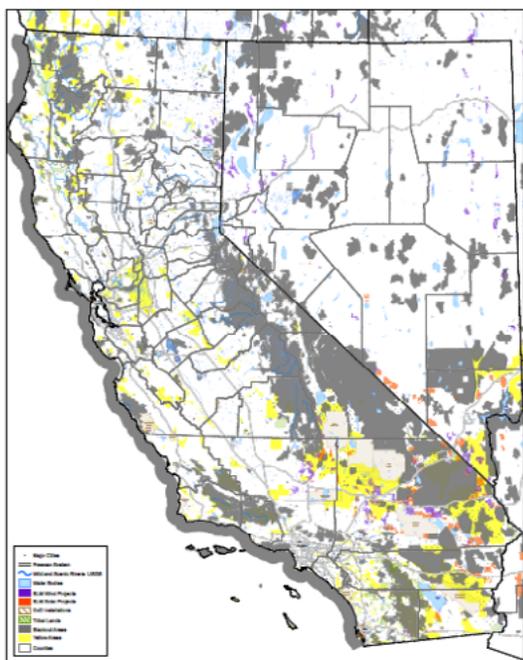
Building on Texas' model, many other states have found renewable energy zoning to be an important strategy for prioritizing environmentally desirable, lower conflict sites for new generation and transmission. Some form of renewable energy zoning has since been adopted by state and federal agencies in California, Arizona, Colorado, Nevada, Utah and across the west. California's Renewable Energy Transmission Initiative identified renewable energy development zones statewide and recommended transmission upgrades to serve them. The California process enhanced the environmental values portion of the zoning process, as compared to Texas' process, by developing the first-ever environmental screening process for ranking the relative risk of environmental and cultural conflicts in new transmission proposals (see figure 2).

WECC's Regional Transmission Expansion Project is a transmission planning process funded by a stimulus grant from the U.S. Department of Energy (DOE) that uses geospatial information to identify the risk of encountering environmental and cultural resource conflicts. The project uses 10 and 20 year plans for its analysis, developed by an unusually diverse set of stakeholders to forecast transmission needs in the Western Interconnection under a variety of futures.

Establishing renewable energy development zones remains in its infancy in the Eastern Interconnection, owing to the fact that the region is far more complex: with three times as many states, far less federal public land and a much more diverse set of wildlife and environmental management regimes. Ownership in

the East is so complex that resource zoning is often impractical if not impossible. Still, for transmission, the Eastern Interconnection Planning Collaborative is completing a planning initiative, funded by the DOE that may include a tool (see figure 2) that uses geospatial information to suggest the location of potential renewable energy development zones. The project is engaging diverse stakeholders to develop scenarios of future transmission needs. Siting criteria will likely be the default approach for these areas, and will be extremely valuable in avoiding areas at high risk for environmental and cultural resource conflicts.

Argonne National Laboratory has undertaken an innovative mapping effort to cut through the complexity of the Eastern Connection at a system level, and the lab's work is very promising for renewable energy zone and environmental risk modeling in the region. For example, Argonne's tool has numerous layers of data that could be used to identify more optimal, lower-conflict sites for renewable energy and transmission development. Even more promising: the WECC Environmental Data Task Force is currently considering the possibility of populating the Argonne platform with data from the west to create a uniform national database to ease renewable energy and transmission siting for planners, project developers and the public.



YELLOW & BLACKOUT AREAS

Figure 2. Ranked environmental and cultural risk zones for the state of California.^{9, 10}

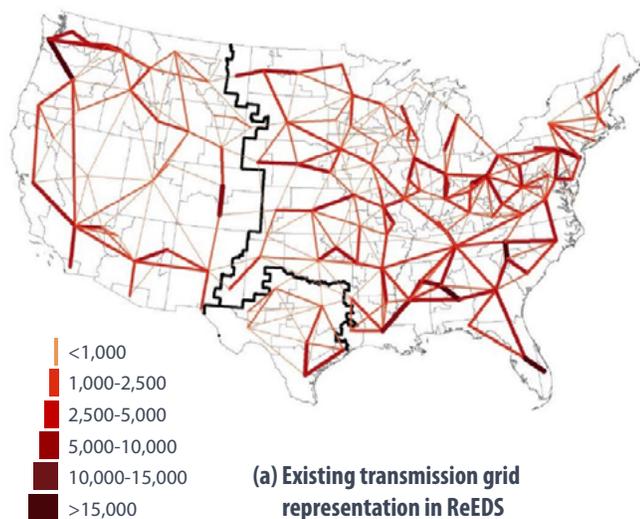
Other states are using landscape-level analysis to locate renewable energy and transmission projects. Oregon is currently developing a landscape-level renewable energy planning analysis that could result in the identification of promising low impact resources areas, or de facto zones.

DECISION-MAKER	RECOMMENDATION
WECC, state authorities, Power Marketing Administrations, FERC, transmission sponsors, utilities	Fully utilize available planning processes to identify issues early in the process that will need to be addressed ultimately when a project enters siting consideration. One of the goals of the planning process is to expedite the siting process. By understanding and mitigating issues early on, detailed siting analyses should proceed more quickly.
FERC, RPEs, BLM, DOE, DOI, EIPC, state authorities	Use data from regional planning processes and Smart from the Start principles in choosing transmission solutions (such as in Order 1000 planning), renewable energy zones, development sites and federal energy corridors.
FERC, RPEs, BLM, DOE, DOI, EIPC, state and local authorities	Consider renewable energy generation and transmission development and siting simultaneously. Develop clear siting criteria where zones are not possible.
Congress, DOE, DOI, national labs, State and local authorities	Create and maintain national cultural and environmental conflict risk data and mapping capabilities to support federal, regional and state-level generation and transmission siting. Develop clear siting criteria where zones are not possible

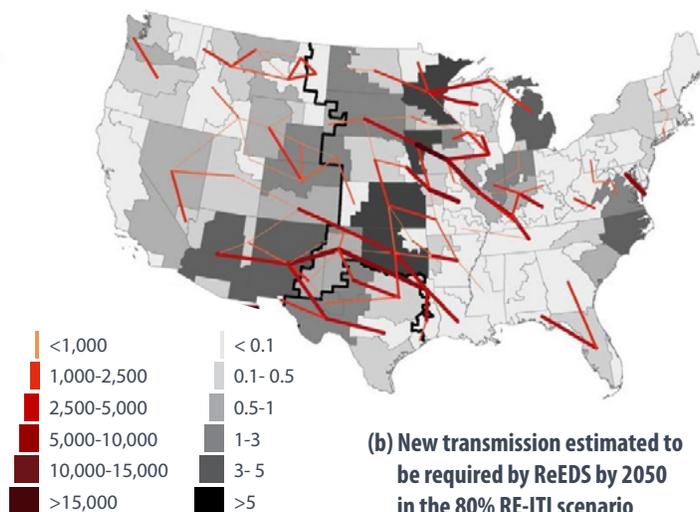
Improve interagency, federal-state and interstate coordination

The lack of coordination within federal agencies and between the federal and state agencies has been a major hindrance to siting renewable energy projects, but substantial progress has been made in the last four years. The Obama administration took action in 2009 to address the coordination issues raised by both environmental and renewable energy development stakeholders. A Memorandum of Understanding (MOU) delineated how federal land managers and the Energy Department would coordinate on project approvals for both generation and transmission siting on public lands. The MOU was signed by the heads of U.S. Department of Agriculture, Department of Commerce, Department

of Defense, Department of Energy, Environmental Protection Agency, the Council on Environmental Quality, the Federal Energy Regulatory Commission, the Advisory Council on Historic Preservation and Department of the Interior. Leadership at the Secretarial level in the Interior Department resulted in the establishment of four Renewable Energy Coordination Offices tasked with focusing agency resources on managing siting issues on public lands. The offices reached out to several states that were expecting large amounts of renewable energy, and useful partnerships were established to facilitate joint permit activities. By coordinating these permitting activities, sequential environmental reviews can be eliminated while still addressing all the requirements of both state and federal processes. The resulting uptick in project approvals has been dramatic.



(a) Existing transmission grid representation in ReEDS



(b) New transmission estimated to be required by ReEDS by 2050 in the 80% RE-ITI scenario

Figure 3. Existing transmission (a) and potential 2050 transmission (b).

For example, a partnership between the Departments of Interior and Energy and the state of California, as well as leading environmental stakeholders, resulted in permits for more than 4,000 megawatts of renewable generating capacity in less than a year. The largest solar projects ever developed are under construction in California, as are the transmission system upgrades needed to bring their power to customers. They are collaborating on large-scale resource conservation and infrastructure planning, drafting the largest Habitat Conservation Plan ever attempted. The plan is being prepared through an unprecedented collaborative effort between the California Energy Commission, California Department of Fish and Game, the U.S. Bureau of Land Management and the U.S. Fish and Wildlife Service. When completed, this joint effort will identify resource areas (essentially zones) that will be interconnected to the grid and that will enjoy swift siting approval for new renewable energy generation.

One of the most important lessons from this work has been that land and wildlife conservation efforts – and new mitigation strategies – need to be developed in tandem with project planning. Taking these impacts into account early enhances stakeholder participation. Getting the right parties involved as early as possible is an essential element of success.

Interagency coordination

A federal Rapid Response Team for Transmission (RRTT) was established in 2009 to close the gap between new renewable energy generation and the transmission to bring it to market. The RRTT seeks to improve the overall quality and timeliness of the federal government's role in electric transmission infrastructure permitting, review and consultation through:

- Coordinating statutory permitting, review and consultation schedules and processes among federal and state agencies, as appropriate, through Integrated Federal Planning.
- Applying a uniform and consistent approach to consultations with Tribal Governments.
- Resolving interagency conflicts to ensure that all involved agencies are meeting timelines.

Federal-state and interstate coordination

Some progress has been made in coordinating federal and state actions, but much more remains to be done. Long-distance transmission lines crossing several states face the most acute problems. For example, a project usually needs to go through a review in each jurisdiction, and the reviews often happen in series rather than at the same time. This can add huge costs and delay projects for years.

Public Utilities Commissions hold the authority to approve transmission line siting in most states. But some states have three or four separate entities involved

in transmission approvals and siting. And while most states have some statutory recognition of the need to coordinate on transmission with their neighbors, 11 states are still statutorily silent on this topic.¹¹

The variation in the way states handle siting presents an unnecessary level of complexity that frustrates public interest groups, landowners and project developers alike. Project developers are often overwhelmed by having to coordinate with many agencies — from natural resource departments to land-use entities. A single agency could be established in each state to ensure that permit requirements are not duplicated, but that the process includes all-important considerations. A one-stop-shopping approach to siting in each state would greatly expedite and enhance siting for interstate transmission.

Congress took steps to address interstate coordination via the Energy Policy Act of 2005 (EPAAct 2005), encouraging collaboration between states in two important ways. First, it authorized them to form interstate compacts to create their own rules to govern siting of new lines. This authority has not been used successfully to date, but it may yet prove important in expediting transmission projects that cross state lines. For example, the Council of State Governments is currently exploring ways to improve interstate coordination and better take advantage of this interstate compact tool. Second, the EPAAct 2005 gave the Federal Energy Regulatory Commission (FERC) “backstop” siting authority for certain transmission corridors that DOE identified as critical to grid reliability. This meant that if states did not reach a siting agreement within a year, FERC was allowed to site the line. This provided a strong incentive for state coordination, but subsequent court rulings undercut the FERC’s backstop authority as granted in EPAAct 2005.

Two years later, FERC’s Order 890 opened up transmission planning to all stakeholders and tied payments (“open access tariffs”) to developers’ ability to meet nine transmission planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, congestion studies and cost allocation. But interconnection-wide programs either did not exist or lacked the authority to allocate costs or select projects until last year.

FERC took decisive action to reform transmission planning by adopting Order 1000 in 2012. This is the most beneficial FERC policy ever adopted for renewable energy development. Order 1000 requires regional and interconnection-wide planning, enabling broader benefits and wider and fairer cost distribution for new transmission. The order also requires that the need for states, utilities and system operators to comply with public policy mandates, such as state and federal laws such as renewable portfolio standards, must be considered in selecting transmission options eligible for federal cost allocation. Moreover, Order 1000 requires that incumbent utilities surrender their right of first refusal to build certain kinds of transmission lines in their service territories. This can save time and money for independent transmission investors, driving down the risk they see in new transmission projects. In addition to requiring regional planning and driving down investment risk, Order 1000 requires planners to consider alternatives to transmission that can meet system and energy needs. These alternatives might include demand side management, distributed generation and energy efficiency programs. These requirements are likely to result in vast improvements in planning coordination across broad geographies and better resource choices for the grid system as a whole.

The Federal Energy Regulatory Commission's Order 1000 emphasizes stakeholder involvement, public policy goals and transmission competition. It also encourages grid planners to assess alternatives (distributed generation, demand-response, etc.) on equal footing. Here are some reasons why this Order could unlock transmission siting for remote renewables:

1. Non-traditional stakeholders (consumer advocates, environmental groups, Native American tribes, etc.) have a seat at the table. The result: more buy-in throughout the process, as well as better solutions with fewer conflicts.
 2. States are treated as key stakeholders. They can help make choices about transmission alternatives, giving them a greater interest in siting lines quickly while resolving local land use conflicts.
 3. Planners must identify beneficiaries. Concerns about paying for other states' benefits could be reduced if not eliminated.
 4. The transmission planning process is required to be more transparent and open.
- State involvement in selecting the needed transmission and allocating costs reduces the likelihood of FERC having to exercise backstop siting authority.

FERC backstop siting authority can play an important psychological role in encouraging states to coordinate and lead in transmission planning, making it a useful siting tool. The best value of backstop siting is not in its exercise, but in the *possibility* of its exercise. One of the most potent arguments against FERC's backstop siting authority was the indiscriminate way that DOE originally defined its National Interest Electric Transmission Corridors (NIETC) in EPOA 2005. Those "corridors" encompassed entire eastern states as well as most of Arizona and southern California. State and public opposition was understandable and should have been expected. But FERC backstop siting authority could

be very effective for Order 1000 transmission lines. The Order 1000 process involves states and regional planners, considers environmental and cultural risks by using regional planning data, and ensures that alternative solutions are weighed.

A pair of promising, interrelated initiatives to coordinate interstate transmission authorities is unfolding as of this writing. The Western Governors Association (WGA) is convening a transmission siting and permitting task force to coordinate transmission interstate transmission development across state and federal jurisdictions, and perhaps equally importantly, between state and local jurisdictions. The DOE is also developing a transmission

“pre-application process” in coordination with WGA, state and local authorities and transmission sponsors, environmental and other stakeholders, to identify and avoid conflicts that could block transmission *before the* NEPA process begins. In so doing, it is hoped that NEPA can proceed with greater efficiency and less conflict, shaving years off of the approval time for interstate transmission lines needed for renewable energy projects.

DECISION-MAKER	RECOMMENDATION
Congress, DOE, FERC	Facilitate the participation of non-traditional stakeholders in regional and federal (FERC Order 1000) transmission planning by providing financial support to stakeholder representatives .
Congress, state authorities	Redefine FERC backstop siting authority to apply to lines selected through and whose costs were allocated in Order 1000 planning.
DOE, FERC	Adopt the use of environmental and cultural risk screens in federal corridor designation processes required under EPCRA 2005 and federal transmission planning efforts, such as the implementation of FERC Order 1000.
State authorities	Neighboring states with renewable energy resources and transmission needs should act to harmonize siting requirements and explore the possibility of creating interstate compacts for this purpose and to facilitate regional planning for renewable energy transmission.
State authorities	States should consider the establishment of a one-stop siting agency for large energy and transmission projects. Applicants are overwhelmed with having to deal with multiple agencies, from natural resource departments to land use entities. Because one of the main goals of this project is to save time for permit applicants without sacrificing important considerations, having one agency ensure that permit requirements are not duplicated can substantially shorten an applicant’s timetable.
CEQ, DOE, States, Counties	Complete and implement a transmission pre-application process to shorten NEPA compliance timelines.

Work with land owners to develop new options for private lands

The past decade has seen increased investment in transmission. More lines now traverse state boundaries. The scope of each proposed transmission project continues to grow. Now more than ever transmission lines are affecting private land and productive agricultural ground, at a time when commodity prices are at all-time highs and land prices are reaching unprecedented levels. Considered in tandem with the growth of renewable resource development, these changes indicate that the function of the electric grid has evolved. For the most part, however, each state's approach to transmission siting has stayed the same. Typically, states are required to legally review issues of project cost, environmental impact, size, type, timing, cultural and historical impacts, among others. These issues fall generally into the two categories: need and environmental impact. By focusing primarily on project need and environmental impact, states often undervalue the interests of the landowner when approving and subsequently siting a proposed transmission line.

If negotiations break down between the transmission provider and a landowner, the transmission provider can most often fall back on eminent domain. Intended as a reflection of fair market value, eminent domain in fact often fails to adequately compensate landowners. Eminent domain does not account for the subjective value each landowner places on a parcel of ground, nor does it compensate landowners based on the heightened land values that come from land assembly and potential development. Eminent domain also fails to account for the decrease in value of each landowner's remaining land, as prospective buyers often find encroaching infrastructure aesthetically troubling.

Prominent recent cases such as the Montana-Alberta Tie-Line and the Keystone XL pipeline show that opposition to eminent domain remains intense. Attorneys in the Upper Midwest and the Great Plains are now handling more eminent domain cases than ever before. Each time a new project is proposed, transmission developers in these regions are faced with a bevy of opponents. This can have a dramatic effect on the cost of siting as project developers pay millions for litigation and state agency administrative costs. Just one holdout can delay development for years.¹²

Eminent domain, however, is not always available. "Determination of need" – the most important prerequisite for eminent domain – requires the transmission developer to demonstrate that the proposed project is needed and the siting authority to confirm that construction of the project will serve the public interest. Because many state siting statutes and regulations have not been updated to account for expanding interstate balancing areas, they continue to base the determination of need on benefits to in-state ratepayers only. Often state statutes prohibit non-utilities from applying for a determination of need, or refuse to grant non-utilities eminent domain even if their application is successful. Siting authorities in states such as Massachusetts and Mississippi have declined to site proposed projects that cross state lines but do not deliver ratepayer benefits exclusively to in-state citizens. Moreover, eminent domain is not an option for merchant transmission lines in several states (e.g., Illinois, Maryland, New Hampshire and Nebraska), making it very difficult to build new transmission to support renewable energy development.

While eminent domain must remain available as a necessary last resort, providing viable alternatives will accelerate siting of the infrastructure needed to deliver renewable energy. Several options exist:

- *Special Purpose Development*

Corporations (SPDCs) focus on providing landowners with another option for just compensation. The condemning authority creates an SPDC, allowing the landowner to choose between two options. Landowners can either opt to receive the traditional fair market value for the parcel or they can elect to receive shares in the SPDC. The value of these shares is commensurate with the fair market value of the parcel the landowner has committed to the project. The condemning authority then sells the SPDC to a transmission developer at auction. The sale increases the value of the SPDC, and the landowners' shares are transferrable on the open market. Each shareholder is entitled to project dividends. The result is that the landowners' compensation is tied directly to market value, unlike traditional "just compensation." By giving landowners a stake in the project's success, things can move more quickly and fairly. This framework is applicable to utility-owned transmission projects; a merchant developer does not have a mechanism for recovering equity dilution from rates and may instead prefer to offer landowners annual payments tied to project royalties.

- *Landowner Associations* refer to groups of landowners that come together with a shared interest. These associations have been particularly successful for wind development, and are also suitable for shorter transmission lines. Each participating landowner is given a proportional share of ownership in the association based on the amount of land they want to make available for development. As an association, landowners then approach developers for projects. Members of the association that physically host turbines or transmission infrastructure are given a premium, but all members of the association receive a portion of profits.
- *Tender Offer Taking* enables developers to test landowner interest in several corridors by drawing proposed boundaries for a given project, and offering an above-market price for all landowners within the boundary. The developer then confidentially monitors acceptance, and goes forward with the project once a predetermined threshold is met (applying eminent domain authority to any remaining holdouts). If the threshold is not met, the developer shifts attention to a different corridor. Tender offer taking is well-suited to large projects that can be broken into discrete segments.

- *Good Neighbor Payments* represent ongoing payments to landowners that are near enough to a new project that it affects them even if it does not require taking over their land. For example, wind farm opposition sometimes comes not from direct landowners but from neighbors who are affected; thus wind developers often pay neighbors annually for noise impact. This concept could be applied to transmission development by providing annual payments to aesthetically affected landowners and neighbors. In the case of a landowner, good neighbor payments would be in addition to any easement negotiation made. Developers could also pay bonus payments to farmers who are affected by infrastructure on the land they cultivate.
- *Self-assessment* enables landowners to report the value of their land once a plan to condemn is announced. The landowner's tax liability is then adjusted to the reported value. The condemning authority then decides whether to take the land at the reported price or look elsewhere. If the developer chooses to look elsewhere, the landowner is thereafter prohibited from transferring his land for less than the announced value. This solution allows

the landowner to assign a personal value to the benefit or deterrent of hosting new infrastructure. A variation of self-assessment involves an opt-in mechanism whereby a landowner can choose to receive a property tax break in exchange for agreeing to be subjected to condemnation.

- *Annual payments* allow landowners directly impacted by transmission projects to receive compensation tied to the amount of power transmitted on the line. Under this scenario, payments are distributed each year the project is in service. Payments can be adjusted yearly, to account for inflation, and can be augmented in the event that the agreed upon right of way is used for an additional purpose. Annual payments could provide the landowner with a greater sense of ownership in the project, decrease the incidence of landowner holdouts and ensure compensation commensurate with the growing value of land. The Colorado-based Rocky Mountain Farmers Union has proposed a version of this concept for both transmission and wind farm development.

Any significant change in siting policies will require action on the part of the relevant state legislature or siting commission. However, there are steps that utilities and developers can take right now to repair their relationship with affected landowners. At a minimum, each utility or developer should engage landowners early and often. Today, landowners are often not even notified until the developer has submitted a proposed route and been granted the power of eminent domain. Meeting with landowners before a route is submitted allows affected parties to point out problematic areas and suggest a new approach. Open communication before a route is approved can help mitigate concerns, speed the process and solidify the role of the landowner as a participant rather than a spectator.

For example, many utilities have learned that the biggest impediment to an efficient siting process is landowner concern. They have since adopted a practice of soliciting early feedback. When feedback is solicited at the same time as the siting process, concerns are greatly reduced and the entire procedure becomes much more efficient. Many utilities now realize that holding landowner meetings more often than required can dramatically improve project efficiency. When new rights of way are needed, affected landowners and community stakeholders may be able to outline a developable route. These early steps can save developers and utilities time and money.

DECISION-MAKER	RECOMMENDATION
State authorities	Enable condemning authorities to create Special Purpose Development Corporations.
State authorities	Enable local governments to implement a self-assessment policy.
PUCs, state authorities	Approve developer and utility costs to work with Landowner Associations, employ Tender Offer Taking, allow for annual payments, and make Good Neighbor Payments.

Refine the process to support siting offshore wind developments

America’s spectacularly rich offshore wind potential is located relatively close to major load centers—especially along the Atlantic coast. Offshore wind can be a balancing resource, and is well-suited to replace fossil generation now being retired in ever-larger amounts. In part to facilitate this opportunity, the Bureau of Ocean Energy Management (BOEM) has created a version of “Smart from the Start” for offshore wind that begins by identifying promising areas via planning and analysis then opens them for competitive leasing. Developers must submit a Site Assessment Plan and a Construction and Operation Plan. These Smart from the Start areas are still subject to Coastal Zone Management Act review, and developments are subject to full NEPA review.

This BOEM initiative has streamlined the leasing program by eliminating redundant NEPA requirements, speeding up adoption of vast amounts of new renewable energy in the Eastern Interconnection, the most coal-dependent

part of the nation. The first lease sales under the program were announced by the Interior Department in November 2012 in the waters off of Rhode Island, Massachusetts and Virginia.

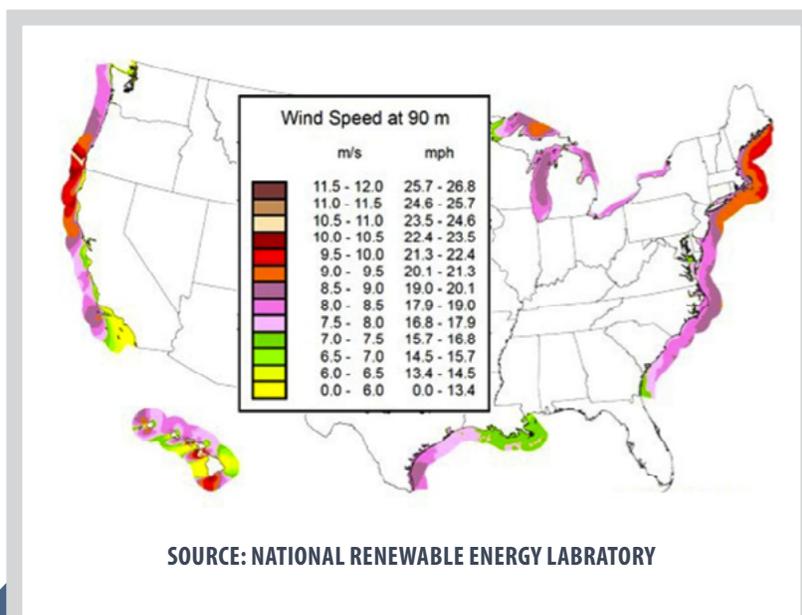


Figure 4. America's offshore wind resources.¹³

Still, BOEM's version of Smart from the Start lacks a cornerstone of its land-based counterpart: early and meaningful participation from a broad range of stakeholders. To date, BOEM's Smart from the Start process has been a purely intergovernmental effort, largely excluding public interest stakeholders and traditional users of coastal resources — a divergence from land-based Smart from the Start programs. This flaw

could undermine the success of the offshore siting effort. Early buy-in from affected stakeholders is important, so they do not hear about the project for the first time during the required public comment period under NEPA. By involving stakeholders earlier, developers can benefit from decreased opposition and early identification of major conflicts and proposed solutions.

BOEM's offshore wind program also currently lacks data regarding marine and avian wildlife migration and behavior. Addressing this data gap should be a priority, and can help avoid NEPA issues during project development. Obtaining better information early on

will make the site selection, planning, and analysis process much more reliable. This data would also be valuable during the more stringent NEPA review that wind development projects must pass before beginning construction.

DECISION-MAKER	RECOMMENDATION
BOEM	The Interior Department and its BOEM should prioritize data gathering, research and monitoring for marine and avian wildlife populations, behavior, and migration—both baseline and related to wind energy development. This research should be immediately initiated and incorporated into environmental assessments used to establish Wind Energy Areas.
BOEM	The Interior Department through BOEM should require more open stakeholder participation as part of the intergovernmental task force processes for Wind Energy Area identification as part of the BOEM Call for Nominations.

CONCLUSION

America has made substantial progress deploying and interconnecting new renewable energy resources, with thousands of megawatts of renewable power having entered the grid in recent years. The U.S. Energy

Information Administration estimates that in 2012, wind power additions alone outstripped additions from all other sources, including even the natural gas sector with its historically low prices.

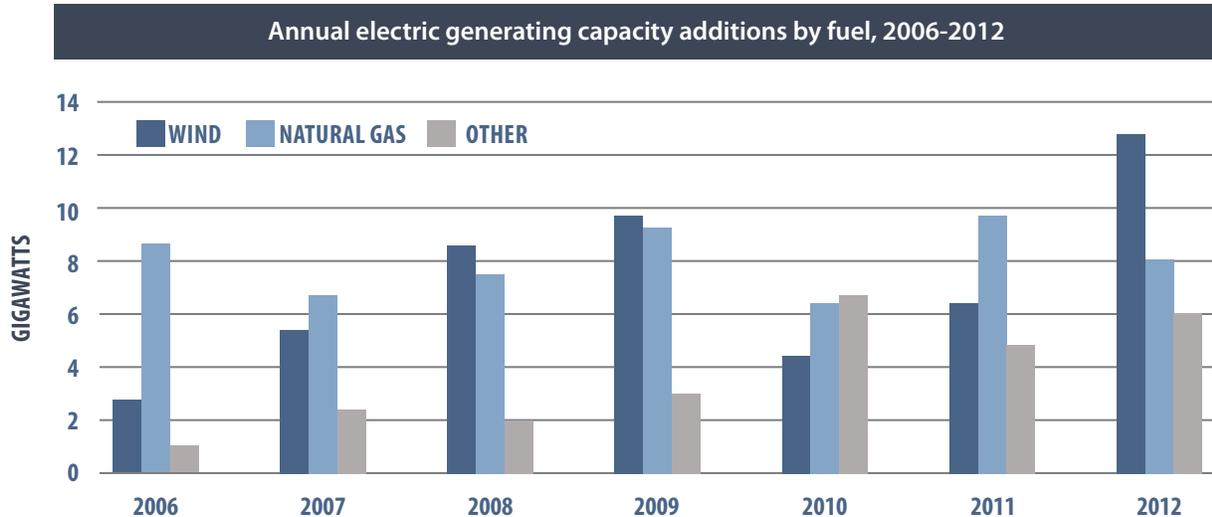


Figure 5. New power capacity additions by year.¹⁴

Yet while this data is encouraging, renewables still comprise a relatively minor share of America's overall electricity generation. Reaching 80 percent renewable energy by 2050 will require a major expansion of both generation and transmission infrastructure. In order to accomplish such a shift, new approaches to siting will be necessary. As described in this paper, these new approaches will require the early engagement of stakeholders, innovative policy and business models, better coordination among regulatory bodies, smart strategies to avoid the risk of environmental and

cultural-resource conflicts and improved operation and expansion of the grid to take better advantage of existing infrastructure and reduce costs of integrating more renewable energy. We already know how to do much of this – and most importantly, we know that accelerating renewable energy adoption needn't cause harm to landowners, cultural sites or wildlife. On the contrary, as a part of the effort to remedy climate change and stem the profound economic and environmental consequences it will cause, taking action today will provide long lasting benefits.

ENDNOTES

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- 7 See America's Power Plan report by Jimison and White.
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APPENDIX A: ACRONYMS

APPA	America's Public Power Association	IPPs	Independent Power Producers
AWEA	American Wind Energy Association	IREC	Interstate Renewable Energy Council
BLM	Bureau of Land Management	ISO(s)	Independent System Operator(s)
BOEM	Bureau of Ocean Energy Management	kWh	Kilowatt-hour
CEC	California Energy Commission	LBNL	Lawrence Berkeley National Laboratory
CPR	Clean Power Research	MECO	Maui Electric Company, Ltd.
CPUC	California Public Utilities Commission	MLP	Master Limited Partnership
CSI	California Solar Initiative	MW	Megawatt
DG	Distributed generation	MW-dc	Megawatts of direct current
DOE	U.S. Department of Energy	MW-miles	Megawatt- miles
DOI	U.S. Department of the Interior	NARUC	National Association of Regulatory Utility Commissioners
DOT	U.S. Department of Transportation	NEM	Net energy metering
EIPC	Eastern Interconnection Planning Collaborative	NERC	North American Electric Reliability Corporation
ERCOT	Electric Reliability Council of Texas	NREL	National Renewable Energy Laboratory
FERC	Federal Energy Regulatory Commission	NTA	Non-Transmission Alternatives
FHFA	Federal Housing and Finance Authority	PACE	Property Assessed Clean Energy
FIT	Feed-in tariff	PMA's	Federal Power Marketing Administrations
GDP	Gross Domestic Product	PNM	New Mexico's largest electricity utility
GW	Gigawatt	PUC(s)	State Public Utilities Commission(s)
HECO	Hawaii Electric Company, Inc.	PURPA	Public Utilities Regulatory Policies Act
IDP	Integrated distribution planning	PV	Photovoltaic(s)

QF	Qualifying facility
RAM	Renewable Auction Mechanism
RE Futures	Renewable Electricity Futures study
Re-Mat	Renewable market adjusting tariff
REC	Renewable Energy Credit
REIT	Real Estate Investment Trust
REIT	Real Estate Investment Trust
RFP	Request for proposal
RPEs	Regional Planning Entities (other than ISOs or RTOs)
RPS	Renewable portfolio standard
RTO(s)	Regional Transmission Organization(s)
RUS	Rural Utilities Service
SCEPA	State Clean Energy Policies Analysis project
SCG	Small Customer Generator
SGIP	Small Generator Interconnection Procedures
SolarDS	Solar Deployment System model
T&D	Transmission and distribution
WECC	Western Electricity Coordinating Council
WGA	Western Governors Association

APPENDIX B: RATE DESIGN AND THE NET ENERGY METERING COST/BENEFIT CALCULATION



The first step in framing an assessment of the economics of Net Energy Metering (NEM) is to clarify the scope of the NEM transaction. In this regard, it is helpful to consider what would happen if a customer installed renewable distributed generation (DG) without NEM. In that case, federal law—the Public Utilities Regulatory Policies Act of 1978 (PURPA)¹—would require the public utility to interconnect with the renewable DG system, allow the DG customer to serve the customer’s on-site load and purchase excess power exported from the system at a state-regulated avoided cost price in a wholesale power transaction. The impact of NEM is only to change the price that the DG customer receives for its exports, from an avoided cost price to a bill credit set, in most cases, at the customer’s retail rate. As a result, in evaluating NEM, the key question is whether this rate credit for exported power accurately reflects the value of that power, which the utility uses to serve other nearby loads.

Utilities in the U.S. routinely use sophisticated cost-effectiveness tests to evaluate demand-side energy efficiency and demand response programs.² It is important to evaluate the costs and benefits of DG as a demand-side resource, or to conduct a narrower analysis of NEM exports as one element of a DG transaction, using the same tests employed for energy efficiency and demand response programs. This promotes the consistent evaluation of all demand-side programs.³

Finally, it is critical that cost-benefit assessments of NEM, or of DG resources, should use long-term costs and benefits because renewable DG is a long-term resource with an expected useful life of 20-25 years. A long-term perspective is particularly important for assessing avoided transmission and distribution (T&D) costs. Although utility resource planners may consider DG in their integrated resource plans for future generation resources, DG is not well integrated into transmission or distribution system planning at most utilities, as discussed in more detail in the paper’s section on integrated distribution planning. Yet standard regressions of long-term utility T&D investments as a function of peak demand—for example, in standard utility calculations of marginal T&D costs—show a close correlation between long-term T&D investments and peak demand. In the long-term, lower peak loadings on the T&D system will reduce investment-related T&D costs.⁴ DG provides another tool to manage the growth of peak demand on the delivery system, such that long-term costs to expand transmission or substation capacity or to re-configure distribution circuits can be avoided.

In a ratepayer impact analysis of NEM, the principal costs are the retail rate credits that the utility pays for NEM exports. These credits are based on existing retail rates. The principal benefits of incremental NEM exports reflect the utility's avoided or marginal generation costs, in addition to the T&D benefits described above. If retail rates are based closely on the utility's marginal costs, then the impacts of NEM on non-participating ratepayers—positive or negative—will be minimized. However, rates typically are based on average or embedded costs, and as a result may depart, perhaps substantially, from marginal costs. The reasons for this departure from marginal cost-based rates are complex but often involve considerations such as universal access, equity, promotion of conservation and economic development. Furthermore, the centerpiece of the regulatory compact in the U.S. is providing the regulated utility with the opportunity to earn a reasonable return on its historical investments—a structure that naturally emphasizes rates designed on the basis of those historical, embedded costs. However, changes in retail rate design that move rates towards marginal costs represent one important avenue for addressing the ratepayer impacts of NEM.

For example, in states with significant low-cost base load generation, average rates tend to be well below marginal costs. In particular, retail rates often are much lower than the costs of the more expensive peaking power that are avoided by NEM exports from solar photovoltaics (PV). For example, in 2010, the Public Service of New Mexico (PNM) proposed a standby charge on new DG (mostly solar PV). The charge was based on the fixed T&D costs, which the utility alleged it would not recover from net metered DG. Analysis performed by the Interstate

Renewable Electricity Council, however, showed that the benefits of this generation, based on PNM's own marginal costs⁵, exceeded the lost revenues based on the utility's embedded cost rates for many customer classes, such that these classes should receive a standby credit rather than paying a standby rate.⁶ The parties settled this case by supporting the utility's withdrawal of its proposal.

The opposite side of the coin is when rates are set artificially above marginal costs. The residential rate design for California's investor-owned utilities is an increasing block structure with four or five rate tiers. Since the 2000-2001 California energy crisis, increases to the rates for the first two tiers of usage have been limited by statute, resulting in very high, above-cost rates for usage in the two or three upper tiers. The CPUC conducted a cost-effectiveness evaluation of NEM in 2009, at a time when upper tier rates were close to their peak.⁷ That study showed that NEM would result in a modest cost for non-participating ratepayers—a rate increase of 0.38 percent upon completion of the full build-out of the more than 2,500 megawatts of PV in the California Solar Initiative and its predecessor programs. Eighty-seven percent of this cost shift was the result of NEM in the residential market with these very steep tiered rates. Since 2009, the upper tier rates of California's three large investor owned utilities have dropped significantly, and statutory changes have allowed Tier 1 and Tier 2 rates to increase. The most recent cost-benefit analysis of NEM in the California market now shows that the net costs of residential NEM in California have dropped significantly, to the point that the costs and benefits are roughly equal—in other words, non-participating ratepayers should be indifferent to NEM.⁸

The results of cost-benefit evaluations of NEM will vary state-by-state, depending on rate structure, fuel costs, resource mix and other factors. However, in every case it is clear that the outcome is influenced significantly by retail rate design. The above examples show clearly that rate structures that more closely align rates with marginal costs (such as time-of-use rates for residential customers) result in reducing the costs of NEM for non-participating consumers, and that concerns with the cost-effectiveness of NEM can be addressed through standard cost-benefit analyses and rate design reforms.

More broadly, rate design will encourage customers to consider cost-effective forms of DG if rates provide customers with signals that reflect the long-term costs to provide service. In the long-run, few costs are truly fixed, and all utility facilities must be replaced. This suggests that economically efficient rates should use volumetric rate structures to the greatest extent possible, as customers have little ability to respond to rates that consist predominantly of fixed charges. Moreover, smart meter technology is now available, which allows all utility customers to be billed on a much more granular basis and which can provide consumers with more detailed feedback on their energy use. This will enable the broader adoption of precise and time-sensitive rate designs, replacing blunt instruments like the monthly maximum demand charge that are artifacts of older metering technology. A customer whose usage peaks at noon should not have to pay the same amount as another customer with identical peak usage, but whose peak coincides with the system peak at 4 p.m. Smart meter technology will not fulfill its promise unless it is accompanied by rate designs that are time- and usage-sensitive, providing customers with the information and ability to impact the amount, timing and costs of their electricity usage.

(Endnotes)

- 1 The PURPA requirements can be found in 18 CFR §292.303.
- 2 California Public Utilities Commission (2001). "The California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects." <http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF>
- 3 For example, due to NEM's more limited scope, an evaluation of the cost-effectiveness of NEM is a different inquiry than the assessing the costs and benefits of DG as a demand-side resource. Analyses of NEM are ratepayer impact measure (RIM) tests designed to assess the impacts of NEM on ratepayers who do not install DG, whereas assessments of the overall cost-effectiveness of DG as a resource typically will use broader, societal cost-benefit tests, such as the total resource cost (TRC) test, in addition to RIM tests.
- 4 Impact studies of large-scale DG programs such as the California Solar Initiative have shown that DG systems do reduce peak demands on both the transmission and distribution systems. See Itron, *2009 CSI Impact Evaluation Report*, at ES-17, at <http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm>; Itron, *CPUC Self-Generation Incentive Program—Sixth Year Impact Evaluation Report*, at 5-29 - 5-33 (Aug. 30, 2007), available at <http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm>.
- 5 PNM is the largest electricity provider in New Mexico.
- 6 See *Direct Testimony and Exhibits Of R. Thomas Beach On Behalf of the Interstate Renewable Energy Council in Support of Stipulation*, New Mexico Public Regulation Commission Case No. 10-00086-UT, at ¶¶ 13, 30 (Feb. 28, 2011).
- 7 California Public Utilities Commission (2010). "Introduction to the Net Energy Metering Cost Effectiveness Evaluation." <http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FD-BE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf>
- 8 Beach, R. Thomas, and Patrick G. (2013). "Evaluating the Benefits and Costs of Net Energy Metering in California." The Vote Solar Initiative. <<http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf>> This result is driven both by the reduction in upper tier residential rates in California since 2009 as well as by the higher avoided costs that reflect the fact that NEM exports are 100-percent renewable and will displace grid power that is 20-percent to 33-percent renewable.