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Markets for low carbon, low cost electricity systems

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About this paper

This paper is part of CPI Energy Finance's workstream on market design and incorporates work already published as part of the Energy Transitions Commission, and new concepts presented as part of the Eurelectric Market Design 2050 program, among others.

Descriptors

Sector	Electricity wholesale markets, renewables	
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About CPI

Climate Policy Initiative is a team of analysts and advisors that works to improve the most important energy and land use policies around the world, with a particular focus on finance. An independent organization supported in part by a grant from the Open Society Foundations, CPI works in places that provide the most potential for policy impact including Brazil, China, Europe, India, Indonesia and the United States.

Our work helps nations grow while addressing increasingly scarce resources and climate risk. This is a complex challenge in which policy plays a critical role.

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Executive summary

Competitive markets for electricity have brought many benefits since they were widely introduced in the 1980s and 1990s. Operators improved efficiency, competition drove down costs and encouraged developers and investors to manage risk, and fuel mix and investment patterns changed, usually for the better. But the electricity industry has changed. Decarbonization and clean energy goals are pursued with increasingly ambitious policies, the cost of low carbon generation has plummeted, new storage technologies have developed, and information technology now allows consumers and distributed resources to participate in electricity markets like never before. Markets that were designed to encourage investment in gas and coal fired generation in the 1990s may not be appropriate to shape investment and operational decisions for future electricity systems.

The falling cost of variable renewable energy opens up the possibility that a low carbon electricity system could be built and operated with today's technology at a lower cost than a fossil fuel based system. But variable renewable energy sources are fundamentally different from fossil fuel based power, and incremental changes to existing markets will only take us so far before current market designs run into major challenges. Wind and solar have near zero marginal costs, and capital costs account for most of the cost of energy. Electricity system costs will increasingly be locked in when projects are developed and built, rather than when they burn fuel to generate power, and volatile price signals may do little more than raise the cost of financing these projects because of the greater risk perceived by investors. Moreover, the wind and sun do not respond to price signals. Wind and solar power are variable, even if their output can be predicted accurately. As these resources are scaled up, electricity markets will need more flexibility from new sources like batteries or intelligent, automated demand response, or from using existing thermal generation, hydro and transmission.

In this paper, we highlight at least four major problems of incremental refinement to existing market models:

- Under high penetrations of variable renewable energy, hourly prices based on marginal costs could drop to zero or below for extended periods of time, no longer sending meaningful signals for operations or investment. If this happens, the markets could threaten the

financial viability of much of the generation business.

- Electricity prices in current markets are determined by the last unit of supply needed to meet demand, which is often natural gas fired generation. But as gas's role on the grid diminishes, it may no longer make sense to closely link gas and electricity prices.
- Existing market models could cause financing costs to rise significantly, even for those generators not directly exposed to the market price, increasing the costs of electricity systems and overwhelming the benefit of efficient system operation that these markets are intended to foster.
- Market mechanisms as currently structured could further blunt incentives for investment and innovation and, as a result, delay the emergence of new technologies and innovative business models required to keep a low carbon electricity system low in cost.

A low carbon grid will undoubtedly rely on resources with high capital costs and limited flexibility – renewable energy, and in some cases nuclear and fossil fuel with carbon capture and storage. To manage the costs of such a system, we need to create incentives that apply when investment decisions are made. Additionally, the market needs to increase incentives for those assets and participants that can provide the needed flexibility to the market. We propose to achieve both goals by separating these two activities into their own markets:

- An **energy market** will be a market for commodity electricity production, independent of time and location, that relies on auctions for long-term energy contracts to enable long-term low cost financing of low cost, capital intensive energy resources. While generators will be able to choose which market they wish to participate in, we believe that this market will attract mainly the low carbon, less flexible energy supply from renewable energy, nuclear, carbon capture equipped fossil fuels, and possibly combined heat and power. This market will set the notional wholesale price for electricity used in many system wide planning and investment decisions.
- A **delivery market** will be a market for the delivery of energy when and where it is needed to meet demand and ensure reliability. This

market would concentrate incentives for flexibility on the participants that are best suited to manage those risks. Prices in this market would vary locationally and fluctuate widely across the day and year. The price in the delivery market would be in addition to (or subtracted from if the delivery price goes negative) the wholesale price in the energy market.

The combination of these markets could lead to lower financing costs for long-term, capital intensive energy resources, as many of the key risks facing these assets would be transferred into the delivery market. At the same time, sharpened market signals for flexibility would provide clear signals to flexible power plants, battery energy storage, and demand-side flexibility providers. This two-market model could lead to considerable cost savings, but also highlights several key challenges that would need to be overcome:

- Incentivizing participants in the energy market to reduce flexibility needs over the long-term;
- Integrating the cost of long-term and shorter term transmission and distribution system operating and investment;
- Optimizing the use of fossil fuel plants and dispatchable hydro as they fit into long-term energy supply; and
- Maintaining system security and reliability.

This concept is only a starting point. We believe it highlights the biggest challenges facing cost-effective decarbonization of the power sector, but further development is needed before this concept can be robustly applied to specific markets. We believe that new electricity market models can be a critical tool in enabling a cost-effective transition to a low carbon electricity system, spurring innovation in technology and market models that will lead to further improvement in costs, quality and the environmental performance of the future electricity system.

1 Introduction - The evolving role of electricity markets

The electricity business has always been different from other commodity markets. With millions of consumers using electricity at any given moment, supplied by generators at hundreds of locations, using transmission systems thousands of kilometers wide, and with supply and demand needing to be balanced each instant at each point in the grid, electricity was long thought of as too complex to enjoy the benefits of a market.

A well-structured market assimilates data and preferences from multiple buyers and sellers about the value of a product or service. It then produces a price which represents the point where the cost of supplying one more unit equals the benefit a consumer gains from that unit, leading to an efficient allocation of resources in the economy. Over time, an effective market will foster competition between suppliers that encourages them to reduce costs and improve product quality. But before a market can work effectively — whether it is a stock market for shares in companies, a commodity market for wheat, or a consumer market for automobiles — the buyers and sellers must agree on what the product is, how it will be specified, measured, and regulated, and who will be allowed to buy or sell into the market. Different market designs and product scopes can lead to very different market outcomes. For example, a market for cars versus one for transport from point A to B could result in a very different transportation system. Thus, market design is critical, as is knowing what outcome the design is looking to achieve.

A crucial insight of the 1980s and 1990s was that markets could be designed and implemented to bring both the price discovery and efficiency incentives to some parts of the electricity industry which typically had been regulated monopoly businesses. Increasingly sophisticated design in some markets created different pricing at each point on an electricity grid, reflecting differences in costs of delivering electricity from various generators to consumers on different parts of the system, differences that result from transmission losses or congested networks. Market prices at each node were set at short intervals, usually much less than an hour, to encourage generators to operate when demand was high and to figure out how to reduce output when demand was low. Separate markets and contract auctions were often put in place to procure additional services that made the grid operate securely, for instance standby capacity to address unexpected demand spikes or transmission line failures.

The impact of these markets was significant, encouraging generators to improve operations and operate more flexibly, aligning investment in new generation facilities with system needs in ways that altered fuel mixes and reduced investment needs, encouraging transmission system operators and generators to integrate generation and transmission planning in ways that reduced total system costs, and forcing generation owners to address risk management across the business, but particularly in areas like fuel procurement, transmission availability, demand risk and price hedging. Yet the focus of these markets often has rested mostly on optimizing the dispatch, operation and investment in fossil fuel plants, often with flexible hydroelectric generation and transmission filling in the gaps. Independent power producers (IPPs) and other new players entered these markets and were able to achieve higher returns for investors, while delivering enough cost savings and risk management to outweigh higher costs of capital and thus reduce costs to consumers.

With the emerging mix of new, low carbon generation and storage options coming to the market, the systems that have worked well in the past may no longer be optimal. Wind and solar generation have very different financial and operating characteristics that will respond differently to market designs. These generation sources, as well as high capital cost, low carbon generation such as nuclear or carbon capture and sequestration, will benefit strongly from market designs tailored for their characteristics. In fact, their emergence is likely to lead to changes in the roles of utilities, IPPs, and energy suppliers, as well as changing the pool of investors in the industry and the financial vehicles they use to invest in electricity generation. The development of storage technologies, increasingly sophisticated information technology, growing options for small-scale, distributed generation and storage, and shifting electricity demand, including for transport, all alter the basis for competition, and the role of investors, consumers and producers, and the issues that markets need to address.

In this note we begin by setting out a few basic principles of market design, followed by a discussion of how the low carbon energy transition may be changing some of the fundamental technological and investment parameters that guided earlier market design. We then will show how these changes threaten to make existing market design concepts inefficient and, in some cases, unworkable. We then conclude with a proposal for a market design that will be more aligned with the characteristics of a future electricity market.

2 Guiding principles for electricity market design

Electricity markets are more artificial than many markets. While many markets have grown organically as buyers and sellers develop trading norms, which then have been codified through standards or regulation, most electricity markets have been developed from scratch to replace regulated monopolies or state ownership. Nevertheless, the electricity market development should follow three market principles:

- 1. Markets need to deliver clear incentives to both consumers and suppliers reflecting what each side needs or is willing and able to supply.** Electricity markets need to deliver clear incentives around operating efficiency and plant availability, low energy costs, the flexibility to adapt to consumer or supplier needs, delivering energy where and when it is needed, and system reliability and security. The market also needs to deliver incentives and signals to optimize investment in keeping with long-term costs and system reliability, as well as public policy goals such as environmental protection, carbon reduction, or economic development. Finally, consistent with the needs of an energy transition and lower long-term costs, markets (or the policy sitting alongside them) may be asked to provide incentives to encourage technology development.
- 2. Markets need to balance the benefits of providing these incentives against the**

administrative and transaction costs of operating and participating in the market.

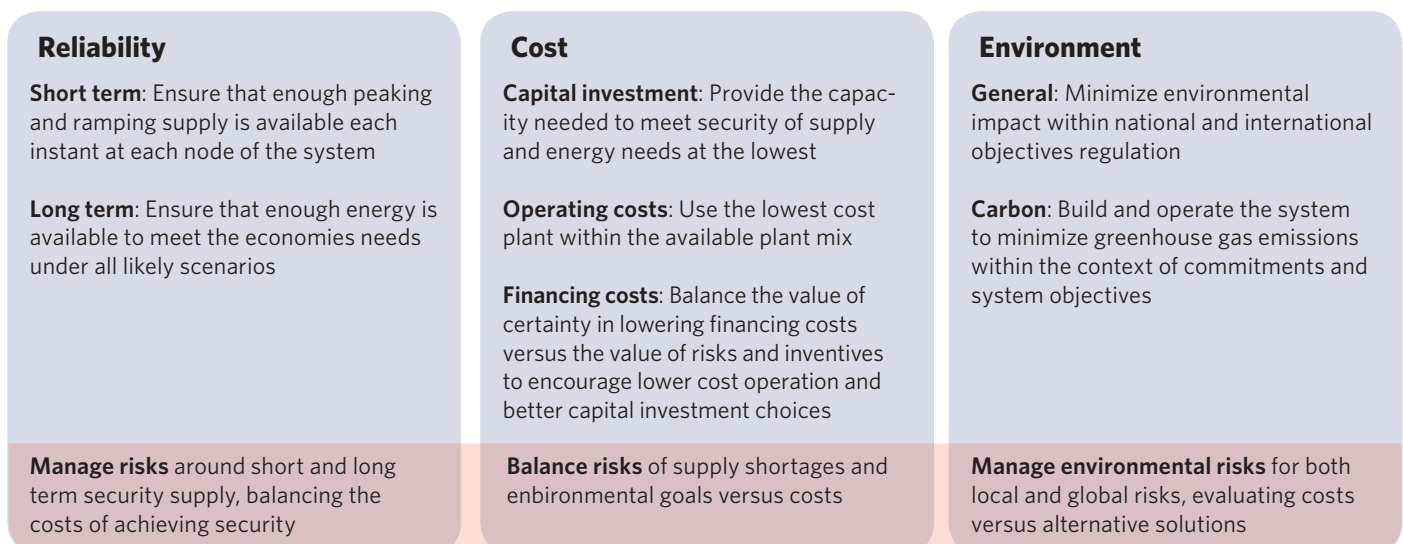
Operating a market can be expensive, not only in the systems and equipment, such as metering and billing systems, required to run the market, but also in terms of the cost of regulation and the cost of consumers' and suppliers' time to participate in these markets. Thus, effective markets must seek to lower the cost of operating the market, but also to ensure that the benefit of the market are greater than the systems and transactions costs associated with operating and participating in the market.

- 3. Markets need to allocate risks in ways that access the lowest cost of capital for the relevant pieces of the supply system.**

Delivering incentives is a double-edged sword. For instance, even if a market indicates that a new power plant is cost competitive today, there is always a risk to the investor in that it will not be in future. Where there is incentive, there is risk which will prompt investors to demand higher returns. Thus, a key principle of market design should be that the value of providing an incentive — for example in terms of how much a producer will be able to lower costs or adjust the timing of output to improve its value — must be greater than the cost that the additional risk will bring by raising the cost of capital.

Beyond these general market principles, there are the specific objectives that electricity markets need to balance: reliability, cost and environmental goals.

Figure 1: Electricity markets balance competing objectives



3 A changing electricity system

Since electricity markets began restructuring and liberalizing in the 1980s, the world of electricity supply and demand has changed. Relative fuel prices have changed, plant efficiency and operating characteristics have evolved, energy efficiency has slowed demand growth even as new sources of electricity demand have emerged and changed usage patterns. But the two changes that are likely to have the greatest long-term impact on electricity markets are closely linked: the carbon constraints emerging from growing efforts to combat climate change, and relatedly, the rapid development of several relevant sets of technology. We highlight three general categories of carbon-related technology development that have major implications for electricity market design: the falling cost of very low carbon, but non-dispatchable and variable output forms of renewable energy including wind and solar power;

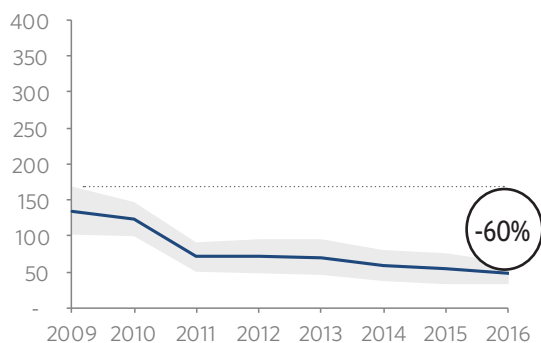
the falling costs and development of many storage options including batteries, as well as automated demand response and other information technology driven, consumer-facing flexibility options; and, the growing power of information technology which allows markets the potential to assimilate ever greater quantities of information and participants.

The falling cost of variable output renewable energy (VRE) opens up the possibility that a clean, low carbon electricity system is feasible with today's technology at costs that could be lower than a fossil fuel based system.

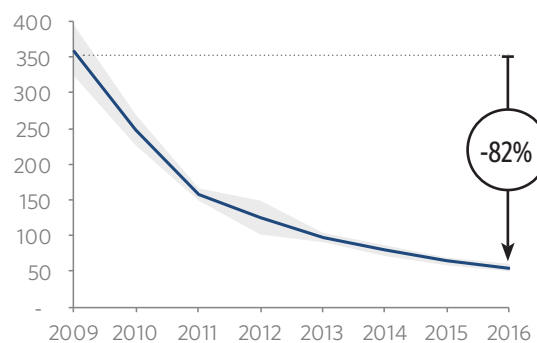
Wind and solar have experienced dramatic cost declines over the last several years. According to Lazard, the levelized cost of wind energy declined 66% between 2009 and 2016, while utility-scale solar fell 85% over the same period.

Figure 2: Levelized cost of wind and solar energy

Levelized cost of wind
\$/MWh, unsubsidized



Levelized cost of utility-scale PV
\$/MWh, unsubsidized



Source: Lazard, Levelized cost of energy 10.0, 2016.

Low carbon technologies like wind, solar, hydroelectricity and nuclear power are highly capital intensive. For variable renewables, all project costs are capital or fixed maintenance costs, while variable costs are negligible or non-existent. For nuclear, variable fuel and maintenance costs amount to under 10 percent of total levelized costs, with fixed capital and maintenance accounting for 90 percent or more.¹ For all these resources, upfront project costs and the cost of financing are by far the most critical determinants of the lifetime levelized cost of energy.

New financing mechanisms promise to further reduce the cost of wind and solar. As Climate Policy Initiative finds in *Mobilising cost institutional investment in renewable energy: Structuring the Clean Energy Investment Trust*, structuring a new financing instrument for institutional investors around the long-term, low-risk characteristics of renewable energy assets could reduce the cost of energy from these sources by an additional 15-17%.

Since capital costs are a much greater share of total electricity costs, the cost of capital and the impact of risks on the final costs become much more important. Meanwhile, variable output renewable energy, once built, cannot respond easily to hourly incentives without just throwing away energy that is generated. Thus, the emergence of VRE moves the emphasis of the market

objectives away from ever finer incentives during the operation phase, to stronger incentives during project development and construction and lower risks during operation, as the weight of finance costs and pre-financing planning outweigh smaller benefits from operational efficiency.

As the share of energy supplied by less-flexible but cheaper VRE rises, ever more flexibility will be needed from new sources like batteries or demand response, or from using existing thermal generation, hydro and transmission. Fortunately, technological innovation and cost reduction are providing increasingly cost-effective solutions.

Wind and solar energy only produce power when the underlying resources are available, and flexible resources are needed to fill in the gaps. For example, if we assume a system with wind, solar and demand profiles similar to Germany's and equipped with sufficient renewable capacity to match annual consumption in aggregate, only 80 percent of the renewable output will be coincident with load in the hour it is generated. The figure below clearly illustrates this timing mismatch, which results in surpluses and shortfalls on daily, multi-day and seasonal timeframes.

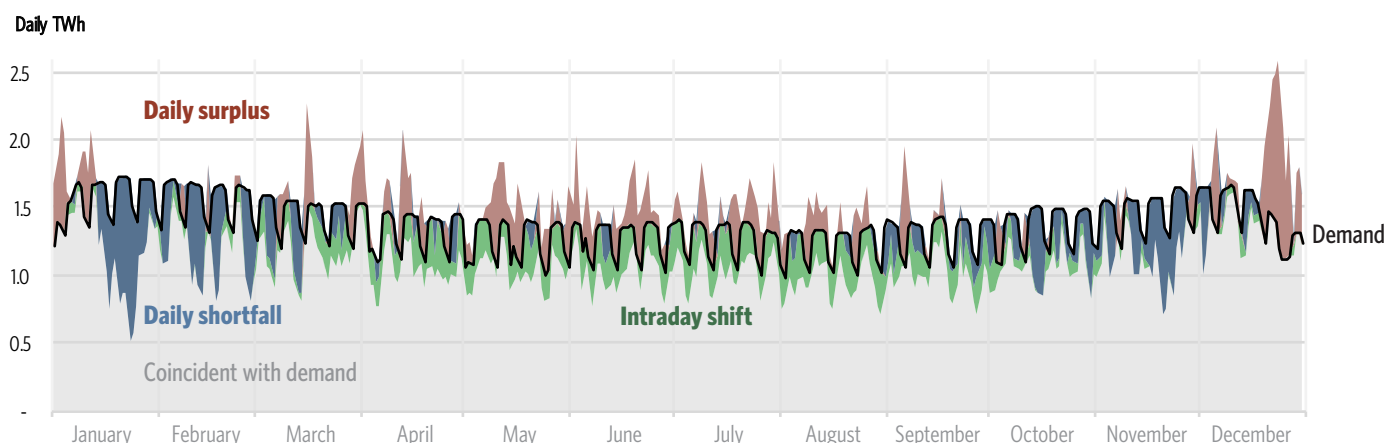
¹ Lazard, 2016.

Figure 3: Variable vs. fixed costs for various energy technologies

	Levelized variable costs (\$/MWh)	Levelized fixed costs (\$/MWh)	Variable cost share
Gas Combined Cycle	26	22-52	33-54%
Gas Peaking	39-41	124-178	18-25%
Coal	14-23	46-120	16-23%
Nuclear	10	87-126	7-10%
Wind	0	32-62	0%
Utility-Scale Solar	0	46-61	0%

Source: Lazard, Levelized cost of energy 10.0, 2016.

Figure 4: Daily demand vs renewable energy production profile



Source: Climate Policy Initiative, Flexibility: the path to low carbon, low-cost electricity grids, 2017.

Both technology and market mechanisms can increase the availability and affordability of flexible resources. Climate Policy Initiative’s recent study *Flexibility: the path to low-carbon, low-cost electricity grids* compared the costs of many options to meet specific flexibility needs. Across the board, demand-side flexibility and existing, depreciated power plants were the least expensive options, but in most markets they are limited in the amount of flexibility they can provide. Where new flexible capacity is needed, the lowest cost option was often flexible gas generation, although low-cost batteries promise to soon be competitive for short-term

reserves and daily shifting of energy from low to high value times.

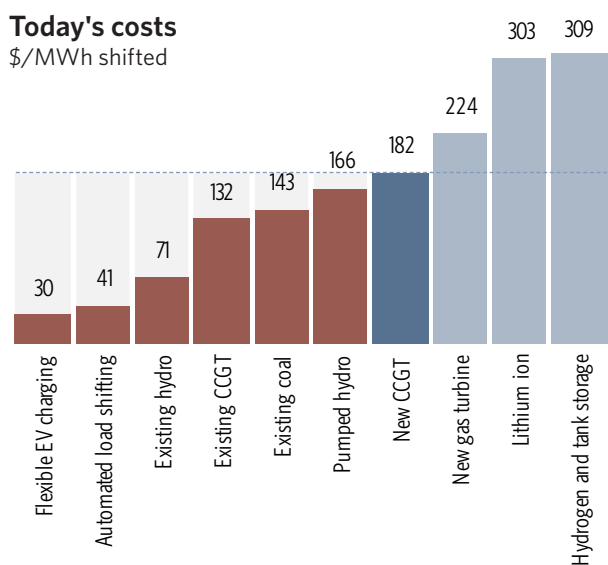
With rapidly falling wind and solar costs and low cost flexibility options at hand, a low carbon system based on renewable power looks increasingly cost-competitive. As CPI found in the *Flexibility* report, meeting all demand in a system that is over 80 percent reliant on variable renewable energy may soon be a cost-effective proposition even absent carbon pricing—indeed, by 2030 building such an electricity system could cost less than a new system exclusively supplied by natural gas.

Figure 5: Cost of shifting energy on a daily basis, comparison of flexibility options

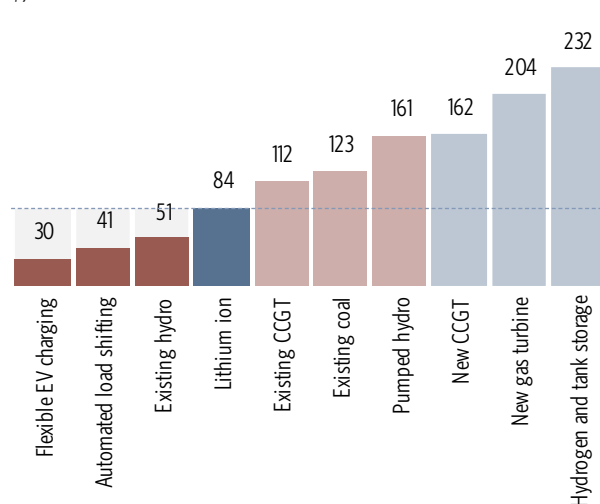
Cost of daily shifting (30% capacity factor)

■ Not scalable resources ■ Scalable resources
 ■ Cost savings using existing or limited resources

Today's costs
 \$/MWh shifted



Post-2030 costs
 \$/MWh shifted



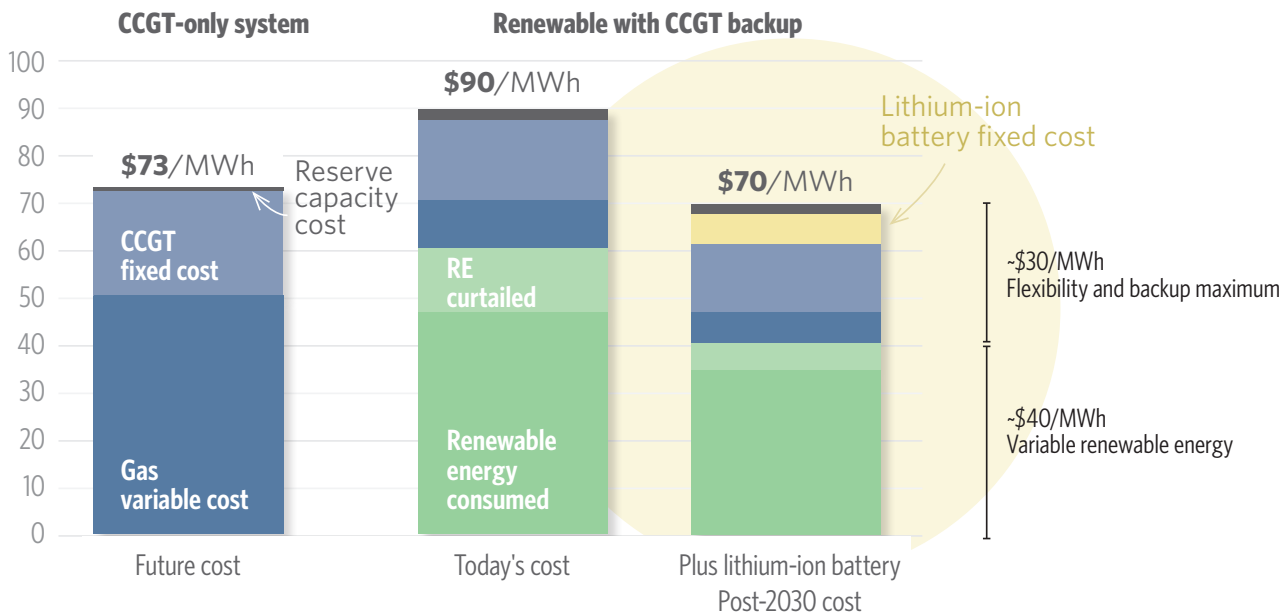
Source: Climate Policy Initiative, Flexibility: the path to low-carbon, low cost electricity grids, 2017.

Figure 6: Power generation and balancing cost

Total cost of generation from renewables and CCGT-based systems including flexibility (no carbon price)

Power generation and balancing cost

\$/MWh, excluding carbon price



Source: Climate Policy Initiative, Flexibility: the path to low carbon, low-cost electricity grids, 2017.

A low carbon future will require electricity systems to manage a different set of risks and coordinate new types of market participants. In today's electricity systems, the biggest cost and reliability risks are fuel costs, fuel availability and the risk of outages from large centralized power plants. Moreover, system operations aim to coordinate the actions of a limited number of large, controllable power plants. A low carbon electricity system will almost certainly seek to manage a far larger number and variety of resources, including renewable energy producers as well as demand-side assets capable of automated response to changing grid conditions. In such a system, the most significant challenges will be in predicting wind and solar output, maintaining sufficient flexibility to manage periods of supply surpluses and shortfalls, and coordinating the actions of potentially millions of grid-connected devices.

Information technology will allow systems to access and integrate more distributed sources of energy and flexibility and enable new models for balancing electricity systems using both consumer and producer led flexibility, but only if we can make these systems transparent and easy to use with low administrative and transaction costs.

Here, markets need to sharpen the incentive to meet the growing flexibility needs. We will need systems that allow for competition between a wide range of flexibility options and can assimilate the need to inject this flexibility and different geographic points on the system. Fortunately, both batteries and demand response can be quite distributed resources, while the ever-increasing improvement of information technology enables ever more intricate market designs to optimize the use of these resources. However, the risk of complexity raising transaction costs and confusing consumers and suppliers is very real. So creating consumer and supplier friendly markets, or markets that foster the emergence of quality aggregators of services, will become a very important challenge.

Technology development is driving the market in two directions. For low carbon, less flexible generation, costs will be driven by lowering the cost of capital and incentives delivered at the time of project development and commissioning. For other technologies, ever more disaggregated and specific incentives are needed to synthesize the actions of many players and assets, but with the ability to aggregate these actions to reduce transaction costs. We will return to this theme shortly, but first we should look at the challenges that could face existing market designs.

4 The state of current market design

The emphasis of electricity market reform over the last 30 years has rested squarely on sharpening, extending and deepening incentives to private players like utilities, IPPs and energy suppliers. The reforms have been successful, but not universally so, often with hiccoughs due to the transactions and administrative costs and the impact on financing discussed in section 2. For example:

- Retail competition in the UK has led to consumer and political backlash as the complexity and administrative costs to consumers has grown and as the benefits to the supply companies from strategic selection of customers has outweighed any benefit they experience from reducing costs or competing on quality.
- Risks and uncertainty have often delayed the build of new generation supply, as the short term focused markets have not offered adequate long-term certainty required to finance new plants.
- The responsiveness of consumer demand to electricity price signals has been lower than hoped, partly due to weak long-term price signals needed to justify investment, but also due to a blunting of the incentives, in order to avoid politically unattractive spikes in prices, and the relatively small value of the incentive when compared to the inconvenience and administrative costs.

The recent focus of electricity market reform has predominantly rested on issues like these, including the impact that carbon constraints, renewable energy and storage technology development might have on these issues. But we believe that a more forward looking view would also concentrate on the impact that variable renewable energy and the emerging storage and information technology revolution could pose in other areas. Namely:

- Under high penetrations of variable renewable energy, hourly prices based on marginal costs could drop to zero or below for extended periods of time, no longer sending meaningful signals for operations or investment.
- The role of natural gas as a price setter in many markets will increasingly make less sense.

- Strict adherence to existing market models could cause greater uncertainty in market prices, leading financing costs to rise significantly, increasing the costs of electricity systems and overwhelming the benefit of efficient system operation.
- Market mechanisms as currently structured could continue to blunt incentives for investment and innovation and, as a result, delay the emergence of new technologies and innovative business models required to keep a low carbon electricity system low in cost.

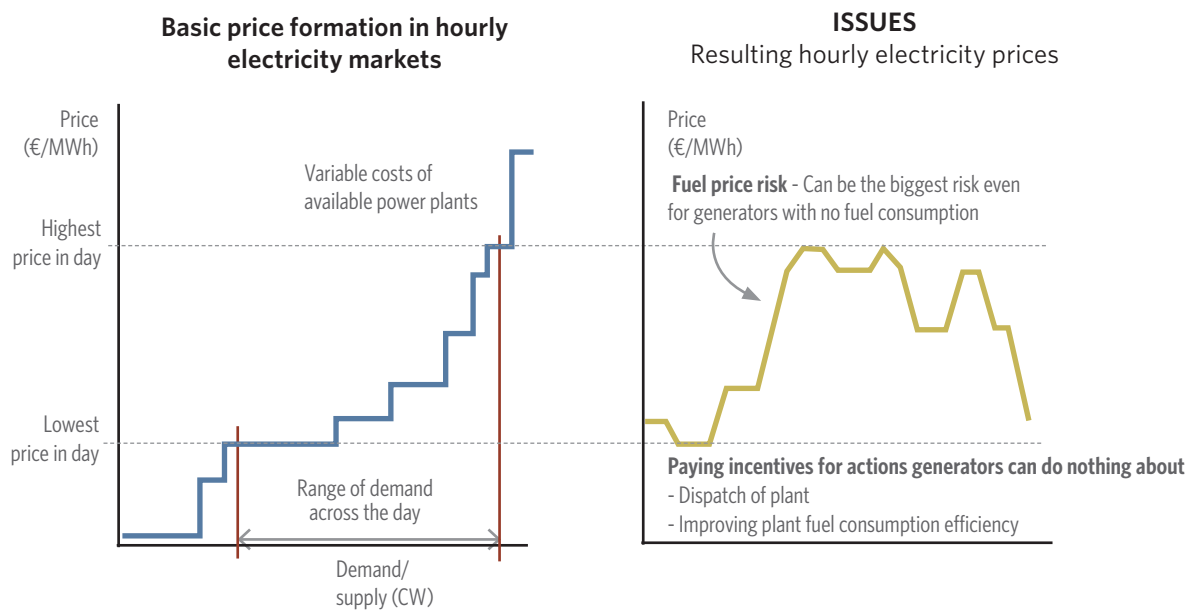
The key is to leverage the experience and value of the last 30 years' of experience in electricity market design, while creating a new system that avoids these issues.

Under high penetrations of variable renewable energy, hourly prices based on marginal costs could drop to zero or below for extended periods of time, no longer sending meaningful signals for operations or investment.

Today's electricity market designs emerged under a different market environment with a different set of needs. As less capital intensive and more efficient natural gas plants became commercially available, there was significant value in markets that dispatched plants based on fuel and other short-run costs while optimizing the use of the transmission network.

Prices in many of today's markets are based on the variable costs of the "marginal" power plant. In simplified terms, the market operator stacks all of the power plants in a system from lowest to highest variable cost, and the last plant that has to turn on to meet demand in a given hour sets the clearing price for the market. The marginal power plant in many regions is often fueled by natural gas, creating an intimate link between electricity prices and natural gas prices. This means that the market revenues for all market participants, including low carbon resources that do not burn natural gas, are often tied to the price of natural gas. This system rewards actors who can best manage fuel price risks and respond to fluctuating price signals. Variable renewable generators have almost no ability to respond to these incentives, since they inherently lack variable costs and flexibility.

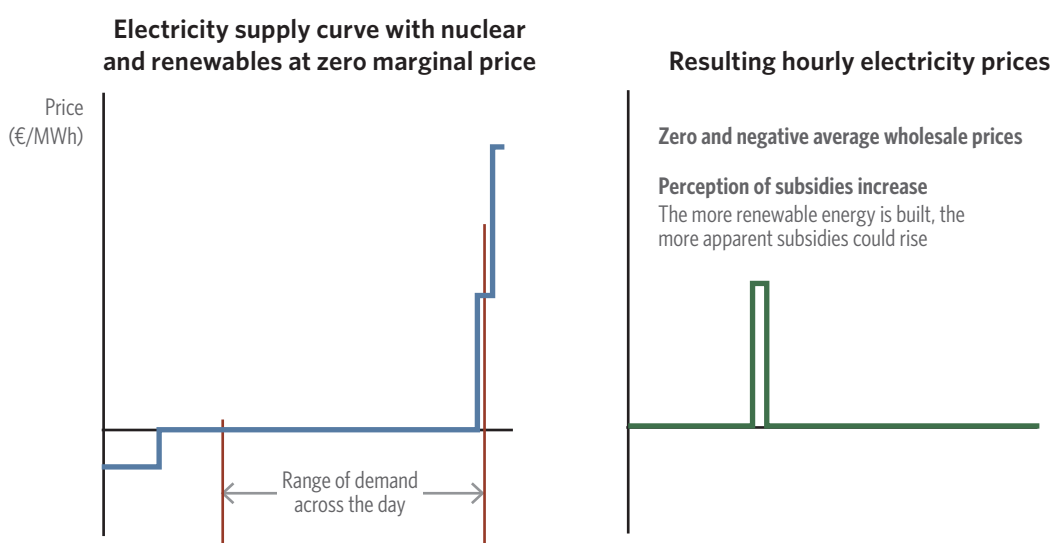
Figure 7: Prices are set by the marginal power plant in today's markets



As zero and low variable cost power plants become a greater share of the energy mix, wind and solar may at times be the marginal plant, sending prices to zero. If excess production from renewable sources requires generators to turn down or curtail output, clearing prices can even go negative. These price signals are helpful for indicating the value of flexibility to the market. As we enter a world where 30-50% or more of annual electricity supply comes from sources like wind, solar, and to some extent nuclear or run of river hydro,

the number of hours where no variable cost energy is needed will increase. Under such a market prices could be zero or negative much of the year, blunting the economics of conventional fossil fuel generation as well as renewable energy. One initial reaction has been to slow the development of low carbon energy, to “reflect the economics of the system.” But the issue is the design of a system based on short term marginal cost pricing when much of the system does not have a short term marginal cost.

Figure 8: Challenges for a clearing price market when marginal price tends toward zero



The role of natural gas as a price setter in many markets will make increasingly less sense

For those hours where electricity prices are not zero, prices are notionally determined by the marginal power plant, that is the last, most expensive plant that needs to be turned on to meet demand in a given hour. Since in many markets, that plant is natural gas fired, natural gas prices will have a strong influence on energy prices. In today's markets, power prices often move in lockstep with fuel prices. For the investor in a gas fired power plant this is a benefit, a natural hedge. When costs rise, prices rise, meaning that their return on the investment is much less volatile than power prices.

But as new investment in generation increasingly moves away from baseload gas fired generation, fuel prices driving electricity prices will have the opposite effect. If natural gas prices fall, driving down power prices, the fixed costs of renewables stay constant, so returns become more volatile rather than less. Put another way, power plants that do not use natural gas are significantly more exposed to gas price risk than those plants that do. This dynamic imposes unnecessary price risks on an increasingly large share of the total investment base of the power sector, raising financing costs, and ultimately, electricity costs. At the same time, this market design gives fossil fuel generation a competitive advantage through lower financing costs, even though no cost advantage to the sector is realized.

Strict adherence to existing market models could cause financing costs to rise significantly, increasing the costs of electricity systems and overwhelming the benefit of efficient system operation.

The existing short term marginal price based market concept will also raise the financing costs of electricity generation in several ways. We highlight two.

First, even where generators are protected from short term marginal prices by contracts or regulation, the design of a notional wholesale price of electricity based on short-term marginal prices significantly raises investor risk perceptions around new low carbon energy projects. Interviews with a range of investors and analysts indicate that default risk and political risk, and particularly the risk that tariffs will be adjusted or regulation changed, are two of the biggest risks that investors face in investing in contracted renewable energy projects. Default risk can be mitigated by selling the contracted energy back to the wholesale markets, but if wholesale prices are low, the protection offered by

wholesale markets decreases. Furthermore, investors often view political risk to be a function of the "notional subsidy," that is, the difference between the feed in tariff or contract price and the wholesale market price.

When additional renewable energy generation hits a short term marginal price based wholesale market, average wholesale prices fall, increasing both default risk and political risk, significantly raising financing costs. Thus, the result of more attractive renewable energy and falling renewable energy prices could have the perverse effect of increasing the apparent subsidy and risk experienced by renewable energy investors as deployment increases, even when the actual "subsidy" has fallen or has disappeared. The result will stall the momentum for falling costs and lead to a backlash against the lower-cost energy precisely at the time that renewable energy becomes fully cost competitive. Evidence is very strong that we have already reached the point of both backlash and competitiveness in many markets.

Second, viewing market design purely from the perspective of short term incentives can create risks that will discourage investors and raise return requirements. Curtailment of renewable energy is a prime example. Many electricity market designers argue, rightly, that the ability to curtail production from renewable energy projects is a source of flexibility to electricity markets. They further argue that renewable energy generators should be given incentives to provide this flexibility to the system. Where they often err is in how these incentives interface with the market and the impact that their design would have on financing costs. In work that CPI published in 2016 *Policy and Investment in German Renewable Energy* CPI worked with a range of German investors, policymakers, analysts and project developers to assess the impact of different policy options on which investors would likely invest in renewable energy, at what required return, under different policy adjustments being considered. One part of that project addressed curtailment risk as it would be addressed by investors.

German and EU proposals have suggested that feed-in-tariffs should not be paid to generators when electricity prices are negative. As in figure 9 below, CPI modeled the trajectory of annual hours of negative prices in Germany assuming that renewable energy build-out met government targets and system flexibility – outside of renewable energy curtailment – did not increase. By 2025, the annual number of negative price hours would increase more than tenfold and continue rising steeply from there. We have specified both a P50 level,

which reflects the level of annual negative prices we would expect to be exceeded 50% of the time, and a P90 that would be exceeded 90% of the time. While the P50 level is important in that it sets base expectations for developers and equity investors, the P90 level is arguably more important in that this is the forecast that debt investors, who are more worried about downside risk and default protection, are likely to look at. As P90 curtailment levels rise, the amount that investors are willing to lend to projects decrease, since they need more protection against potentially higher curtailment and lower revenues. As debt levels and leverage decrease, the project return, or weighted average cost of capital, required for the project increases. The graph on the right shows how the required electricity price would rise with increasing expectations for curtailment as a result of the financing response to the increasing risk of curtailment. In the words of one investor; "unspecified economic curtailment risk will make wind energy uninvestable." The report does go on to show that there are many fixes to reduce this risk, including capping annual curtailment or curtailing only enough renewable energy to make prices go positive². But the risk is clear, and it is a risk created by market design.

The key is that incentives around issues like whether or not the wind park would be an attractive investment need to be delivered when that decision is being made. Forcing investors to make decisions about how to invest in and design a project where there are open, unspecified risks like the potential curtailment due to negative prices is possible, but it will raise costs much more than the value of their improved decision making. That is not to say that wind or solar should not be curtailed, just that the level of curtailment and the compensation received should be known at the time of final investment decision, rather than set on an hourly basis to be discovered only in the fullness of time.

Market mechanisms as currently structured could continue to blunt incentives for investment and innovation and, as a result, delay the emergence of new technologies and innovative business models required to keep a low carbon electricity system low in cost.

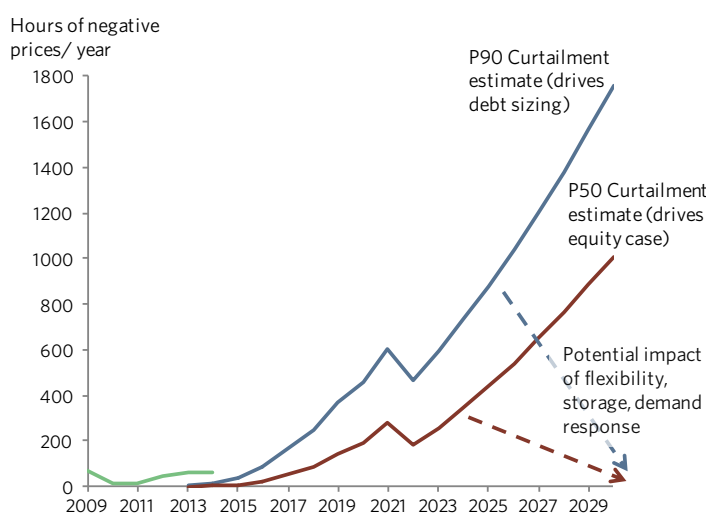
There are many designs and suggestions for electricity market design, including so-called energy only markets. In these markets, nearly all potential revenue for a generator comes from the per MWh payments made for energy generated, providing an incentive for generators to respond to the variation of prices over the day. In

Figure 9 - The impact of unspecified potential curtailment of financing costs for wind projects in Germany

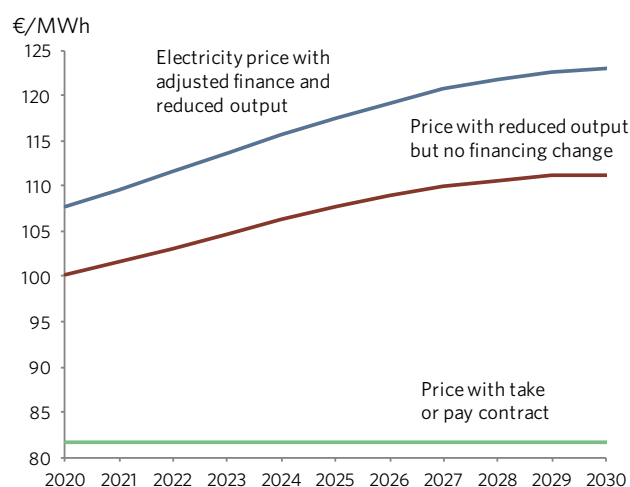
The number of hours with negative electricity prices in Germany will rise rapidly with the current market structure, unless flexibility is increased markedly

If renewable electricity producers are forced to curtail with no compensation when prices are negative, costs will rise as a result of reduced output and higher finance costs due to risk

Negative electricity prices per year in Germany
For a typical wind project as would be estimated by debt and equity investors



Impact on bid prices of reduced output and higher finance costs



Source: CPI Analysis (see Policy and Investment in German Renewable Energy (2016))

2 In the German example, in 2025 curtailment of just 15% of wind production, on average, would cause prices to go from negative to positive. Thus applying curtailment of incentives to all feed in tariffs would be overly punitive.

one unpublished analysis CPI performed for a US state system, we found that a market that was restructured to value flexibility and energy services separately, could change the dispatch of fossil fuel dramatically. In our example, we found that the load factor of some coal-fired power plants fell in the separated market from 80% to closer to 20%, but that these plants were almost as profitable despite generating $\frac{1}{4}$ of the energy, since the true value of their services lies in the flexibility and system support they could provide.

To achieve this result, we need markets that concentrate the flexibility signals on those who have the ability to respond to the signals. When all energy is priced at the marginal price, there is a tendency to cap price spikes, either explicitly or effectively, in order to prevent

shock and political fallout that could occur when consumers were exposed to very high prices. While these effective caps keep the system from distress, they also blunt the incentives from those that would build flexibility assets to reap the rewards from the high prices. That being said, no investor will invest on the basis of even an infinite price that has already passed. To encourage innovation and investment, the short term price signals need to be translated into something that justifies longer term investment. In the medium term, policymakers may need to develop contract markets that help technology develop. In the longer term, with developed storage and flexibility asset bases and a more stable flexibility market, these transition arrangements may likely be replaced by technology-neutral market mechanisms.

5 Structuring a new electricity market

We begin with the hypothesis that future electricity systems will be composed of ever greater quantities of low carbon, lower flexibility supplies such as variable renewable energy, nuclear, or fossil fuel generation with carbon capture and storage. On the other hand, batteries, transmission and distribution, hydro, consumer flexibility and the remaining fossil fuel generation will play a growing role to provide the balancing and system flexibility that will make this lower-carbon system work. These two sets of assets have very different financial characteristics and financing patterns.

We believe that the key to a future electricity market is to break these two components into two distinct markets, each with their own market setting processes that deliver sharp incentives when they provide the most impact on the efficiency of overall system design and operation. These two markets must work together, requiring development of enabling systems and policy.

One approach to meeting these goals would be splitting the market into two parts:

- An **energy market**: a market for commodity electricity production, independent of time and location, that relies on auctions for long-term energy contracts to enable long-term low cost financing of low cost, capital intensive energy resources. While generators will be able to choose which market they wish to participate in, we believe that this market will

attract mainly the low carbon, less flexible energy supply from renewable energy, nuclear, carbon capture fitted fossil fuels, and possibly combined heat and power. This market will set the notional wholesale price for electricity used in many system wide planning and investment decisions.

- A **delivery market**: a market for the delivery of energy when and where it is needed to meet demand and ensure reliability. This market would concentrate incentives for flexibility on the participants that are best suited to manage those risks. Prices in this market would vary locationally and fluctuate widely across the day. The price in the delivery market would be in addition to (or subtracting from if the delivery price goes negative) the wholesale price in the energy market. Thus, as in figure 10 below if the annual wholesale price from the energy market is \$50/MWh a gas turbine that received \$40/MWh for delivery of energy at peak, would receive a total of 90\$/MWh. Conversely, a battery that was paid \$60/MWh in the flexibility market to absorb excess energy on the system, would receive \$10/MWh net for the charging, but would then receive the delivery market price plus the \$50/MWh energy price back when the energy was sold back to the market.

Figure 10: Long-term energy prices are stable while delivery prices vary significantly



Figure 11: Characteristics of the energy and delivery markets

	ENERGY MARKET	DELIVERY MARKET
Price formation	Based on long-run, levelized costs	Based on short-run locational costs and scarcity value
Risk	Low, primarily credit and counterparty risks	High, including fuel price, availability, storage levels, etc.
Time frame	Annual rolling auctions for delivery 1-3 years ahead, with long-term contracts	Day-ahead and real-time markets, potentially some longer-term contracts for reliability and resource adequacy
Objective	Minimize financing cost for bulk of kWh	Minimize operating cost for flexible resources and encourage consumer flexibility

Making the two markets work together will require some careful design. We highlight 4 areas where special consideration will be required to get the two markets working together:

- Creating incentives for participants in the energy market to reduce flexibility needs over the long-term;
- Incentives to integrate the cost of long-term and shorter term transmission and distribution system operating and investment;
- Optimizing the use of fossil fuel plants and dispatchable hydro as they fit into long-term energy supply;
- Maintaining system security and reliability.

The combination of these markets could lead to lower financing costs for long-term, capital-intensive energy resources, as many of the key risks facing these assets would be transferred into the delivery market. At the same time, sharpened market signals for flexibility would provide clear incentives to flexible power plants, battery energy storage, and demand-side flexibility providers.

In addition, a variety of electricity system services – ancillary services such as short-term reserves and frequency control – would continue to be needed and could rely on market mechanisms similar to those we have today.

This market design concept is meant to be a starting point for discussion. By proposing a drastically different market model, we hope to highlight the major challenges facing today's electricity markets and ignite a debate on the right solutions. The remainder of this section describes this market concept in more detail.

5.1 The long-term energy market

In this new market model, energy would be procured through auctions for long-term contracts for

“commodity” kWhs of electricity, priced independently of location and timing of production. This market design accomplishes two critical goals.

First, by awarding energy resources long-term contracts, this market enables low cost financing. Locking in energy prices for 20 years can lower the cost of wind and solar energy by over 10% by enabling more low-cost debt and less high-cost equity. Long-term contracts can also serve as the basis for new financial instruments for institutional investors which can lower energy costs by 15-20%.³

Second, relying on an auction mechanism to set prices for these long-term contracts incentivizes cost reductions and efficient project delivery. As technology costs for wind and solar continue to drop, an auction mechanism can create the competitive pressure needed for those cost reductions to translate into lower long-term energy prices.

5.1.1 Description of long-term energy market

The long-term energy market could be constructed as follows:

- Each year, the system operator or electricity retailers would construct a long-term forecast of energy needs to determine how much contracted energy the market would need to procure.
- Based on this long-term forecast, a certain portion of that energy need would be auctioned, where the lowest-cost bidder(s) would receive long-term contracts to supply electricity at a fixed price, with delivery starting in 1-3 years (to allow time for construction of new plants).
- As old contracts expire and demand estimates change each year, the amount of energy

3 CPI 2011 paper and CEIT analysis.

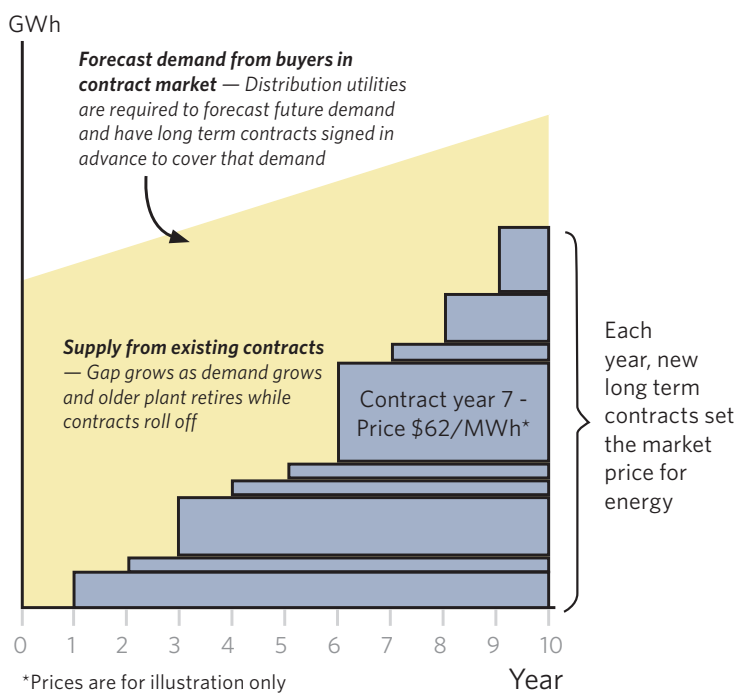
procured through these long-term energy auctions could be adjusted.

- While long-term contracted energy resources would be paid the clearing price for their auction (or in some cases may be paid as they

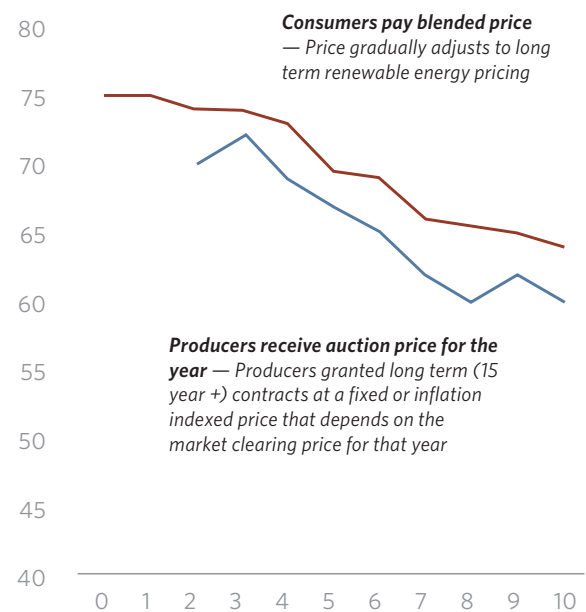
bid), consumers and non-contracted energy suppliers (eg, those that provide energy while participating in the delivery market) would receive a blended price, reflecting the weighted average price across all contracted energy in a given year.

Figure 12: Illustration of stacking long-term contracts of different vintages to meet demand

Annual auctions to meet forecast demand



Consumers and producers receive energy prices based on that auction



Drawing on experience with long-term energy auctions in Brazil

Auction mechanisms have been used for decades to procure electricity. Auctions are common in renewable energy procurement as a tool for price discovery for long-term renewable energy contracts (for example, California's Renewable Auction Mechanism). In addition, most renewable energy tenders and requests for offers for bilateral contracts strongly resemble auctions.

However, Brazil's electricity market structure puts auctions for long-term energy contracts at the center of their electricity market.⁴

In 2004, Brazil introduced market reform changes that required that all electricity demand must prove to be 100 percent covered by an energy contract on an annual basis. In other words, each year, a distribution company or direct electricity buyer would need to show that their total MWh of consumption for the past 12 months was fully covered by contracted MWh over the same time period, and any shortfall was subject to a penalty.

To ensure that long-term energy procurement is efficient, regulated distribution companies in Brazil fulfill their energy contracting obligations through a series of long-term contracting mechanisms (whereas direct electricity buyers are free to meet their contracting obligations however they see fit). Each year, a certain amount of new and existing generation is procured through long-term contracts (typically 15-30 years with a 3-5 year lead time), while existing plants that are not currently contracted can bid to supply shorter-term contracts with immediate to short lead times.

Brazil's long-term energy auction system has yielded low costs and facilitated investment in new hydro generation in the country. However, the system is not without its challenges, particularly exclusion of technologies other than hydro from auctions, potential gaming of hydroelectric production estimates, and crowding out of private generation investments by low-cost, publicly funded projects.

4 As described by the World Bank (2011), "Energy Auctions: An Overview of Efficient Practices" and Moreno et al. (2010), "Auction approaches of long-term contracts to ensure generation investment in electricity markets: Lessons from the Brazilian and Chilean experiences."

5.2 The delivery market

Once commodity kWhs have been contracted for in the long-term energy market, the electricity system needs to ensure that electricity can be delivered at the time and location where it is needed, instantaneously. The delivery market would be designed to meet the difference between expected generation from the long-term energy market and real-time electricity demand at each location in the grid by providing robust market signals for flexibility. The delivery market takes many of the design features of the more sophisticated electricity markets currently in operation and redefines the scope to focus on incentivizing flexibility.

This market would have several key characteristics. It would provide short-term price signals, based on day-ahead or near real-time markets. It would also provide locational price signals, differentiating the value of delivery services between locations on the grid. This delivery market would have several layers.

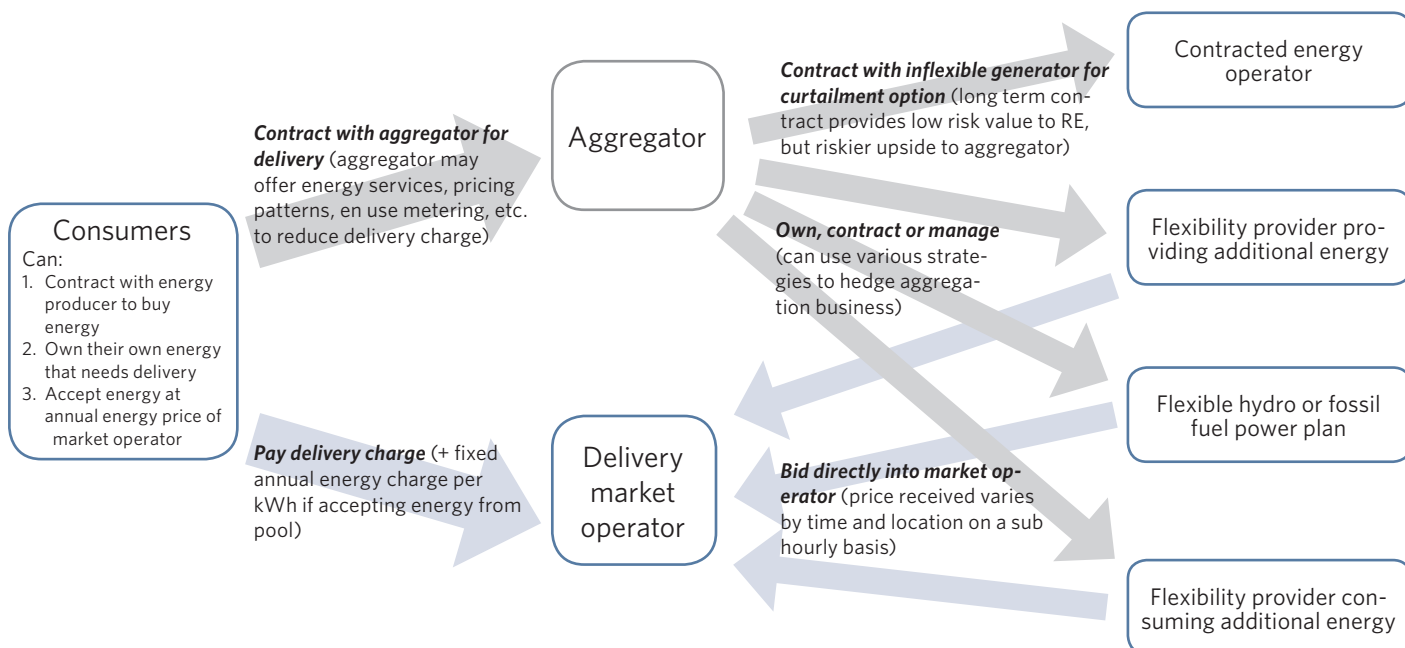
First, flexibility resources – those that can generate, hold back generation, consume, or store and shift electricity – would be able to bid directly into a delivery market. Ideally, this delivery market would be open to a wide range of technologies, and would aim to minimize

the cost of serving demand at a particular place and point in time.

Second, those same flexibility resources could be owned and/or operated by businesses that manage a portfolio of assets, much in the way an independent power producer or power trader might today. By managing a diversified portfolio of flexibility resources, each of which can provide a range of flexibility services, these businesses would have the incentive to effectively manage flexibility risks and compete to keep costs low.

And finally, consumers could play several roles in the delivery market. They could contract with an aggregator who manages delivery costs on their behalf (like today’s competitive energy retailers), or purchase delivery services directly from the market at market clearing prices (and potentially use automated demand-side flexibility technologies to manage their own exposure to delivery market risks).

Figure 13: Delivery market pays to deliver energy purchased to a specific time and place



5.2.1 Concentrating flexibility risks in a flexible market

In today’s power markets, most market participants are either directly or indirectly exposed to volatile electricity prices. For flexible generators that can respond quickly to changing grid conditions, these prices are effective signals for driving flexible operations. But for some resources – namely capital-intensive renewables that produce power only when the underlying resource is available, or capital-intensive baseload resources like nuclear with limited flexibility – these volatile prices introduce risk that the resources have little ability to manage.

By partitioning the market into energy and delivery markets, the volatile price signals for flexibility would be concentrated in the delivery market, where more flexible resources would have stronger signals to respond. Meanwhile, those resources that opt for price stability through the long-term energy market can reduce their exposure to risks they cannot manage, driving down cash flow risks and financing costs for those resources.

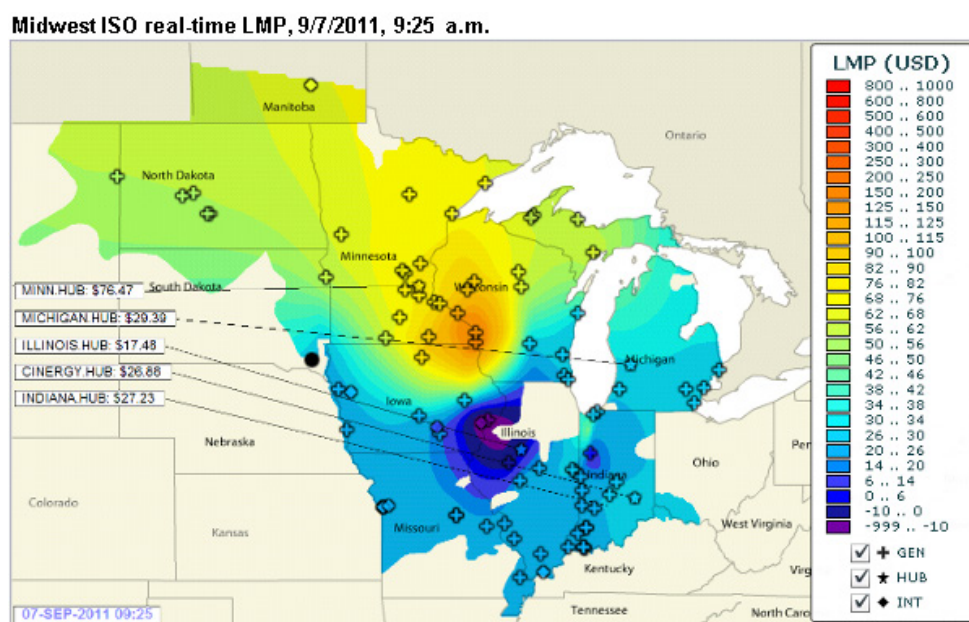
In addition, this new market model would separate the value of commodity kWhs from delivery and flexibility services. In doing so it would allow consumers (and aggregators acting on consumers’ behalf) to see a clear market signal for the value of firm delivery of electricity to a particular point in space and time. Electricity consumers could then develop more sophisticated strategies for contracting their energy – for instance,

they may be willing to pay for complete reliability for a portion of their electricity needs, while accepting lower reliability (say, by allowing an aggregator to curtail their demand for electricity consumption from some appliances) at a lower delivery price for the rest. By specifically revealing the value of electricity delivery, market participants can develop strategies to respond efficiently.

5.2.2 The role of locational marginal pricing

To achieve both time and locational granularity, a number of electricity markets today use locational marginal pricing for time- and location-specific price signals. In a market that uses locational marginal pricing, the market operator receives bids from generators in the form of a marginal cost curve (and often, operating constraints like startup times and ramp rates). The market operator then applies the characteristics of the transmission system and solves a large-scale market model for the least-cost system dispatch. This model also generates prices for every node on the grid, which represent the marginal cost of serving a kWh of energy at a particular location and time – even if no generators exist at that particular node to provide market liquidity. These prices incorporate transmission constraints, transmission losses, and the optimal flow of power across the transmission network. Prices are determined by the market operator’s model, and the market operator then sends dispatch signals to those generators that cleared the market to run.⁵

Figure 14: Example of locational marginal pricing in Midwest Independent System Operator



5 See Chao and Wilson, “Design of Wholesale Electricity Markets.”

Much like the PJM market or other locational marginal price based markets, the delivery market could use the concept of locational marginal pricing for delivery services. The key difference would be that rather than bidding to supply energy to meet demand at a given point in time and space, the delivery market would clear the difference between demand and production from contracted generators in the energy market, which in some cases could be negative. This, of course, would send strong signals for energy storage, demand shifting, and strategies that combine turning down contracted wind or solar with generating power from another resource at a different time.

In addition, a locational marginal price-based delivery market would preserve the efficient use of transmission that today’s market models have realized, while sending clear locational price signals that could serve as the basis of transmission investment (or non-wires alternatives to transmission investment).

5.3 Ancillary services

Finally, today’s electricity markets include a variety of “ancillary services” – which make up a small portion

of total electricity system costs, but provide essential services to support the reliability and efficiency of the power system. Today, many of these services are provided by a combination of competitive markets and regulated or administratively determined procurement mechanisms. As the grid evolves, mostly incremental changes to these markets and mechanisms will be needed, building on the models in place today. Certain services – for instance, the inertia and instantaneous frequency response that large spinning generators provide to a power system – are unpriced characteristics of the power system that may require compensation in a future grid with fewer spinning generators and more power electronics. A market may reveal new low-cost ways to provide system inertia that don’t depend on running large generators. In addition, there is significant scope to expand the supply (and lower the cost) of some ancillary services – frequency control and short-term reserves – using energy storage, demand-side flexibility and distributed energy resources of many types. The potential evolution of ancillary services markets is summarized in the table below.

Figure 15 – Ancillary service markets: slight adaptation needed

	Description	Current market design	New market design
Inertial response	Inertia of spinning generators physically slows down drops in frequency during loss of power	Currently uncompensated	May need to be compensated at times when few high-inertia generators are online
Spinning and load-following	Rapid corrections in output to correct mismatches between supply and demand	Generators withhold some power output and bid into reserve market to be “on-call” or follow automatic generation signal	No significant change needed, but should be open to demand side and battery technologies, and pay more for faster and more accurate response
Short-term reserve	Capacity available within ~10 minutes for longer duration events and mismatches	Generators withhold some power output and bid into reserve market to be “on-call”	No significant change needed, but should be open to demand-side and battery technologies, and pay more for faster and more accurate response
Reactive power and voltage	Reactive power for inductive loads (e.g. large motors) and to support grid voltage	Payment for lost real power output when more reactive power needs to be generated	No significant change needed, but should be available to inverter-based renewables and batteries that can also supply VARs.
Black start	Startup sequence to repower grid after a blackout	Generators typically paid an administratively-set annual price to be available for black start services	No significant change needed, but black start sequence may become more complex with greater distributed energy
Ramping	Ability to rapidly adjust output to meet predictable but large-scale changes in power needs	Not currently differentiated from capacity payments in most markets (CA exception)	Mechanism to pay generators to be available to meet ramping needs, or reflect in structure of delivery market pricing

Challenges and interfaces between the markets

There are several key challenges and interactions between the long-term energy market and delivery market.

5.3.1 Creating incentives for participants in the energy market to reduce flexibility needs over the long-term

While variable renewable energy or nuclear may not be the most attractive options for many types of electricity system flexibility, how much of each is built, where it is built and how it is maintained can have significant impacts on how much flexibility is needed from other sources. One example would be seasonal flexibility, that is, the need to shift energy that might be produced in the summer to satisfy electricity demand in the winter. Another could be reducing the amount of daily shifting that would be needed to meet evening lighting demands if all of a system's electricity was generated by solar power.

In the case of seasonal shifting, it turns out that there will be an optimal mix of low carbon resources that will minimize total shifting requirements. For example, in Germany there tends to be more wind in the late fall and winter and more solar generation in the spring and summer. A mix of the two sources would, therefore, reduce the amount of seasonal shifting required by the system. But if a market is purely based on price, the likely result would be winning bids made up of all, or nearly all, one technology.

The optimum mix in any year will depend on the forecast of future flexibility needs and their cost of serving through the delivery market, balanced against the relative cost and impact on flexibility needs of the various competitive technologies in the energy market. As demand, costs and existing assets change, this mix is likely to change each year.

One solution would be to run separate auctions for different technologies, based on long-term assessments of the least-cost mix of resources. A more attractive option could be to run the market with price adjustments to reflect the cost or benefit of each technology or project on the expected future flexibility costs. Although such a system might still lead to a greater uptake of one technology versus another, in subsequent auctions the effect would gradually balance out. In the long-term, once the flexibility market is developed, we

can imagine a market where bidders bid against load profiles and secure the required flexibility balancing services to produce this profile through long-term contracts with flexibility asset owners.

Additionally, for daily balancing we can imagine options where bidders bid on a maximum number of curtailment hours in a year where they would not be paid, or, where all contracts are take or pay, with small incentives given to operators to disconnect generators at periods of excess energy production (while they continue to be paid for the energy they would have generated to avoid creating this risk to investors). Each market will need to explore which option would be most cost effective given their particular circumstances.

The key to these adjustments is that they would be made and applied at the time of bidding in the auction, so that investors would know the adjustment before financing and could make financing decisions based on known variables.

5.3.2 Incentives to integrate the cost of long-term and shorter term transmission and distribution system operations and investment

Generation in the energy market will also have an impact on transmission, distribution and locational flexibility costs. We imagine potential price adjustments as well as the potential to contract with local flexibility suppliers, or transmission and distribution operators, to adjust to a more attractive (to the system) load and location profile. When combined with locational marginal pricing and long-term forward transmission capacity contracts, this approach should offer incentives to balance generation with long-term transmission build.

The growing impact of generation at the distribution level is more challenging. The need to balance the local distribution grid while helping address bulk, or transmission level flexibility costs and needs already poses a problem for system operators and will continue to do so. While each of the options, planning, price adjustments, and contracting for balancing flexibility – for instance with combined PV storage projects – could be part of the tool kit, the cost and administrative burden of setting distribution level locational pricing may reduce the feasibility of some options, while there is room for distribution system operators to work with their consumers and producers to minimize system costs.

5.3.3 Optimizing the use of fossil fuel plants and dispatchable hydro as they fit into long-term energy supply

In the long-term, a region may expect to retain some fossil fuel based generation or take advantage of local hydroelectric resources. It is worth considering how the role of these resources would change in the proposed market model discussed here.

We imagine that fossil fuel and hydroelectric generators could participate in the annual, energy market, if they choose. By doing so they would lock themselves into providing 15-20 years⁶ of a defined quantity of energy at a fixed or inflation indexed price. They could choose to do so for all, or part, of their expected generation. They would then also be able to receive the delivery price for when and where they deliver the electricity.

The alternative would be for these generators to not enter the energy market, but participate only in the delivery market. A generator that offers flexibility, for instance peaking supply, while not being in the energy market, receives the current (blended) energy market price plus the flexibility price. The advantage of entering the energy market would be to set a guaranteed price over a long-term period for a quantity of production. The disadvantage is being locked into a price. For fuel based generators, particularly those without long-term fixed price fuel contracts, locking in a price will create fuel price risks, carbon price risks, and availability and lifespan risks, so we assume that few fuel based generators will enter this auction. If prices fell, these generators would likely need to contract for supply from lower cost sellers to minimize their losses.

Hydroelectric generators, on the other hand, may choose to enter some of their generation into the energy market in order to provide some certainty around future revenues.

5.3.4 Maintaining system security and reliability

Some flexibility options, such as natural gas generation or existing, depreciated power plants, are capital light, and volatile prices based on short-term marginal costs may be sufficient to incentivize investment or keep a resource open and on the market.

However, more capital-intensive flexibility options may need assistance in mitigating this volatility risk. For instance, while batteries, pumped hydro systems, and new hydroelectricity may be flexible enough to capture value from fluctuating prices, this strategy could still be too risky to ensure investment. And if the delivery market is not able to incent investment in enough capacity and flexibility, the reliability of the power system could be compromised. A delivery market operator would likely need to consider whether long-term contracts for flexibility or resource adequacy services would be required in some cases to ensure reliable operation of the delivery markets. These measures could mimic today's capacity market constructs, or build on novel concepts like California ISO's flexible ramping service.

6 Although, as in Brazil, we imagine a set of shorter term auctions, say 3-8 years, for plants that are already built and are rolling off of their initial contracts. These contracts are competitive around life extension and repowering costs and could provide a very good option for fuel generators with shorter term lock in requirements.

6 Bringing the pieces together

A low carbon electricity system will look very different than today's grid. Costs will be determined less by how well we manage fuel costs, and more by the cost of financing low carbon electricity and managing the flexibility needs of more variable energy sources. As the share of low or zero variable cost resources increases, the current market constructs used in electricity markets around the world will face significant challenges. New market fundamentals clearly require new thinking about how we structure our electricity markets.

The two-part market concept outlined in this paper changes what we think of as the market price of electricity. Rather than market prices being based on short-run variable costs, this concept would base the price of electricity on the long-run price needed to build, finance and operate power generation over the long-term, creating a stable price signal that enables low-cost financing of new energy resources. Bifurcating the market also sharpens the market signals for flexibility, and

concentrates flexibility risks on those resources that are well suited to respond. This can support investment and development in a broad range of flexibility technologies, promoting competition and reducing system costs, and utilizing the transmission and distribution systems more efficiently. This model builds on the success of current market models, but aims to address the mis-allocation of risk in today's markets that can distort signals for investment in low carbon power generation.

This concept is only a starting point. We believe it highlights the biggest challenges facing cost-effective decarbonization of the power sector, but further development is needed before this concept can be robustly applied to specific markets. We believe that new electricity market models can be a critical tool in enabling a cost-effective transition to a low carbon electricity system, spurring innovation in technology and market models that will lead to further improvement in costs, quality and the environmental performance of the future electricity system.

