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Price Signals and Greenhouse Gas Reduction in the Electricity Sector

Prepared for

COMPETE
Electricity Competition **IS** the Public Interest

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Foreword

As former Secretary of Energy and Transportation under President Clinton, I supported energy efficiency initiatives and alternative energy production for our nation. I also believed that consumers would benefit from competition in our electricity markets.

Today, 10 years after I left federal service, there are two very important public policy debates under way in Washington. The Obama administration and Congress seek to limit greenhouse gas emissions contributing to the threat of climate change. Meanwhile, there is a public debate on whether the recent competitive reforms in the electricity sector have been successful. While these two debates are seemingly occurring in isolation of one another, they are critically interrelated. Electricity production accounts for 40 percent of U.S. emissions, and how we align competitive forces in electricity markets with a market-based system of limiting greenhouse gas emissions is essential to encouraging clean energy generation and the reduction of greenhouse gas emissions.

This study, "Price Signals and Greenhouse Gas Reductions in the Electricity Sector", demonstrates that competitive electricity markets are essential to any market-based program for reducing greenhouse gas emissions. As was noted in a recent joint statement between the Environmental Defense Fund and the COMPETE Coalition: "Markets have proven to be the most cost efficient and effective means to deliver goods and services to consumers and will bring the same benefits to help achieve the policy goals of federal climate legislation. Market forces will ensure that investments are made in the right places with cleaner, more efficient and innovative technologies. For that reason, we believe that well-structured competitive electricity markets offer the most benefit to consumers, our economy and the environment."

For more than a century, what we paid for electricity was the product of monopoly regulation at the state level. There was little competition and therefore choice for electricity customers. But during the latter years of the last century, after regulatory decisions in the 1970s and 1980s saddled consumers with billions of dollars in unnecessary costs, regulators started to embrace competition as a more efficient and consumer-friendly means of setting prices than the old-style monopoly regulation.

Today, federal law and policy encourage competition in setting electricity prices at the wholesale level. In fact, organized competitive wholesale power markets serve two-thirds of our nation's population and Gross Domestic Product (GDP). At the retail level, nearly half the states have enacted retail competition programs that, where allowed to work, have promoted innovation and provided consumers with important options in managing their energy use and purchasing renewable energy. These competitive markets have driven cleaner generation, allowed greater market entry for renewable energy, provided fertile ground for demand response and other innovative products and services, and have offered a superior platform for any national policy to limit greenhouse gas emissions.

Yet, critics of competition would have us ignore a century of questionable monopoly regulation as we progress into the 21st Century with its demands for cleaner, low-carbon electricity. These critics would leave consumers captive to monopoly providers and have them assume the estimated $2 trillion risk for future investment in electricity infrastructure necessary to meet rising demand and to replace aging power plants and transmission lines. Now is clearly the wrong time to turn our backs on the still-unrealized promise of competition, particularly as the Obama administration and Congress have made $4 billion available for "smart grid" technology and smart meters that will empower consumers to manage and control their electricity usage.

As the economist Paul Joskow observed, under any regime of controlling greenhouse gases"… it is important that market or regulatory mechanisms work effectively to convey to consumers price signals that include the price placed on carbon dioxide emissions."

These clear"price signals", determined by well-functioning competitive markets for electric generation and emissions reductions, will drive changes in consumer behavior and investment in low-carbon resources required for our nation to effectively and efficiently respond to the climate change threat.

If consumers are going to be encouraged to reduce electricity use and buy electricity from new clean energy suppliers, they will need to be guided by clear price signals. And these price signals will only come in well-functioning, competitive markets that will reduce emissions by providing added value for low-carbon electricity. In addition, these organized electricity markets can optimize and increase the value of renewable energy and its access to the grid.

In the long run, consumers and the environment will be better off if investment and demand decisions are driven by the discipline of market forces rather than regulators. Under monopoly regulation, consumers will ultimately bear the cost of carbon emissions. Monopoly regulation will not be as effective in producing the changes in electricity production and consumption that a market-based program of pricing carbon emissions can effectuate.

This paper effectively brings together the two policy debates and firmly demonstrates why policymakers should not abandon the competitive market model for electricity just as we are on the cusp of important technological and environmental change. I believe the thorough analysis and assessment herein is required reading for policymakers.

By Federico Peña, Co-Chairman of the COMPETE Coalition and former U.S. Secretary of Energy from 1997-1998

Executive Summary

Competitive electricity markets will play a vital role in the success of any market-based program for controlling heat-trapping emissions that contribute to climate change. Restructured competitive electricity markets help promote the technological innovation and changes in consumer behavior required for a greenhouse gas (GHG) reduction program to be successful.

Competitive wholesale and retail electricity markets were implemented to provide the financial incentives that encourage efficient electricity production and consumption patterns. Similarly, state and federal policymakers are embracing "cap-and-trade" policies (a.k.a the carbon market[1]) that rely on the same market forces and financial incentives to reduce GHG emissions – primarily carbon dioxide (CO_2). President Barack Obama recently stated that he is interested in a cap-and-trade approach precisely because he thinks the market makes decisions about these technologies better than the public sector.[2] Policy supporters argue that a market-based approach to reducing GHG emissions will be the most cost-effective and result in more innovative approaches to emission reductions than other regulatory approaches. With non-utility competitive suppliers owning approximately 40 percent of today's installed electric generating capacity, it is therefore important to understand the complementary interaction between competitive electricity markets and market-based GHG policies.

A cap-and-trade system producing the most cost-effective reductions in GHG emissions by the electricity sector is based on the premise that market players will change behavior and operations in response to two different, but related, price signals – one for carbon emissions and the other for electricity. Pricing carbon emissions will cause higher electric generation costs which increase the costs of electricity and reward efficiencies in electricity production. Producers will exhibit a preference for lower-cost (lower carbon) generation technology options, while higher electric commodity costs will drive efficiencies in consumption and promote conservation.

Competitive electricity markets reinforce market-based approaches to pricing carbon emissions, and provide the basis for a direct relationship between carbon prices and electricity prices. Having both the electric generation and carbon markets operate on an unencumbered supply-and-demand basis will produce those price signals that are critical to the success of proposed polices to reduce GHG emissions.

Electricity market restructuring has already led to the types of behavioral changes expected from competitive forces. Our analysis of Regional Transmission Organization (RTO) and Independent System Operator (ISO) wholesale markets, where participants are provided with transparent pricing signals, demonstrates how owners of existing power plants have responded to competitive forces. These forces have lead to improvements in thermal efficiency for coal generating units and to increased availability for nuclear units. These improvements were driven in large part by financial incentives for plant operators to improve plant performance and availability. Generators in restructured wholesale markets are financially rewarded for maximizing their output and minimizing their down time – lower heat rates for coal, increased capacity factors for nuclear – which translates into lower production costs and increased profitability.

Competitive market forces will also shape how a carbon market can lead to cleaner generation through the dispatch of lower-carbon generation, investment in renewable

1. For simplicity, this paper uses the terms "cap and trade" and "carbon market" synonymously and use them to refer to compliance based trading systems. Although the authors recognize that the term "carbon market" can also refer to baseline and credit trading systems (carbon offset markets) as well as other types of GHG emissions trading systems both domestically and internationally.
2. President Barack Obama in a March 12, 2009 speech to senior corporate executives sponsored by the Business Roundtable.

energy and other low-carbon generating capacity, increased consumer demand response, and more efficient use of electricity. In competitive markets, investors and developers make investment decisions on new generating capacity in order to maximize returns. They bear the risk of their decisions. For carbon price signals to work effectively, investment decision processes need to align risk and reward. This is a function of the interaction of carbon prices and electricity prices. Investors will support low-carbon generation more readily if they can accurately assess the impact that carbon costs will have on wholesale power prices. Analyzing a project's potential risk and return is made easier, and can be done more accurately, when market prices are transparent and reflect true costs.

The more easily investors can assemble accurate market data, the better they can assess the risk-return tradeoff for investments in low carbon generation such as renewable energy. Well-functioning, representative, and liquid electricity markets allow potential renewable energy developers to observe information as to whether prices are likely to produce the cash flows needed to support required investment returns. Additionally, coordinated dispatch in a regional control area can optimize the output of large variable resources such as wind farms. In theory, coordinated dispatch can optimize the output of large wind farms because grid operators call on the lowest-cost producers available and shift generation away from more expensive units. This can lead to increased value for wind energy operators.

At the retail level, carbon price signals will change consumer electricity consumption patterns, leading to GHG reductions. This is particularly well illustrated by the Demand Response programs being implemented by RTO/ISOs. These programs are based on the economic principle that markets perform well if supply and demand are both active participants in the market. Demand Response programs provide the means for end-use consumers to efficiently evaluate conservation and peak-load reduction options while considering the full costs (including CO2 emission costs) of available alternatives – as embodied in wholesale market prices. Active participation from both sides of the market ensures that prices reflect the value of consumption and the marginal cost of supply. Restructured markets accomplish this by providing clear and transparent price signals that serve as a value benchmark not only for investors, but also for consumers to use in deciding when and how they consume electricity. Also, RTO/ISO markets provide the scope that enables customers and demand-response aggregators to benefit directly from the broad regional value associated with improved efficiency and reductions in peak demand.

Competitive electricity markets will play a vital role in the successful implementation of regional and/or national CO_2 emission trading programs. Regional, federal and state policymakers who are designing GHG policies for the electricity sector should consider the interdependent nature of carbon markets and RTO/ISO electricity markets—and importantly, how prices in these two markets are related.

"Keep in mind that the reason I'm interested in a cap-and-trade approach is precisely because I think the market makes decisions about these technologies better than we do."
President Barack Obama in a March 12, 2009 speech to senior corporate executives sponsored by the Business Roundtable

Introduction

Political pressure to deliver comprehensive national greenhouse gas (GHG) reductions is intensifying under the Obama Administration. These reductions will result from legislation and/or accelerated action by the Environmental Protection Agency (EPA). While 2008 saw considerable debate on the structure and stringency of national GHG legislation, either Congress or the EPA (through the authority granted to it by the 2007 Supreme Court ruling in *Massachusetts v. EPA*[3]) will likely enact comprehensive GHG regulation in 2009 or 2010. The likely legislative outcome will be a market-based approach, with the cornerstone being a cap-and-trade system for CO_2 emissions.

President Obama proposes to reduce GHG emissions to roughly 14 percent below 2005 levels by 2020, and to approximately 83 percent below 2005 levels by 2050. The Waxman-Markey American Clean Energy and Security Act of 2009 proposes a similar 'decarbonization' of the U.S. economy by 2050. Together, these proposals provide a clear indication of likely future emission-reduction targets. Both proposals advocate a cap-and-trade structure as the principal policy mechanism – as do most other proposed GHG reduction measures with similar targets for emission reductions.

Regulatory action is not limited to the federal government. As of April, 2009 almost half of U.S. states are in the process of creating and implementing GHG regulations that feature cap-and-trade mechanisms. For example, the final scoping plan for California's Global Warming Solution Act (AB32), published in October 2008, includes a cap-and-trade system as the central mechanism to achieve the state's GHG reduction goals. The Western Climate Initiative (WCI), an organization comprised of seven states (including California) and three Canadian provinces, is designing a regional carbon market scheduled to begin operations in 2012. Northeastern states have commenced a cap-and-trade program under the Regional Greenhouse Gas Initiative (RGGI). Midwestern states, through the Midwestern Greenhouse Gas Reduction Accord (MGGA), are designing a carbon trading system that will likely come online in the next few years, as is the state of Florida.

How such limits will be administered is in large part a function of the current structure of the power generation market. At one time the electricity industry was a network of vertically integrated operations managing all aspects of energy production and delivery, from generation to transmission to distribution. However, the structure of the electric industry has changed dramatically in the last ten to fifteen years. The Federal Energy Regulatory Commission (FERC) has issued a number of orders designed to open wholesale generation markets to competition, and has promoted institutional structures to facilitate such competition.[4] In addition, nearly half of all states have restructured electricity markets at the *retail* level in order to promote competition.

While the restructuring is still evolving, it has resulted in competitive suppliers owning approximately 40 percent of today's installed generating capacity.[5] More dramatically, competitive suppliers have built approximately 80 percent of the new

3. *Massachusetts v. Environmental Protection Agency, 549 U.S. 497(2007)*
4. For example, Order No. 888 prevented transmission owners from discriminating against wholesale sellers of electricity. Order No. 889 set standards of conduct related to a utilities communications between the transmission and wholesale power functions. Order 2000 encouraged the formation of ISOs and RTOs.
5. NCI analysis of VENTYX generating unit data. Capacity owned by unregulated entities in the VENTYX data base have been referred to as "competitive suppliers." Unregulated entities are defined as entities that do not have a designated franchised service area and that do not file forms listed in the Code of Federal Regulations, Title 18, part 141 are considered unregulated entities. This includes qualifying CHP, qualifying small power producers, and other generators that are not subject to rate regulation such as independent power producers. This ownership designation is reported is several government reports including the EIA 860, the NERC ES&D and the EIA 906/923.

electric generation capacity that has come into service since the mid-1990's.[6] Hence, competitive electricity markets will play a vital role in the successful implementation of regional and/or national CO_2 emission programs. Therefore, it is important to understand the interaction and synergies between competitive electricity markets and market-based GHG policies. In a competitive environment, market-based environmental policies allow emission reductions to be realized at the lowest possible overall cost to society. Markets provide incentives that encourage reductions by the producers and consumers that can achieve the desired reductions most efficiently. The emission reductions and economic efficiencies achieved by the nation's "Acid Rain" cap-and-trade program are well documented.[7]

Under the proposed cap-and-trade program, incentives to change the way electricity is produced and consumed will be fundamentally tied to how carbon costs are reflected in electricity prices. The question will be whether or not carbon costs are appropriately aligned and transparent enough to induce electricity producers and consumers to alter their short- and long-term production and consumption decisions. Below are two characterizations – one for electricity production, one for consumption – of a successful regulatory regime for reducing carbon emissions in today's competitive power market.

» **Electricity Production:** In competitive wholesale markets, power producers will be financially rewarded for lower CO_2 emissions stemming from more efficient production or the use of lower carbon fuels. In the long term, new power plants will be built based on the level of investor confidence that the appropriate return on investment will be achieved, given the level of risk associated with building and operating a respective power plant. Investment will flow more towards renewable and low-carbon generation options as carbon costs reduce the financial attractiveness of higher carbon options.

» **Electricity Consumption:** When wholesale and retail prices of electricity accurately reflect the marginal costs of CO_2 emissions, they will provide the appropriate incentives to consumers. With fuels and electricity priced to reflect their CO_2 emissions, consumers will make the informed economic trade-off decisions envisioned for GHG policies to reduce carbon. For example, accurate fuel and electricity prices ensure that consumer choices among electric, natural gas and oil-fired heating systems appropriately reflect the significant differences in CO_2 emissions associated with each option.

Key short- and long-term responses to price signals for both electricity consumption and production are illustrated in *Figure 1.*

FIGURE 1: PRICE SIGNALS AND CO2 REDUCTIONS IN THE ELECTRICITY STECTOR

SHORT AND LONG TERM PRICE SIGNALS THAT LEAD TO CARBON REDUCTIONS		
ELECTRICITY CONSUMPTION	Consumers are more likely to reduce wasteful electricity consumption if the price they pay more accurately reflects the true cost of produciton.	Consumers react to higher carbon prices over the long term by altering purchasing decisions on household energy consumption, for example energy efficient appliances or electric powered cars.
ELECTRICITY PRODUCTION	Wholesale power producers that are financially rewarded for more efficient production or utilizing lower carbon fuels are more likely to pursue lower carbon production strategies.	Investors are more likely to integrate carbon abatement costs in investment decisions regarding new power plants if there are accurate and transparent price signals.
	SHORT TERM	LONG TERM

Source: Navigant Consulting, Inc

6. *Navigant Consulting, Inc* estimates based on VENTYX data

7. See for example, Ellerman, D. Markets for Clean Air: The U.S. Acid Rain Program. New York: Cambridge University Press, 2000.

In this paper, we illustrate the potential effectiveness of market-based incentives for CO_2 reduction by drawing on the historical responses of power plant owners/operators to price signals in competitive Regional Transmission Organization (RTO) and Independent System Operator (ISO) electricity markets. These responses are evidenced by improved thermal conversion efficiency and increased availability of conventional power plants. In addition, we discuss the interaction and potential synergies between a competitive market structure and a market-based approach to reducing CO_2 emissions by highlighting instances in which complementary price signals for electricity and CO_2 emissions can act in concert, achieving cleaner generation through the dispatch of lower-carbon sources and investment in renewable energy capacity.

Price Signals and Restructured Energy Markets

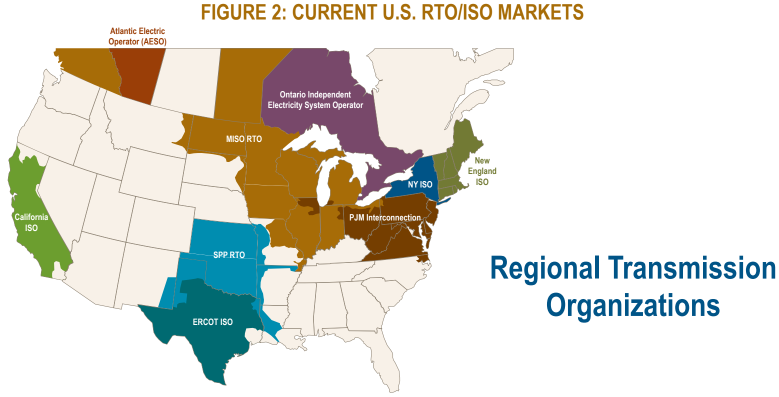
Competition aligns prices with marginal costs to provide efficient price signals to consumers and producers. On the supply side, this alignment stimulates reduction in operating and capital costs and spurs innovation in processes and products. On the demand side, it provides incentives for demand-side management and energy efficiency investments. In addition, competitive markets provide buyers and sellers with the products necessary to manage price and quantify risk.[8] By contrast, in a vertically integrated market, buyers, sellers, and regulators all have different objectives that can work at cross purposes to achieving GHG reductions.

The analysis focuses on the evolution of heat rates in coal plants and capacity utilization factors in nuclear plants in RTO/ISO markets.[9,10] Since coal and nuclear plants account for approximately 70 percent of total electricity generation in the U.S.,[11] the performance of these units is an important indicator of how electricity markets have evolved over the last ten to fifteen years. We also present data that shows increased participation in demand response programs in restructured markets as well as highlights how electricity markets can accurately inform electricity consumers about the cost of carbon.

Reaction to Price Signals in Wholesale Electricity Markets

We examined RTO/ISO wholesale markets because participants in these markets face transparent prices irrespective of state regulatory regimes. As illustrated in *Figure 2,* these markets include the Northeast (New England RTO, New York ISO), the Mid Atlantic (PJM Interconnect) California (California ISO), parts of the Midwest (MISO), and Texas (ERCOT). We excluded the Southwest Power Pool (SPP) because it does not operate a fully integrated real-time energy market. Rather, SPP only provides an "imbalance service" allowing scheduling entities to balance their generation and load with real-time purchases or sales. Only 6 percent of SPP generation is sold through this market.

FIGURE 2: CURRENT U.S. RTO/ISO MARKETS



Source: Federal Energy Regulatory Commission

8. United States of America Federal Energy Regulatory Commission; Conference on Competition in Wholesale Power Markets. Docket No. AD07-7-000; Prepared Remarks of Professor Paul L. Joskow; February 27, 2007.
9. Heat rate is a measure of the efficiency by which a fossil-fired electricity generating unit converts its fuel into electricity. It is measured in terms of the amount of fuel required to generate one kWh of electricity - the lower the heat rate, the more efficient the generating unit.
10. The net capacity factor of a power plant is the ratio of electrical output of the plant over a period of time to its output if it had operated at full nameplate capacity the entire time.
11. *Navigant Consulting, Inc.* based on Ventyx Data.

The performance in restructured competitive markets to date demonstrates how generator owners/operators respond to the economic incentives provided by that market structure. This can be shown most readily by the improvements in thermal conversion efficiency for coal generating units and by the increased annual capacity factors (availability) of nuclear units.

In restructured competitive markets, these improvements directly translate into economic benefits for both producers and consumers. Generators in restructured wholesale markets sell power under bilateral contract arrangements as well as in the spot market, and therefore are financially rewarded for achieving efficiencies – lower heat rates for coal, increased capacity factors for nuclear – which translates into lower production costs and, in the case of coal, reduced emissions.

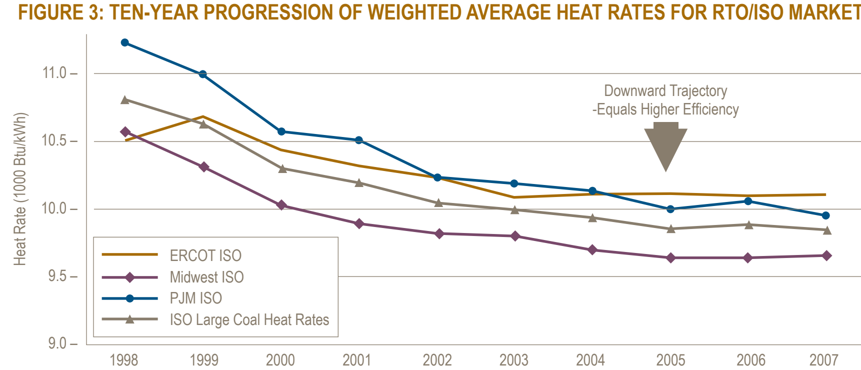
Improvements in Coal-Fired Generator Efficiency

Figure 3 presents the ten-year trend of weighted average heat rates for large coal-fired generating assets in all RTO/ISO markets. The figure also breaks out the average heat rates for the three restructured competitive markets that have the largest quantity of operating large coal-fired units.[12]

This data was developed using Ventyx's Energy Velocity Unit Generation and Emissions database (for which information is taken from the EPA's Continuous Emissions Monitoring System (CEMS) database). From that dataset, coal-fired units rated at 400 MW and larger were selected. Power stations in Canada were removed, along with those operating in regulated markets. Data was then assigned to the appropriate ISO regions, and the heat rates for each unit were weighted by their annual net generation (MWh) to calculate a weighted average heat rate for each ISO. The following diagram presents these weighted average heat rates for all ISOs.

The generating stations in each RTO/ISO were operated within traditional regulatory structures prior to 1998 when the restructuring that formed the RTO/ISOs began. All RTO/ISOs were formed by 2004. As illustrated in *Figure 3,* coal-fired units in each of the restructured markets show a decided improvement in their average heat rates in the years following restructuring. Overall, heat rates improved (declined) from approximately 10,800 Btu/kWh to approximately 9,850 Btu/kWh – a gain in efficiency of 9.4 percent over the ten-year period. These improvements were driven, in part, by competitive electricity pricing that pro-

FIGURE 3: TEN-YEAR PROGRESSION OF WEIGHTED AVERAGE HEAT RATES FOR RTO/ISO MARKETS



Source: Navigant Consulting, Inc. based on Ventyx Data

12. In total, there are 145 coal-fired generating units in the aggregate sample. The three ISO markets with the greatest number of large coal-fired generating units (i.e., >400MW per unit) are Midwest ISO (61 units), PJM ISO (57 units) and ERCOT ISO (22 units).

vided financial incentives for plant owners/operators to improve plant performance.

Improvements in Nuclear Generator Availability

Earnings in restructured competitive electricity markets are tied directly to a generating unit's total output. Therefore, there is a significant incentive for the owners of power plants to shorten maintenance and refueling outages which increases plant availability (that is, operational up-time, the percentage of time that the plant is available to operate). This is particularly true of nuclear units, since the variable costs of operating a nuclear unit are extremely low, and increased availability results directly in increased capacity utilization and higher returns.

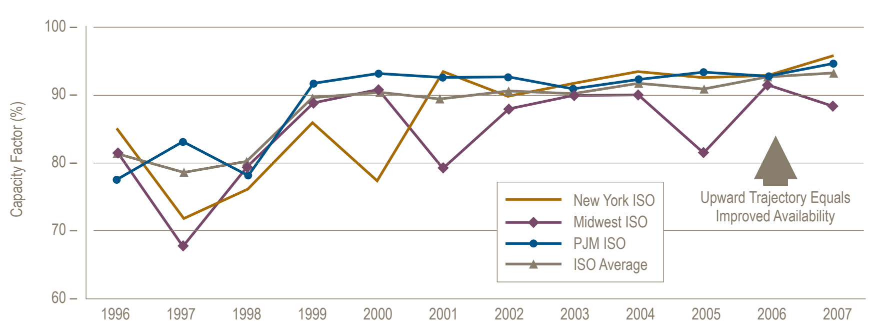
Figure 4 illustrates the average change in the capacity utilization of nuclear power plants operating in all RTO/ISOs between 1996 and 2007. It also presents the average capacity utilization within each of the three ISOs containing the largest number of nuclear power plants – PJM, MISO, and New York.[13,14]

On average, the capacity utilization of nuclear power plants in the RTO/ISO markets increased from 81 percent to 93 percent between 1996 and 2007. Capacity utilization is a direct function of two variables: the measure of how closely the plant is operated to its rated capacity when it is running, and the down time the plant experiences each year. Since nuclear plants typically operate at their maximum rating when they are available, plant down time is the main factor impacting capacity utilization. A 93 percent utilization factor represents an average of approximately three weeks of down time per year, or about 5 weeks over an 18-month refueling cycle. This level is close to the physical limit for refueling and maintenance cycles of typical nuclear plants.

This data indicates that competitive forces and price signals have led nuclear plant operators to seek out and take advantage of opportunities to maximize their output and minimize their down time.[15]

Consolidation of nuclear plant ownership under merchant fleet operators has also led to substantial performance improvement. Data on the performance of thirteen nuclear units sold by traditionally regulated utilities to merchant operators between 1999 and 2003 indicates that, for the five-year

FIGURE 4: RTO/ISO NUCLEAR POWER PLANT CAPACITY UTILIZATION



Source: Navigant Consulting, Inc. based on Nuclear Regulatory Commission, 2002 and 2008

13. These data were developed from the Nuclear Regulatory Commission (NRC) 2002 Information Digest and the NRC 2008-2009 Information Digest. The 2002 digest provides capacity utilization for 1996 through 2001. The 2008-2009 digest provides data for 2002 through 2007.

14. Our analysis removed power plants that were decommissioned during that time period, including Big Rock Point, Haddam Neck, Maine Yankee, Zion 1 and Zion 2. Also, to avoid biasing the average, any reactors that were shut down for one full year within the analysis period were removed. The following reactors had zero capacity utilization for at least one year between 1996 and 2007: Clinton Power Station, Donald C. Cook 1 & 2; Davis Besse, La Salle County 1 & 2, Millstone 2 & 3, and PSEG Salem 1 & 2.

15. EPSA Forcefully Rebuts APPA Paper on "Nuclear Power Plant Performance: What Does Restructuring Have To Do With It?" Five page report by EPSA, June 2007.

period prior to the sale, the average capacity factors for these plants was below the five-year industry average, while the average capacity factor for the five-year period after the sale was above the industry average.

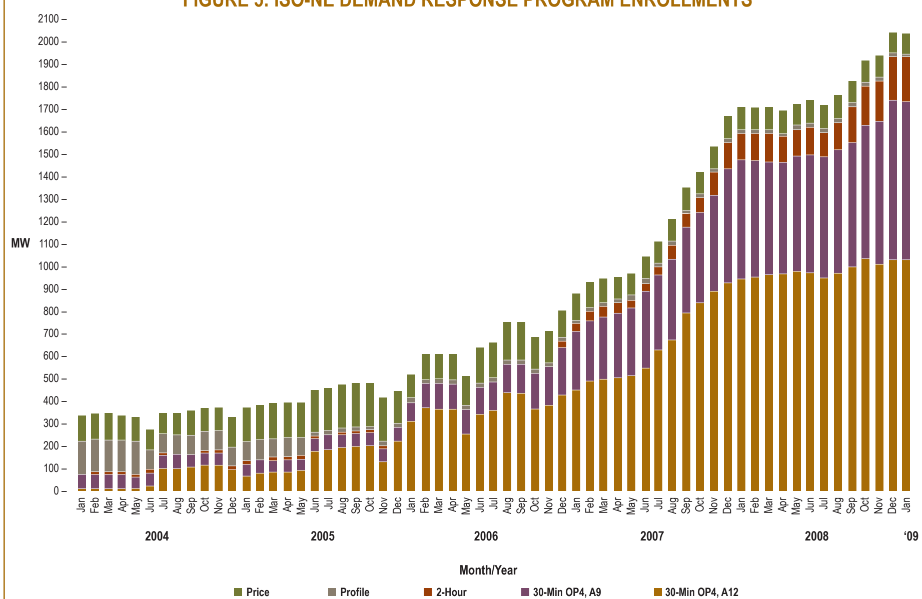
Reaction to Price Signals in Retail Electricity Markets

While the elasticity of electricity consumption is difficult to generalize, and the degree to which carbon costs are passed through to retail power prices will differ by state, the addition of carbon costs to electricity prices will likely spur interest and participation in a variety of energy efficiency and demand response programs. For example, PJM stated in a recent report that

Regardless of the higher electricity prices that could result from CO_2 prices, the increased market penetration of energy efficiency and some types of demand response can reduce total consumption and customer costs for electricity, and in turn mitigate the wholesale price impacts, and result in additional, CO_2 emission reductions.[16]

Demand Response programs within competitive markets illustrate the linkage between price signals and consumer response, and the ability of markets to provide the innovative products and services necessary for tapping energy efficiency as a resource. RTO/ISOs are moving rapidly to implement programs that enhance the ability of end-use consumers (and their agents, the demand response aggregators) to trade off investments in improved end-use efficiency against electricity purchases. By relying on individual companies engaged in the demand response business to enroll individual end-use consumers, these markets have created opportunities for innovative solutions, while providing the structured oversight necessary to ensure resource delivery. Demand Response programs provide the means for end-use consumers to efficiently evaluate conservation and peak load reduction options while considering the full costs (including CO_2 emission costs) of available alternatives.

FIGURE 5: ISO-NE DEMAND RESPONSE PROGRAM ENROLLMENTS



Source: ISO-NE

16. "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market" PJM. January, 2009.

Demand Response programs decrease peak electricity consumption. These programs are based on the economic principle that markets perform well if demand is an active participant in the market in addition to supply. Active participation helps prices reflect the true value of consumption and the marginal cost of supply. Restructured markets accomplish this by providing clear, timely, and transparent price signals that serve as a valuable benchmark for consumers deciding when and how to consume electricity. Also, restructured markets enable customers and demand-response aggregators to participate directly in the market and more fully realize the broad regional value associated with improved efficiencies and reductions in peak demand.

Developments in the ISO-NE market illustrate the significant response to the incentives created in that market. As shown in *Figure 5,* the capacity enrolled in ISO-NE Demand Response programs increased nearly fivefold between 2005 and 2008.

Even more Demand Response capacity will come on line over the next two years in response to ISO-NE's incorporation of Demand Response capacity into its Forward Capacity Market.[17] The 3,424 MW of new and existing Demand Response that qualified for the 2010/2011 auction represents twelve percent of the forecasted ISO-NE peak load for the summer of 2010. Approximately, 2,554 MW of Demand Response cleared in the auction. Hence, Demand Response resources will represent approximately nine percent of the 2010 peak load.[18]

17. The objective of the Forward Capacity Market is to purchase sufficient capacity for reliable system operation for a future year at competitive prices where all resources, both new and existing, can participate.

18. ISO New England Press Release "Wholesale Marketplace Helping to Achieve Long-term Power System Reliability Goals" February 13, 2008. Holyoke, MA.

Price Signals, Dispatch Decisions, and a Lower-Carbon Generation Mix

Restructured markets were created largely to provide price signals that encourage more efficient production and consumption of electricity. Likewise, a cap-and-trade system will harness market reactions to a price ascribed to CO_2 emissions in order to induce a change in how the U.S. produces and consumes electricity.

Carbon cap-and-trade policies are based on the assumption that the dispatch of electricity generators will reflect the marginal costs of CO_2 emissions and therefore cause a market response. In other words, carbon cap-and-trade policies are based on the premise that market-derived price signals accurately reflect the underlying cost of production.

In competitive electricity markets, prices reflect supply and demand conditions at the time electricity is generated and consumed. Thus, competitive markets facilitate the trade-off of all scarce resources, including tradable CO_2 emission allowances, on an equal footing. Competitive electricity markets operating in conjunction with market-priced carbon emissions support the relationship between electricity value and carbon prices. This is likely to lead to more accurate price signals in the marketplace, resulting in a preference of both generators and consumers to avoid higher costs, which will achieve the intent of climate change policy – to reduce CO_2 emissions.

However, evaluating the eventual impact of CO_2 reduction policies requires a detailed examination of how carbon markets interact with the electricity market structure and how this dynamic impacts investment decisions about low carbon energy resources and load management technologies. In competitive markets, investors and developers bear the risk of investment decisions concerning new generating capacity in order to maximize returns. In regulated markets, investment returns are set by regulators and the risk of investment is borne by ratepayers. Ultimately, if a cap-and-trade system is to shift electricity generation to low-carbon sources, investors will need to be adequately compensated for the risk they incur as a function of their investment decisions. Analyzing a project's potential risk and return is made easier, and can be done more accurately, when prices in the market are transparent.

The Importance of Marginal Pricing to Carbon Reductions

It is widely recognized that economic efficiency (social optimality) involves the market price of a good being equal to the marginal cost of producing that good. This is often referred to as the marginal cost pricing principle. A situation in which the market price is greater than marginal cost is less than optimal because another unit of the good could be produced at a marginal cost below what the market is willing to pay. Both producer and consumer are better off if production is increased in this situation. Alternatively, if prices are below marginal costs, welfare is increased by reducing production levels, since the marginal production cost is greater than consumer willingness to pay (market price).

In electricity markets, market-based marginal cost pricing reflects the variable generating cost of the most expensive unit needed to meet load. It provides the proper price signal for dispatch of existing resources, new entry of generation, innovation, and customer demand response, since the incremental cost is fully reflected in the price earned by suppliers and paid by wholesale purchasers. Market-based marginal cost pricing will ultimately lead to an efficient allocation of resources and resulting in optimal average prices over the long-term.

Because marginal costs represent the incremental cost of serving the final unit of demand, market-based marginal costs rates are directly impacted by changes in input costs (such as fuel, environmental costs and capital costs) and the marginal supply/demand balance of generation and load.

The incremental cost of serving the final increment of load represents the true opportunity cost that new resources can appropriately benchmark against. In other words, if market prices rise to a level where they allow new capacity to cover operating and capital costs, then that capacity will have an incentive to enter the market. If market prices remain below this level, the market will utilize cheaper existing resources.

The choice of electricity generating technology depends on the forward-looking economics of different types of generation using the various price signals generated by competitive markets. The price signal for revenues is the forward price of electricity that reflects a market consensus on future electricity supply and demand and the marginal costs of converting different fuels into electricity. The price signals for costs are the forward prices for different types of fuel (e.g. gas, coal, etc.) that reflect supply and demand conditions in those markets.

Decision makers can integrate these price signals into a consistent picture of the relative economics of different generation types and then decide accordingly. Different decision makers may have different long-term expectations and different appetites for risk, but each decision maker will monitor market prices and invest capital derived from decisions based on these differences in expectations and risks.

Carbon Prices and the Dispatch Order

In this section, we discuss how price signals for electricity and CO_2 emissions can act in concert to change the dispatch order and increase investment in new renewable energy capacity, leading to cleaner generation on the electricity grid.

The most immediate effect a price on CO_2 emissions will have in the power sector is to alter the relative cost of generating electricity with different fuels and technologies. Under a cap-and-trade program, electricity generation costs should reflect the costs of the CO_2 emissions that are produced by a generating plant. In order to appropriately reflect CO_2 emissions costs in dispatch decisions, CO_2 emissions costs (as well as the associated opportunity costs) will need to be factored into all decisions regarding optimal generator dispatch.

Regardless of the eventual structure of GHG regulations, the overall financial impact on generation owners will be determined by the manner in which carbon costs are recovered. In restructured competitive wholesale power markets, carbon costs will be recovered through the wholesale prices received by generators. Since competitive markets are designed to clear at prices set by the marginal generator, market prices reflect marginal generation costs. Suppliers with generating costs that are lower than the marginal cost of production (or the market price) earn a profit on their output. If the marginal generator's cost of production increases as a function of carbon compliance costs, then wholesale prices increase, as do the profits accruing to lower-cost generators, therefore rewarding low-carbon generation. Since market prices reflect the carbon costs of the marginal generator, those with carbon costs that are higher than those of the marginal generator will not be able to fully recover their carbon-related expenses. This will eventually lead to the retirement of carbon-intensive generating units.

The ultimate impact of market-based CO_2 regulations on the energy mix will depend on the relative cost of fuels, other variable operating costs, and the cost of carbon emissions. In its recent report on the impact proposed GHG policies can have on its markets, PJM states:

The greater the relative cost of natural gas to coal, the higher is the CO_2 price required to

THE RELATIONSHIP BETWEEN CARBON PRICES AND ELECTRICITY PRICES

Electricity prices are based on production costs. These include fixed costs, such as the cost of building the power plants and transmission lines, as well as variable costs, such as the cost of fuel, operation, and maintenance. Policies that assign a cost to CO_2 emissions will add to the variable costs of producing power from fossil fuels, therefore increasing the cost of electricity.

The price for carbon allowances will be driven by supply and demand, which in turn is a function of many factors. The supply of carbon allowances ultimately depends on political decisions such as setting the level of the cap (equal to the total allowances in the market) and allocating compliance targets among regulated sectors. Demand for carbon allowances from the electricity sector will depend on how much fossil fuel is burned and what type it is, which in turn will manifest differently at the regional level due to differences in the generation mix. Therefore, demand for carbon allowances is fundamentally tied to variables affecting the price of electricity. This is complicated by the fact that demand for carbon allowances will also stem from sectors other than electricity as well as from speculators in the market. Regardless, carbon prices and electricity prices will be inextricably linked, given that variables affecting demand and supply of these two commodities are so closely interrelated.

make the natural gas combined cycle units less expensive to dispatch than the representative coal unit, and to achieve emission reductions from re-dispatch.[19]

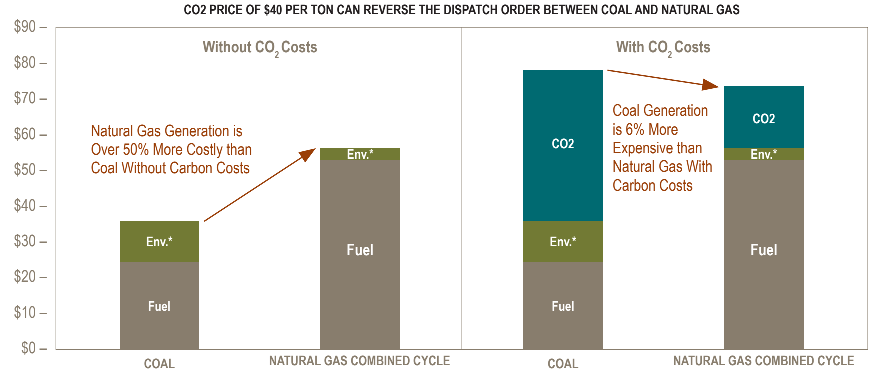
PJM's analysis points to the interrelationship between carbon costs and fuel costs, and to the importance this relationship has on the dispatch order.

Figure 6 illustrates this relationship by analyzing the relative impacts of a $40/ton cost for CO_2 on the relative costs of various types of generation.[20] As illustrated, with no CO2 costs, the dispatch costs of coal-fired generation are over $20/MWh below those of a gas-fired combined cycle plant, assuming gas price of $7.50/mmBtu and coal price of $2.50/mmBtu. But an assumed CO_2 price of $40/ton raises the dispatch costs of the coal unit substantially over the dispatch costs of the gas-fired combined cycle unit, reflecting the higher CO_2 content of coal as well as the less efficient (higher heat rate) coal generating process.

The result of this dynamic is the market-clearing price appropriately reflects the marginal cost of carbon emissions. If elec-

FIGURE 6: CARBON IMPACTS ON THE DISPATCH ORDER

CO2 PRICE OF $40 PER TON CAN REVERSE THE DISPATCH ORDER BETWEEN COAL AND NATURAL GAS



* Environmental costs include controls vor VOM, NOx, SOx and Mercury.

Note: Analysis assumes coal costs of $2.50/mmBtu and Natural Gas costs of $7.5/mmBtu. The $40/ton price for CO_2 emissions used in this analysis is indicative only, and is not based on an analysis of future CO_2 prices.

Source: Navigant Consulting, Inc. Estimates

19. "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market" PJM. January, 2009.

20. The $40/ton price for CO_2 emissions used in this analysis is indicative only, and is not based on an analysis of future CO_2 prices.

tricity prices are distorted by erroneous production costs, dispatch decisions will be based on suboptimal information. If the full marginal CO_2 cost of electricity generation is not reflected in prices, then GHG policies will not reduce emissions as effectively as desired. Traditional average-cost regulated pricing will mask price signals and potentially limit their effectiveness.

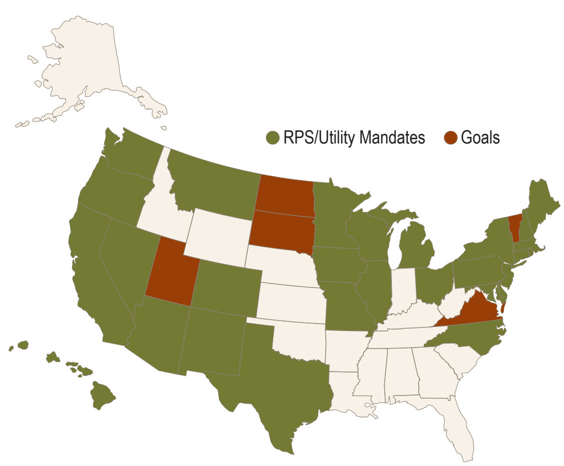
Price Signals and Investment in Renewable Energy Generation

Investment in renewable energy is driven by many factors, including resource availability, renewable portfolio standards (RPS) requirements *(see Figure 7),* and regional transmission access, capacity, and availability. The cost of installation, which is aided by federal and state tax credits, is also a principal driver. Taken together, these policies and market dynamics largely determine where, when, and how much investment in renewable energy occurs.

A price on carbon emissions will likely increase investment in renewable energy generation. As carbon compliance costs rise, there will be an increased incentive for entities with a carbon compliance obligation to use renewable resources to meet future load growth. Moreover, the increase in electricity prices caused by carbon-related costs will make renewable energy more cost-competitive. Electricity price increases driven by carbon costs can also encourage more diverse and innovative energy applications, such as renewable and distributed generation resources.

When electricity prices reflect the marginal abatement cost of the most carbon-intensive fuel, renewable energy and load management will tend to benefit. As was demonstrated in the section titled"Price Signals, Dispatch Decisions, and a Lower-Carbon Generation Mix", restructured markets dispatch generators in the order of their operating costs; the more expensive units are dispatched later and set the price at which all units in the region earn revenues. Price-taking zero-carbon resources like wind energy can benefit from this dynamic because they receive prevailing wholesale market clearing prices even though they do not have a corresponding carbon compliance costs. In other words, generators are rewarded based on performance in the marketplace.

FIGURE 7: RENEWABLE PORTFOLIO STANDARDS



1. Guam has enacted an RPS goal of 25% by 2035

Source: Navigant Consulting, Inc. December 2008, Database of State Incentives for Renewable Energy (DSIRE) and California Energy Commission

	TARGET		
AZ	15% by 2025	ND	10% by 2015
CA	20% by 2010	NH	23.8% by 2025
CO	20% by 2020 (IOUs), 10% munis and co-ops	NJ	22.5% by 2021
CT	27% by 2020	NM	20% by (IOUs), 10% (co-ops) by 2020
DC	11% by 2022	NV	20% by 2015
DE	20% by 2019	NY	24% by 2013
HI	20% by 2020	OH	12.5% by 2025
IA	105 MW (2% by 1999), add'l 1000 MW goal by 2011	OR	25% (large utilities), 5%-10% (small utilities) by 2025
IL	25% by 2025	PA	18% in 2020
MA	4% by 2009 (+1/ year after)	RI	16% by 2020
MD	20% by 2022	SD	10% by 2015 goal
ME	10% additional by 2017	TX	5,880 MW by 2015
MI	10% by 2015	UT	20% by 2025 goal
MN	25% by 2025, (Xcel 30% by 2020)	VA	12% of 2007 sales by 2022
MO	15% in 2021	VT	Energy growth 2005-'12 met by RE; 20% by 2017
MT	15% in 2015	WA	15% by 2020
NC	12% of 2020 sales by 2021 (IOUs), 10% of 2017 sales by 2018 (munis & co-ops)	WI	10% by 2015

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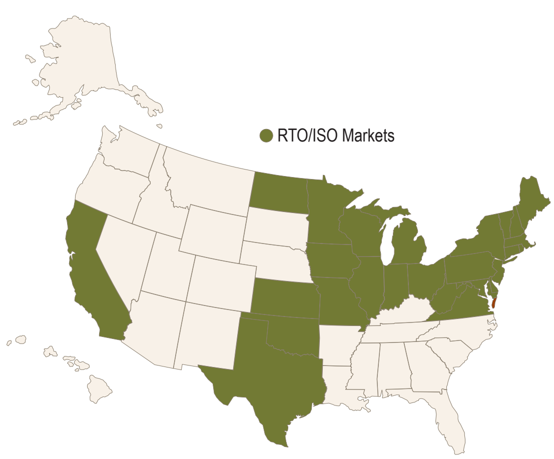
"Joining the Midwest ISO makes good business sense for our customers because it provides access to the ancillary services market to support our leadership position in wind generation and helps ensure the company has a wider opportunity to buy and sell electric power."
Bill Fehrman, President of MidAmerican Energy Company

Figure 8 shows the top ten states in terms of existing and planned cumulative wind capacity. While roughly two thirds of wind capacity exists in states having organized wholesale markets, assessing the degree to which market structure leads to increased levels of renewable energy development is highly complex because of the jurisdictionally fractured, stop-and-start history of renewable resource development. The salient questions are whether or not organized electricity markets are conducive to optimizing and increasing the value of renewable energy on the grid, and whether or not there is enough information available to investors to adequately value future investments in renewable energy.

Reduced uncertainty and risk make investment decisions easier. Without a publicly visible, readily determined dispatch price, valuing an investment in new generation capacity is more difficult. Well-functioning liquid hour-ahead and day-ahead markets provide useful information and data to energy developers that can inform decision makers whether or not prices will support the cash flows needed to meet required investment returns. For CO_2 prices to induce a shift in the capital stock to low-carbon generation sources, investment decisions need to incorporate the impact that carbon costs will have on electricity prices. In markets with transparent pricing mechanisms and market rules, investors will be better able to assess the risk and return trade-offs of their decisions.

In theory, coordinated dispatch can optimize the output of large wind farms because grid operators call on the lowest-cost producers available and shift generation away from more expensive units. In practice, the ability to coordinate different control areas and an availability of transmission capacity are needed to optimize resources in markets with a diverse fuel mix and varying generator performance in order to allow for accommodation of intermittent resources. The broader the geographical reach of the market, the more renewable energy producers' variable output can be efficiently accommodated. This accommodation is achieved through ancillary services, which are needed to manage the variable nature of wind generation. By broadening the supply of ancillary services, RTOs effectively lower the cost of managing intermittent resources while maintaining overall grid reliability. This is evidenced by MidAmerican Energy Company's recent announcement that it intends to fully integrate into the MISO as a

FIGURE 8: ORGANIZED WHOLESALE MARKETS AND WIND GENERATION CAPACITY



	CURRENT WIND CAPACITY (MWs)	WIND CAPACITY UNDER CONTSTRUCTION (MWs)
TX	7,116	1,651
IA	2,790	20
CA	2,517	275
MN	1,752	0
WA	1,375	70
CO	1,068	0
OR	1,067	250
IL	915	201
NY	832	464
KS	815	199

RTO/ISO
Non RTO/ISO

Source: Navigant Consulting, Inc. based on American Wind Energy Association Data.

transmission-owning member.[21] According to recent reports from the Department of Energy and the National Renewable Energy Laboratory, this can lead to increased value for wind energy operators.[22,23]

The degree to which investors can assemble accurate data to inform an investment decision, and increase the value of their investment through optimizing the output, improves the investor's ability to make rational risk return trade-offs as renewable energy investments are considered.

Conclusion

Competitive electricity markets will play a vital role in the successful implementation of regional and national CO2 emission trading programs. If the intended results of a carbon market are to be achieved, CO_2 prices will need to alter the manner in which the U.S. produces and consumes electricity.

Our empirical analysis of the history of coal plant heat rates and nuclear generator capacity factors demonstrates how electricity generators react to price signals in order to improve operating profit margins. The expectation of a similar price-signal reaction is at the core of market-based GHG policies. Behavioral changes stemming from accurate and transparent prices – and the financial incentives and disincentives they create – will drive decisions that will likely reduce emissions from existing generation sources. As a corollary, these price signals will also likely lead to increased penetration of renewable energy and load management technologies, which in turn will facilitate a faster transition to a lower-carbon electricity grid.

Regional, federal, and state policymakers designing GHG policies need to consider the inter-dependant nature of carbon markets and electricity markets – and more importantly, how prices in these two markets are related. Policymakers need to understand that consumers' and producers' abilities to increase efficiency and improve utilization of innovative technologies will be enhanced and rewarded in a market-based environment, which will ensure the best opportunity for success in achieving the goal of significant CO_2 reduction nationwide.

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