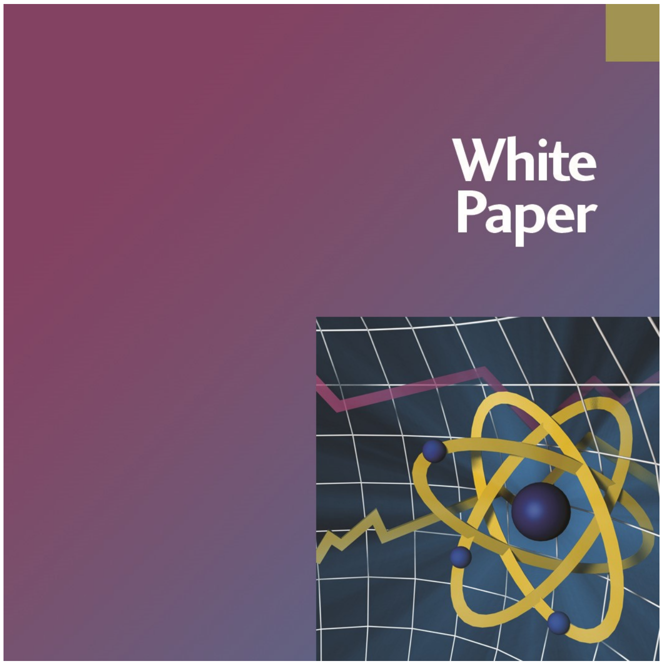

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Status and Outlook for Nuclear Energy In the United States

Executive Summary

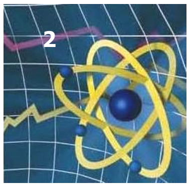
The electric power industry is passing through a period of unprecedented stress and transformation, caused partly by rapid, disruptive advances in technology. For example:

- Horizontal drilling techniques coupled with hydraulic fracturing have unlocked vast reserves of low-cost shale gas, which virtually guarantees that wholesale electricity prices will remain at historically low levels, likely for some years.
- The last 10 years have seen continuing improvements in the cost and performance of wind, solar and electricity storage technologies.
- The traditional electric power industry business model – based on large central-station power plants – is adjusting to distributed generation.

On top of this, federal environmental regulations – notably requirements to control emissions of mercury and air toxics (MATS) and carbon dioxide – are forcing major changes in the generating portfolio. As much as 20 percent of U.S. coal-fired generating capacity – 60,000 megawatts (MW) – is expected to close by 2020, due to the MATS rule and competition from low-cost gas-fired generation. The Environmental Protection Agency's Clean Power Plan – designed to reduce CO_2 emissions – could force shutdown of another 40,000 MW of coal-fired capacity.

America's nuclear energy industry is not immune to this stress. Five nuclear power plants (six reactors) have shut down prematurely in the last three years, and additional reactors are at risk of premature retirement.

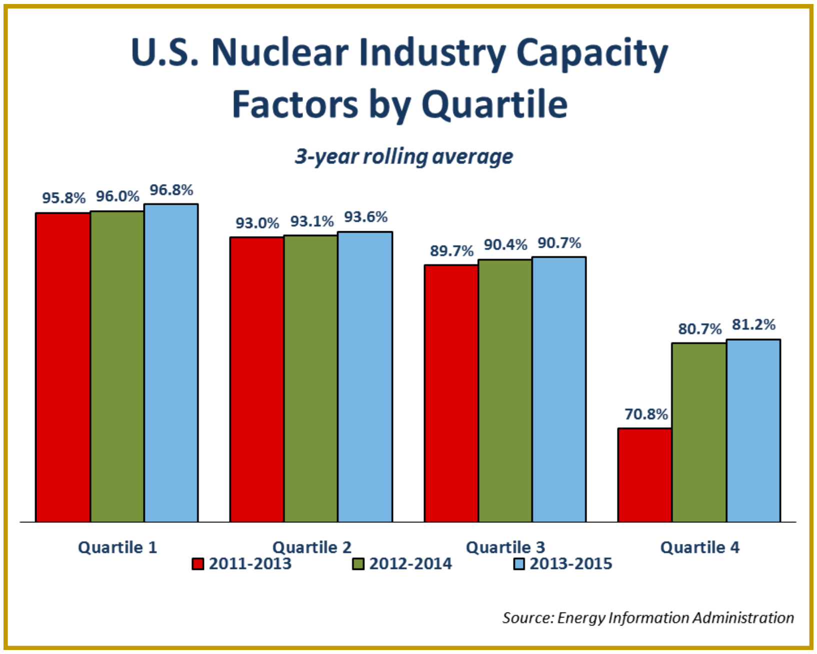
At the same time, however, new nuclear capacity is being deployed. The Tennessee Valley Authority has completed Unit 2 at its Watts Bar nuclear station in Tennessee and it started commercial operation in October 2016. Four new reactors are halfway through construction – two in Georgia, two more in South Carolina – and will reach commercial operation in 2019 and 2020.



Nuclear Energy's Value Proposition

The 99 nuclear power plants that supply approximately 20 percent of the nation's electricity and approximately two-thirds of the nation's carbon-free electricity provide a uniquely valuable set of attributes:

- Nuclear power plants produce large quantities of electricity around the clock, safely and reliably, when needed. They operate whether or not the wind is blowing and the sun is shining, whether or not fuel arrives by truck, barge, rail or pipeline when needed.
- Nuclear plants provide price stability.
- They provide "reactive power" – essential to controlling voltage and frequency and operating the grid.
- Nuclear power plants have portfolio value, contributing to the fuel and technology diversity that is one of the bedrock characteristics of a reliable, resilient electric sector.
- Finally, nuclear power plants provide clean air compliance value. In any system that limits emissions – of the so-called "criteria" pollutants or carbon dioxide – the emissions avoided by nuclear energy reduce the compliance burden that would otherwise fall on emitting generating capacity.



In 2015, nuclear energy produced 19.5 percent of U.S. electricity supply (797 billion kilowatt-hours) and 62 percent of its zero-carbon electricity. The industry's 2015 average capacity factor was 92.2 percent, compared to 86.1 percent in 2012. This level of performance — i.e., capacity factors in the 90-percent range — has been sustained for the last 15 years.

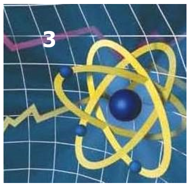
Other sources of electricity have some of these attributes. None of the other sources has them all.

According to a recent analysis by The Brattle Group[1], nuclear energy:

- contributes approximately $60 billion annually to gross domestic product;
- accounts for about 475,000 full time jobs (direct and secondary);
- helps keep electricity prices low. Without nuclear generation, retail rates would be about 6 percent higher on average, and
- is responsible for nearly $10 billion annually in federal tax revenues, and $2.2 billion in state tax revenues.

Nuclear energy is America's largest source of low-carbon electricity. In 2015, nuclear energy produced 19 percent of U.S. electricity supply (797 billion kilowatt-hours) and prevented 564 million metric tons of CO_2 emissions.

Nuclear energy accounted for 62 percent of America's carbon-free electricity in 2015 – three times more carbon-free electricity than hydropower and four times more than wind energy. For perspective, just three typical nuclear power stations produce approximately 24 billion kilowatt-hours of carbon-free electricity every year – approximately equal to the production from all utility-scale solar



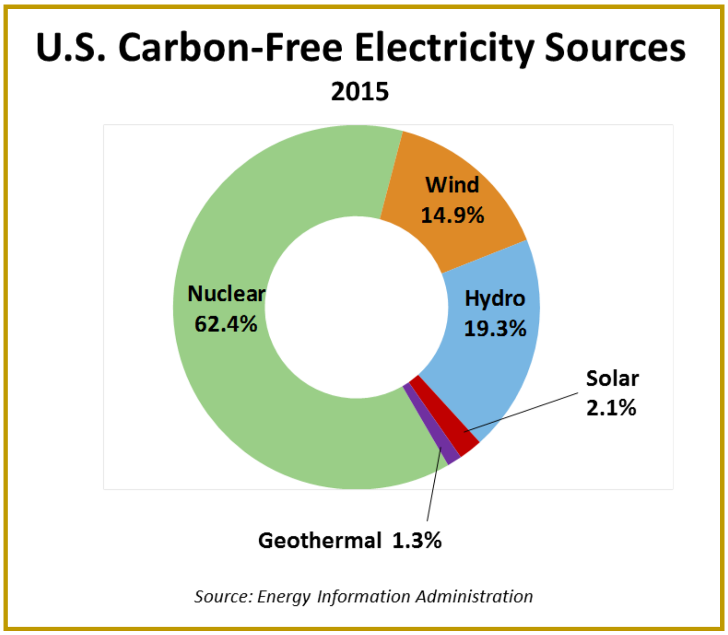
in the entire country in 2015. (U.S. utility-scale solar output in 2015 was 26 billion kilowatt-hours.) The amount of CO_2 emissions avoided by U.S. nuclear energy facilities is equal to the CO_2 emissions from 128 million passenger cars – more than all the passenger cars in the United States. Without nuclear power plants operating in 30 states, carbon emissions from the U.S. electric sector would be 27 percent higher.

America's 99 nuclear reactors are also a significant Clean Air Act compliance tool. They avoid over one million tons of sulfur dioxide and 650,000 tons of nitrogen oxide emissions annually. In the absence of nuclear energy, emissions of SO2 and NOx from the U.S. electric sector would be 13 percent and 18 percent higher every year, respectively.

The Challenges Facing Operating Nuclear Power Plants

Since a number of states restructured their electricity markets in the late 1990s, the business of producing and transmitting electricity has evolved into two distinctly different enterprises.

In those states still subject to traditional cost-of-service regulation, companies and regulatory commissions use the process of integrated resource planning to evaluate resource options on a long-term basis, analyze project economics over a 40-year or 60-year time horizon, and assign value to "public goods" like fuel and technology diversity and forward price stability.



Competitive markets have not yet developed mechanisms to value these "public goods" and internalize them in their decision-making.

Fifteen years of experience with deregulated markets suggests that these markets are not producing price signals sufficient to stimulate investment in new generating capacity (except for gas-fired capacity), or to support continued operation of existing capacity.

Since 2013, six nuclear reactors (Crystal River 3 in Florida, San Onofre 2 and 3 in California, Kewaunee in Wisconsin, Vermont Yankee and Fort Calhoun in Nebraska) have shut down permanently. Entergy announced in October 2015 that it would close its Pilgrim plant in Massachusetts by June 2019, and possibly sooner. In November 2015, Entergy announced that it would shut down its FitzPatrick nuclear plant in upstate New York in late 2016 or early 2017, but New York state has since implemented policies to prevent that (see sidebar, page 10-11). In May 2016, Exelon announced that it planned to close two of its Illinois plants – the Clinton plant and the two-unit Quad Cities station – in June 2017 and June 2018, respectively. In June 2016, Pacific Gas & Electric announced the shutdown of Diablo Canyon 1 and 2 when their licenses expire. And there are other nuclear plants at risk in addition to these.

Crystal River and San Onofre were unique situations that are unlikely to be repeated. Diablo Canyon is the victim of aggressive state renewable and energy efficiency goals that would force the reactors to operate only part of the time, thereby compromising their economic viability.

But Kewaunee, Vermont Yankee, Pilgrim, FitzPatrick, Clinton, Quad Cities, and Fort Calhoun all fell victim to a combination of market-related factors (and, in some cases, a combination of several factors), including:

- Sustained low natural gas prices, which are suppressing prices in wholesale power markets, and will continue to do so. In ERCOT, for example, the average gas price in 2015 was $2.57 per MMBtu, down roughly 40 percent from the 2014 average price of $4.32 per MMBtu.[2] In PJM, the load-weighted average real-time locational marginal price (LMP) was 32 percent lower in 2015 than in 2014 – $36.16 per MWh versus $53.14 per MWh. The average price in 2015 was about 20 percent lower than the average of annual prices in all years from 1999 through 2015.[3]

- Relatively low growth (in some markets, no growth) in electricity demand due partly to subpar economic performance since the 2008 recession, partly to greater efficiency.

- Federal subsidies and state mandates for renewable generation, which tend to suppress prices, particularly during off-peak hours (when wind generation is highest and the electricity is needed the least).

- Transmission constraints, which require a power plant to pay a congestion charge or penalty to move its power on to the grid. Certain nuclear plants at particularly congested points on the grid pay a penalty of $5-10 per megawatt-hour to move their power out.

- Market designs that do not compensate the baseload nuclear plants for the value they provide to the grid, and market policies and practices – e.g., reliance on out-of-market revenues – that tend to suppress prices.

This combination – which represents a unique combination of short-term, unsustainable factors – is a "perfect storm," which is forcing companies to make decisions in the short-term that do not serve the long-term national interest.

Thanks to these factors, or a combination of them, some nuclear plants – particularly the smaller, single-unit nuclear stations – operating in competitive markets are not able to recover their costs from market revenues.

"Out of Market" Revenue for Renewables. It is worth noting, however, that wind and solar facilities do not cover their costs through the market either, but they have the advantage of other sources of revenue that are "out of market."

In ISO-New England, for example, "over 70 percent of the estimated net revenues for both wind and solar units in the 2015/16 period were from federal and state programs, such as Renewable Energy Credits (RECs) and the Investment

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In the New York ISO, a new solar PV project would have earned 58-69 percent of its 2015 net revenues from RECs and the ITC. Onshore wind units would have received 51-66 percent of their 2015 net revenues from state and federal subsidies.

or Production Tax Credits (ITC or PTC)." [4]

Similarly in the New York ISO: "A new solar PV project would have earned 58 percent to 69 percent of its 2015 net revenues from RECs and the ITC, depending on the location. Similarly, onshore wind units would have received 51 percent to 66 percent of their 2015 net revenues from state and federal programs." [5]

Needless to say, it is difficult for an unsubsidized nuclear unit to compete in these markets, given the advantage conferred on other forms of carbon-free generating capacity and the price suppression that occurs as a result of federal and state subsidies and mandates.

The Impact of Premature Nuclear Power Plant Shutdowns

In New England and New York, the cost of avoiding carbon emissions by preserving a nuclear power plant is significantly lower than other options, particularly the other carbon-free options, according to the independent market monitor.

Closing down a nuclear power plant has major impacts – on the environment, on consumers of electricity (who will pay more for electric power in the long-term than they would if the nuclear plant continued to operate), and on the states, counties and towns in which they are located.

Environmental Impact. The nuclear plant shutdowns that have already occurred, or that have been announced, are a major setback for the Obama Administration's Clean Power Plan, because the zero-carbon nuclear energy has been, and will continue to be, replaced largely with gas- and coal-fired generation.

The reactors that have already closed, and those at risk, represent between 59 million tons and 80 million tons of increased CO_2 emissions, depending on what sources of fossil-fueled electricity replace them. The higher number represents nearly 20 percent of the 414-million-ton reduction expected in 2030 under the Clean Power Plan.

The loss of nuclear generating capacity clearly compromises the Clean Power Plan goals.

In addition, the cost of avoiding carbon emissions by preserving a nuclear power plant is significantly lower than other options, particularly the other carbon-free options.

In its assessment of the New England market[6], the market monitor calculated the cost of reducing CO_2 emissions using various technologies. The results showed that:

- a new combined cycle unit with access to gas priced at Iroquois Zone 2 would cost $30-$32 per ton, depending on the efficiency of the unit.
- Building a new onshore wind unit would cost $64-$68 per ton, excluding state and federal subsidies.
- Retaining a small, single-unit nuclear plant would cost $20 per ton.
- Using utility-scale solar PV resources would cost $139 per ton.

The market monitor found similar results in its assessment of the New York

(Continued on page 9)

Perspective on Costs and a New Initiative To Improve Efficiency, Reduce Costs

In 2015, the average total generating cost for nuclear energy was $35.50 per megawatt-hour. Total generating costs include capital, fuel and operating costs.

Three-quarters of nuclear power in the U.S. comes from plants with multiple reactors. The ability to spread costs over a greater amount of electricity production means that the generating cost at multi-unit sites is generally lower than at single-unit plants. In 2015, the total generating cost at multi-unit plants was $32.90 per megawatt-hour compared to $44.52 for single-unit plants.

2015 Cost Summary
($/MWh)

Category	Number of Plants / Sites	Fuel	Capital	Operating	Total Operating (Fuel + Operating)	Total Generating (Fuel + Capital + Operating)
All U.S.	58*	6.91	7.97	20.62	27.53	35.50
Plant Size						
Single-Unit	23	7.10	10.26	27.15	34.25	44.52
Multi-Unit	35	6.85	7.31	18.74	25.60	32.90
Operator						
Single	12	7.49	9.30	22.05	29.54	38.84
Fleet	46	6.74	7.58	20.21	26.95	34.53

** Costs exclude shutdown plants. Also excludes Fort Calhoun, Fitzpatrick, and Pilgrim because no data was provided for 2015.*

Source: Electric Utility Cost Group (EUCG)

U.S. Nuclear Plant Costs
(2015 $/MWh)

Year	Fuel	Capital	Operating	Total
2002	5.73	3.92	18.61	28.27
2003	5.60	4.94	18.87	29.40
2004	5.29	5.66	18.56	29.50
2005	5.02	5.81	18.97	29.80
2006	5.05	5.56	19.23	29.85
2007	5.13	6.12	19.09	30.35
2008	5.36	6.77	19.53	31.66
2009	5.94	8.92	20.52	35.38
2010	6.77	9.17	20.66	36.59
2011	7.10	10.07	21.91	39.08
2012	7.47	10.77	21.50	39.75
2013	7.74	8.21	20.95	36.91
2014	7.22	8.19	20.95	36.35
2015	6.91	7.97	20.62	35.50
2002-2015 Increase	**21%**	**103%**	**11%**	**26%**
2010-2015 Increase	**2%**	**-13%**	**0%**	**-3%**

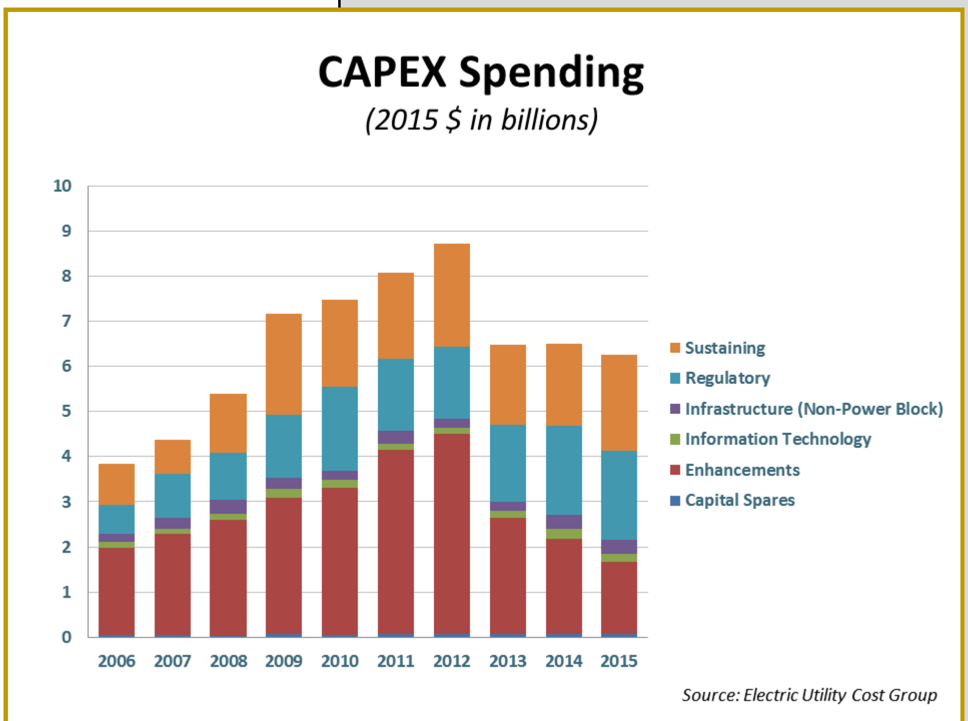
Source: Electric Utility Cost Group (EUCG)

The 2015 generating costs were 2.4 percent lower than in 2014 and almost 11 percent below the 2012 costs. Prior to the 2012 peak, nuclear generating costs had increased steadily over the previous decade. Between 2002 and 2015, fuel costs increased 21 percent, capital expenditures by 103 percent, operating costs by 11 percent (in 2015 dollars per megawatt-hour). Total generating costs are up 26 percent in the last 13 years.

Capital Appears to Have Peaked

Industrywide capital spending increased from $4.4 billion a year in 2006 (2015 dollars), peaked at $8.7 billion in 2012, and dropped to $6.25 billion in 2015.

Capital investment took a step change up in about 2003, leveled off for several years, then took another step change in 2009 and has declined over the last two years. These inflections are the result of several major items: a series of vessel head replacements, steam generator replacements and other upgrades as companies prepared their plants for operation after the initial 40-year license, and power uprates to increase output from existing plants. As a result of these investments, 81 of the 99 operating reactors have received 20-year license renewals and 92 of the operating reactors have been approved for uprates that have added over 7,000 megawatts of capacity.



Source: Electric Utility Cost Group

Capital spending on uprates and items necessary for operation beyond 40 years should moderate as most plants complete these efforts. Capital investments in uprates peaked at $2.5 billion in 2012 but declined to $315 million in 2014. This decline has been offset in other areas where spending has increased. Capital spending to meet regulatory requirements was around $1 billion in 2007 and 2008 before jumping to $1.8 billion in 2010 and holding near that level until reaching a peak of almost $2 billion in 2014. This increase began with significant investments post-9/11 to enhance security, followed by expenditures for post-Fukushima items, which totaled $1 billion in 2014. As the industry completes Fukushima-related safety upgrades, regulatory capex should also moderate, and revert toward 2007-2008 levels.

Operating Costs: Flattening Out

Operations costs increased over the last twelve years from $18.59 per megawatt-hour in 2002 to $20.92 per megawatt-hour in 2014. Operations costs have declined 4 percent from the peak in 2011.

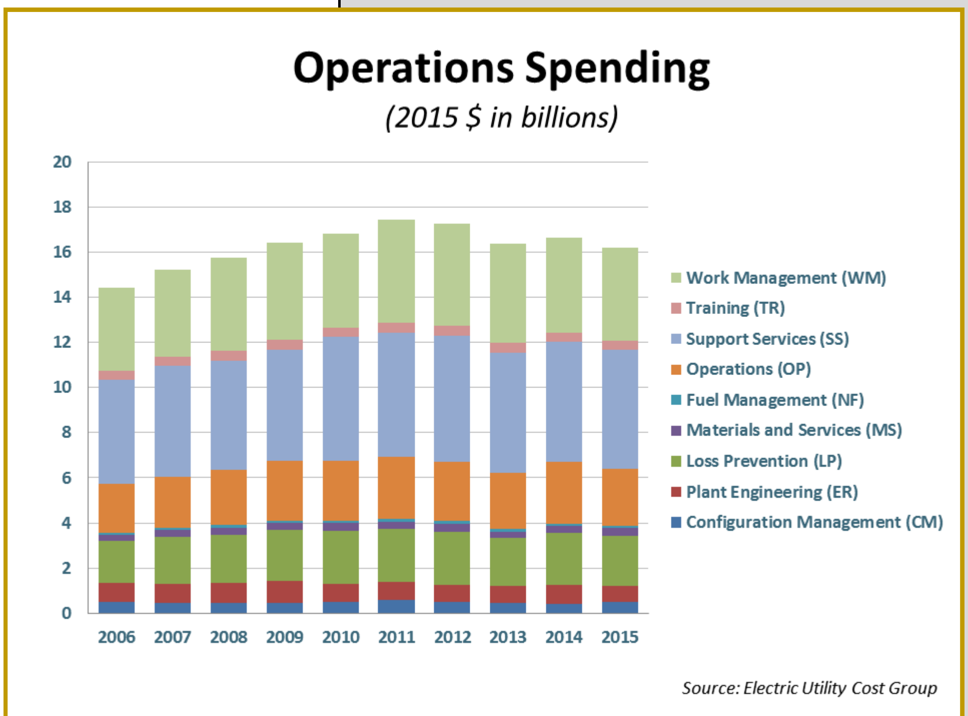
This increase in operations costs was not driven by any single category. Operations costs in the 2002-2008 periods are similar to where money was being spent in the 2009-2014 period. However, operations costs have remained flat compared to the past decade. Between 2006 and 2010, operations costs increased 16 percent while, over the past five years, the increase was only 1 percent.

Fuel Costs: 15-20 Percent of Total Generating Cost

Fuel costs represent 15-20 percent of the total generating cost. Fuel costs experienced a relatively rapid increase from 2009 to 2013. This was largely the result of an escalation in uranium prices that peaked in 2008. Since uranium is purchased far in advance of refueling and remains in the reactor for four to six years, the effect of this commodity price spike persists for a long time after the price increase actually occurred.

A New Initiative: Greater Efficiency

Although U.S. nuclear power plant reliability is consistently high, total electric generating costs have increased over the last 15 years or so. Given the economic stress facing a number of plants, in December 2015, the industry launched an initiative to identify efficiency measures and adopt best practices and technology solutions to improve operations, reduce electricity generating costs and prevent premature reactor closures. Industry teams led by chief nuclear officers are identifying improvements to programs such as work management, security and engineering. The goal of this initiative is to provide companies that operate nuclear power plants with innovative solutions, enabling a significant reduction in operating expenses across the industry by 2018, while continuing to advance safety and reliability.



Source: Electric Utility Cost Group

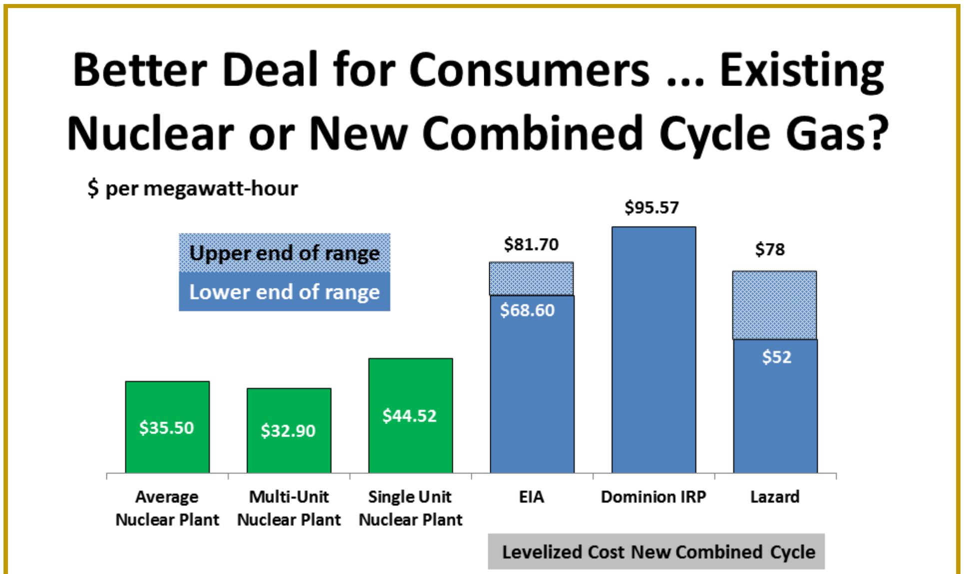
The industry teams produce efficiency bulletins that are distributed to nuclear plant operators to clearly identify, characterize and standardize efficiency improvement opportunities. As of October 2016, 34 efficiency bulletins have been issued to the industry, enabling over $500 million in potential savings. Dozens of additional bulletins are planned or under development. These efforts already are leading to greater efficiency at plant sites.

ISO.[7] Retaining existing nuclear capacity in upstate New York would cost $20-$43 per ton. Using onshore wind and utility-scale solar PV resources on Long Island would cost $41 and $115 per ton, respectively.

Impact on Consumers. Closing a nuclear power plant – even one of the higher-cost single-unit stations like Kewaunee, Vermont Yankee or Pilgrim – results eventually in higher electricity prices to consumers.

For example, the closure of the San Onofre Nuclear Generating Station resulted in higher electricity bills. On top of an increase in carbon emissions of 9 million tons a year, California consumers paid $350 million more for electricity in the year following the closure.[8]

It might be possible to find cheaper electricity off the grid for a short time – for as long as there's spare gas-fired combined cycle capacity, and spot gas available below $2 per million Btu, which is clearly not sustainable.



Sources: Existing nuclear costs are 2015 total generating costs (fuel, O&M, capital) from Electric Utility Cost Group. Gas-fired combined cycle costs are levelized costs from (1) Energy Information Administration, *Annual Energy Outlook 2015;* (2) Dominion Virginia Power 2016 Integrated Resource Plan; (3) Lazard, *Levelized Cost of Energy Analysis*, 9.0, 2015.

But sooner or later, that nuclear capacity must be replaced and, when it is replaced with new gas-fired combined cycle capacity, consumers will pay more on a levelized cost basis.

The green bars on the chart compare the average cost of electricity from U.S. nuclear plants – the fleet average, the average for multi-unit plants (like the Quad Cities plant scheduled for shutdown) and single-unit plants. The most costly nuclear plants – the smaller single-unit stations – produced electricity, on average, for approximately $45 per megawatt-hour in 2015.

The blue bars show various estimates of the levelized cost of electricity from a new gas-fired combined cycle plant – from the Energy Information Administration, from an integrated resource plan filed recently by a regulated utility, and from Lazard. All are above – sometimes well above – the cost of electricity from even the single-unit nuclear sites.

The bottom line: It makes no logical sense to shut down a carbon-free $45-per-megawatt-hour nuclear plant that provides 600-or-so direct jobs, and replace it with a $50-95 per-megawatt-hour gas-fired plant that provides maybe 30 jobs and has roughly one-half the carbon emissions of a coal-fired power plant.

Productive nuclear generating assets are being retired, fuel and technology diversity is being compromised, and electricity consumers are being exposed to long-term reliability risks and price volatility. Market conditions are forcing companies to make decisions that our nation will regret for the next 20 or 30 years, or longer, on the basis of short-term, unsustainable price signals.

Principles to Govern Competitive Market Design

There was nothing wrong with any of the nuclear plants that have shut down for market-related reasons, or any of those at risk. Kewaunee, Vermont Yankee and others were all highly reliable plants with high capacity factors and relatively low generating costs. When the Vermont Yankee nuclear plant closed at the end of 2014, it had just completed a 633-day continuous run. The nuclear plants at risk in western PJM are producing in the low-$30-per-megawatt-hour range.

There's clearly something wrong with the competitive markets.

They are not structured to recognize the value of the resources in place.

They are not operated so that all costs are reflected in prices.

They are distorted by out-of-market revenues and mandates.

For these plants, there's clearly something wrong with the markets in which they're operating. The markets are not structured to recognize the value of the resources in place. They are not operated so that all costs are reflected in prices. They are distorted by out-of-market revenues and mandates.

The process of developing solutions to this set of problems must start with simple economic principles. Goods and services will only be produced in a competitive market when they are priced and valued in the market. It is also a mistake to think of electricity as an undifferentiated bulk commodity. Every kilowatt-hour of electricity on the grid has a unique set of attributes, depending on how it is produced.

So, for example, electricity generated from wind is carbon-free (a valuable attribute) but it is not dispatchable and it tends to be correlated inversely with demand (the wind generally blows at night when the electricity is needed the least).

Electricity from coal-fired power plants is dispatchable (a valuable attribute), and it has reserves of fuel on site (another valuable attribute), but it's not carbon-free.

On-site fuel supply, and the ability to run when needed, is a valuable attribute. It deserves compensation. The New England ISO and PJM recognize this, with their "pay for performance" and Capacity Performance capacity markets. Other ISOs have not yet evolved to that point.

Nuclear generating capacity has its own set of attributes, starting with production of large quantities of electricity around the clock, safely and reliably. In some markets, even that value is not fully recognized because of the price suppression that's occurring. Nuclear power plants also provide forward price stability, and they have portfolio value, contributing to the fuel and technology diversity that is one of the characteristics of a reliable, resilient electric sector. These attributes are not valued. Nuclear power plants also provide clean air compliance value. This attribute, too, is not valued. Nuclear power plants also provide reactive power – essential for voltage support and frequency control –

but the modest compensation for this service does not, in many cases, fully reflect the value of this service.

In short, every kilowatt-hour of electricity on the grid has a distinct pedigree. If markets fail to identify those attributes, incorporate them in decision-making, and value them in market design and market policies, then companies will stop providing those attributes – and that, of course, is what's happening.

To achieve sustainable results, competitive electricity markets must satisfy the needs of consumers, grid operators, electricity suppliers, asset owners and investors, regulators and policy-makers. As Susan Tierney of The Analysis Group, an expert in electricity issues, noted in comments in a 2013 FERC proceeding on capacity markets: "We continuously expect our electric industry to solve a complex 'simultaneous equation' in which the countless decisions of myriad actors need to produce a reliable, efficient and increasingly clean supply of electricity." In Tierney's view, the markets today are not solving that 'simultaneous equation' correctly: "Something has to change for the numbers to support a sustainable, healthy and vibrant electric industry capable of meeting system operators' technical necessities, consumers' implicit needs, policy makers' explicit demands, and investors' inherent requirements. That entire equation must be satisfied, or the system isn't sustainable." [9]

Sustainable and effective market design demands consideration of all the factors that constitute a robust and resilient market – including short-term prices, long-term price stability, environmental factors, the portfolio value associated with fuel and technology diversity and others. Although short-run cost is an important and necessary metric, solving this complex equation for one variable only – i.e., lowest short-run electricity price – is unlikely to produce a satisfactory result in the long-term.

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Progress to Date. There has been movement on the part of the Federal Energy Regulatory Commission (FERC) and a number of Regional Transmission Organizations to address some of the underlying problems.

In 2015, for example, FERC approved a proposal from PJM to reform its capacity market to provide additional compensation to generating resources – like nuclear power plants – capable of sustained, predictable operation. These so-called Capacity Performance resources are expected to be available and capable of providing energy and reserves when needed, and face substantial penalties if they are not.

PJM held its first capacity auction – for the 2018-2019 delivery year – in August 2015 and two transitional auctions in September. In all three auctions, the Capacity Performance resources cleared at significantly higher prices than previous auctions that did not include a Capacity Performance product.

There's clear evidence that these market reforms work. They provided a short-term reprieve to certain nuclear plants in 2015. But by themselves, they are not enough. Unfortunately, any gains from Capacity Performance last year had been eroded by year's end by the continuing deterioration in the energy markets.

(Continued on page 14)

New York's Clean Energy Standard: A Model for Other States

With its Clean Energy Standard (CES), New York is leading the way among states considering ways to reduce greenhouse gas emissions while maintaining reliability and affordability of electricity supply. Under New York's CES, the state's load-serving entities must ensure that a certain amount of their electricity comes from non-emitting, clean technologies including nuclear, solar, wind and hydro.

The New York Clean Energy Standard includes a zero-emission credit (ZEC) that values the non-emitting attribute of nuclear energy. The value of this credit is based on the social cost of carbon used in federal government cost-benefit analyses. The Clean Energy Standard will allow Exelon to continue operation of two plants (Ginna and Nine Mile Point) that had been facing early closure. Exelon will also buy and operate the FitzPatrick plant from Entergy, which had planned to close the facility in early 2017.

Background. On December 2, 2015, New York Governor Andrew Cuomo directed the state Public Service Commission to develop a Clean Energy Standard (CES). The CES was to enable the state to meet the ambitious environmental goals in the New York State Energy Plan, including a 40-percent reduction in greenhouse gas emissions from 1990 levels by 2030. This 40-percent reduction is intended to move the state toward a longer term goal of an 80-percent decrease in carbon emissions by 2050. The state aims to have 50 percent of electricity consumed in New York come from renewable sources.

Closing nuclear facilities "would eviscerate the emission reductions achieved through the state's renewable energy programs, diminish fuel diversity, increase price volatility, and financially harm host communities."

– New York Gov. Andrew Cuomo
Dec. 2, 2015

Gov. Cuomo recognized the challenge that New York would face if it were to lose any of its nuclear plants. In his letter directing the Department of Public Service to develop a Clean Energy Standard, he said that the closure of nuclear facilities "would eviscerate the emission reductions achieved through the state's renewable energy programs, diminish fuel diversity, increase price volatility, and financially harm host communities." (In 2015, New York's nuclear power plants produced 44.6 million megawatt-hours of non-emitting electricity, which represented 59 percent of the state's clean electricity and avoided the emission of about 26 million additional tons of carbon dioxide.)

New York's Department of Public Service issued a white paper in January 2016 that started the discussion about how a CES could be created to preserve the attributes of nuclear generation in the state. The white paper introduced the concept of zero-emission credits (ZECs) that would provide monetary value for the non-emitting attribute of nuclear plants. Originally conceived as an estimate of the revenue shortfall facing threatened plants, the ZEC concept was refined through the comment period into a more robust price signal that would enable continuing investment in economically challenged nuclear facilities.

Zero-Emission Credits. On August 1, 2016, the Public Service Commission adopted the Clean Energy Standard including a Tier 3 that addresses nuclear facilities in the state. Under the plan, at-risk nuclear plants in the state will receive a ZEC for each megawatt-hour they produce. The ZEC recognizes that nuclear can help the state meet its emission reduction goals, and the credit provides monetary value to encourage continuing investment and operation. The ZEC is structured to be analogous to the renewable energy credits received by wind and solar under many state policies, like renewable portfolio standards.

A state energy agency, the New York State Energy Research and Development Authority, will conduct the transaction of ZECs. The Authority will pay nuclear plant owners for the credits they produce. The load-serving entities in New York are then required to buy the ZECs from the Authority. Each load serving entity's share of the payments is determined by its percentage of the electricity consumed in the state.

The value of a ZEC is set for two years at a time, based on a formula set in the policy. The calculation starts with the social cost of carbon, estimated by the federal government to be $42 per ton of emissions. Since New York participates in the Regional Greenhouse Gas Initiative (RGGI) carbon pricing system, a small portion of that avoided emission value is already captured by RGGI, so the expected price of a RGGI allowance is subtracted from the ZEC value. The remaining carbon cost is multiplied by the carbon emission rate for New York to calculate the credit in terms of dollars per megawatt-hour. Under current values, the ZEC value would be worth $17.48/MWh. The value of the credit is expected to grow in the future as the social cost of carbon increases over time and with inflation. The ZEC concept includes a provision that will limit the value of the credit if market prices rebound in the future. If the market revenues for electricity and capacity payments are forecasted to exceed $39/MWh, then the ZEC price will be lowered by that amount.

Analysis of the CES has shown that the cost to provide ZECs is more than offset by lower power prices to New York consumers. The Brattle Group found that electricity costs would be $1.7-billion a year lower by preserving the at-risk nuclear units, since they would be replaced by more costly generation. With the cost of the ZEC program estimated to be less than $500 million a year in the first two years of the program, the net annual savings to consumers are expected to be more than $1 billion annually.

Impact of the Clean Energy Standard. As soon as the Public Service Commission finalized the CES, Exelon, owner of the Ginna and Nine Mile Point nuclear plants, announced its intention to invest $200 million to enable the long-term operation of these facilities. (Exelon had announced that Ginna and Nine Mile Point Unit 1 were facing early closure.) In addition, Exelon and Entergy announced an agreement in principle under which Exelon would purchase the Fitzpatrick plant and continue to operate it. (Before the CES, Entergy had intended to close the plant.)

The New York approach could serve as a model for other states. Many states already have Renewable Portfolio Standards to encourage the deployment of wind and solar technologies. A Clean Energy Standard builds on this approach by recognizing the need to retain all types of generation that do not emit greenhouse gases. A Clean Energy Standard can be particularly important in states with nuclear plants operating in competitive electricity markets. These markets are seeing historically low power prices driven by the flood of low-cost natural gas. Absent a mechanism such as a Clean Energy Standard, companies operating nuclear plants in these markets have no way to monetize the non-emitting attribute of nuclear power.

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In the energy markets where baseload plants generate most of their revenue, accurate price formation is absolutely essential. The goal here is relatively simple: Ensure that all costs necessary to operate the system are reflected in locational marginal prices (or LMPs).

Transparent, accurate price formation breaks down when grid operators take actions that deviate from least-cost dispatch. In such cases, system operators manually dispatch a resource that is needed to resolve a constraint, or address a reliability concern, but those costs do not show up in the clearing price. The RTOs provide make-whole payments, or "uplift" payments, to those resources. This uplift tends to suppress price signals and inhibit accurate price formation.

The economic foundation under today's nuclear power plants would be much stronger if the United States had a meaningful, economy-wide program to reduce carbon emissions.

Given that such a program is both necessary and inevitable, the sooner it is in place, the better.

FERC has developed an exhaustive record on price formation issues, starting with a series of technical conferences in late 2014. In September 2015, FERC took a first step, with a Notice of Proposed Rulemaking (NOPR) that would revise its regulations governing how the Regional Transmission Organizations set prices in the energy markets.

The agency followed the NOPR with an order directing the RTOs to report back on how they manage various price formation issues, including uplift. Earlier this year, FERC proposed another change to its regulations in this area. The most recent proposal would change the policy on offer caps, and would allow the RTOs to use the higher of $1,000 per megawatt-hour or a cost-based offer.

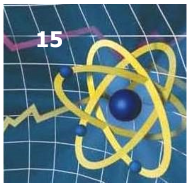
FERC recently issued an order requiring the RTOs to implement the changes to settlement intervals and shortage pricing. Although welcome, the two changes could be described as "low-hanging fruit." These are issues that influence the real-time market, but revenue to the baseload nuclear units is determined in the day-ahead market. Closing the gap between day-ahead and real-time markets is also essential.

And despite the progress, there is reluctance in some quarters to acknowledge the problems that have surfaced in competitive markets over the last several years.

For example, in a recent white paper,[10] PJM Interconnection declared: "No evidence suggests the PJM markets inadequately compensate legacy units and thus are forcing a premature retirement of economically viable generators." Ironically, the PJM white paper was published a day before Exelon announced that it would close its Clinton and Quad Cities nuclear stations – two low-cost generating stations – because the markets do not recognize their value.

Additional Steps Are Needed. The economic foundation under today's nuclear power plants would be much stronger if the United States had a meaningful, economy-wide program to reduce carbon emissions. Given that such a program is both necessary and inevitable, the sooner it is in place, the better. For the electric power industry, which makes 40- to 80-year investment decisions, certainty over an issue like carbon is an imperative, and the continuing uncertainty over potential carbon regulations makes long-term planning extremely difficult.

Continued operation of the existing nuclear plants would not even be an issue if there was a meaningful price signal for carbon. Or, put another way, continued



operation of the existing nuclear plants would be assured if the nuclear plants' carbon-free attribute was appropriately valued by the market.

Absent a price on carbon, however, the federal government (including the Executive Branch, the Federal Energy Regulatory Commission and the Congress), the regional transmission organizations and the states have a number of options available to preserve existing carbon-free baseload generating capacity. The states also have options to preserve valuable assets, or to maintain fuel and technology diversity, or to ensure price stability.

Federal and Regional Options. Competitive markets must fully value the attributes of existing nuclear plants and the services they provide to the grid. The competitive markets must continue the process, already started to a limited extent, of identifying the services and attributes provided by the nuclear plants, and developing mechanisms – either through the capacity markets or the ancillary services markets – to provide compensation for those services and attributes (like Capacity Performance in PJM or Pay-for-Performance in ISO-New England).

Several of the RTOs — including ISO-New England and PJM — recognize the distortions occurring in the energy markets due to federal and state subsidies and mandates. Allowing market participants to reflect out-of-market revenues in their bids into the energy markets distorts and suppresses competitive price signals. Both ISO-New England and PJM are considering various options to address this market defect.

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- Recognizing that the New England states have developed an unwieldy and unsustainable patchwork of state mandates, the New England Power Pool (NEPOOL) launched a process in the summer of 2016 called IMAPP (Integrating Markets and Public Policy). IMAPP is a stakeholder process to identify and explore potential changes to the wholesale power markets that would sweep away this patchwork and replace it with a single market-based policy — a price on carbon, for example.

- Under its Grid 20/20 initiative, PJM has begun exploring additional changes to its capacity market that would offset price suppression caused by out-of-market revenues for subsidized renewable sources.

State Options. States could follow New York's lead and convert existing renewable portfolio standards into zero-carbon or low-carbon portfolio standards, with a system of zero-emission credits to compensate nuclear plants for providing carbon-free electricity (see pages 10-11). Illinois has been considering a low-carbon portfolio standard for several years. The Connecticut legislature is considering a clean energy procurement process that would include nuclear energy. But states have other options, including:

- authorize long-term PPAs (power purchase agreements) to secure the output from nuclear plants at prices that reflect their true value to the grid.

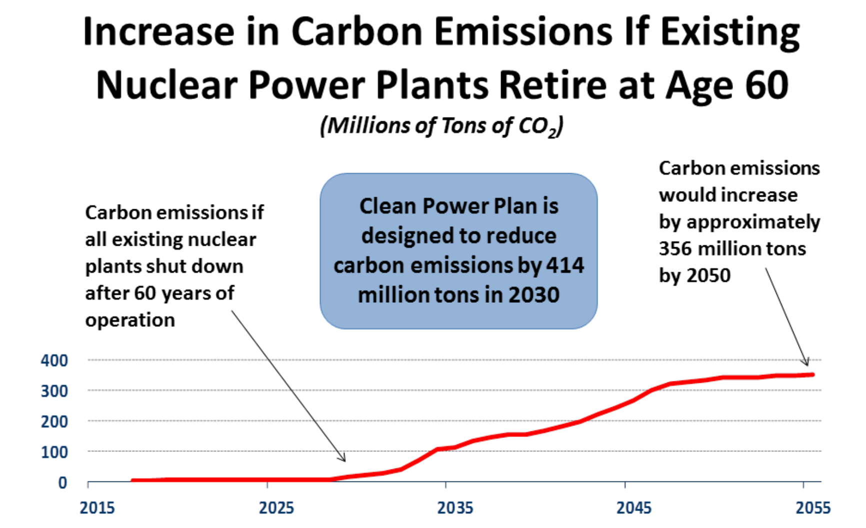
- return certain nuclear plants to traditional cost-of-service regulation on the grounds that they constitute critical infrastructure that is too valuable to lose because price signals are distorted and prices are suppressed in the short-term by unsustainably low natural gas prices.

- require load-serving entities under their jurisdiction to procure a balanced, diversified portfolio of supply, including zero-carbon baseload resources.

- elect mass-based compliance programs to implement the Clean Power Plan, covering both existing and new sources, which would implicitly value carbon-free nuclear generating capacity.

Other Actions to Preserve Existing Nuclear Plants

In addition to market-related actions to ensure continued operation of the nation's nuclear energy assets, a number of additional steps are necessary:



Assumes retiring nuclear power plants are replaced by gas-fired combined cycle plants meeting the 111(b) emission standard.

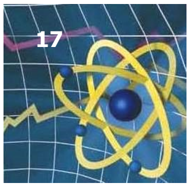
Ensuring a stable, predictable regulatory framework for second license renewal. By 2030, several nuclear power reactors in the U.S. will have been generating electricity for 60 years and, by 2040, half of the nation's nuclear fleet will have turned 60. Second license renewal is essential to retaining as much of this generating capacity as possible.

The regulatory process here is well-established, and the Nuclear Regulatory Commission (NRC) affirmed last year that the existing process needs no revision.

The industry, the Department of Energy (DOE) and the NRC are conducting extensive research and development on managing aging issues safely during a second 20-year license renewal period. The research has shown there are no generic technical issues that would prevent a nuclear plant from operating safely beyond 60 years. Absent second license renewal, if all U.S. nuclear reactors shut down at 60 years and are not replaced with new nuclear generating capacity, any gains from the Clean Power Plan will be virtually eliminated. The Clean Power Plan is expected to reduce carbon emissions by 414 million tons in 2030. Replacing the lost nuclear capacity with new highly efficient gas-fired combined cycle plants will add back 356 million tons a year.

The industry is preparing for second license renewal. Dominion's Surry plant, a pressurized water reactor, and Exelon's Peach Bottom plant, a boiling water reactor, will pilot the Nuclear Regulatory Commission process. Since March 2000, when it granted the first 20-year license renewal, the Nuclear Regulatory Commission has approved license renewals for 83 nuclear reactors.

Providing a financial incentive to companies that pursue second license renewal. Preparing a nuclear power plant for operation past 60 years



will require capital investment – likely on the order of $1 billion to $1.5 billion – to replace major components and systems and perform other upgrades necessary to ensure safe, reliable operation. Some form of tax benefit – e.g., bonus depreciation or an investment tax credit – would provide a signal that these plants are critical national assets and should be preserved. So would a Presidential mandate that federal government agencies and installations buy a certain amount of their electricity from carbon-free sources, including nuclear plants.

Continuing progress by the NRC toward a more safety-focused, more efficient regulatory regime managed by a leaner, more effective agency.

Restructuring the used fuel management program – creating a new management entity to operate the program, completing the licensing of the Yucca Mountain disposal facility, and building one or more storage facilities until such time as a permanent disposal facility is operating.

New Nuclear Development: Priorities and Policy Recommendations

Planning for the long-term future of the U.S. electricity system – and the role of nuclear energy in that system – must start by defining a reasonable and desirable destination.

It is not unreasonable to expect that, by mid-century, the U.S. electric grid will include a range of reactors, varied in size, design and mission – the product of several decades of continuous innovation. Some will make electricity around the clock. Others will produce electricity when it's needed, as a critical component of a low-carbon grid that also relies heavily on intermittent renewable energy. Some will provide high-quality heat for chemical processing or other industrial uses. Some will supply the transportation market, either with electricity to charge batteries, or hydrogen or other chemicals to be burned in engines, in a system with a vastly reduced carbon footprint. Some will make fresh water, or move water to where it is more valuable. Some reactors will produce energy from the used fuel of light-water reactors and, in the process, reduce the volume and toxicity of these materials.

The runway to that future is a continuum of developments, which starts with preservation of America's existing nuclear power plants (including second license renewal), proceeds through construction of more large Generation III+ nuclear plants, then small modular reactors and, finally, development, demonstration and deployment of advanced non-light-water reactors.

Allowing existing nuclear plants to close down prematurely because markets do not recognize their attributes and value compromises – perhaps fatally – America's ability to develop and deploy the more advanced technologies.

Allowing existing nuclear plants to close down prematurely leads to loss of technical knowledge and operational experience; erosion of the infrastructure that provides fuel, components and services; and loss of political and corporate confidence in the technology – the foundation on which the next generation would be built.

(Continued on page 21)

Status of New Nuclear Power Plant Development

There are four new nuclear power plants under construction in the United States.

All four are the same design – the Westinghouse AP1000. Southern Company is building Vogtle 3 and 4 at the Alvin W. Vogtle nuclear plant in Waynesboro, Ga.; South Carolina Electric & Gas is building Summer 2 and 3 at the Virgil C. Summer nuclear plant in Jenkinsville, S.C.

Construction of a fifth reactor, Tennessee Valley Authority's Watts Bar 2, was completed in 2015 and received its operating license from the Nuclear Regulatory Commission in October 2015. The plant started commercial operation in October 2016. The reactor began construction in 1973 and was halted in 1985 because of reduced electricity demand in the region. Construction resumed in 2007.

Three other combined license applications, representing five new reactors, are under active review at the NRC.

The four U.S. AP1000s are more than 50-percent complete, and are expected online in 2019 and 2020. Four AP1000s are also under construction in China at the Sanmen and Haiyang sites. Many lessons learned are being shared between China and the U.S. to improve construction efficiencies and processes.

The four reactors at Summer and Vogtle have been under construction for more than three years. The first units at each site were originally scheduled to begin commercial operation in April 2016, with the second unit at Vogtle following one year later and the second Summer unit in 2019. This start date assumed South Carolina Electric & Gas and Southern Co. would receive their construction/operating licenses from the Nuclear Regulatory Commission in September 2011. The NRC, however, did not grant Southern Co. its license until February 2012 and South Carolina Electric & Gas until March 2012 – seven and eight months later than originally scheduled.

The reactor pressure vessel for Summer Unit 2 is placed inside the containment in October 2016. Photo: Courtesy of South Carolina Electric & Gas Co.

Delays in obtaining NRC approval for the AP1000's design, and problems with the construction of plant components manufactured in Lake Charles, Louisiana, have resulted in schedule and cost changes at both projects.

Rebooting the EPC Contract. In October 2015, the project sponsors and the engineering-procurement-construction (EPC) consortium took a number of steps designed to improve project management and cost and schedule certainty.

Southern, South Carolina Electric & Gas and Westinghouse restructured the EPC contracts to resolve long-standing disputes that had plagued the projects. The agreements also ended litigation over disputed costs between the Vogtle owners and the Westinghouse-led EPC consortium.

Workers set the final roof truss for the Vogtle Unit 3 turbine building. Photo: Courtesy of Georgia Power Co.

In exchange for a cash payment from each of the project owners, the parties agreed to drop all claims for delay costs, and clarified what constitutes nuclear regulatory changes, which had been the source of many of the legal disputes. The amendment to the EPC contract also provided for higher liquidated damages, linked to timely completion of the nuclear plants and qualification for federal production tax credits, and incorporated financial incentives for the EPC contractor to meet the timeline.

In a separate but related agreement, Westinghouse agreed to acquire Stone and Webster, one of the original construction contractors on the projects, from Chicago Bridge & Iron (CB&I). The project owners had hoped that CB&I's 2013 acquisition of Stone and Webster would improve the quality and timely delivery of modules, but quality and delivery problems continued. In addition, Westinghouse engaged Fluor to manage construction at both projects.

Georgia Power Company agreed to pay approximately $350 million to the EPC contractors, of which about $120 million has been paid previously under the dispute resolution procedures in the current EPC Agreement. This is significantly less than the approximately $900 million previously in dispute. Georgia Power believes the settlement amount will allow it to remain within the 6-8 percent total rate increase it expects for the Vogtle project; a 4.5-percent increase is already in rates, with 1.5–3.5 percent still to come.

South Carolina Electric & Gas, which owns 55 percent of the Summer project, agreed to an additional $286 million in project costs over the $6.827 billion approved by the South Carolina Public Service Commission in September 2015. The new EPC agreement included an option to fix the remaining cost of the project at $6.082 billion (SCE&G's portion would be around $3.345 billion). This option would increase total project costs for SCE&G by an additional $488 million, but provide the certainty of a fixed-price transaction.

Both projects are collecting financing costs during construction (called construction work in progress, or CWIP), subject to periodic reviews by the state public service commissions. Despite the changes to schedule and cost to date, state support for the projects continues strong. Both the Georgia and South Carolina commissions have approved all rate increases requested to date.

Current Status. Both projects continue to focus on two major issues – labor and module assembly. At the Summer project, for example, Fluor is operating a 2-6-10 and 1-5-10 schedule – i.e., construction crews are scheduled to work six 10-hour days for two weeks, then five 10-hour days for one week. Approximately 3,800 contractor personnel and subcontractor workers are on each site daily. Fluor is also increasing the night shift to a full complement of 1,000 craft workers. Recruiting and retention of craft labor continues to present challenges, although the attrition rate (currently about 3-percent per month) is lower than is typical for most large construction projects.

Containment rings are set at the Summer project in South Carolina.

Fluor is also overhauling the legacy Chicago Bridge & Iron Co. processes for requisition, procurement and delivery of commodities and other materials and supplies used on site. CB&I's system was geared to "just in time" delivery, which did not allow for sufficient time to process deliveries for documentation review, inspection, stocking and distribution. Delays resulted in shortages that created construction inefficiencies. A number of mechanical modules previously shipped to the site by CB&I contained misalignments and other deviations from final design criteria. These modules are being disassembled and repaired on site.

Regulatory Status – South Carolina. In September 2016, South Carolina Electric & Gas, the Public Service Commission staff and a number of intervenors reached agreement on SCE&G's petition to update construction and capital cost schedules, including SCE&G's election of the fixed price option. The agreement includes substantial completion dates of August 2019 and August 2020 for Units 2 and 3; inclusion of an additional $831 million in capital cost, and a reduction in the allowed return on equity (ROE) for the new nuclear project from 10.50 percent to 10.25 percent. Under the Base Load Review Act, the revised ROE will be applied prospectively to rate revisions sought on and after January 1, 2017, until the new nuclear units are completed. SCE&G also agreed that it will not file future requests to amend capital costs prior to January 28, 2019.

In October 2016, the South Carolina PSC approved an increase of $64.4 million in SCE&G's rates. Lower fuel costs and purchased power costs more than offset the 2.66-percent increase, however. SCE&G had filed for the increase in June under provisions of South Carolina's Base Load Review Act (BLRA), a law enacted in 2007 that allows for annual adjustments to rates during construction of the units as a means of recovering the financing costs associated with the project.

Regulatory Status – Georgia. Also in October 2016, Georgia Power and the PSC staff reached a settlement agreement on the costs of Vogtle Units 3 and 4. Under the agreement, which must still be approved by the PSC:

- None of the $3.3 billion of costs incurred through December 31, 2015, and approved by the Georgia PSC in August 2016, will be disallowed from rate base on the basis of imprudence.
- Financing costs on verified and approved capital costs will be deemed

Conversely, failure to create a durable long-term program to develop and deploy new nuclear plants and the advanced nuclear technologies makes preservation of the existing nuclear plants even more difficult.

New nuclear plants and the advanced nuclear technologies are a magnet drawing the nuclear enterprise toward a sustainable future in which nuclear power plants – of varying sizes and designs – supply bulk electricity and a range of other products and services, and allow integration of larger amounts of renewable energy than might otherwise be possible. A promising future creates a compelling rationale for tackling challenges in the present.

In a short-term world of low-cost natural gas and no cost for releasing CO_2 to the atmosphere, it is counterintuitive and difficult to plan for construction of more large light water reactors and SMRs, and development and deployment of even more advanced nuclear technologies. But long-term planning is essential, and government and industry must both play their part.

Continued Deployment of Large Generation III+ Reactors

The first imperative is capitalizing on the lessons learned during construction of

prudent provided they are incurred prior to December 31, 2019, and December 31, 2020, for Vogtle Units 3 and 4, respectively.

- The in-service capital cost forecast will be adjusted to $5.68 billion (including $240 million of contingency), capital costs incurred up to the revised forecast will be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs, and Georgia Power would have the burden to show that any capital costs above the revised forecast are reasonable and prudent.

- The certified in-service capital cost for purposes of calculating the NCCR (Nuclear Construction Cost Recovery) tariff will remain at $4.418 billion. Construction capital costs above $4.418 billion will accrue an allowance for funds used during construction (AFUDC) through commercial operation.

- The return on equity (ROE) used to calculate the NCCR tariff will be reduced from 10.95 percent (the ROE authorized by the Georgia PSC in Georgia Power's most recent rate case) to 10 percent effective January 1, 2016.

- For purposes of the AFUDC calculation, the ROE on costs between $4.418 billion and $5.44 billion will also be 10 percent, and the ROE on any amounts above $5.44 billion would be Georgia Power's average cost of long-term debt.

- If the Georgia PSC adjusts Georgia Power's ROE in a rate case prior to Plant Vogtle Units 3 and 4 being placed into retail rate base, then the ROE for purposes of calculating both the NCCR tariff and AFUDC will likewise be 95 basis points lower than the revised ROE.

- Vogtle Units 3 and 4 will be placed into retail rate base on December 31, 2020, or upon reaching commercial operation, whichever is later.

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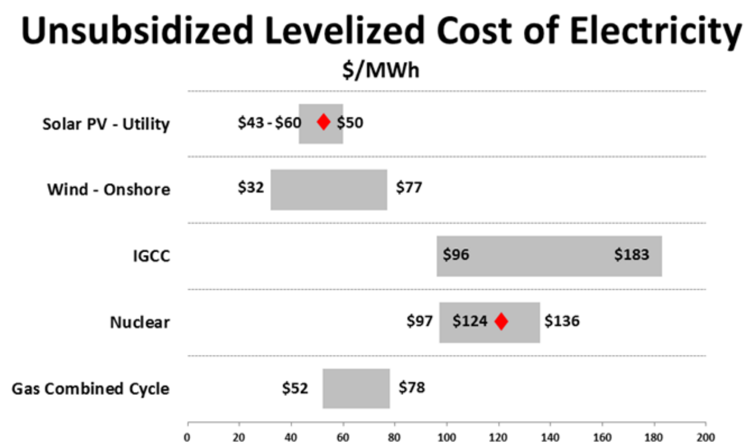
the new reactors in Georgia and South Carolina. When Vogtle and Summer are completed and operating is precisely the time for companies pursuing combined construction and operating licenses (COLs) to move toward construction of additional plants – assuming, of course, a need for the electricity. For those companies planning to use the AP1000 design, the detailed design and engineering will have been completed, thanks to the Vogtle and Summer projects, thus removing a major threat to cost and schedule certainty. In addition, the lessons learned from these two projects can be applied immediately to new projects, before too much time passes and those lessons are forgotten, in both the regulatory process and in construction and startup activities.



Solar PV - Utility: Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 30 MW system in high insolation region (e.g., Southwest U.S.). Does not account for differences in balance-of-system costs or other potential factors which may differ across solar technologies. Diamond represents estimated levelized cost of electricity in 2017, assuming $1.35/watt for single-axis tracking system.
Solar, Wind: Does not include grid integration cost, which can add $2 - $10/megawatt-hour.
Nuclear: Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies. Diamond represents estimate of current U.S. nuclear construction (e.g., AP-1000).
Gas Combined Cycle: Assumes natural gas price of approximately $3.50 per million Btu.

Source: Lazard, Levelized Cost of Energy Analysis, Version 9.0, 2015

Since the licensing process will have been tested on these first projects, and since the next projects will have already received and banked their COLs for a design that is already certified, it should be possible to reduce time-to-market to the time required for construction.

Companies must also satisfy themselves that new nuclear development makes economic sense. Generating companies today typically are hard-pressed to contemplate new nuclear development in a world dominated by low-cost gas.

New nuclear capacity is closer to being economically viable than commonly assumed, however. Lazard (see table) puts the unsubsidized levelized cost of electricity from new nuclear capacity in a range from $97 to $136 per MWh, with the plants now under construction in Georgia and South Carolina at an estimated $124 per MWh. At the low end, this is much closer than commonly assumed to the cost of electricity from a new gas-fired combined cycle plant. (Lazard's analysis assumes a long-term equilibrium natural gas price of $3.50 per million Btu.) Other estimates of the cost of electricity from a combined cycle plant are directionally similar (see the Energy Information Administration's estimates, next page).

But Lazard's estimates assume a traditional 50-percent-debt/50-percent-equity capital structure. With a more leveraged capital structure (i.e., 80-20 debt-equity) and non-recourse project financing supported by a federal loan guarantee, the $124/MWh nuclear plant becomes an $80-90/MWh plant, more closely competitive with the gas-fired option – and even more competitive when accounting for the other attributes of a nuclear power plant, like carbon-abatement value, forward price stability, and others.

So the most significant difference between a new nuclear project and a gas-fired combined cycle plant is not cost. This is not to say that a nuclear project and a combined-cycle gas project are identical. The nuclear project has unique licensing risks and construction execution risks. Time to market is longer for the nuclear project. But cost of electricity produced is not the massive impediment commonly assumed.

The major challenge for a new nuclear project is scale. These are large capital investments – $6-7 billion for a new reactor – being built by relatively small companies. The U.S. electric power sector consists of many relatively small companies, which do not have the size, financing capability or financial strength to finance power projects of this scale on their own, in the numbers required to reduce the electric sector's carbon "footprint."

Projects this large are not unique in the energy sector. In fact, $6-7 billion projects – and much larger – are routine in the petroleum industry. Shell's Prelude floating LNG facility offshore Australia cost in excess of $10 billion. Chevron's Gorgon natural gas project in Australia – which includes production, gathering and liquefaction facilities – cost more than $50 billion. Even the major oil companies, large as they are, seldom undertake major project development on their own.[11] They form project consortia to carve up the risk into portions they can readily absorb.

Estimated Levelized Cost of New Generating Capacity Resources

Plant Type	Range for Total System Levelized Costs (2013$/MWh)		
	Minimum	Average	Maximum
Geothermal	43.8	47.8	52.1
Wind - Onshore	65.6	73.6	81.6
Natural Gas – Conventional Combined Cycle	70.4	75.2	85.5
Hydro	69.3	83.5	107.2
Advanced Nuclear	91.8	95.2	101.0
Natural Gas – Advanced CC with CCS	93.3	100.2	110.8
Biomass	90.0	100.5	117.4
Advanced Coal	106.1	115.7	136.1
Solar PV	97.8	125.3	193.3
Advanced Coal with CCS	132.9	144.4	160.4
Wind – Offshore	169.5	196.9	269.8
Solar Thermal	174.4	239.7	382.5

Source: Energy Information Administration, *Annual Energy Outlook 2015*

New nuclear projects will require similar approaches: special-purpose entities to develop projects, with financing support to manage the scale risk – to offset the disparity in scale between project size and company size. For new nuclear projects, the federal loan guarantee program – authorized in the 2005 Energy Policy Act – is an essential financing technique. Loan guarantees have many benefits: They allow the industry to use project-finance-type structures, to employ higher leverage in the project's capital structure, and to fence off the project's credit risk from the project sponsors' balance sheets.

Continuing deployment of large light water reactors like the AP1000 and the ESBWR (Economic Simplified Boiling Water Reactor) will require a number of steps:

- Develop innovative approaches to financing, project development and ownership, and identify other policy changes (e.g., CWIP for wholesale nuclear plants in competitive markets or tax-related benefits) that would support a more forward-leaning construction program than is now contemplated. In addition to financing, new approaches to project development and ownership should be explored – including, for example, formation of a project development company, consisting of all companies interested in new nuclear development or all companies committed to a certain reactor design, that would finance and build new projects on a non-recourse basis, then sell them to a host utility when ready for commercial operation.

- The clean energy loan guarantee program, established in Title XVII of the 2005 Energy Policy Act, is as important a risk-management tool today as it was when the law was enacted. The Department of Energy should undertake an exercise, jointly with the nuclear energy industry, to identify lessons learned from initial implementation of the Title XVII loan guarantee program, including the reasons for certain projects abandoning the program. For example, calculation of the credit subsidy cost was a major stumbling block for certain nuclear projects. The industry believes that the most accurate and equitable process for calculating credit subsidy costs is a detailed, project-specific assessment. The approach used in 2009-2010, which relied on standard assumptions applied to all technologies, with limited project-specific flexibility, cannot produce accurate results, and will not serve the loan guarantee program's objectives – to support deployment of clean energy technologies in such a manner that the risk to the federal government is offset by fees paid by the borrower.

- The Department should also consider changes to current practices – e.g., allowing project sponsors to finance the credit subsidy cost (standard practice at the Export-Import Bank) – and seek legislative authority to accomplish this, if necessary.

- Targeted revisions to the Atomic Energy Act are also necessary to produce a more stable, more efficient licensing process, and to incorporate lessons learned during the licensing and construction of the new Vogtle and Summer projects.

New Nuclear Plants Under Consideration

Status	Company	Location (Existing Plant)	Design (Units)
Under Construction (4 units)	Southern Co.	Burke County, GA (Vogtle)	AP1000 (2)
	South Carolina Electric & Gas	Fairfield County, SC (V.C. Summer)	AP1000 (2)
Combined License Issued (5 units)	DTE Energy	Fermi, MI (Fermi)	ESBWR (1)
	Nuclear Innovation North America	Matagorda County, TX (South Texas Project)	ABWR (2)
	Duke	Levy County, FL	AP1000 (2)
Combined License Applications Under Active NRC Review (3 applications; 5 units)	Dominion	Louisa County, VA (North Anna)	ESBWR (1)
	Duke	Cherokee County, SC	AP1000 (2)
	Florida Power & Light	Miami-Dade County, FL (Turkey Point)	AP1000 (2)
Early Site Permits	Entergy (Issued)	Port Gibson, MS (Grand Gulf)	-
	Exelon (Issued)	Clinton, IL (Clinton)	-
	PSEG (Issued)	Lower Alloways Creek, NJ (Salem/Hope Creek)	-

Development and Deployment of Small Modular (Light Water) Reactors

In parallel with continued construction of large light water reactors will come first deployment of small modular reactors (SMR) in the early to mid-2020s.

Small modular reactors are a major step toward greater flexibility – e.g., shorter construction time, flexibility in siting, and possibly more manageable financing. Because of their small size (typically 50-250 megawatts), they can be built in a factory and assembled on site, minimizing field construction. An SMR facility may consist of several self-contained modules, allowing a utility to add new generating capacity in smaller

increments, which may be particularly valuable in a world where electricity demand is growing slowly. Financing may be easier, since construction of an SMR facility does not require a single large $6-7 billion commitment: The capital investment can be staged as modules are constructed. SMRs could be used to replace older fossil-fueled generation facing new clean air requirements that are too costly to meet. SMRs will be more flexible operationally than large nuclear plants, able to follow load. And some will use dry cooling, minimizing water requirements.

NuScale Power to Seek Design Certification by Year's End

NuScale Power LLC will be the first small modular reactor to file an application for design certifiction with the Nuclear Regulatory Commission. The company plans to submit its application by the end of 2016.

The NuScale Power Module is an integral — i.e., all major components are contained inside the pressure vessel — pressurized water reactor. Each NuScale Power Module produces 50 megawatts, with a full-size plant consisting of up to 12 reactors. The reactor vessel module can be shipped by rail, truck or barge to the plant site to allow for efficient manufacturing and construction.

NuScale reactors are submerged in a below-grade storage pool enclosed. The storage pool provides seismic dampening and radiation shielding. The NuScale reactors use natural forces like gravity and conduction for decay heat removal. In an accident, the NuScale reactors can shut down safely without operator action and will remove decay heat indefinitely, without electrical power or additional water.

In 2000, NuScale Power started a large-scale, test program for the NuScale Power Module at Oregon State University to demonstrate the potential of its design.

In June 2013, NuScale Power launched the Western Initiative for Nuclear (Project WIN), a multi-state collaboration to study the possible deployment of NuScale technology in western states. Project WIN is supported by the Western Governors' Association and many local leaders. Project WIN partnerships include several major, western utilities, including Energy Northwest in Washington state and the Utah Association of Municipal Power Systems (UAMPS). In 2014, UAMPS announced that it will apply to the NRC for a combined construction and operating license in 2017 for a NuScale facility. NuScale has also partnered with Fluor Corporation (a major investor in NuScale) to develop the supply chain for the NuScale reactor system.

In late 2013, the U.S. Department of Energy awarded funding for the NuScale Power design under DOE's Small Modular Reactor Licensing Technical Support Program. This public-private cost-shared program is a six-year, $452-million program that helps fund SMR licensing and development work.

To reduce the financial risk of the first movers and accelerate commercial deployment of SMR technologies, the U.S. Department of Energy (DOE) launched a cost-shared industry partnership program in early 2012. The DOE Licensing Technical Support program is funded on a 50-50 cost-shared basis by DOE and industry participants, with U.S. government support capped at $452 million over six years.

This program – which will carry a single SMR design through NRC design certification – is clearly not sufficient. A cost-shared program beyond the current DOE SMR program is essential. That program must include a much larger federal financial commitment and larger scope, including funding for at least two designs and design finalization beyond what's necessary for design certification. Necessary next steps include:

- The small modular reactor (SMR) program must be re-baselined to reflect realistic expectations of cost and private sector capability. The Department of Energy and Congress should increase support for small reactors beyond the current cost-share program. Even doubling or tripling the size of the current program – from $452 million to $1 billion or $1.5 billion – would represent a sound investment. DOE and the industry should also explore innovative approaches to close the funding gap, including use of the Title XVII loan guarantee program.

- Where appropriate, federal installations (like those operated by the Department of Energy and the Department of Defense) should use their unique positions and resources to advance SMR deployment – e.g., by serving as customers for the output. Options include long-term power purchase agreements, favorable leasing agreements, and making sites available. I fact, the leading SMR project has an agreement to use the Idaho National Laboratory as the host site.

Advanced non-light water reactor designs offer many technological advantages – passive cooling even in the absence of an external energy supply; operation at or near atmospheric pressure, which reduces the likelihood of a rapid loss of coolant; consumption of nuclear waste as fuel; the ability to adjust output to match intermittent sources of energy like wind and solar; and a larger product slate, including process heat for industrial applications, hydrogen for automobiles, clean water for human consumption and irrigation.

Development and Deployment of (Non-Light Water) Advanced Reactors

As the first SMRs start commercial operation in the mid-2020s, industry and government will be building and operating the facilities needed to demonstrate the safety and commercial feasibility of even more advanced designs. The goals:

- Demonstrate two or more advanced non-light water reactors by 2025.
- Ensure two or more advanced non-light water reactor designs are commercially available (i.e., ready to build) in the U.S. by 2030.
- Develop a licensing approach to facilitate deployment of these advanced technologies and encourage continued private-sector investment.
- Develop a business model that will support financing of the advanced technologies' development, demonstration and licensing.

Advanced non-light water reactor designs offer many technological advantages – passive cooling even in the absence of an external energy supply; operation at or near atmospheric pressure, which reduces the likelihood of a rapid loss of coolant; consumption of nuclear waste as fuel; the ability to adjust output to match intermittent sources of energy like wind and solar; and a larger product slate, including process heat for industrial applications, hydrogen for automobiles, clean water for human consumption and irrigation.

Advanced non-light water reactors come in various sizes, ranging from a few megawatts to over 1,000 megawatts. There are several advanced reactor technologies with great promise – molten salt (in which the molten salt serves as both fuel and coolant); liquid metal coolants, which have much higher heat transport capability than water, and thus provide a larger safety margin; and high temperature gas-cooled reactors.

The uncertainties associated with designing, testing and demonstrating, licensing, building, and operating first-of-a-kind technologies are major challenges. As with light-water SMRs, designing and licensing advanced non-light-water reactors is a capital-intensive proposition.

Due to the capital cost and long lifetime of a nuclear reactor, potential customers will likely want to see a demonstration of any particular technology to prove technical feasibility and cost-competitiveness.

Industry and government must address several major challenges to move successfully from proof-of-concept and small-scale fuel and component testing (today) to commercial deployment by 2030. Success requires a new licensing approach and a new business model to finance demonstration and development. As with continued deployment of large light water reactors, and development and deployment of SMRs, "business as usual" will not lead to success.

Licensing. Licensing conventional light water reactors is challenging and time-consuming. Licensing an advanced reactor is even more challenging because the existing regulatory framework is, understandably, based on light water reactor technology. The existing regulatory structure is not designed to facilitate innovation or encourage private investment. The structure must be modernized to establish a more technology-inclusive, risk-informed, performance-based framework. The regulatory approval process must be staged – i.e., it must include meaningful regulatory milestones that match investment decisions, to give investors confidence that the technology will meet NRC safety requirements and can be licensed.

Licensing an advanced reactor is even more challenging because the existing regulatory framework is based on light water reactor technology.

The structure must be modernized to establish a more technology-inclusive, risk-informed, performance-based framework. The regulatory approval process must be staged.

Financing. Developing a new approach to financing the demonstration and development of these advanced technologies is also a top priority. In January 2016, the Department of Energy awarded funds (up to $80 million over five years) to two consortia for advanced reactor development. This was a good first step, but this traditional "business as usual" approach – a government-industry program in which costs are roughly equally shared – will not be sufficient to meet the task at hand. Neither the private sector nor the federal government will be able to raise the funds necessary.

As a rule of thumb, a demonstration reactor – necessary to demonstrate basic design and safety concepts – can be expected to cost at least $1 billion.[12] Sufficient design and engineering to obtain a design certification from the NRC will add another $1 billion to $1.5 billion. The detailed first-of-a-kind engineering – necessary to produce bid specifications and support an engineering-procurement-construction contract – will add another $500 million. In all, approximately $2.5 billion to $3 billion per design.

It is likely that there are two or three different designs – each with different capabilities and attributes – with major commercial potential. This brings the total development and demonstration cost to perhaps $9-10 billion. Even spread over 10 years ($900 million to $1 billion a year), this is much larger than any program currently contemplated. For example, funding for advanced reactors in the 2016 fiscal year is $141 million. The Department of Energy requested $109 million for FY2017.[13]

Given the funding needs, in parallel with reforms to the NRC licensing process to accommodate advanced, non-light-water technologies, industry and government must start immediately to create a new, durable platform to finance advanced technology development. It is difficult to imagine that the Department of Energy (or the private sector, for that matter) will be able to raise the funds necessary to meet the challenge through annual appropriations.

The Challenge Facing the Electric Sector: Risk of Increasing Dependence on Natural Gas

Natural gas has many advantages – a relatively clean-burning fuel (certainly compared to coal), sourced domestically, with a large resource base. Low-cost natural gas is driving a manufacturing renaissance in the United States – particularly in the chemicals industry in the Gulf Coast states. Power plants fueled with natural gas have many unique advantages. Simple cycle gas turbines and combined cycle plants are flexible and relatively nimble – increasingly important for regions with large amounts of intermittent renewable generating capacity.

This aerial infrared photograph shows natural gas escaping from the Aliso Canyon storage field in southern California.

Gas-fired capacity has long been used to meet peak demand and mid-merit or intermediate load requirements. For the last decade, the capacity factor of the combined cycle fleet has averaged in the low- to mid-40-percent range. Current trends suggest, however, that these plants are increasingly used to meet base-load requirements, running 24-by-7.

But excessive reliance on natural gas carries with it vulnerability to price volatility and supply interruptions. The United States has had repeated warnings over the last five years of what can happen when states or regions find themselves too heavily dependent on natural gas – the Polar Vortex in 2014, a cold snap in New England in early 2013, and a period of cold weather in Texas in February 2011, which resulted in a massive service interruption.

During the Polar Vortex of 2013-2014, for example, natural gas and power prices reached record highs. On January 6-7, 2014, spot gas reached over $34 per million Btu (MMBtu) at the Algonquin city gate and over $55 per MMBtu at the New York city gate; reached over $120 per MMBtu at the New York city gate on January 22, and approximately $50 per MMBtu in Chicago a week later. PJM and MISO both experienced forced outage rates well in excess of average. Of PJM's 140,000 MW of generating capacity, 41,000 MW (almost 30 percent) was out of service. Of that, almost 10,000 MW was gas-fired capacity that could not obtain gas at any price; the rest, largely coal-fired capacity where coal piles or coal-handling equipment froze. Of MISO's 107,000 MW of generating capacity, almost 33,000 MW was forced out of service – over 6,500 MW because it could not obtain natural gas.

In 2016, the warning came in southern California, the result of major problems with the Aliso Canyon natural gas storage reservoir.

In October 2015, a gas leak was detected at the Aliso Canyon natural gas storage facility in southern California. The Aliso Canyon facility is a critical component of the gas system in the Los Angeles Basin. It is one of the largest natural gas storage facilities in the U.S. and is essential in providing a reliable gas supply to 18 large power plants with approximately 9,800 megawatts of capacity in the Los Angeles basin.

In a recent report – another in a series of such reports going back several years – the North American Electric Reliability Council warned of the threat to reliability associated with excessive dependence on natural gas in the power sector:

> "Until recently, natural gas interdependency challenges were most experienced during extreme winter conditions and focused almost exclusively on gas delivery through pipelines. However, a recent outage of an operationally-critical natural gas storage facility in Southern California — Aliso Canyon — demonstrates the potential risks to BPS [bulk power system] reliability of increased reliance on natural gas …The challenges faced in California represent a series of risks that have been layered into the system over the past decade: significant dependency on a single and just-in-time delivery fuel source, specifically for ramping capability to meet load and generation variability; reduced amount of baseload and dispatchable resources; increased amounts of variable and distributed resources; increasing need of system flexibility; gas system dependency on storage to maintain operating pressure; and a lack of clear understanding of natural gas operational characteristics and potential impacts on BPS operations …
>
> "[A]reas with a growing reliance on natural gas-fired generation are increasingly vulnerable to issues related to gas supply unavailability. Common-mode, single contingency-type disruptions to fuel supply and deliverability in areas with a high penetration of natural gas-fired generation are reducing resource adequacy and potentially introducing localized risks to reliability … Not only can impacts to BPS reliability occur during the gas-load peaking winter season, but they can also manifest during the summer season when electric demand is high and natural gas facilities are out of service, which can lower the operational capacity and flow of the pipeline system …
>
> "As gas-fired generation increases, the amount of generation capacity potentially impacted also increases, particularly when conditions affect a wide geographic area and support from the neighboring areas is unavailable. [E]xtreme weather events serve as early indicators of more frequent impacts to the BPS as more natural-gas-fired units continue to rely solely on just-in-time and non-firm fuel sources."

New England on Thin Ice. In New England, the grid operator continues to raise concerns about the region's growing dependence on natural gas for power generation. In its *2016 Regional Electricity Outlook*, published in January 2016, ISO New England notes:

A diverse portfolio of fuels and technologies – coal, nuclear, natural gas, hydro, non-hydro renewables, efficiency – is the core strength of the U.S. electric power supply system.

This fuel and technology diversity serves as a hedge against price volatility or supply disruptions in any part of the portfolio.

As with a financial portfolio, risks are lower with a diversified mix of assets.

> "[W]intertime access to natural gas has grown tight over recent years because the regional fuel transportation network has not kept up with demand from both generation and heating sectors. These natural gas constraints have led to grid reliability challenges, emission increases during winter, and spikes in wholesale electricity prices. The situation is exacerbated by other market dynamics: low gas prices during most of the year except winter are putting economic pressure on coal, oil, and nuclear resources. By 2020, resources representing about 30% of regional capacity have committed to cease operation or are at risk of retirement. Taking their place are even more natural-gas-fired units—currently, more than 60% of new generation being proposed by private investors across the six states will be primarily or exclusively fueled by natural gas."

The region's growing dependence on natural gas for power generation exposes consumers of electricity to increasing price volatility:

> "Because so much of the region's generating capacity runs on natural gas, the price of this single fuel source sets the price for wholesale electricity about 70% of the time. Both electricity and gas prices have seen dramatic swings in recent years. Between February and June 2015, for example, the region's average monthly wholesale electricity price plummeted from the third-highest price to the lowest price since 2003, the year that competitive markets in their current form were introduced in New England. Behind these ups and down is the region's inadequate natural gas delivery infrastructure, which can cause price spikes."

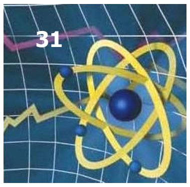
When New England's gas-fired generators have unconstrained access to natural gas, wholesale electricity prices are competitive nationally. During the winter, when gas supplies are constrained, it is a different story. In its report, ISO-New England compares electricity and natural gas prices in the Midcontinent ISO with those in New England during an average summer (June–August 2015) and winter (December 2014–February 2015):

Summer

Midcontinent ISO	**ISO New England**
$28.78/MWh	$26.86/MWh
$2.80/MMBtu	$2/MMBtu
(at Chicago City Gate)	(at Algonquin City Gate)

Winter

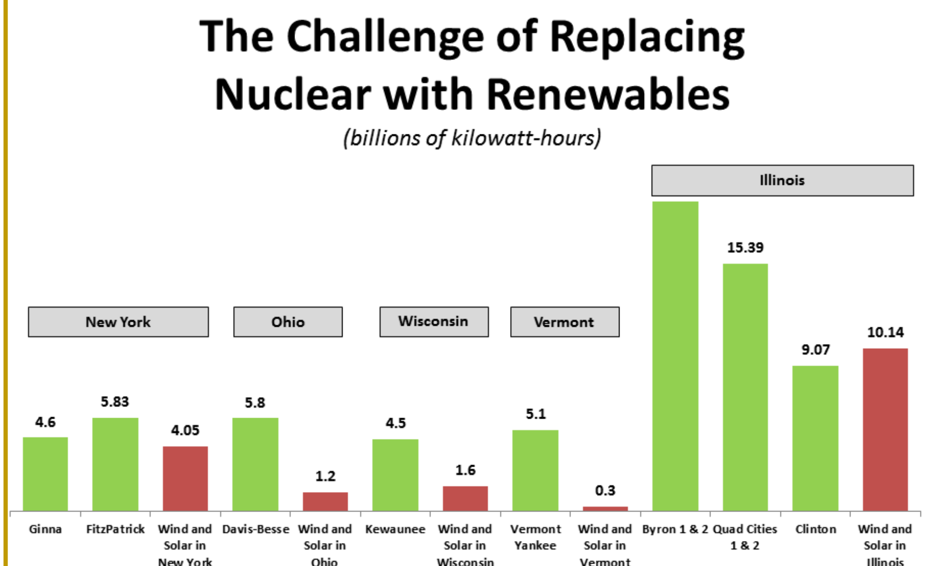
Midcontinent ISO	**ISO New England**
$29.31/MWh	$76.64/MWh
$3.74/MMBtu	$10.70/MMBtu
(at Chicago City Gate)	(at Algonquin City Gate)



It Takes A Portfolio to Ensure a Robust, Reliable Electricity System

Even at less-than-one-percent annual growth in electricity demand, the Energy Information Administration (EIA) forecasts a need for 196 gigawatts of new electric capacity by 2040 (22-percent growth) in the United States. To satisfy this demand at lowest possible cost without compromising the nation's environmental goals, the U.S. electric power industry must have a portfolio of electricity generating technologies, particularly low-carbon technologies.

Unfortunately, trends are moving in the other direction. America's electric generating technology options are narrowing dramatically:



Note: In reality, a nuclear plant would never be replaced with renewables because solar and wind are intermittent and non-dispatchable. Nuclear plants are dispatchable and operate 24-by-7. Nuclear would be replaced largely by emitting generation.
Source: Energy Information Administration. 2014 data except for Kewaunee (Wisconsin), which is 2012 generation, its last full year of operation

- Coal-fired generating capacity is declining in the face of increasing environmental restrictions, including the likelihood of controls on carbon, and uncertainty over the commercial feasibility of carbon capture and sequestration. The U.S. has about 280,000 MW of coal-fired capacity, and the consensus is that about 60,000 MW of that will shut down by 2021 because of escalating environmental requirements.[14] In addition, the pipeline of coal-fired projects under development is all but empty.
- Natural gas-fired generating capacity is growing dramatically. Since 1995, the United States has built approximately 367,000 megawatts of gas-fired capacity, approximately 73 percent of all capacity additions. Coal and nuclear, the two sources of electricity that can produce electricity around-the-clock at stable prices, represent a scant six percent of the generating capacity added. Clearly, the United States should not continue to build only gas-fired generating capacity.
- Renewables will play an increasingly large role but, as intermittent sources, cannot displace the need for baseload generating capacity, absent dramatic advances in energy storage. And replacing lost nuclear energy capacity with renewables would be a heroic undertaking.

A diverse portfolio of fuels and technologies – coal, nuclear, natural gas, hydro, non-hydro renewables, efficiency – is the core strength of the U.S. electric power supply system. This fuel and technology diversity serves as a hedge against price volatility or supply disruptions in any part of the portfolio. As with a financial portfolio, risks are lower with a diversified mix of assets.

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Endnotes

[1] *The Nuclear Industry's Contribution to the U.S. Economy*, The Brattle Group, July 2015.

[2] *2015 State of the Market Report for the ERCOT Wholesale Markets*, Potomac Economics, June 2016.

[3] *State of the Market Report for PJM*, First Quarter 2016, Monitoring Analytics, LLC, May 12, 2016.

[4] *2015 Assessment of the ISO New England Electricity Markets*, Potomac Economics, June 2016.

[5] *2015 State of the Market Report for the New York ISO Markets*, Potomac Economics, May 2016.

[6] *2015 Assessment of the ISO New England Electricity Markets*, Potomac Economics, June 2016.

[7] *2015 State of the Market Report for the New York ISO Markets*, Potomac Economics, May 2016. (These values for carbon-abatement cost apply to the Northeast. Regions of the country with different wind regimes and solar insolation levels would have different values. But preserving existing nuclear power plants is clearly one of the lowest-cost ways to reduce CO_2 emissions. In its proposed rule for the Clean Power Plan, the Environmental Protection Agency used these values: keeping "at risk" nuclear plants operating costs $12-$17 per metric ton of CO_2 abated; adding renewable capacity costs $10-$40 per metric ton of CO_2 abated; increasing natural gas combined cycle power plant utilization rates to 70 percent costs $30 per metric ton of CO_2 abated; and implementing demand-side management programs costs $16-$24 per metric of CO_2 abated.)

[8] *Market Impacts of a Nuclear Power Plant Closure*, Lucas Davis and Catherine Hausman, Energy Institute at Haas, University of California at Berkeley, May 2015.

[9] Supplemental Comments of Susan F. Tierney, Managing Principal, Analysis Group, Post-Technical Conference Comments on Centralized Capacity Markets, January 8, 2014, Docket AD13-7-000.

[10] Resource Investment in Competitive Markets, PJM Interconnection, May 5, 2016.

[11] Exxon-Mobil, for example, has a market capitalization of approximately $352 billion; Chevron Texaco, $196 billion. Southern Company's market cap is $50

billion; Duke's, $54 billion. (Data as of October 30, 2016.)

[12] This is likely unrealistically conservative. The 600-megawatt (thermal) demonstration project contemplated under the NGNP (Next Generation Nuclear Plant) program was estimated to cost approximately $4 billion.

[13] Senate appropriators raised that to $130 million; House appropriators, to $140 million.

[14] This is the estimated coal-fired capacity likely to be shut down due to existing regulation of so-called "criteria pollutants" (e.g., SO_2, NOx, fine particulates, mercury, air toxics). The Environmental Protection Agency's regulation to reduce carbon emissions from existing power plants would lead to an additional 30,000-35,000 MW of coal-fired retirements, by most estimates.