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Nuclear Power in Maryland: Status and Prospects

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MARYLAND POWER PLANT
RESEARCH PROGRAM

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The Maryland Department of Natural Resources seeks to preserve, protect and enhance the living resources of the state. Working in partnership with the citizens of Maryland, this worthwhile goal will become a reality. This publication provides information that will increase your understanding of how the department strives to reach that goal through its many diverse programs.

Jeannie Haddaway-Riccio, *Secretary*
Maryland Department of Natural Resources

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1.0 INTRODUCTION & BACKGROUND

1.1 PURPOSE- LEGISLATIVE MANDATE

This report summarizes the results of a detailed literature-based research study conducted by the Maryland Department of Natural Resources (DNR) Power Plant Research Program (PPRP). This study was required as the result of the Maryland Clean Energy Jobs Act, passed by the General Assembly in April 2019. The objective of this report is to assess the current status and future prospects for the use of nuclear power in Maryland.

Specifically, this report section (Section 1.0) presents the current state of nuclear energy in and around Maryland, a summary of the nuclear plant closures around the U.S., and the current and future economic status of the Calvert Cliffs Nuclear Power Plant (CCNPP) and the Peach Bottom Atomic Power Station. Also discussed in other report sections is the use of nuclear energy as a low-carbon resource (Section 2.0), an analysis of the emerging nuclear energy technologies (Section 3.0), a review of the nuclear energy development in other states and countries (Section 4.0), and a review of the potential state initiatives to support existing and new nuclear power plants (Section 5.0).

1.2 U.S. NUCLEAR POWER PLANT STATUS

1.2.1 National Overview

There are 96 commercial nuclear reactors generating electricity at 57 sites in the United States. In 2018, these reactors generated about 807 billion kilowatt-hours (kWh) of electricity, or about 63% of all electricity supplied by utility-scale generation facilities in the U.S.[1]

Commercial nuclear power became economically and technically viable in this country in the late 1950s, and new plants came online during the 1960s up until the early 1990s. In 1990, there were three new reactors commissioned; one new unit began operating in 1993 and another one in 1996. Since then, only one new reactor has begun operating in the U.S.: Watts Bar Unit 2 in Tennessee, which came on line in 2016.

The U.S. Nuclear Regulatory Commission (NRC) has approved multiple applications to increase output from nuclear plants, also referred to as an "uprate." As of April 2018, NRC has approved 164 uprates for a total of

[1] Information Digest 2019-2020 (NUREG-1350, Vol. 31), Chapter 3: Nuclear Reactors.

7,923 MW. In all, uprates have collectively added the equivalent of seven new reactors' worth of electrical generation to the power grid. NRC expects a few more power uprate applications through 2019.[2]

Over the past few years, construction has begun on new reactors in Georgia and South Carolina; these are discussed further in Section 3.

1.2.2 Current Status in and around Maryland

Calvert Cliffs is the only nuclear power plant operating in Maryland. Peach Bottom Atomic Power Station is located in Pennsylvania, but it is quite close to the state border. Maryland lies within the 10-mile emergency planning radius for the Peach Bottom facility. Other operating nuclear reactors in neighboring states include:

- Pennsylvania- Beaver Valley 1 & 2, Limerick 1 &2
- Virginia- North Anna 1 &2, Surry 1 & 2
- New Jersey- Hope Creek 1, Salem 1 &2

Delaware and West Virginia have no commercial nuclear power plants in operation.

Nuclear power accounts for approximately 34% of the electricity generated in Maryland.

1.2.2.1 Calvert Cliffs Nuclear Power Plant

CCNPP, operated by Exelon Generation Company, consists of two nuclear power reactors, Units 1 and 2. The plant is located in Lusby, Maryland, approximately 40 miles south of Annapolis.

[2] Information Digest 2019-2020 (NUREG-1350, Vol. 31), Chapter 3: Nuclear Reactors.

Figure 1-1 ***Calvert Cliffs Nuclear Power Plant***

NRC issued the operating license for CCNPP Unit 1 on July 31, 1974.[3] The Operating License was renewed on March 23, 2000, and expires on July 31, 2034. CCNPP's operating license for Unit 2 was issued on Aug. 13, 1976, and renewed on March 23, 2000. It expires on Aug. 13, 2036. Units 1 and 2 are both pressurized water reactors (PWRs)[4], each with a rated capacity of 2,737 MWt[5]. The combined electricity output of CCNPP is 1,756 MWe. The CCNPP also holds a separate NRC license for the Independent Spent Fuel Storage Facility Installation (ISFSI) at the site. The Calvert Cliffs ISFSI received a license extension in 2014 through November 2052.

1.2.2.2 *Peach Bottom Atomic Power Station*

The Peach Bottom Atomic Power Station (PBAPS), operated by Exelon, is located 17.9 miles south of Lancaster in Delta, Pennsylvania, and 2.7 miles north of the Maryland/Pennsylvania border. Peach Bottom originally consisted of three nuclear reactors, although Unit 1 is now shut down. PBAPS employs Maryland citizens and the operation of the PBAPS has an economic impact on the surrounding Maryland communities. Each unit is briefly described below.

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[3] nrc.gov/info-finder/reactors/

[4] PWR and BWR are both considered to be types of light water reactors. See NRC website for process description for a PWR and BWR: nrc.gov/reactors/power.html

[5] Megawatts electric (MWe) represents the electricity output capability of a power plant and megawatts thermal (MWt) represents the thermal input energy required by the power plant. See reference: R. Wolfson, "Energy and Heat," in *Energy, Environment and Climate,* 2nd ed. New York, U.S.A.: Norton, 2012, pp. 86-87

Figure 1-2 Peach Bottom Atomic Power Station

Unit 1 was a 200 MWt, high temperature, gas-cooled reactor that operated from June 1967 to October 1974, when it was permanently shut down. All spent nuclear fuel from Unit 1 was removed from the site, and the Unit 1 spent fuel pool was drained and decontaminated. The Unit 1 reactor vessel, primary system piping, and steam generators remain in place.

NRC issued an operating license for Unit 2 on October 25, 1973. It was renewed on May 7, 2003 and expires on August 8, 2033. Unit 3's operating license was issued on July 2, 1974, and it was also renewed on May 7, 2003. It expires on July 2, 2034. Units 2 and 3 are Boiling Water Reactors (BWRs), each with a rated capacity of 4,016 MWt.[6] The total electricity output for Units 2 and 3 is a combined 2,770 MWe. Used (spent) nuclear fuel from PBAPS are presently stored on-site within spent fuel pools for the recently discharged fuel or, in the case of older fuel generated in earlier years of plant operation, at an on-site ISFSI.

Exelon has filed an application with NRC for a second license renewal at Peach Bottom that would enable the facility to operate for an additional 20 years until 2054.[7]

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[6] nrc.gov/info-finder/reactors/

[7] Peach Bottom is only the third commercial nuclear generating facility in the U.S. to seek a second 20-year license renewal from NRC, so-called "subsequent re-licensing."

1.3 NUCLEAR PLANT CLOSURES AROUND THE U.S.

Table 1-1 provides a listing of the U.S. commercial nuclear power reactors that have closed since 2013. Table 1-2 presents a list of U.S. commercial nuclear power reactors that have publicly announced their plans to close, but have yet to close.

Table 1-1 U.S. Commercial Nuclear Reactor Closures Since 2013

Plant Name	State	Date Closed
Three Mile Island Unit 1	PA	9/20/2019
Pilgrim	MA	05/31/2019
Oyster Creek	NJ	09/17/2018
Fort Calhoun	NE	12/31/2016
Vermont Yankee	VT	12/29/2014
San Onofre 2 & 3	CA	06/12/2013
Kewaunee	WI	05/07/2013
Crystal River	FL	02/05/2013

NRC is currently evaluating the applications of both Turkey Point Nuclear Generating Station in Homestead, Florida, and Surry Power Station in Surry, Virginia.

Table 1-2 U.S. Commercial Nuclear Reactors that have Publicly Announced Closures and Updates on their Closure Plans

Plant Name	State	Announced/Planned Closure Date
FitzPatrick	NY	Announced closure for January 2017, but ratepayer subsidy has extended operations. Planned closure date is unknown at this time.
Ginna	NY	Announced closure for March 2017, but ratepayer subsidy has extended operations. Planned closure date is unknown at this time.
Palisades	MI	Announced closure for June 2022.
Davis-Besse	OH	Announced closure for May 31, 2020; now being changed as a result of state legislative action.
Indian Point 2	NY	Announced closure for April 2022.
Duane Arnold	IA	Announced closure for December 2020.
Indian Point 3	NY	Announced closure for April2021.
Perry	OH	Announced closure for May 31, 2021; now being changed as a result of state legislative action.
Beaver Valley Unit 1	PA	Announced closure for May 31, 2021.
Beaver Valley Unit 2	PA	Announced closure for Oct. 31, 2021.
Diablo Canyon 1	CA	Announced closure for Nov. 2, 2024.
Diablo Canyon 2	CA	Announced closure for Aug. 26, 2025.

At present, nuclear energy supplies approximately 20% of the world's electricity and constitutes a major fraction of low-carbon electricity generation in the United States, Europe, and globally.[8]

Despite its prominence, nuclear power generation in the U.S. faces a variety of economic challenges. Nuclear energy has become less cost competitive in the electricity marketplace compared to combined cycle power plants fueled by natural gas, along with alternative renewable power generation projects, which utilize hydroelectric, wind, and solar power.

The economic challenges faced by nuclear power generation are especially acute in PJM Interconnection, LLC, a regional transmission organization. PJM manages wholesale electricity in all or part of 13 states and the

[8] MIT, 2018: "The Future of Nuclear Energy in a Carbon-Constrained World," An Interdisciplinary MIT Study

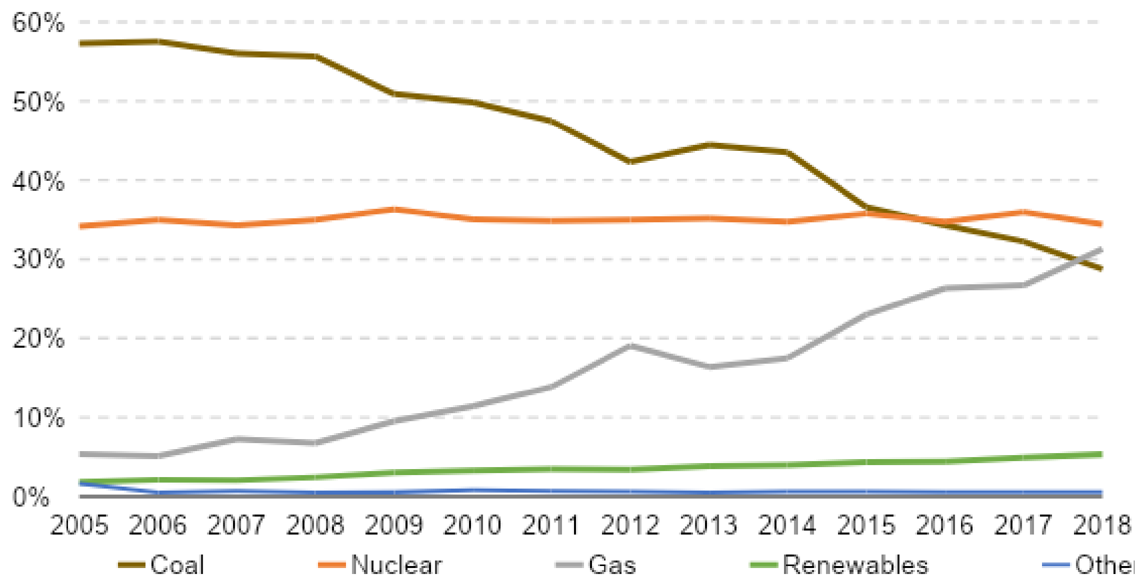
District of Columbia that are in the mid-Atlantic and Midwest region, including almost all of Maryland. Electric generators in PJM, including nuclear power plants, compete on an economic basis. This competition manifests itself in two important market constructs: an energy market, whereby resources are committed and dispatched on a day-ahead and real-time basis, respectively, to provide power, and; a capacity market, whereby resources are committed on a three-year forward basis to be available to provide power in the future. In both markets, resources are selected on the basis of least-cost, meaning lower cost resources are given priority subject to constraints including availability and location.

Several concurrent factors are working to push both energy and capacity market prices downward. First, natural gas prices have fallen steeply in the aftermath of the shale boom in the early 2010s, during which time producers gained access to abundant supplies of natural gas using advanced drilling techniques. The resulting increase in supply created a glut of available natural gas and drove down fuel prices. The electric power sector responded to this change by increasing the use of natural gas-fired generation to take advantage of reduced fuel costs. For example, natural gas prices to electric power sector users in Pennsylvania fell from $5.04 per thousand cubic feet (MCF) in 2014 to just $1.94/MCF in 2016, before bouncing back to $3.12/MCF in 2018.[9] Changes in the PJM resource mix, as illustrated in Figure 1-3, show the resulting impact of reduced natural gas prices. In 2005, coal contributed approximately 57% of total electricity generation in PJM. In 2018, this share fell to approximately 29%. In contrast, natural gas generation has expanded its share from 5% in 2005 to nearly 31% in 2018.[10]

[9] "Natural Gas Prices," Energy Information Administration, eia.gov/dnav/ng/NG_PRI_SUM_DCU_SPA_A.htm

[10] "PJM System Mix," PJM Interconnection, LLC, gats.pjm-eis.com/gats2/PublicReports/PJMSystemMix

Figure 1-3 Share of PJM Generation (in GWh), by Fuel Source (2005-2018)



Source: PJM GATS

The second contributing factor to the decline in PJM energy and capacity prices is flat or declining demand. This drop, along with tepid growth thereafter, is shown in Figure 1-4, which tracks retail energy sales in states that participate in PJM regardless of when they joined PJM or what proportion of the state participates. Maryland demand follows a similar, albeit flatter, trend, having decreased by over 9,000 GWh in total from a peak requirement of 68,365 GWh in 2005 to the 2017 total retail sale level of 59,304 GWh.[11] The ongoing decline of demand is due, at least in part, to energy efficiency initiatives. Declining demand coupled with increased supply has put downward pressure on prices from existing resources. Note that PJM-specific retail energy sales continued to grow during this period despite stagnated demand in the states that participate in PJM due to the ongoing expansion of the PJM footprint.

[11] "Sales to Ultimate Customers (Megawatthours) by State by Sector by Provider, 1990-2018," Energy Information Administration, eia.gov/electricity/data/state/sales_annual.xlsx.

Figure 1-4 Total Retail Energy Sales in States that Participate in PJM (2004-2017)

Note: The retail energy sales data in this figure include the totality of sales in states that participated in PJM from 2004 through 2017 regardless of what portion of the state participates in PJM, or when the state joined PJM. These data distinguish broader trends in retail energy sales from changes due to the ongoing growth of the PJM footprint.

Source: eia.gov/electricity/data/eia861/

Finally, in addition to increased natural gas generation and declining electricity demand, renewable energy's share of net generation has grown from 1.1% in 2005 to 5.4% of total PJM generation in 2018, as shown earlier in Figure 1-3. The share of non-hydro renewable energy generation has grown from 0.9% in 2005 to 3.9% in 2018.[12] Increased penetration of renewable energy, including low-marginal cost resources like wind and solar, has put further downward pressure on energy prices and, where applicable, also capacity prices. As with the above factors, this reduction in prices has eroded the competitiveness of nuclear power plants in energy and capacity markets. More specifically, falling energy and capacity prices are sometimes below the cost for nuclear power plants to produce energy and, as a result, they are not dispatched or committed in energy or capacity markets, or both. Despite these challenges, the U.S. nuclear industry remains a world leader in nuclear power generation with the continued operation of the existing fleet of commercial nuclear power plants. However, the U.S. nuclear industry has had problems managing the cost and construction schedule of both new commercial nuclear power plants and significant modifications at existing commercial nuclear power plants.

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[12] "PJM System Mix," PJM Interconnection, LLC, gats.pjm-eis.com/gats2/PublicReports/PJMSystemMix

Examples of the cost overruns and construction schedule delays include the component-replacement projects at the San Onofre commercial nuclear power plant, which were significant factors associated with the premature closure of both units at San Onofre in 2013. Other examples include the Vogtle and V. C. Summer commercial nuclear power plant expansion projects with the Westinghouse AP1000 nuclear reactor technology. Both projects reported significant cost overruns and construction schedule delays.

Vogtle Units 3 and 4 located in Georgia have two new nuclear reactors which are actively under construction. The V.C. Summer nuclear expansion project began as a shared effort between V.C. Summer Nuclear Generating Station owners, SCANA Corporation (a regulated electric and natural gas public utility) and Santee Cooper, to add two reactors (Units 2 and 3) to the South Carolina plant. However, the decade-long, $9 billion expansion was bogged down by delays and cost overruns until the effort was ultimately abandoned in July 2017. Also, it has been reported that for the Vogtle and V.C. Summer commercial nuclear power plant projects, costs doubled and construction time increased by more than three years, contributing to reactor supplier Westinghouse's decision to declare bankruptcy.[13] The V.C. Summer project was officially canceled in 2017.

These cost overruns and construction schedule delay problems are not unique to the U.S. nuclear power industry. New nuclear power plant construction projects by French reactor suppliers Areva and EDF at Olkiluoto (Finland), Flamanville (France), Hinkley Point C (United Kingdom), and Wylfa Newydd (United Kingdom) have reportedly suffered similar problems.

Another issue facing the nuclear industry is public confidence regarding the safety of commercial nuclear power generation following the March 2011 accident at the Fukushima Daiichi commercial nuclear power plant in Japan. The 2011 accident resulted from the magnitude 9.0 Tohoku earthquake and subsequent tsunami. As a safety precaution, the Japanese authorities evacuated approximately 200,000 people from the region surrounding the Fukushima Daiichi commercial nuclear power plant. While the event had significant human impact,[14] in contrast, the *radiological* consequences of the accident have been reported to be

[13] Cardwell, D., and J. Soble, 2017: "Westinghouse Files for Bankruptcy, in Blow to Nuclear Power." The New York Times, March 29, 2017. Website: nytimes.com/2017/03/29/business/westinghouse-toshiba-nuclear-bankruptcy.html

[14] The earthquake and tsunami resulted in the death of more than 15,000 people, including those who were evacuated and experienced accidents or adverse conditions during the evacuation process. The Japanese government has recognized that four people, all workers at the plant, were sickened by radiation exposure caused by the accident; one of the workers died of lung cancer in 2018.

minimal. [15] The political consequences of the accident resulted in a temporary shutdown of the entire Japanese fleet of commercial nuclear power reactors in 2012, with a very gradual process to restart power generation from these facilities. Post-Fukushima, several countries have announced their intentions to ultimately phase out nuclear energy, including Belgium, Germany, South Korea, Spain, Switzerland and Taiwan.

1.4 *CURRENT AND FUTURE ECONOMIC STATUS OF CCNPP AND PBAPS*

As of 2018, there were 18 operational nuclear plants operating on the PJM grid. PJM's market monitor, Monitoring Analytics, LLC, conducted a net revenue analysis (i.e., whether the plant's revenues from PJM markets exceed or are below the plant's cost to operate) of these plants using publicly available energy and capacity price data from PJM as well as unit cost data from the Nuclear Energy Institute (NEI).[16] The unit cost calculations are based on NEI's most recent operating cost and incremental capital expenditure data (2017). Monitoring Analytics found that 15 of the nuclear plants in PJM did not recover all fuel, operation, and capital expenditure costs in 2016, eight did not in 2017, and two did not in 2018. The surplus or shortfall for each of these plants during the last three years is shown in Table 1-3.

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[15] United Nations Scientific Committee on the Effects of Atomic Radiation, 2017: "Developments since the 2013 UNSCEAR report on the levels and effects of radiation exposure due to the nuclear accident following the Great East-Japan Earthquake and Tsunami—A 2017 white paper to guide the Scientific Committee's future programme of work."

[16] "PJM State of the Market- 2018," Monitoring Analytics, monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf

Table 1-3   PJM Nuclear Unit Surplus (or Shortfall) from 2016-2018

	Installed Capacity (MW)	2016	2017	2018
Beaver Valley	1,808	($0.60)	$2.40	$11.90
Braidwood	2,337	($3.40)	($1.70)	$3.90
Byron	2,300	($9.70)	($2.90)	$3.80
Calvert Cliffs	**1,708**	**$7.10**	**$5.90**	**$14.30**
Cook	2,069	($0.70)	$1.30	$7.00
Davis-Besse	894	($4.30)	($8.60)	($1.80)
Dresden	1,797	($1.80)	($0.40)	$5.10
Hope Creek	1,172	($2.40)	$1.20	$10.00
LaSalle	2,271	($3.70)	($2.00)	$4.00
Limerick	2,242	($2.20)	$1.40	$10.20
North Anna	1,892	$2.80	$4.60	$14.00
Peach Bottom	**2,347**	**($2.50)**	**$1.10**	**$9.70**
Perry	1,240	($4.20)	($7.60)	$1.00
Quad Cities	1,819	($9.60)	($3.60)	$2.40
Salem	2,328	($2.40)	$1.10	$10.00
Surry	1,676	$2.40	$4.40	$14.00
Susquehanna	2,520	($1.90)	$1.50	$7.90
Three Mile Island	803	($12.40)	($10.30)	($4.50)

Note: Excludes Oyster Creek, which retired in September 2018.

From 2016-2018, CCNPP obtained the highest surplus of all nuclear plants in PJM and was one of only three plants with a surplus in 2016. Additionally, in 2018, CCNPP's surplus ($14.30/MWh) exceeded the average $/MWh surplus of PJM nuclear plants ($6.83/MWh) by more than 100%. This largely stems from CCNPP's very high energy revenues, owing to the plant's location in a constrained portion of the PJM grid. CCNPP's average day-ahead locational marginal price (LMP), which reflects location-specific supply and demand conditions, from 2016-2018 was the highest of the 18 plants evaluated by Monitoring Analytics.

PBAPS, by comparison, experienced a shortfall in revenue in 2016. This shortfall, however, was recovered through surpluses in 2017 and 2018. Additionally, the PBAPS revenue shortfall in 2016 was the only shortfall at PBAPS from 2008-2018, the full period of Monitoring Analytics' analysis. Despite PBAPS having lower energy revenues (33rd percentile) than most PJM nuclear power plants, it also has higher capacity revenues (88th percentile) than most, helping support a revenue surplus.

Both CCNPP and PBAPS have retained positive revenue according to this methodology despite declining capacity and energy revenues in PJM generally. Besides the above advantages in terms of capacity and energy revenue, this is also partially because nuclear unit costs have declined in recent years. Unit costs spiked in 2012 when, in the aftermath of the Fukushima accident, many plants made safety-related upgrades. The declining unit costs has benefited most nuclear plants, including CCNPP and PBAPS.

Monitoring Analytics also assessed expected revenues to PJM's nuclear plants on a forward basis using future energy market prices, known capacity market prices, and unit cost data as of 2017 from NEI. Future energy market prices are based on existing trades in the forward day-ahead market. Energy market prices and unit costs are both subject to change. Nevertheless, these figures represent the best available estimate of nuclear plant revenues using public data. Monitoring Analytics estimates that five of the above nuclear plants will not recover all fuel, operation, and capital expenditure costs in 2019, nine will not in 2020, and (the same) nine will not in 2021. The surplus or shortfall for each of these plants for the next three years is shown in Table 1-4.

Table 1-4 Estimated Future PJM Nuclear Unit Surplus (or Shortfall) from 2019-2021 ($/MWh)

	Installed Capacity (MW)	2019	2020	2021
Beaver Valley	1,808	$1.40	$0.78	$1.38
Braidwood	2,337	$1.24	($0.17)	($0.73)
Byron	2,300	$1.18	($0.18)	($0.74)
Calvert Cliffs	**1,708**	**$2.13**	**$1.43**	**$1.99**
Cook	2,069	($0.20)	($2.03)	($1.36)
Davis-Besse	894	($10.39)	($11.78)	($10.32)
Dresden	1,797	$2.06	$0.67	$0.09
Hope Creek	1,172	$0.63	$0.59	$0.74
LaSalle	2,271	$1.24	($0.17)	($0.73)
Limerick	2,242	$0.75	$0.63	$0.78
North Anna	1,892	$1.83	$0.85	$1.48
Peach Bottom	**2,347**	**$0.16**	**$0.47**	**$0.62**
Perry	1,240	($9.62)	($10.44)	($9.04)
Quad Cities	1,819	$0.28	($1.31)	($1.84)
Salem	2,328	$0.62	$0.57	$0.72
Surry	1,676	$1.52	$0.70	$1.34
Susquehanna	2,520	($2.58)	($2.93)	($2.31)
Three Mile Island	803	($12.95)	($15.10)	($14.49)

Note: Excludes Oyster Creek, which retired in September 2018.

Much like CCNPP has produced the highest estimated revenue in the last three years, it is also expected to retain positive revenue going forward.

This is primarily due to high projected LMPs from being in a transmission-constrained area. However, the level of surplus is substantially lower than in recent history. This is driven by steep declines in capacity market prices. CCNPP's capacity market revenues range from \$4.03/MWh to \$5.57/MWh. Capacity market revenues for PBAPS are slightly higher, ranging from \$7.00/MWh to \$7.67/MWh. PBAPS, like CCNPP, is expected to achieve revenue surplus in all three forward years. This surplus is lower than CCNPP, however, in part due to low estimates of future energy prices. Energy market revenues are estimated to range from \$23.84/MWh to \$24.36/MWh for PBAPS. In contrast, energy market revenues for CCNPP are expected to range from \$27.45/MWh to \$28.29/MWh.

2.0 NUCLEAR ENERGY AS A LOW-CARBON RESOURCE

2.1 IDENTIFICATION OF THE BENEFITS OF NUCLEAR ENERGY USE IN MARYLAND

2.1.1 *Climate Change/Carbon Emissions*

Nuclear power plants produce virtually no greenhouse gas (GHG) emissions or air pollutants during their operation and only very low GHG emissions over their full life cycle.[17] Use of nuclear power can therefore contribute to Maryland's effort to reduce GHG emissions and address climate change while delivering clean energy in large quantities.

The advantages of nuclear power in terms of climate change are an important reason why many countries, including China, Russia, Belarus, Finland, India, Japan, and the United Arab Emirates, are planning to introduce the use of commercial nuclear power or to expand existing commercial nuclear power programs in the coming decades.[18] However, the capital cost of new nuclear plants is high compared to fossil fuels (i.e., coal and natural gas). Under current conditions, traditional fossil fuels are on an average more cost-effective alternative to building new nuclear plants for baseload commercial electricity generation.[19]

There have been numerous studies performed and papers written regarding the lifecycle of GHG emissions associated with electricity generation. The World Nuclear Organization (WNO) published a report in 2011 that compares lifecycle GHG emissions of various electricity generation sources.[20] The report provided a compilation of research literature and detailed an approach to determine which literature sources would be referenced as part of the report. The WNO requirement criteria were as follows:

- Be from a credible source. Studies published by governments and universities were sought out, and industry publications used when independently verified.

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[17] MIT, 2018: "The Future of Nuclear Energy in a Carbon-Constrained World," An Interdisciplinary MIT Study

[18] world-nuclear.org/information-library/current-and-future-generation/plans-for-new-reactors-worldwide.aspx

[19] MIT, 2018.

[20] World Nuclear Organization, 2011: "Comparison of Lifecycle Greenhouse Gas Emissions of Various Electricity Generation Sources," world-nuclear.org/uploadedFiles/org/WNA/Publications/Working_Group_Reports/comparison_of_lifecycle.pdf

- Clearly defined the term "lifecycle" used in their assessment. Although the definition can vary, the source needed to clearly state what definition was being used to be considered credible.

- Include nuclear power generation and at least one other electricity generation method. This would ensure that the comparison to nuclear was relevant.

- Express GHG emissions as a function of electricity production (e.g., kg CO_2e/kWh or equivalent). This would ensure that the comparison across different methods of electricity generation was relevant.

As shown by Table 2-1, the maximum mean tons CO_2e/GWh (i.e., 1,054) is for lignite,[21] followed by coal (i.e., 888). The nuclear CO_2e/GWh maximum mean tons value (i.e., 29) was calculated to be 3.3% of the coal CO_2e/GWh maximum mean tons value (i.e., 888) and 5.8% of the natural gas CO_2e/GWh maximum mean tons value (i.e., 499). Only hydroelectric and wind technologies have a slightly lower lifecycle CO_2e/GWh maximum mean tons value (i.e., 26 for both) compared to nuclear.

Table 2-1 Summary of Lifecycle GHG Emission Intensity

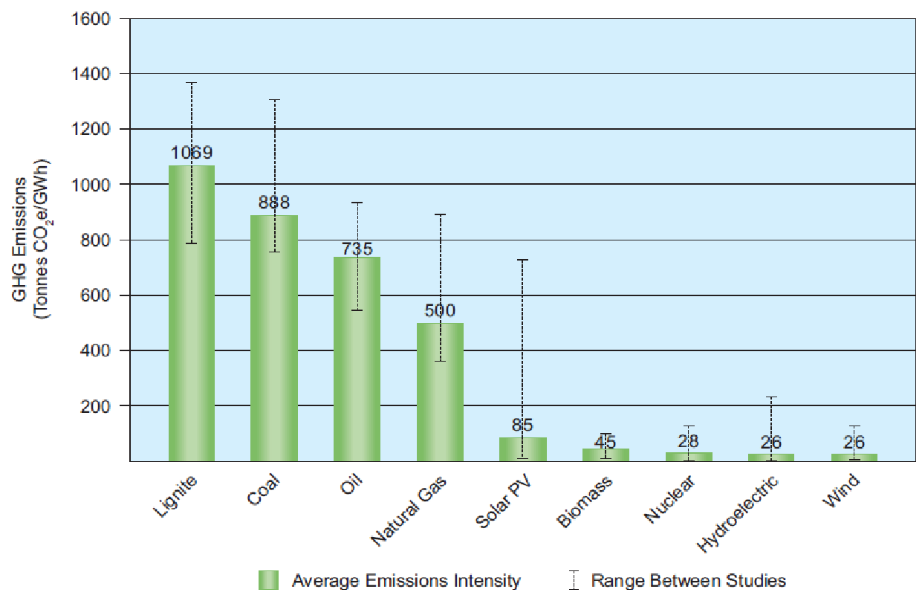
Technology	Mean	Low	High
	tonnes CO_2e/GWh		
Lignite	1,054	790	1,372
Coal	888	756	1,310
Oil	733	547	935
Natural Gas	499	362	891
Solar PV	85	13	731
Biomass	45	10	101
Nuclear	29	2	130
Hydroelectric	26	2	237
Wind	26	6	124

A total of 83 different literature sources were used in the WNO evaluation. Based on the data obtained from different literature sources, including industry associations, government, and academia, the report concluded that the emission intensities depicted in Table 2-1 are consistent regardless of the data source.

[21] Lignite is a brownish-black coal, intermediate between peat and bituminous.

Figure 2-1 presents the lifecycle GHG emissions for different electricity generation methods, depicting the mean and the range between values from different studies. Lignite/coal fired power plants have the highest GHG emissions on a lifecycle basis. Natural gas and, to some degree, oil have relatively lower GHG emissions compared to lignite/coal. However biomass, nuclear, hydroelectric, wind, and solar photovoltaic all had lifecycle GHG emissions that are significantly lower than those associated with generation from burning fossil fuels (i.e., lignite, coal, oil, and natural gas).

Figure 2-1 Lifecycle GHG Emissions of Various Electricity Generation Methods



Commercial nuclear power plants are designed with multiple physical barriers (e.g., a containment building). Multiple physical barriers are generally not built within other electrical generating sources like lignite, coal, natural gas, solar photovoltaic (PV), biomass, hydroelectric, and wind. As a result, it is concluded that GHG emissions attributed to construction of a commercial nuclear power plant are higher than GHG emissions resulting from construction of other generation methods. These additional GHG emissions were accounted for in each of the studies presented in Figure 2-1. Even when GHG emissions from the multiple physical barriers and additional safety barriers are included, the GHG lifecycle emissions of nuclear energy has been shown to be much lower than fossil fuel-based generation methods.

2.1.2 *Other Air Emissions*

Combustion of fossil fuels results in emissions of regulated air pollutants, which can be harmful to human health and the environment. The only combustion sources routinely operating at CCNPP are the emergency diesel generators that are tested routinely and emit insignificant emissions of regulated criteria air pollutants.

Other sources of regulated criteria air pollutants at the CCNPP are particulate emissions, which are insignificant and primarily associated with plant vehicular traffic over paved plant roads. Overall, regulated criteria air pollutants from nuclear energy and renewable fuels (solar PV, biomass, hydroelectric, and wind) are insignificant compared to regulated criteria air pollutant emissions from fossil fuels (lignite, coal, fuel oil, and natural gas) used by commercial electric power plants.

Another study assessed the reductions in mortality and GHG emissions attributed to the use of nuclear energy as a replacement for fossil fuels as a portion of electrical generation.[22] The study considered historical global electricity production data from 1971 through 2009, and provided projections of the expected benefits through the year 2050.

The study concluded that for the time period 1971-2009, the use of nuclear power to replace a portion of the electrical generation that otherwise would have been provided by fossil fuels has resulted in a reduction of more than 60 gigatons of carbon dioxide-equivalent GHG emissions as well as improvements in air quality that have prevented a number of premature deaths (see Figure 2-2).

Figure 2-3 presents the world electrical generation by power source for the time period 1971–2009. From 2000–2009, nuclear energy provided an average of approximately 15% of the worldwide power generation; coal, natural gas, and oil provided approximately 40%, 20%, and 6%, respectively; and renewables provided approximately 19% (with hydroelectric being 17% and non-hydroelectric being 2%). The study concludes that “nuclear power has provided a large contribution to the reduction of global mortality and GHG emissions due to fossil fuel use” and that meeting future GHG emissions targets requires “expanding the role of nuclear power, as well as energy efficiency improvements and renewables, in the near-term global energy supply.”[23]

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[22] Kharecha, A. and Hansen E.: “Prevented Mortality and Greenhouse Gas Emissions from Historical and Projected Nuclear Power”, Journal of Environmental Science & Technology, American Chemical Society (ACS) publication, Volume 47, published March 15, 2013.

[23] Ibid.

Figure 2-2 Mean Number of Deaths Prevented Annually by Use of Nuclear Energy from 1971- 2009

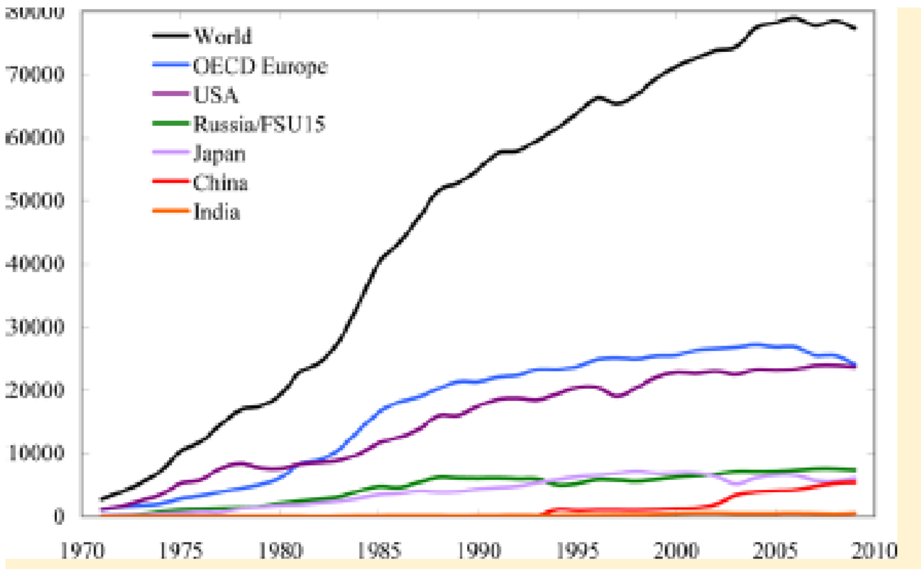
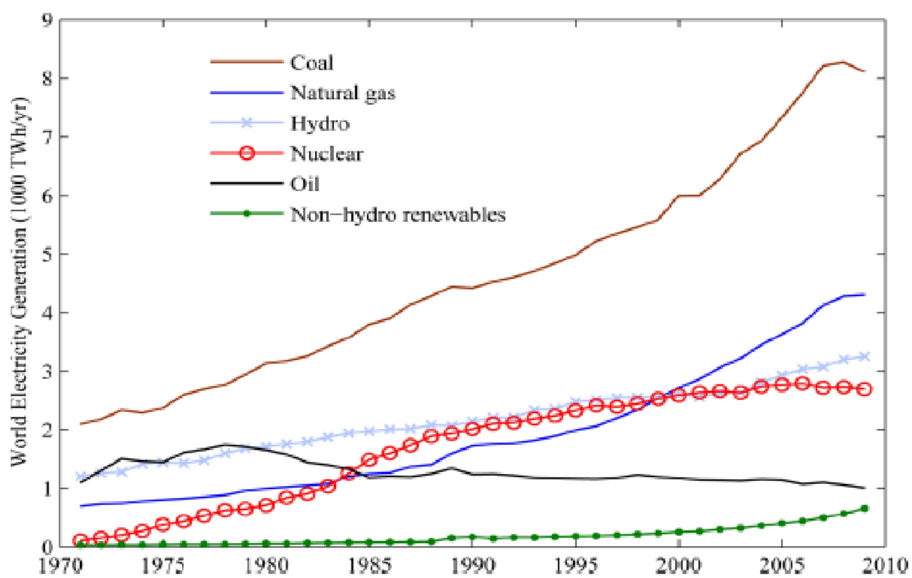


Figure 2-3 World Electricity by Electrical Power Source for the Historical Period 1971- 2009



2.1.3 *Economic Benefits to Maryland of Existing Nuclear Power Plants*

Maryland already receives economic benefits from the continued operations of CCNPP and, to a lesser extent, PBAPS. According to Exelon, CCNPP employed approximately 900 workers with an annual payroll of approximately $125 million as of 2016. The plant also paid approximately

$22.8 million in tax payments in 2016.[24] According to Calvert County, CCNPP is the fourth biggest employer located in the county as of 2018, with an estimated 822 employees. CCNPP also contributes a significant Payment in Lieu of Tax (PILOT) to the county equal to $19.6 million per year. This contribution represents 6.6% of Calvert County's 2019 revenues.[25] Besides direct contributions, CCNPP and its employees also sponsor or volunteer with local science fairs, career day events, and charities. Indirect economic impacts also arise from the CCNPP workforce purchasing goods and services within Calvert County and the nearby area.

There are less direct impacts to Maryland from PBAPS as compared to CCNPP. According to Exelon, PBAPS employed approximately 860 workers with an annual payroll of approximately $84.2 million as of 2016.[26] More recent figures from NEI suggest the plant employed 775 people in 2018 with an annual payroll of $85 million.[27] Many of these workers, however, live in Pennsylvania. Although PBAPS paid approximately $1.5 million in property taxes in 2016, all of these payments were to York County, Pennsylvania.[28] Additionally, although PBAPS employees support a variety of local charities and community activities, including donating over $460,000 to local organizations in 2017 and $540,000 in 2018, most of the recipient organizations (as listed on Exelon's website) are based in Pennsylvania.[29,30] Exelon is not identified among the major employers of either Harford County or Cecil County.[31]

24 "Calvert Cliffs Nuclear Power Plant Fact Sheet," Exelon Generation, exeloncorp.com/locations/Documents/Calvert%20Cliffs%20Fact%20Sheet%20-%202017.pdf

25 "Operating and Capital Budget Fiscal Year 2020," Board of County Commissioners, Calvert County, co.cal.md.us/DocumentCenter/View/26976/FY2020-Adopted-Budget

26 "Peach Bottom Atomic Power Station Fact Sheet," Exelon Generation, exeloncorp.com/locations/Documents/Peach%20Bottom%20Atomic%20Power%20Station%20Fact%20Sheet.pdf

27 "5 Things to Know About Peach Bottom Nuclear Plant," Nuclear Energy Institute, nei.org/news/2019/5-things-know-about-peach-bottom

28 "Peach Bottom Atomic Power Station Fact Sheet," Exelon Generation, exeloncorp.com/locations/Documents/Peach%20Bottom%20Atomic%20Power%20Station%20Fact%20Sheet.pdf

29 Ibid.

30 "5 Things to Know About Peach Bottom Nuclear Plant," Nuclear Energy Institute, nei.org/news/2019/5-things-know-about-peach-bottom

31 "Harford County-Major Employer Lists (Listed Alphabetically) - Workforce Information & Performance," Maryland Department of Labor, dllr.state.md.us/lmi/emplists/harford.shtml

In addition to the above employment figures, both CCNPP and PBAPS draw periodic surges of workers during refueling events. For example, during a recent refueling outage at CCNPP in February 2019, the first in nearly two years, over 1,000 workers traveled to Calvert County and provided indirect benefits from their presence (e.g., occupying hotels, visiting restaurants, etc.).[32] Likewise, as many as 2,000 people visit PBAPS during refueling events, providing an influx of spending to the local economy.[33]

Other economic benefits from these plants relate to power production. Both plants are highly reliable sources of power and have minimal downtime. This high level of reliability helps prevent brownouts due to a shortage of local generation. Additionally, since nuclear power plants are generally "price-takers" in the energy market, meaning they sell energy at the prevailing market rate, these plants have the effect of drawing down costs on the margin for consumers located in proximity to the plants. These sorts of benefits are only passed on to a very small subset of customers, however, who are exposed to nodal pricing, meaning market energy prices set at a local level. Finally, because these plants provide a low-carbon source of energy, their impact on local air quality is minimal, as compared to fossil-fuel generation sources.

2.1.4 *Other Benefits of Nuclear Power*

Maintaining nuclear power plants as part of Maryland's energy mix offers several additional advantages besides the climate change, air emissions, and economic benefits noted above. First, nuclear power plants can provide low-carbon baseload power. That is, nuclear plants can operate at a high capacity factor and thereby act as a consistent source of power during all-hours. Baseload power sources serve ambient energy demand, meaning electricity demand that exists around-the-clock. This is as opposed to intermediate or peak power demand, which change throughout the day in response to variable consumer energy requirements and are in addition to baseload demand.

Second, nuclear energy contributes to a diverse fuel mix. According to figures from the Energy Information Administration (EIA), nuclear generation as a share of net utility-scale generation in Maryland has ranged from 32% to 44% in the last 10 years, from 2009-2018. The relatively constant portion of nuclear within Maryland's generation mix

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32 "Calvert Cliffs Refueling Outage Powers Local Economy," Exelon Generation, exeloncorp.com/newsroom/calvert-cliffs-refueling-outage-powers-local-economy-(3)

33 "5 Things to Know About Peach Bottom Nuclear Plant," Nuclear Energy Institute, nei.org/news/2019/5-things-know-about-peach-bottom

contrasts with coal, which is steadily falling since 2007, and natural gas, which has increased rapidly since 2014.[34] Although natural gas prices are low, Maryland's increased reliance on natural gas increases the state's exposure to related fuel risks. For example, a gas supply shortage during the winter, when gas is also used for heating, could force natural gas power plants offline. Continued operation from local nuclear power plants can help alleviate these power constraints. Additionally, the continued presence of nuclear power in PJM helps hedge against volatile changes in commodity prices for natural gas or coal power. The impact of a spike in natural gas prices, for instance, would be blunted by continued power production from nuclear along with other power sources.

Third, nuclear has proven a predictable source of power. Besides scheduled refueling periods, during which time plants are taken offline for maintenance, nuclear power generally operates year-round without interruption. Over the long-term, this level of reliability can be built into regional planning decisions, including economic development in proximity to plants. Calvert Cliff recently ran for 715 consecutive days between refueling, a record for the plant.[35] Typical maintenance and refueling outages occur every 18 to 24 months during the shoulder seasons (Spring and Fall), when system demand tends to be lower.[36]

Fourth, large-scale nuclear plants offer some economies of scale as compared to distributed or smaller sources of power. CCNPP and PBAPS both leverage existing transmission and distribution capacity to its fullest extent and each require only one major point of interconnection. Additionally, both plants are able to generate a significant amount of power in a relatively concentrated amount of space. CCNPP occupies approximately 1,500 acres, while PBAPS occupies approximately 600 acres.[37] [38] Obtaining the equivalent installed capacity as CCNPP (1,708 MW) and PBAPS (2,347 MW) with solar photovoltaic generation would

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[34] "Electricity Data Browser: Net Generation," Energy Information Administration, eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvv&geo=g0000008&sec=g&freq=M&start=200101&end=201906&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=

[35] "Calvert Cliffs Refueling Outage Powers Local Economy," Exelon Generation, exeloncorp.com/newsroom/calvert-cliffs-refueling-outage-powers-local-economy-(3)

[36] nei.org/why-nuclear-energy/reliable-affordable-energy/unmatched-reliability/how-power-plants-prep

[37] "Calvert Cliffs Nuclear Power Plant Fact Sheet," Exelon Generation, exeloncorp.com/locations/Documents/Calvert%20Cliffs%20Fact%20Sheet%20-%202017.pdf

[38] "Peach Bottom Atomic Power Station Fact Sheet," Exelon Generation, exeloncorp.com/locations/Documents/Peach%20Bottom%20Atomic%20Power%20Station%20Fact%20Sheet.pdf

require approximately 13,664 acres and 18,776 acres, respectively, assuming 8 acres per MW of installed capacity.

Fifth, nuclear power can be characterized as a "resilient" resource, meaning capable of anticipating, absorbing, adapting to, and recovering from high-impact, large-scale disruptions.[39] The licensing process for new and existing nuclear power plants requires that nuclear infrastructure be designed to withstand significant hazards. For example, nuclear power plants have reinforced concrete walls and many redundant safety systems. Additionally, as noted above, nuclear generation does not rely on fuel supply chains and has a high load factor. Both of these features help ensure nuclear remains available during and after extraordinary disruptions.

2.2 *NUCLEAR WASTE MANAGEMENT*

More than 68,000 metric tons heavy metal (MTHM) of used nuclear fuel are stored at 72 commercial power plants around the country, with approximately 2,000 MTHM added to that amount every year.[40] In an acknowledgement of the inherent risks, the Blue Ribbon Commission (BRC) on America's Nuclear Future was established by President Obama on January 29, 2010 with a charter to recommend a new strategy for managing nuclear waste associated with the "back-end" of the nuclear fuel cycle.

The BRC issued a final report of recommended actions on January 26, 2012, to the U.S. Secretary of Energy. The final report addressed a wide array of issues and generated a significant number of public comments.

The final BRC report addressed eight key elements:

1. A new, consent-based approach to siting future nuclear waste management facilities.

2. A new organization dedicated solely to implementing the waste management program and empowered with the authority and resources to succeed.

3. Access to the funds that the nuclear utility ratepayers are providing to be used for nuclear waste management. These

[39] For additional definition of "resiliency" as distinct from reliability and security, see: pubs.naruc.org/pub/536F07E4-2354-D714-5153-7A80198A436D

[40] U.S. Department of Energy, 2013: "The Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste"

funds are a part of the Nuclear Waste Fund, which is estimated to contain approximately $21.2 billion dollars; Maryland ratepayers have contributed $432.9 million dollars (NEI, 2016).

4. Prompt efforts to develop one or more geologic disposal facilities.

5. Prompt efforts to develop one or more consolidated storage facilities.

6. Prompt efforts to prepare for the eventual large-scale transport of spent nuclear fuel and high-level waste to consolidated storage and disposal facilities when such facilities become available.

7. Support for continued U.S. innovation in nuclear energy technology and for workforce development.

8. Active U.S. leadership in international efforts to address safety, waste management, and non-proliferation.

There are inherent risks associated with storage of spent nuclear fuel on-site at existing commercial nuclear power plants. Also, progress toward federal, state, and local government approval of a national repository has been slow, although there has been some licensing activity associated with two new Consolidated Interim Storage Facilities (CISF). NRC is currently reviewing applications for a CISF in Andrews County, Texas and in Lea County, New Mexico.[41]

2.2.1 *Safety of On-site Storage of High-Level Radioactive Waste*

The Nuclear Waste Policy Act of 1982 required the U.S. Secretary of Energy to issue site selection guidelines for constructing two permanent, underground nuclear waste repositories. Congress directed the U.S. Department of Energy (DOE) to study five potential sites in the western U.S. and five sites in the eastern U.S. Under the law's requirements, DOE then recommended three of the sites from the west to the president by January 1, 1985, and three sites in the east by July 1, 1989. Ultimately, two repositories (one in the west, one in the east) were selected. In December 1987, Congress amended the Nuclear Waste Policy Act to designate Yucca Mountain, Nevada as the only site to be characterized as a permanent repository for all of the nation's nuclear waste. The plan was added to the fiscal 1988 budget reconciliation bill signed on December 22, 1987.

[41] nrc.gov/waste/spent-fuel-storage/cis.html

The proposed opening date for the Yucca Mountain repository was delayed as the project encountered major technical hurdles, environmental concerns, and considerable local and state opposition. In January 2010, President Barack Obama canceled plans to build the Yucca Mountain site and formed the BRC on America's Nuclear Future.

Since the issuance of the BRC Final Report on January 26, 2012, there has not been much progress made regarding the siting of a new national repository and the plans for a national repository are currently at a standstill based on a review of publicly available literature. In the absence of a national repository, the two CISF applications have been received by NRC and remain under review for a specific license under 10 CFR Part 72 and, as proposed, are not co-located with a power reactor.

Over the past few years, nuclear waste storage considerations in the United States have focused on "interim" storage of high-level radioactive wastes on-site at commercial nuclear power plant sites in spent fuel pools (SFPs) and independent spent fuel storage installations (ISFSIs).

Utilities began looking at options for increasing their spent fuel storage capacity in the early 1980s. This interest emerged as the SFPs at many U.S. commercial nuclear reactors began to approach their storage capacity, indicating that additional storage capacity would eventually be needed. As a result, the utilities developed another option which was "dry storage" of the spent nuclear fuel in ISFSIs. A spent fuel storage license contains technical requirements and operating conditions (e.g., fuel specifications, cask leak testing, surveillance) and specifies what the licensee is authorized to store at the site. The ISFSI at CCNPP received its NRC license in 1992, and is now one of 55 such facilities in the United States.[42] The CCNPP ISFSI license renewal was approved by NRC on October 23, 2014 and expires November 30, 2052.

2.2.2 *Waste Confidence Rule*

In August 2014, NRC issued the Final Rule entitled "Storage of Spent Nuclear Fuel Rule" (previously known as the Waste Confidence Rule), addressing the continued storage of spent nuclear fuel at existing nuclear power plant sites rather than a new offsite central or regional spent nuclear fuel repository. Also, as the result of issuance of this Final Rule, NRC lifted the previously imposed NRC suspensions on pending final licensing actions on nuclear power plant licenses and license renewals.

[42] PPRP, 2012: "Environmental Assessment of the Renewal Licensing of the Calvert Cliffs Nuclear Power Plant Independent Spent Fuel Storage Installation (ISFSI)."

To give a brief history of the rule, in June 2012 the Waste Confidence Rule was remanded by the U.S. Court of Appeals for the District of Columbia Circuit. Specifically, NRC's 2010 revision of the Waste Confidence Rule was remanded. As the result of this remand, NRC was required to assess the possibility that a geologic repository for permanent disposal of spent nuclear fuel may never be built, and was required to perform further analyses and assessments of possible SFP leaks and SFP fires, assuming that use of SFP as a long term storage option along with ISFSIs. Also, as the result of the June 2012 remand, NRC in August 2012 suspended final licensing decisions on new reactors, reactor license renewals, and spent fuel storage facility renewals. Additionally, as the result of the remand, NRC developed a new Waste Confidence Rule and prepared a Generic Environmental Impact Statement (GEIS) to assess the environmental effects of continued storage of spent nuclear fuel at existing nuclear power plant sites, and not in a new central or regional offsite spent nuclear fuel repository.

The GEIS analyzes impacts across a number of resource areas pertaining to each period of time assessed. Environmental impacts were assessed to land use, air and water quality, and historic and cultural resources. Also, the GEIS assessed SFP leaks and SFP fires as part of the court remand.

The Final Storage of Spent Nuclear Fuel Rule adopts the findings of the GEIS regarding the environmental impacts of storing spent fuel at any reactor site after the reactor's licensed period of operations. As a result, those generic impacts do not need to be reanalyzed in the environmental reviews for individual licenses. The GEIS analyzes the environmental impact of storing spent fuel beyond the licensed operating life of reactors over a 60 year (short-term) period, an additional 100 years after the short-term scenario ends (long-term), and indefinitely.

It is important to note that the Final Rule does not authorize, license or otherwise permit nuclear power plant licensees to store spent fuel for any specific length of time. Exelon's dry cask storage facility at Peach Bottom is estimated to have used 93% of its currently installed storage pad space. Peach Bottom's ISFSI license will expire in 2040. The Calvert Cliffs ISFSI is estimated to have used 93% of its currently installed storage capacity. The Calvert Cliffs ISFSI license will expire in 2052. Future modules will be built as needed to continue to store spent nuclear fuel generated at each of the power plants.

3.0 EMERGING NUCLEAR ENERGY TECHNOLOGIES

Ongoing research and development efforts aim to improve nuclear generating technology and make it less costly. This section describes emerging nuclear energy technologies that may contribute to the future of nuclear energy in Maryland.

3.1 SMALL MODULAR REACTORS

3.1.1 *Introduction and General Information*

In the nuclear industry today, there is significant private and government interest in small modular reactors (SMR) technology. A detailed literature review of SMR technology was performed and from this review it was evident that use of SMR technology has a wide range of potential applications, some which may be of interest to Maryland. The versatility of SMRs technology is attributable to it being a newer generation of nuclear reactor technology, and SMRs are designed to be able to generate electric power from 2 MW up to 300 MW.[43,44]

The primary benefit of use of SMRs is that the reactor components and the plant systems can be fabricated off site as modules, which could lead to large cost savings. Once built off site, the modules can be readily transported to the construction site for installation. The concept is very similar to the home prefabrication marketplace. Also determined from the literature review it was found that most of the SMR designs use advanced and inherent safety features and have the flexibility to be installed as a one single module plant or as a multi-module plant.

SMRs are not limited to one type of nuclear reactor technology. SMRs are currently under development for all major reactor types, which include water-cooled reactors; high temperature gas-cooled reactors; liquid-metal, sodium, and gas-cooled reactors with fast neutron spectrum; and molten salt reactors. This report has reviewed the technical specifications for over 50 different SMR designs from throughout the world, and a number of countries and private companies, some in partnership, are developing these prototype reactors.

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[43] energy.gov/ne/nuclear-reactor-technologies/small-modular-nuclear-reactors

[44] IAEA, 2018, "Advances in Small Modular Reactor Technology Developments". Website: aris.iaea.org/Publications/SMR-Book_2018.pdf

The market niche for SMRs appears to be for providing a flexible and expandable power generation platform, which is able to serve a wide range of users and applications. SMRs could replace aging fossil-fired units, serve niche electricity or energy markets where large reactors are not a viable option, provide cogeneration for developing countries with small electricity grids, and provide electricity to remote and off-grid areas. Multiple military applications have also been identified, including supplying power to forward operating bases or providing independent operations for critical U.S. installations. For aging fossil-fired units like some of those in Maryland, the total U.S. coal-fired units that were retired during the 2010-2012 time period are relatively small, averaging 97 MW per unit, and those coal-fired units expected to retire during the 2015-2025 time period average 145 MW.[45]

From an economic standpoint, SMRs realize the cost benefits of mass production, and as a result, SMRs also realize a much shorter construction time than non-modular nuclear reactor projects. There have been significant advancements reported for various SMR technologies in recent years;[46] however, some technical problems with SMR technology still remain unsolved and currently represent a detriment.

It has been reported in the literature that SMRs still have some technical challenges that include control room staffing, human factor engineering for multi-module SMR plants, and developing new codes and standards. Though SMRs have a lower initial capital cost per unit, costs do remain a concern. Their expected generating cost of electricity will probably be substantially higher than that for large reactors.[47]

A review of the literature indicates that there is a concern about the proliferation of nuclear materials and the risks associated with the widespread development of SMRs. Further, NEI submitted a position paper to NRC in July 2012 on the issue of physical security for SMRs.[48] This paper provided an industry viewpoint on this issue. It was recognized by the NEI that the regulatory issue of primary importance as related to physical security of SMRs is security staffing. Security staffing directly impacts annual operations and maintenance costs and as such constitutes a significant financial burden over the life of the facility and potentially could impact the viability of SMR development in the United States.

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[45] world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

[46] IAEA, 2018, op. cit.

[47] Ibid.

[48] NEI, July 31, 2012, "Physical Security For Small Modular Reactors", nrc.gov/docs/ML1222/ML12221A197.pdf

3.1.2 *Status of SMR Projects under Development Worldwide*

Currently there are more than 50 SMR designs under development for different applications. Three industrial demonstration SMRs are in advanced stage of construction: in Argentina (CAREM, an integral PWR), in China (HTR-PM, a high temperature gas cooled reactor) and in Russia (KLT40s, a floating power unit). They are all currently scheduled to start operation no later than 2022. In addition, Russia has already manufactured six RITM-200 reactors (an integral PWR) with four units, which are being installed in ships, the Sibir and Arktika icebreakers, and will be placed into service sometime in 2020. The remainder of the SMRs are in various states of design (i.e., pre-conceptual, conceptual, preliminary, basic, and detailed) or in the experimental phase.[49]

A description of the reactor coolant/fueled technologies being used in the design of the SMRs is provided below:

- ***Land-Based Water-Cooled SMRs:*** SMR designs that use light water reactor (LWR) technologies for land application. This represents the most mature technology and is used by many of the commercial nuclear power plants (i.e., CCNPP Units 1 and 2). Pressurized and Boiling Water Reactors (PWR and BWR) are both types of LWR.

- ***Marine-Based Water-Cooled SMRs:*** SMR designs that use LWR technologies for a marine application. Marine application includes both under the water (i.e., submersibles) or on ship or barge.

- ***High Temperature (HT) Gas-Cooled SMRs:*** HT SMRs use high-temperature heat (≥ 750°C) and are utilized for efficient electricity generation, a variety of industrial applications as well as for co-generation.

- ***Fast Neutron Spectrum SMRs:*** SMRs that have a fast neutron spectrum and can be used with all the different coolant options. These include sodium-cooled fast reactor (SFR), the heavy liquid metal-cooled (HLMC, i.e., lead or lead-bismuth) fast reactor, the gas-cooled fast reactor (GFR), and molten salt fast reactor (MSFR).

- ***Molten Salt SMRs:*** SMRs that use molten salt-fueled/cooled advanced reactor technology.

[49] IAEA, 2018, op. cit.

3.1.3 *Operating and Deployment Status of SMR Projects*

Table 3-1 presents a listing of SMR that are operating, Table 3-2 presents a listing of SMR that are under construction, and Table 3-3 presents a listing of SMR that are considered to be in near-term deployment with reactor development classified as well advanced.[50]

Table 3-1 *SMRs in Operation*

Name	Capacity	Type	Developer
CNP-300	300 MWe	PWR	SNERDI/CNNC, Pakistan & China
PHWR-220	220 MWe	PHWR	NPCIL, India
EGP-6	11 MWe	LWGR	at Bilibino, Siberia (cogen, soon to retire)
KLT-40	35 MWe	PWR	OKBM, Russia
RITM-200	50 MWe	Integral PWR	OKBM, Russia

Table 3-2 *SMRs Under Construction (As of December 2019)*

Name	Capacity	Type	Developer
KLT-40S	35 MWe	PWR	OKBM, Russia
CAREM-25	27 MWe	Integral PWR	CNEA & INVAP, Argentina
HTR-PM	210 MWe	Twin HTR	INET, CNEC & Huaneng, China
ACPR50S	60 MWe	PWR	CGN, China

Table 3-3 *SMRs at Near-Term Deployment*

Name	Capacity	Type	Developer
VBER-300	300 MWe	PWR	OKBM, Russia
NuScale	60 MWe	Integral PWR	NuScale Power + Fluor, USA
SMR-160	160 MWe	PWR	Holtec, USA + SNC-Lavalin, Canada
ACP100/Linglong One	125 MWe	Integral PWR	NPIC/CNPE/CNNC, China
SMART	100 MWe	Integral PWR	KAERI, South Korea
BWRX-300	300 MWe	BWR	GE Hitachi, USA
PRISM	311 MWe	Sodium FNR	GE Hitachi, USA
ARC-100	100 MWe	Sodium FNR	ARC, USA
Integral MSR	192 MWe	MSR	Terrestrial Energy, Canada
BREST	300 MWe	Lead FNR	RDIPE, Russia
RITM-200	50 MWe	Integral PWR	OKBM, Russia

3.1.4 *Joint Ventures*

Since development of SMRs is an expensive undertaking, many of these SMR developmental projects are a joint venture between a private firm

[50] world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

and the sponsoring government. In the U.S., much of the development is being done by DOE. A review of the recent activities is presented below.[51]

In April 2018, DOE selected 13 projects to receive $60 million of cost-shared research and development funding for advance nuclear technologies, including the first awards under the U.S. Industry Opportunities for Advance Nuclear Technology Development initiative.

In September 2018 the Nuclear Energy Innovation Capabilities Act and the DOE Research and Innovation Act passed in the U.S. Congress. The Nuclear Energy Innovation Capabilities Act enables private and public institutions to carry out civilian research and development of advanced nuclear energy technologies. Specifically, the Nuclear Energy Innovation Capabilities Act established the National Reactor Innovation Center to facilitate the siting of privately funded advanced reactor prototypes at DOE sites through partnerships between DOE and private industry. The DOE Research and Innovation Act combines seven previously passed science bills to provide policy direction to DOE on nuclear energy research and development.

In October 2018 DOE announced that it was proposing to convert metallic high-assay low-enriched uranium with enrichment levels between 5% and 20% U-235, into fuel for research and development purposes. This would be performed at Idaho National Laboratory's Materials and Fuels Complex and/or the Idaho Nuclear Technology and Engineering Center, to support the development of new reactor technologies with higher efficiencies and longer core lifetimes.

3.1.5 *NuScale*

The NuScale SMR design is under active development and evaluation by NRC. It has been reported[52] that the NuScale 60 MWe Power Module will be factory-built with a three-meter (i.e., 9.84 feet) diameter pressure vessel and convection cooling, with the only moving parts being the control rod drives. The 60 MWe Power Module uses standard PWR fuel enriched to 4.95% in normal PWR fuel assemblies that are only 2 meters (i.e., 6.56 feet) long, with a 24-month refueling cycle. Also, the 60 MWe Power Module is installed in a water-filled pool below ground level (i.e., depth unknown). The 4.6 meter (i.e., 15.01 feet) diameter and 22.0 meter (i.e., 72.16 feet) high cylindrical containment vessel module weighs 650 tons and contains the SMR with a steam generator located above it. For configuration, a

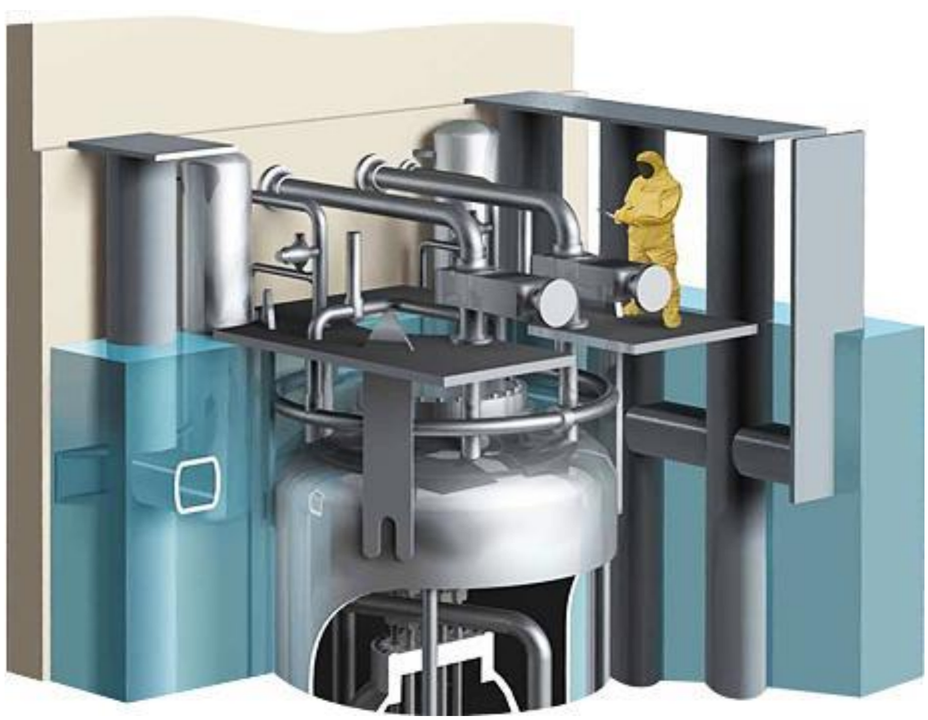
[51] world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

[52] Ibid.

standard power plant would have 12 modules together giving about 720 MWe.

The design operational lifetime is 60 years and has full passive cooling in operation and after shutdown for an indefinite period and does not require a direct current (i.e., DC) battery. Passive cooling is achieved from the design where the reactor and containment vessel operate inside a water-filled pool that is built below grade. The reactor operates using the principles of buoyancy driven natural circulation. As a result, no pumps are needed to circulate water through the reactor. Water is heated as it passes over the core. As it heats up, the water rises through the central riser within the interior of the vessel. Once the heated water reaches the top of the riser, it is drawn downward by water that is cooled passing through the steam generators. The cooler water has a higher density. It is pulled by gravity back down to the bottom of the reactor where it again flows over the core.[53]

Figure 3-1 NuScale Power Module



NuScale SMR Project History

A history of the NuScale SMR project development is provided below.

[53] nuscalepower.com/technology/technology-overview

- In March 2012 DOE signed an agreement with NuScale regarding constructing a demonstration unit at its Savannah River site in South Carolina.
- In June 2013, NuScale Power launched the Western Initiative for Nuclear (Program WIN), a broad, multi-western state collaboration, to study the demonstration and deployment of a series of NuScale SMR power plants in six western states. A NuScale SMR built as part of Program WIN is projected to be operational by 2024. Under Program WIN, the initial project will develop a NuScale SMR plant in Idaho with a possible location within the confines of the Idaho National Laboratory (INL). A further series of projects is contemplated for subsequent deployment in Washington, Utah, Wyoming, New Mexico, and Arizona.[54]

As part of Project WIN, NuScale has signed teaming agreements with key utilities in the western region, which include Energy Northwest in Washington State and the Utah Association of Municipal Power Systems (UAMPS), representing municipal power systems in Utah, Idaho, New Mexico, Arizona, Washington, Oregon, and California.

This initial project, known as the UAMPS Carbon Free Power Project (CFPP), would be sited in eastern Idaho and is being developed with partners who will operate the facility.

- In December 2013, DOE announced that it would support accelerated development of the design for early deployment on a 50/50 cost share basis. A DOE agreement for $217 million over five years was signed in May 2014 by NuScale Power. In September 2017, following acceptance of the company's design certification application by NRC earlier in the year, NuScale applied for the second part of its loan guarantee with DOE.
- In August 2015, DOE awarded a second, $33.2 million cost share award to NuScale for site selection, characterization and the preparation of a combined construction and operating license application for the UAMPS CFPP. Initial licensing and investigative activities are underway with the expectation that the application will be submitted to NRC in 2020.
- In January 2018 NRC concluded that NuScale's design eliminated the need for class 1E backup power, a current requirement for all U.S. commercial nuclear power plants. NuScale claims good load-following capability, in line with EPRI requirements, and also black-start capability.

[54] nuscalepower.com/technology/technology-overview

- It has been reported[55] that NuScale is investigating cogeneration options, including desalination (with Aquatech), oil recovery from tar sands and refinery power (with Fluor), hydrogen production by high-temperature steam electrolysis (with INL) and flexible back-up for wind farm (with UAMPS and Energy Northwest).

3.2 AP1000 Westinghouse Nuclear Reactor

3.2.1 NRC Approval of the AP1000 Design

The Westinghouse AP1000 nuclear power plant utilizes a two-loop pressurized water reactor (PWR). The AP1000 has a gross power rating of 3,415 MWt and a nominal net electrical output of 1,110 MWe.[56]

In December 2005, NRC approved the final design certification for the AP1000.[57] As a result, U.S. constructors could apply for a Combined Construction and Operating License with the condition that the plant being built is "as designed" and that each AP1000 being built is required to be identical to each other.

The AP1000 design was the first Generation III+ reactor to receive final design approval from NRC. In 2009, NRC made a safety change related to the events of September 11, 2001, ruling that all new commercial nuclear power plants are required to be designed to withstand a direct hit from an airplane. To meet the new requirement, Westinghouse planned to encase the AP1000 buildings concrete walls in steel plates for the four new nuclear units to be located in South Carolina and Georgia. These two plants are discussed in further detail in Section 3.2.3.

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[55] world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

[56] westinghousenuclear.com/new-plants/ap1000-pwr/overview

[57] "AP1000 Reactor Technical Description, Chapter 2.1". Website: nrc.gov/docs/ML1117/ML11171A308.pdf

Figure 3-2 The Westinghouse AP1000 Plant (1 of 2)

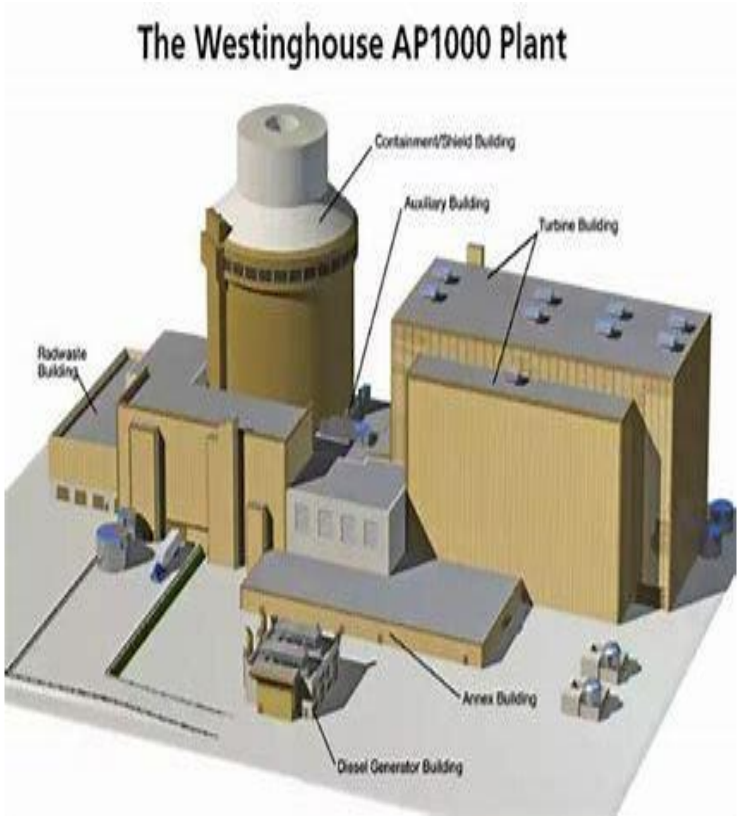


Figure 3-3 The Westinghouse AP1000 Plant (2 of 2)

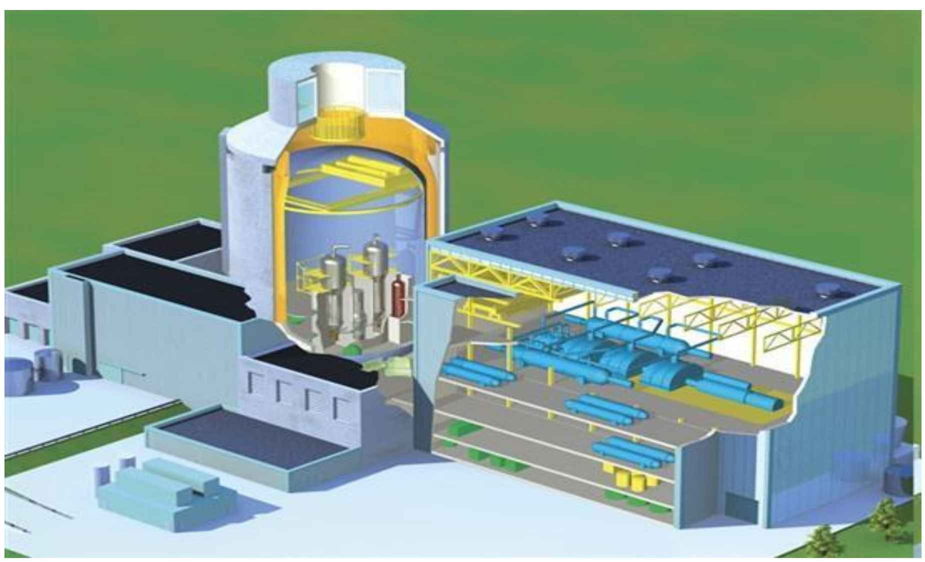
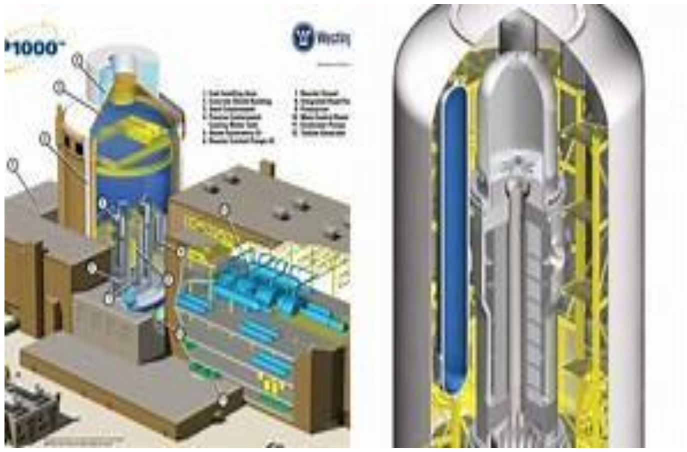


Figure 3-4 The Westinghouse AP1000 Reactor



3.2.2 *Construction of Four New AP1000 Reactors in China*

China has officially adopted the AP1000 as a standard for inland nuclear power plant projects. In April 2009, China started building the first of four new nuclear units reflecting the AP1000's 2005 design requirements.[58] The first two new AP1000 reactors were constructed at the Sanmen Nuclear Power Plant in Zhejiang, and the second two AP1000 reactors were constructed at the Haiyang Nuclear Power Plant in Shandong, China. See Figures 3-5 and 3-6 for construction photographs of the Sanmen and Haiyang Plants, respectively.

The Sanmen Unit 1 and Unit 2 AP1000s started commercial operation on September 21, 2018 and November 5, 2018 respectively. Haiyang Unit 1 started commercial operation on October 22, 2018 and Haiyang Unit 2 started commercial operation on January 9, 2019.

These first four AP1000s reactors were built in accordance with the 2005 revision of the AP1000 design and did not have a strengthened containment structure to provide improved protection against an aircraft crash.

[58] world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

Figure 3-5 June 2014 Photo of the Construction of the Sanmen Nuclear Power Plant Units 1 and 2 in Zhejiang, China

Figure 3-6 May 2014 Photo of the Construction of the Haiyang Nuclear Power Plant Units 1 and 2 in Shandong, China

3.2.3 *Construction of Four New AP1000 Reactors in the U.S.*

In April 2008, Georgia Power Company reached a contract agreement with Westinghouse and Shaw for two AP1000 reactors (Units 3 and 4) to be built at the Vogtle Electric Generating Plant in Waynesboro, Georgia. The license request for the Vogtle plant is based on Revision 18 of the AP1000 design. In February 2010, President Obama announced $8.33 billion in federal loan guarantees to construct the two AP1000 units at the Vogtle plant. The cost of building the two reactors was expected to be $14 billion. See Figure 3-7 for a construction photograph of the Vogtle Plant. In December 2011, NRC approved the Vogtle Units 3 and 4 construction. In the February 2018 Vogtle Construction Monitoring Report (VCM), the Georgia Public Service Commission approved November 2021 and November 2022 as the target in-service dates for Units 3 and 4 respectively. The report notes that the project is being completed on an accelerated schedule and is currently tracking ahead of the 2021 and 2022 in-service target dates, respectively.[59] The Vogtle plant continues to be built. Significant progress continues at the Vogtle site, with the project approximately 75% complete as of March 22, 2019.[60]

In February 2012, NRC approved the construction of an additional two new AP1000 reactors to be built at the Virgil C. Summer nuclear power plant Units 2 and 3 located in Jenkinsville, South Carolina. The V.C. Summer project was abandoned in July 2017, four years after it began, due to Westinghouse's bankruptcy, major cost overruns, significant delays, and other issues.

Figure 3-7 Photo of the Construction of the ***Vogtle Electric Generating Plant Units 3 and 4 in Waynesboro, Georgia***

[59] resources.georgiapower.com/content/assets/PDFS/VCM-18_Report_Final.pdf

[60] georgiapower.com/company/news-center/2019-articles/georgia-power-doe-finalize-billion-loan-guarantee-vogtle-units.html

3.3 TRAVELING WAVE REACTORS

3.3.1 *Introduction and Background*

The concept of Generation IV nuclear reactors was developed by the Generation IV International Forum (GIF) that originally consisted of nine countries.[61] The GIF is an international cooperation framework recognized for the improvement of Generation IV systems. The concept of Generation IV reactors was launched in the U.S. in 2000 and the GIF was established in 2001. Over 100 experts evaluated around 130 reactor concepts, until just six reactor concepts were decided upon and determined as the Generation IV reactors.[62]

The technology used by Traveling Wave Reactors (TWRs) is considered to be a Generation IV advanced nuclear technology with the expectation that TWRs will be commercially deployable by 2030. TWRs and other Generation IV advanced nuclear technologies have recently gained new governmental support for the advancement of these technologies. As background, on September 28, 2018, President Trump signed into law S. 97, the "Nuclear Energy Innovation Capabilities Act of 2017," (S.97, 2017) which amends the Energy Policy Act to update the mission and objectives of DOE's civilian nuclear energy research, development, demonstration, and commercial application programs. President Trump also signed into law H.R. 589, the "Department of Energy Research and Innovation Act," which establishes policy for DOE science and energy research and development programs and reforms National Laboratory management and technology transfer programs.

The Nuclear Energy Innovation Capabilities Act (NEICA) (S. 97, 2017) is expected to eliminate the existing financial and technological barriers that are currently thought to impede nuclear innovation in the U.S. The NEICA provides a strong commitment by the U.S. government to support the advancement of the commercial nuclear energy industry.

The provisions in NEICA are expected to result in the increase of successful private-public partnerships (i.e., joint ventures between the private sector and U.S. government), which utilizes DOE's Gateway for Accelerated Innovation in Nuclear (GAIN) program.[63]

The GAIN program's objectives are:

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61 gen-4.org/gif/jcms/c_59461/generation-iv-systems

62 DOE, December 14, 2018: "Webinar: Generation IV Reactor Systems and Renewable Energy", energy.gov/ne/articles/webinar-generation-iv-reactor-systems-and-renewable-energy

63 gain.inl.gov/SitePages/What%20is%20GAIN.aspx

- To provide the nuclear private sector with access to technical, regulatory, and financial support from the DOE Office of Nuclear Energy and to enhance the development of advanced (i.e., Generation IV) nuclear energy technologies, and
- To expedite the commercialization of these developing advanced nuclear energy technologies while still ensuring that these nuclear energy technologies provide safe, reliable, and economic operation of the U.S. commercial nuclear power fleet.

The DOE Research and Innovation Act (H.R. 589, 2018) requires that DOE move forward with plans to develop a fast neutron source (i.e., a fast test reactor) in order to accelerate the development of advanced reactor fuels and materials. This capability currently does not exist in the U. S. and a fast test reactor will be required to test new reactor materials and fuels for use in the advanced nuclear reactors.

Also, DOE is required to develop a program for the siting of advanced reactor research demonstration facilities using new partnerships between DOE and the private sector. Lastly, H.R. 589 requires DOE to expand its high-performance computing expertise by focusing on the modeling and simulation of advanced nuclear reactors to further accelerate their development. In doing so, the national laboratories, universities, and the private sector will assist in developing new software and tools to be used to accelerate the research on fission and fusion reactors and to assess space applications.

3.3.2 TWR Simplified Concept

The TWR is a liquid sodium-cooled fast reactor design that uses depleted uranium (U-238) to produce a usable fuel, plutonium (P-239). Having a fast reactor design means that very active ("fast") neutrons sustain the nuclear chain reaction or fission that occurs inside the reactor vessel. A TWR differs from a Light Water Reactor (LWR), (e.g., the reactor type used by the CCNPP Units 1 and 2) because the TWR is fueled primarily by depleted uranium-238, known as "fertile fuel". The TWR also requires a small amount of enriched uranium-235 or other "fissile fuel" to initiate the fission process. The TWR would use uranium fuel enriched to a much higher degree (i.e., 15%) compared to present LWRs (i.e., 4 to 5%).[64]

Some of the fast-spectrum neutrons produced by fission are absorbed by neutron capture in adjacent fertile fuel (i.e., the non-fissile depleted uranium), which is "bred" into plutonium by the nuclear reaction. The

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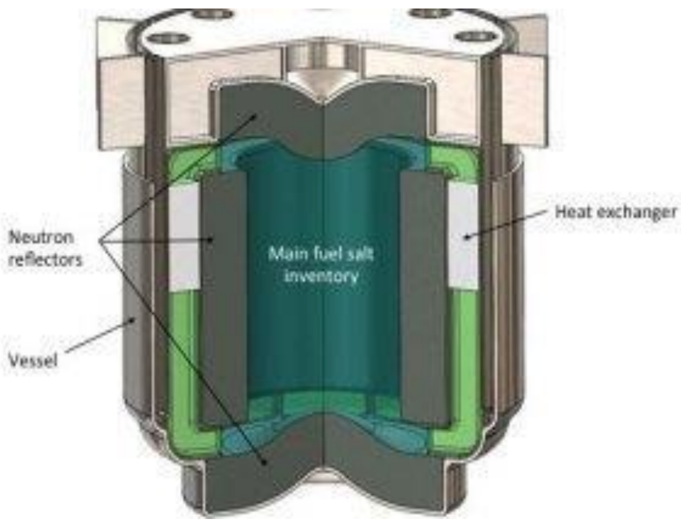
[64] Makhijani, Arjun, 2013: ieer.org/resource/energy-issues/traveling-wave-reactors-sodium-cooled-gold-at-the-end-of-a-nuclear-rainbow/

chain reaction creates heat that is carried away by the liquid sodium. The heated liquid sodium is then used to boil water in a two-step process to produce steam. The steam is then used by a steam turbine generator set to produce electricity. Some existing commercial nuclear power plants, like the CCNPP Units 1 and 2, are Light Water Reactors (LWRs) that use water to cool the nuclear reactor and to slow down or moderate the neutrons that sustain the nuclear chain reaction. The hot water produced by cooling the reactor temperature is used to produce steam, where like the TWR, the steam is used by a steam turbine generator set to produce electricity. Figure 3-8 displays a TWR.

Figure 3-8 A Traveling Wave Reactor



As previously discussed above, a TWR requires very little enriched uranium (U-235), reducing the risk of weapons proliferation. Specifically, the TWR uses depleted-uranium (U-238) fuel packed inside hundreds of hexagonal pillars. In a "wave" that moves through the reactor core at only a centimeter per year, the fuel is transformed (i.e., bred) into plutonium (P-239), which then undergoes fission. The reaction requires a small amount of enriched uranium (U-235) to get started and could run for decades without refueling. The reactor uses liquid sodium as a coolant. The reactor core temperatures are extremely hot, about 550°C, versus the 330°C typical of an LWR.[65]

Also, the TWR simplifies the current nuclear fuel cycle compared to LWRs, by reducing the need for uranium mining and spent fuel storage facilities. In the long term, TWRs could eliminate the need for enrichment facilities and reprocessing plants.

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65 Wald, M., 2009: "TR10: Traveling wave Reactors", MIT Technology Review. Website: www2.technologyreview.com/news/412188/tr10-traveling-wave-reactor/

3.3.3 *Early Generation TWRs*

TWRs are not a new design concept. TWRs first came on the nuclear scene in 1958, but have been intensively investigated only since about 2006, most notably by TerraPower, a company formed in 2008 by venture capitalists, including Bill Gates.[66]

In their early generating operations, TWRs have had generally a poor performance history. The most recent commercial demonstration problem was with the French demonstration reactor, Superphénix, which operated at an average capacity factor of less than 7% over 11 years before being shut down in 1996 with the formal decision not to re-open it being made in 1998. The Japanese Monju reactor, commissioned in 1994, and connected to the grid in 1995, had a sodium leak and fire in 1995. It was closed until May 2010. When it was restarted for testing it suffered another accident in August 2010;[67] based on a review of current literature, it has not been restarted.

One of the most difficult engineering problems with sodium-cooled reactors is that sodium burns on contact with air and explodes on contact with water. Further, some of the non-radioactive sodium nuclei of the coolant absorb a neutron and are thereby converted to intensely radioactive sodium-24. Leaks create difficult clean-up and maintenance and repair problems.

3.3.4 *Generation IV TWRs*

TerraPower LLC located in Bellevue, Washington is the U.S. industry leader in Generation IV TWRs. It is important to note that the early generation of TWRs discussed above are not representative of the new Generation IV TWRs. It would be like comparing a 1908 Ford Model T to a new 2020 Mustang GT. The new Generation IV TWRs are anticipated to reflect the major benefits that include the following:[68]

- **Safe**: TWR systems rely on the natural laws of physics to maintain the safety of the plant without operator intervention.

- **Affordable**: Atmospheric pressure operation and very low fuel costs allow for lower capital and operating costs.

- **Clean**: Used fuel is stored inside the core, slashing the need for external storage and transportation of waste. Longer operating high

[66] Makhijani, A., op. cit.

[67] Ibid.

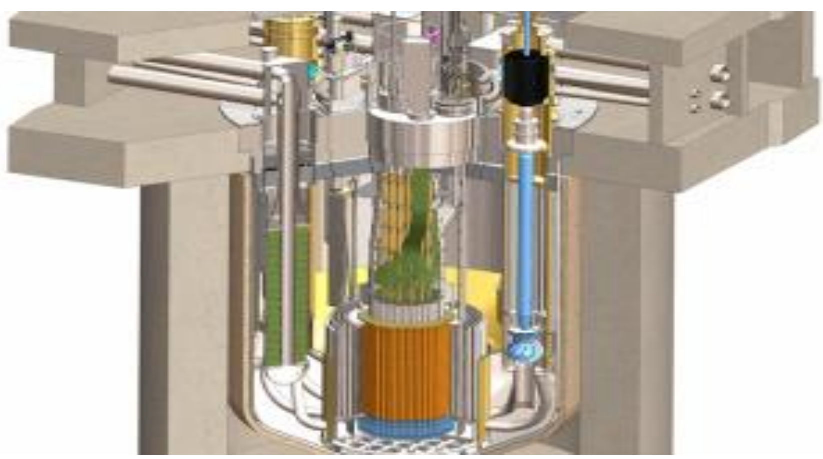
[68] terrapower.com/library/multimedia

efficiency cycles keep carbon-free electricity reliably supplied with reduced needs for mining, enrichment and waste disposal.

- **Secure**: The traveling wave makes the reactor capable of sustaining a fission chain reaction without interruption. Eliminating the need for reprocessing radioactive used fuel and eventual elimination of enrichment facilities greatly reduces risk.

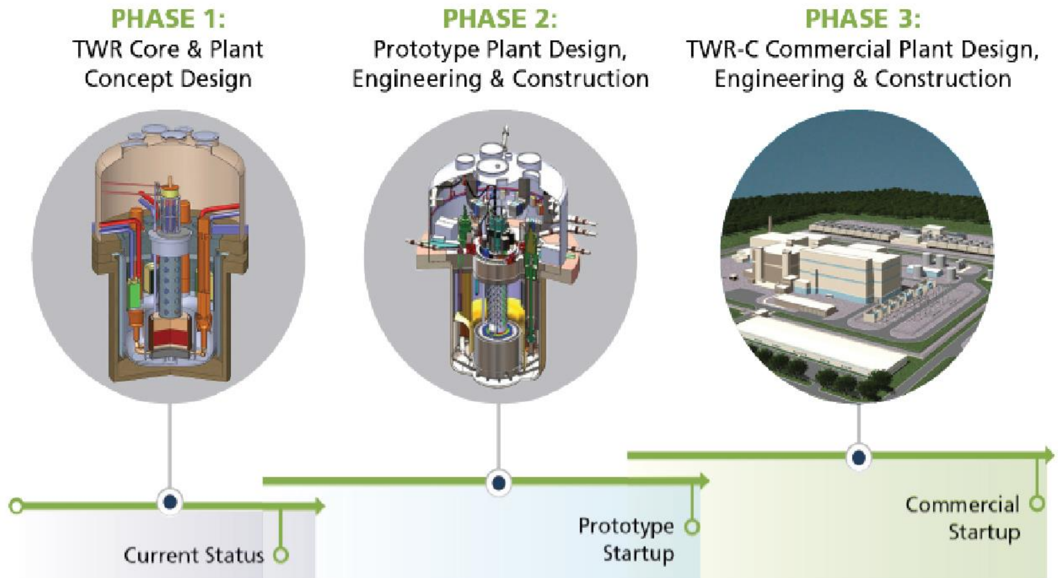
Figure 3-9 View of a Concept TerraPower TWR Power Plant

Figure 3-10 View of a TerraPower Concept TWR Reactor



The commercialization of the TWR technology by TerraPower is expected to occur in the mid-2020s. Figure 3-11 presents the TerraPower three-phase approach for design, prototype, and commercial start-up.

Figure 3-11 TerraPower Three Phase Approach for Design, Prototype and Commercial



3.4 POTENTIAL TIME FRAME FOR NEW DEPLOYMENT

The time horizon required to implement any nuclear generating technology is subject to significant uncertainty. In Maryland, the quickest pathway to putting a new nuclear unit in operation would likely involve the use of an NRC-approved design, which today can be applied only to the AP1000.

The CCNPP site in Calvert County would be a likely candidate for new construction. In 2007, the company UniStar (a joint venture between Exelon and EDF Energy) applied for a state license to construct and operate Calvert Cliffs Unit 3. UniStar planned to use the AREVA advanced reactor, U.S. Evolutionary Power Reactor. As part of the Calvert Cliffs Unit 3 project, UniStar stated that it was working on the design certification application to NRC; however, that was a separate process from the PSC licensing process and the State of Maryland was not directly involved. Key time durations in UniStar's estimated project schedule are listed below:

- Project receives Combined Operating License (COL) from NRC ~3 years after submitting COL application,
- Plant construction completed ~4.25 years after receiving COL,
- Commercial operation begins ~6 months after construction is complete.

Thus, based on this scenario, the minimum time required between submitting an application to NRC and starting commercial operation would be 8 years, assuming that design certification is also in place. If a nuclear operator were to submit an application to construct the AP1000 in Maryland, an optimistic timeline would be to have the new generation on line in 8-10 years. For deployment of NuScale, there is the additional time that will be required to achieve design certification, which might add perhaps 2-5 years. More advanced Generation IV technologies are likely 15-20 years from deployment.

4.0 NUCLEAR ENERGY DEPLOYMENT IN OTHER STATES AND COUNTRIES

4.1 NUCLEAR ENERGY IN THE U.S.

The sources of power generated in the U.S. in 2017 are summarized in Table 4-1 below. Nuclear power plants supplied 20% of the electricity generated in the U.S that year. Fossil fuels, primarily coal and natural gas, were used to produce approximately 63% of the electricity generated in 2017. Hydroelectric power supplied 7% and other renewables, like solar and wind, about 10%.

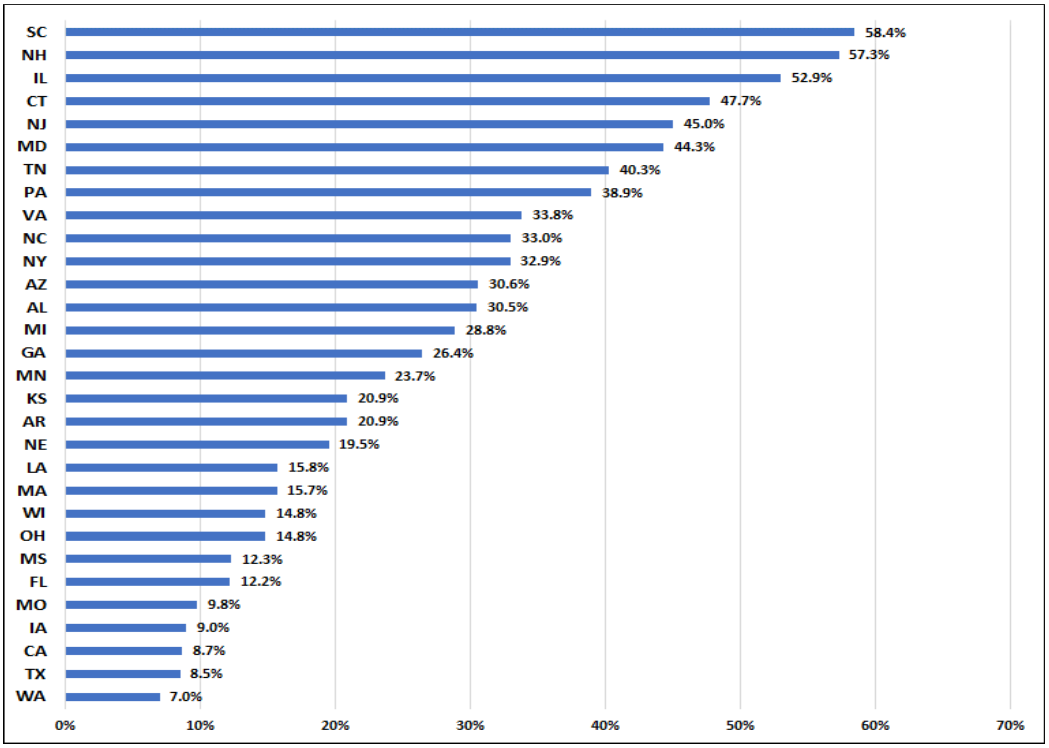
Table 4-1 Sources of Electricity Supply in 2017[69]

Generation Source	Generation MWH	Share	Notes
Natural Gas	1,296,414,692	32.1%	
Fuel Oil	21,389,958	0.5%	Residual Fuel Oil, Kerosene and Other Distillates
Coal	1,205,835,275	29.9%	
Subtotal- Fossil Fuels	**2,523,639,925**	**62.6%**	
Nuclear	804,949,635	20.0%	
Hydroelectric	300,333,156	7.4%	
Solar	53,286,174	1.3%	Photovoltaic & Solar Thermal
Wind	254,302,662	6.3%	
Other Renewable	78,688,435	2.0%	Geothermal, Wood and Other Biomass
Other	19,068,444	0.5%	Other Gases, Solid Waste etc.
Subtotal- Renewable and Other	**1,510,628,506**	**37.4%**	
Total	**4,034,268,431**	**100.0%**	

The percentage of electricity generated in each state by nuclear power plants in 2017 is depicted in Figure 4-1 below. Maryland ranked sixth compared to other states. The analysis of carbon dioxide emissions trends provided in Section 4.2 is limited to South Carolina, New Hampshire, and Illinois because nuclear power exceeded 50% of total generation only in these three states. The extent to which nuclear and renewable energy have been paired to meet carbon dioxide emission reduction goals in these three states is explored in Section 4.3.

69 Source: U.S. Energy Information Administration

Figure 4-1 Percent of Total Electricity Generated with Nuclear Power 2017[70]



4.2 POWER SECTOR CARBON DIOXIDE EMISSIONS TRENDS IN THE U.S.

4.2.1 *The Impact of Fossil Fuel Selection on Power Sector Carbon Dioxide Emissions*

Annual CO_2 emissions for the U.S. power sector have declined 24% from 2,379 million metric tons in 2005 to 1,797 million metric tons in 2016 as shown in Figure 4-2. By contrast, total power generation over the same period remained largely unchanged as can be seen in Figure 4-3. Falling carbon dioxide emissions without a commensurate decline in the amount of power generated is primarily the result of a significant shift from coal to natural gas as the predominant fossil fuel for power generation during this period.

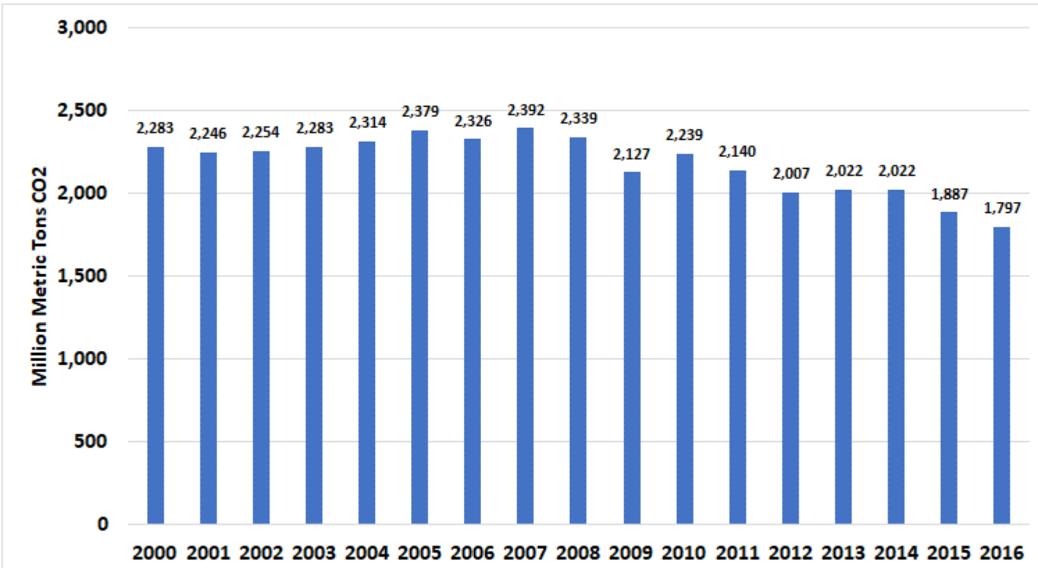
As shown in Table 4-2, coal, fuel oil and natural gas each emit a characteristic amount of carbon dioxide when combusted, with coal emitting the most and natural gas the least.

70 Source: U.S. Energy Information Administration

Table 4-2 Fossil Fuel Carbon Dioxide Emissions Factors[71]

Fuel	Carbon Dioxide Emissions Lbs./MMBtu	Generator Heat Rate Btu/kW	Emissions Factor: Lbs. CO2 per kWh Generated
Natural Gas	117	8,060	0.94
Fuel Oil	163	10,854	1.77
Coal	212	10,442	2.21

Figure 4-2 U.S. Power Sector Carbon Dioxide Emissions, 2000-2016[72]



Fossil fuel power plants are dispatched primarily based on fuel price so that generating plants that use the lowest-priced fuel are given priority and are operated more often than plants that run higher priced fuels. This cost-based dispatch approach is used to minimize the total average cost of electricity over time. For example, when the price of low-emission natural gas falls versus the price of coal, power plants that use natural gas will run more often, natural gas will comprise a greater share of the fuel supply mix versus coal and overall carbon dioxide emissions will decline. Conversely, carbon dioxide emissions will rise when coal prices fall relative to natural gas and coal constitutes a greater percentage of the fuel supply mix.

Natural gas prices have declined significantly since 2003 when hydraulic fracturing techniques were expanded thereby allowing production of

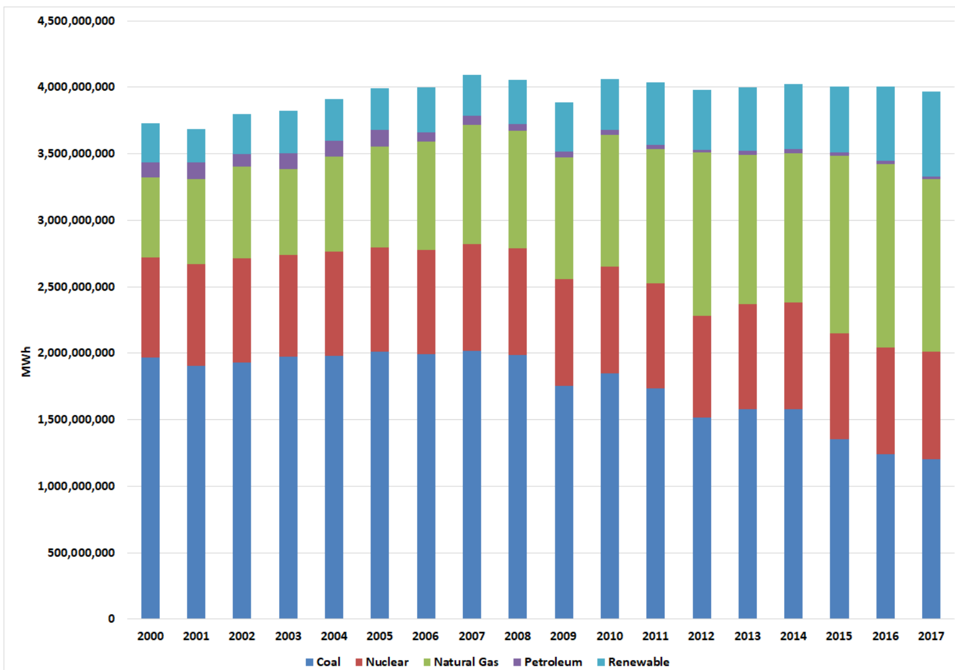
[71] Source: U.S. Energy Information Administration

[72] Source: U.S. Energy Information Administration

natural gas from shale formations that were previously considered uneconomic. As natural gas production increased in the United States because of hydraulic fracturing, gas prices fell, and natural gas-fired power plants were dispatched ahead of coal-fired plants resulting in lower carbon dioxide emissions without a commensurate decline in power generation.

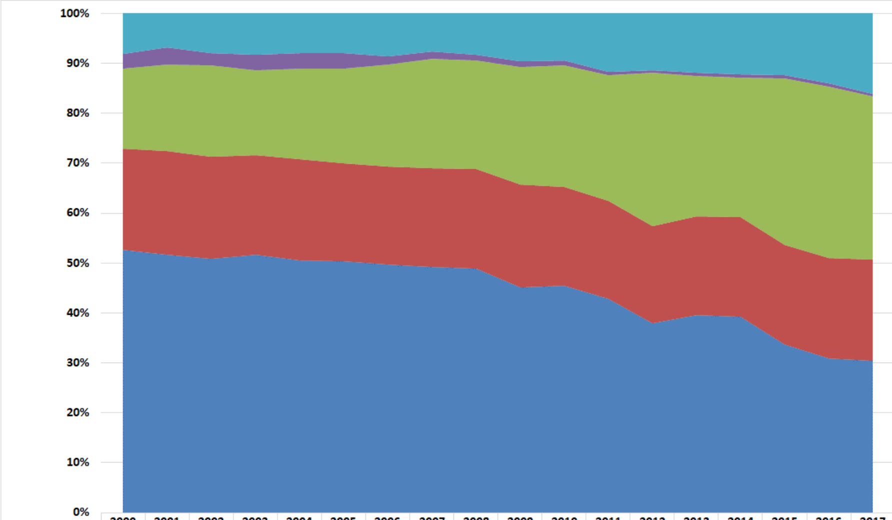
Divergence of natural gas and coal consumption for power generation since 2004 is evident in Figure 4-3, but more clearly seen in Figure 4-4. Increasing supply of renewable power generation also contributed to lower coal use. This phenomenon is also evident in the state-level analyses of power sector carbon dioxide emission trends provided in Sections 4.2.2, 4.2.3 and 4.2.4 herein.

Figure 4-3 U.S. Power Generation by Source, 2000-2016[73]



[73] Source: U.S. Energy Information Administration

Figure 4-4 U.S. Power Generation Resource Fuel Mix, 2000- 2016



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Renewable	8.1%	6.8%	8.0%	8.3%	8.0%	7.9%	8.6%	7.6%	8.3%	9.6%	9.5%	11.7%	11.3%	11.9%	12.1%	12.3%	14.0%	16.1%
Petroleum	3.0%	3.4%	2.5%	3.1%	3.1%	3.1%	1.6%	1.6%	1.1%	1.0%	0.9%	0.7%	0.6%	0.7%	0.8%	0.7%	0.6%	0.5%
Natural Gas	16.1%	17.3%	18.2%	17.0%	18.2%	19.1%	20.4%	21.9%	21.8%	23.7%	24.3%	25.1%	30.8%	28.1%	28.0%	33.3%	34.4%	32.7%
Nuclear	20.2%	20.9%	20.5%	20.0%	20.2%	19.6%	19.7%	19.7%	19.9%	20.5%	19.9%	19.6%	19.3%	19.7%	19.8%	19.9%	20.1%	20.3%
Coal	52.7%	51.6%	50.8%	51.6%	50.6%	50.4%	49.7%	49.2%	48.9%	45.1%	45.5%	42.9%	38.0%	39.6%	39.3%	33.8%	30.9%	30.4%

4.2.2 *State-level Trends*

The analysis of carbon dioxide emissions trends provided in the subsections below is limited to South Carolina, New Hampshire and Illinois because nuclear power exceeded 50% of total generation only in these states.[74]

4.2.2.1 *South Carolina*

Power sector generation and carbon dioxide emissions data for South Carolina from 2000 through 2016 are depicted in Figures 4-5, 4-6 and 4-7[75]. Note that:

- Annual power generation remained between 90 million and 100 million MWh from 2000 through 2017. Power generated from natural gas steadily increased as generation from coal declined throughout this period.
- The percentage of high-emission coal in the generation supply mix fell from approximately 40% before 2008 down to 19.8% in 2017.

[74] Maryland's Clean Energy Jobs Act specifies the inclusion of states where nuclear power exceeds 50% of total generation.

[75] Source: U.S. Energy Information Administration. Carbon dioxide emissions data for 2017 was not available from the EIA.

This resulted in steady decline of carbon dioxide emissions from 41.9 million metric tons in 2008 to 27.5 million metric tons in 2016.

- Nuclear power's contribution to the generation supply mix increased noticeably from 2000 to 2017, but the increase was not as great as that for natural gas. Only a small increase in renewables was observed.

Figure 4-5 Annual Power Generation by Source in South Carolina, 2000-2017

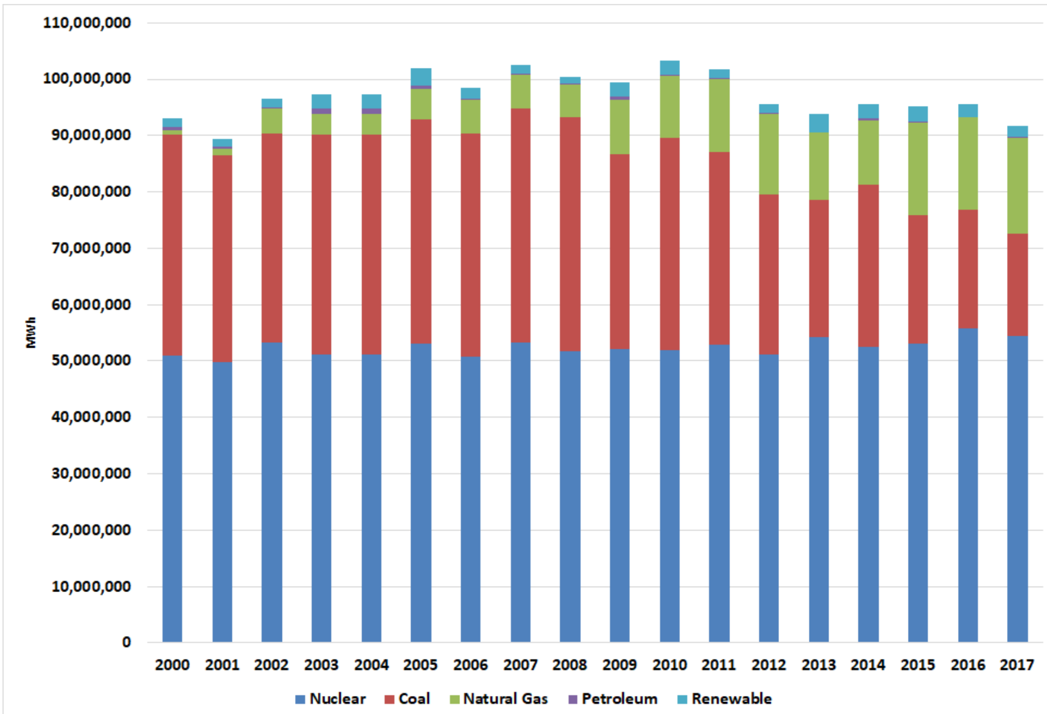
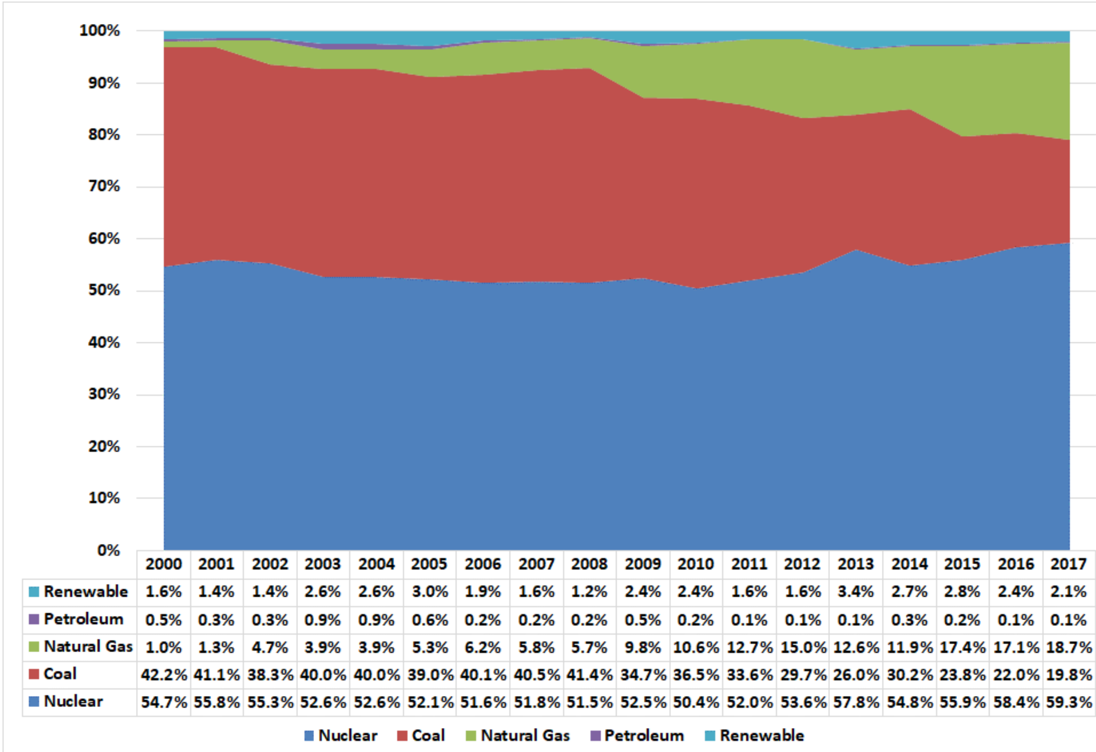
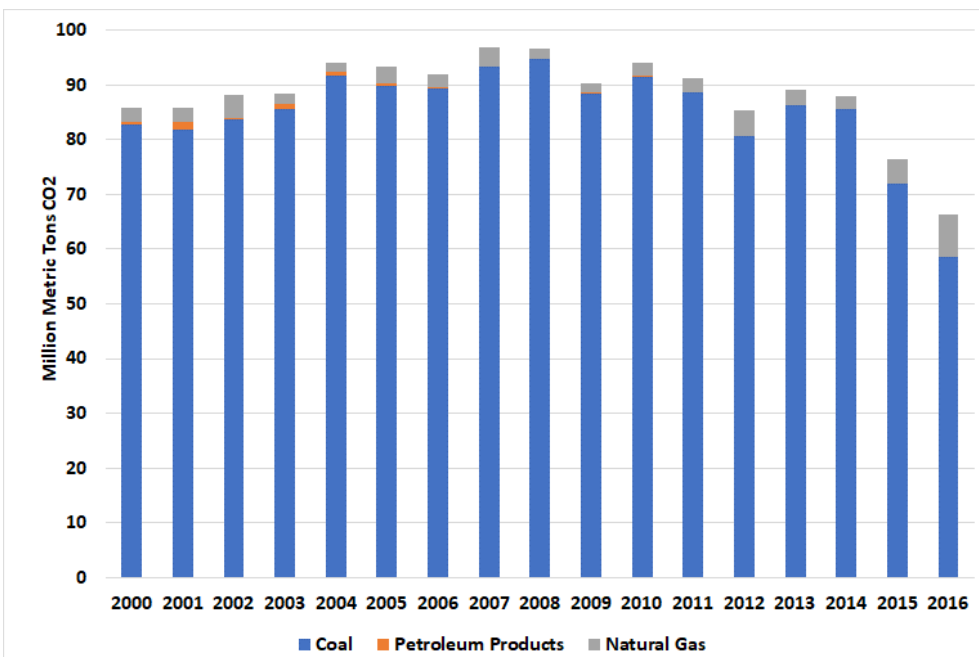


Figure 4-6 Power Generation Resource Mix, South Carolina, 2000- 2017



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Renewable	1.6%	1.4%	1.4%	2.6%	2.6%	3.0%	1.9%	1.6%	1.2%	2.4%	2.4%	1.6%	1.6%	3.4%	2.7%	2.8%	2.4%	2.1%
Petroleum	0.5%	0.3%	0.3%	0.9%	0.9%	0.6%	0.2%	0.2%	0.2%	0.5%	0.2%	0.1%	0.1%	0.1%	0.3%	0.2%	0.1%	0.1%
Natural Gas	1.0%	1.3%	4.7%	3.9%	3.9%	5.3%	6.2%	5.8%	5.7%	9.8%	10.6%	12.7%	15.0%	12.6%	11.9%	17.4%	17.1%	18.7%
Coal	42.2%	41.1%	38.3%	40.0%	40.0%	39.0%	40.1%	40.5%	41.4%	34.7%	36.5%	33.6%	29.7%	26.0%	30.2%	23.8%	22.0%	19.8%
Nuclear	54.7%	55.8%	55.3%	52.6%	52.6%	52.1%	51.6%	51.8%	51.5%	52.5%	50.4%	52.0%	53.6%	57.8%	54.8%	55.9%	58.4%	59.3%

Figure 4-7 Power Sector Carbon Dioxide Emissions by Fuel Source, South Carolina, 2000- 2016

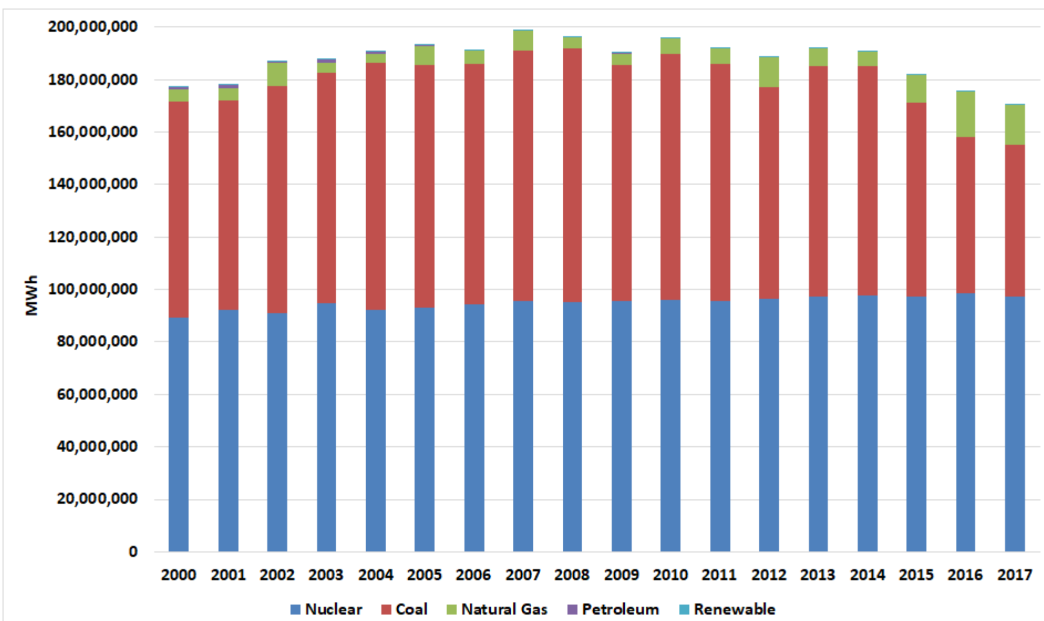


4.2.2.2 *Power Sector Carbon Dioxide Emissions Trends in Illinois*

Power sector generation and carbon dioxide emissions data for Illinois from 2000 through 2017 are depicted in Figures 4-8, 4-9 and 4-10.[76] Note that:

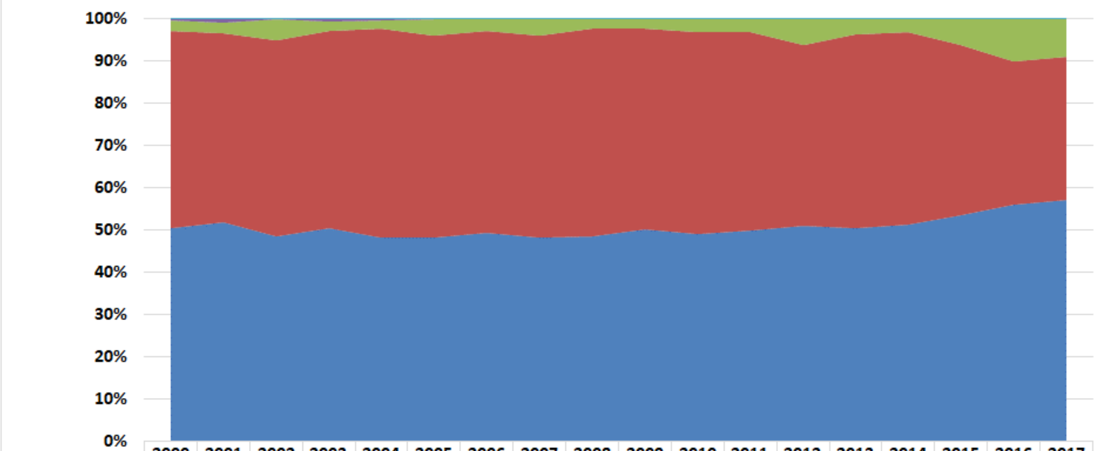
- Annual power generation rose from less than 180 million MWh in 2000 to just under 200 million MWh in 2007, and since has declined to approximately 175 million MWh in 2017. Power generated from natural gas increased after 2014.
- The percentage of high-emission coal in the generation supply mix increased from 46.5% in 2000 up to 49.2% in 2008 and fell to 34% in 2017. This resulted in steady decline of annual carbon dioxide emissions from 94 million metric tons in 2010 to 66 million metric tons in 2016.
- The contribution of nuclear power has increased somewhat from 2000 to 2017. Renewable energy makes up a negligible proportion of the generation supply mix.

Figure 4-8 Annual Power Generation by Source in Illinois, 2000-2017



[76] Source: U.S. Energy Information Administration. Carbon dioxide emissions data for 2017 was not available from the EIA.

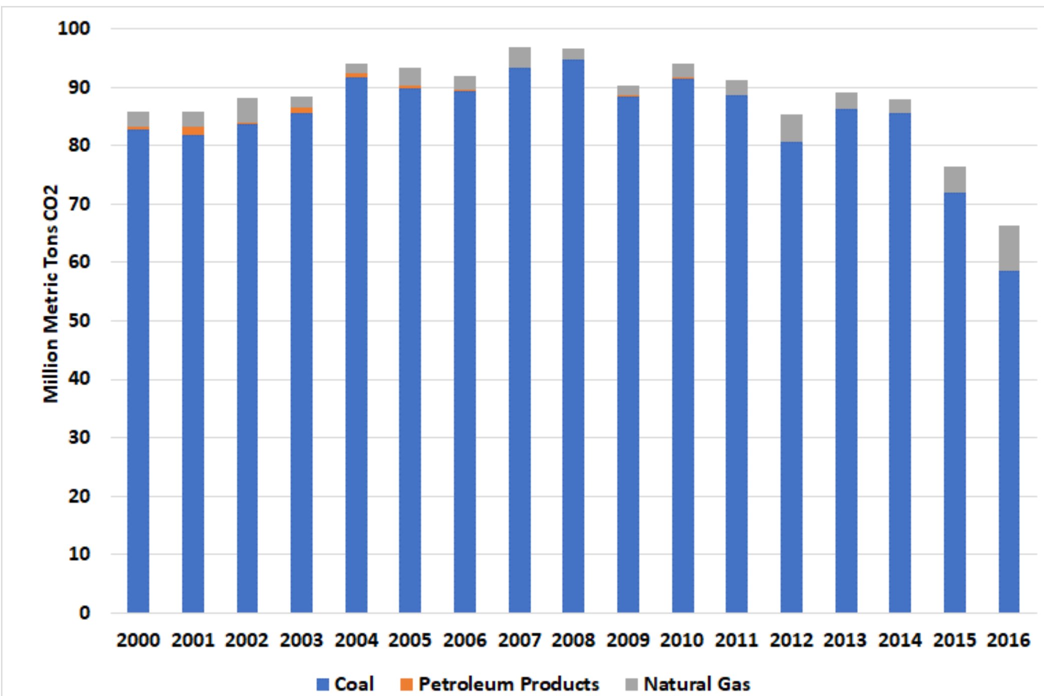
Figure 4-9 Power Generation Resource Mix in Illinois, 2000-2017



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Renewable	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%
Petroleum	0.4%	0.8%	0.1%	0.6%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Natural Gas	2.6%	2.6%	4.9%	2.1%	1.8%	3.7%	2.8%	3.8%	2.2%	2.4%	2.9%	3.1%	5.9%	3.5%	2.9%	6.0%	9.9%	8.8%
Coal	46.5%	44.6%	46.3%	46.8%	49.5%	47.8%	47.9%	47.9%	49.2%	47.3%	47.7%	46.8%	42.8%	45.7%	45.7%	40.4%	33.7%	34.0%
Nuclear	50.5%	51.8%	48.6%	50.4%	48.2%	48.3%	49.2%	48.1%	48.5%	50.2%	49.1%	49.8%	51.0%	50.5%	51.2%	53.3%	56.0%	56.9%

Nuclear Coal Natural Gas Petroleum Renewable

Figure 4-10 Power Sector Carbon Dioxide Emissions by Fuel Source, Illinois, 2000-2016

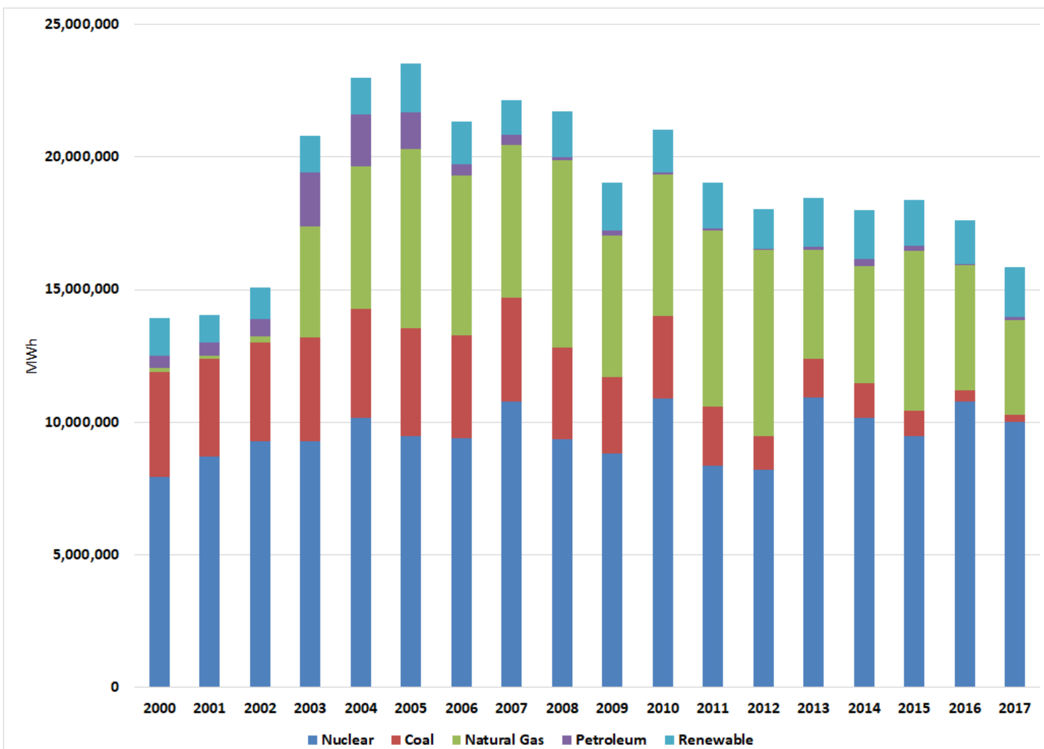


4.2.2.3 *Power Sector Carbon Dioxide Emissions Trends in New Hampshire*

Power sector generation and carbon dioxide emissions data for New Hampshire from 2000 through 2017 are depicted in Figures 4-11, 4-12 and 4-13.[77] Note that:

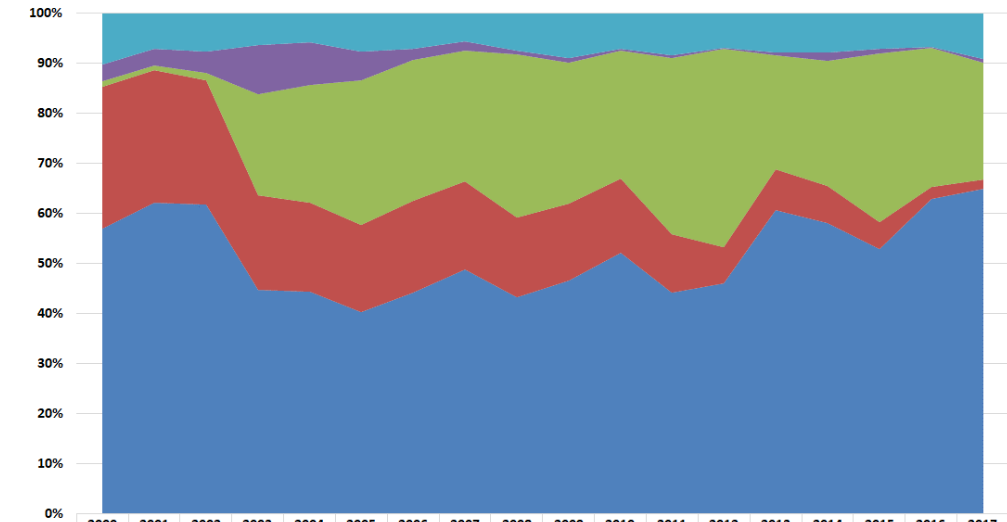
- Annual power generation rose rapidly from less than 15 million MWh in 2000 to approximately 24 million MWh in 2005. Power generated from natural gas ranged from 4 million to 6 million MWh from 2003 through 2016.
- The percentage of high-emission coal in the generation supply mix fell from approximately 25% before 2003 to 2% in 2017. Power generated from petroleum products (fuel oil) also declined to nominal levels after 2007. Reduced coal and fuel oil use resulted in the steady decline of carbon dioxide emissions from 8 million metric tons in 2005 to 2 million metric tons in 2016.

Figure 4-11 Annual Power Generation by Source in New Hampshire, 2000-2017



[77] Source: U.S. Energy Information Administration. Carbon dioxide emissions data for 2017 was not available from the EIA.

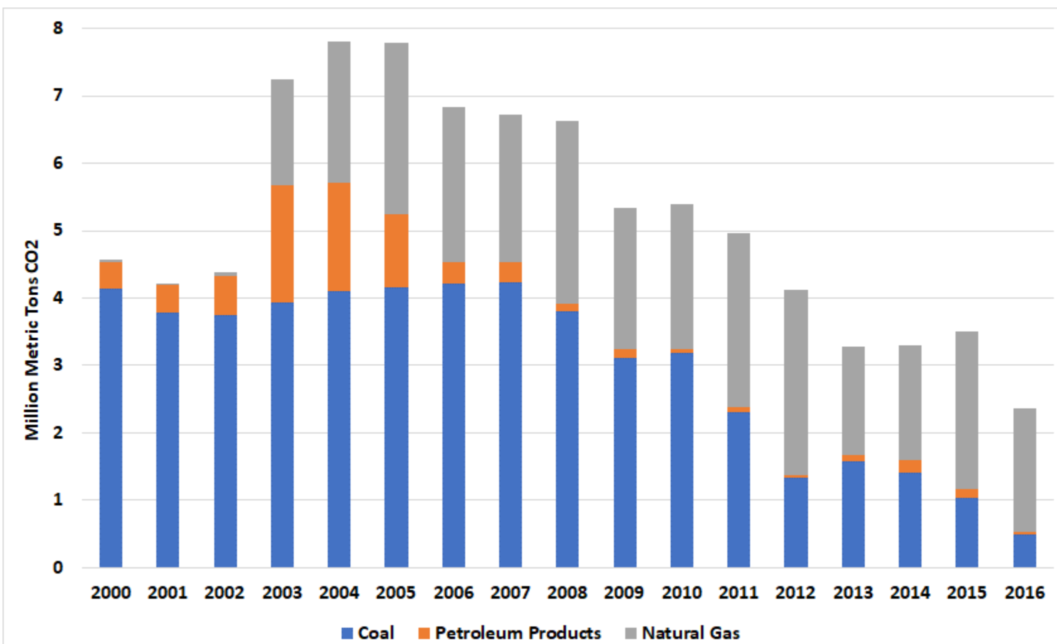
Figure 4-12 Power Generation Resource Mix in New Hampshire, 2000-2017



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Renewable	10.2%	7.1%	7.6%	6.4%	5.7%	7.6%	7.2%	5.7%	7.5%	8.8%	7.0%	8.4%	6.9%	7.7%	7.7%	6.9%	6.5%	8.9%
Petroleum	3.4%	3.4%	4.3%	9.8%	8.5%	5.8%	2.1%	1.7%	0.6%	1.0%	0.3%	0.4%	0.1%	0.6%	1.6%	1.0%	0.2%	0.7%
Natural Gas	1.0%	0.8%	1.5%	20.0%	23.5%	28.8%	28.2%	26.0%	32.6%	28.1%	25.5%	35.0%	39.1%	22.2%	24.4%	32.9%	27.0%	22.6%
Coal	28.5%	26.4%	24.7%	18.9%	17.7%	17.3%	18.2%	17.7%	15.9%	15.2%	14.7%	11.6%	7.0%	7.9%	7.3%	5.1%	2.4%	1.8%
Nuclear	56.9%	61.9%	61.6%	44.6%	44.3%	40.2%	44.1%	48.6%	43.1%	46.3%	51.9%	43.9%	45.4%	59.2%	56.5%	51.6%	61.2%	63.1%

Nuclear Coal Natural Gas Petroleum Renewable

Figure 4-13 Power Sector Carbon Dioxide Emissions by Fuel Source, New Hampshire, 2000- 2017



4.3 PAIRING NUCLEAR AND RENEWABLE ENERGY IN THE U.S.

4.3.1 State Policy Actions

Select states that have established carbon-free policies are listed in Table 4-3 below. Illinois, New York and New Jersey are the only states where legislators have allowed subsidy payments to nuclear plant operators in the form of zero emission credits.[78] Connecticut utilizes state procurements to support carbon-free generation, including nuclear power plants, while Ohio legislators established a customer surcharge to support existing nuclear plants. Other states allow nuclear plants to qualify under a clean-energy requirement. These subsidies are intended to avert plant closures and the resulting loss of jobs and tax revenue. Additional information on these policies and other state efforts to support nuclear plants is included in Section 5.

Table 4-3 State Carbon-Free Policies

State	Policy	Year Implemented
California	100% carbon-free by 2045 mandate, potential to include non-renewable, carbon-free sources.	2018
Connecticut	Establishes state procurement of carbon-free resources, potential to include non-renewable, carbon-free sources.	2017
Illinois	Establishes a zero emission standard and credits for nuclear generation.	2017
New Jersey	Establishes zero emission credits for nuclear generation.	2018
New York	Establishes zero emission credits for nuclear generation.	2016
	100% carbon-free by 2040 requirement, potential to include non-renewable, carbon-free sources.	2019
Nevada	100% carbon-free by 2050 mandate, potential to include non-renewable, carbon-free sources	2019
New Mexico	100% carbon-free by 2045 mandate, potential to include non-renewable, carbon-free sources	2019
Ohio	Establishes customer surcharge account for nuclear generation.	2019
Washington	100% carbon-free by 2045 mandate, potential to include non-renewable, carbon-free sources	2019

4.3.2 Nuclear Operations, Carbon Limits, and Clean Energy in South Carolina

- There are no state-mandated carbon emissions limits in South Carolina.

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[78] International Energy Agency, *Nuclear Power in a Clean Energy System,* Table 4, May 2019, p. 42

- There are four nuclear plants currently operating in South Carolina with a total generating capacity of 6,576 MW.[79] These plants produced 58.4% of all power generated in the state in 2017.[80]
- In July 2017,[81] construction was halted on the 2,200 MW expansion of the V.C. Summer Nuclear Station near Jacksonville that had been plagued by cost overruns and construction delays.[82]
- Duke Energy Carolinas plans to install approximately 84,000 kW of renewable energy capacity by January 2021, with an option to invest in an additional 44,000 kW. Most of this will be comprised of solar photovoltaic installations.[83]
- South Carolina Electric & Gas Company (SCE&G) plans to install 36 MW of solar generation by 2021 and has allowed customers to purchase individual panels on utility-managed solar facilities. SCE&G plans to add up to 100 MW of renewable energy.[84]
- SCE&G currently sources 25% of its total clean energy from hydro, nuclear, solar, and biomass generation facilities. By 2021, SCE&G expects to produce 60% of generation from clean energy, including nuclear.[85]

4.3.3 *Nuclear Operations, Carbon Limits, and Clean Energy in Illinois*

- There are six nuclear plants currently operating in Illinois with a total generating capacity of 11,587 MW.[86] These plants produced 52.9% of all power generated in the state in 2017.[87]
- The Future Energy Jobs Act of 2016 included a Zero Emission Credits (ZECs) program that requires electric utilities to procure ZECs from zero-emission facilities. The law also sets procurement targets for utilities equal to a minimum percentage of each utility's load as follows: 25% by June 2025; 45% by June 2030; 90% by June 2045; increasing to at least 100% by June 2050, and it sets an interim

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[79] Source: U.S. Energy Information Administration.

[80] Ibid.

[81] See chooseenergy.com/news/article/failed-v-c-summer-nuclear-project-timeline/

[82] Akela Lacey, *South Carolina Spent $9 Billion to Dig a Hole in the Ground and Fill it In.* The Intercept, February 6, 2019, theintercept.com/2019/02/06/south-caroline-green-new-deal-south-carolina-nuclear-energy/

[83] South Carolina Energy Office, *Carolinas Energy Planning for the Future*, p. 17, energy.sc.gov/files/view/Carolinas%20Energy%20Planning%20for%20the%20Future.pdf

[84] Ibid.

[85] Ibid., p. 15, energy.sc.gov/files/view/Carolinas%20Energy%20Planning%20for%20the%20Future.pdf

[86] Source: Source: U.S. Energy Information Administration.

[87] Ibid.

target of 100% carbon-free electricity in 2030.[88] Ratepayers will cover the cost of the ZECs program through monthly surcharges.

- In February 2019, the Clean Energy Jobs Act was introduced, which would expand renewable energy development by requiring the Illinois Power Authority to procure renewable and nuclear generating capacity, ostensibly at a higher price than would be realized in the PJM capacity market. Such out-of-market support would allow nuclear plants that are not profitable, but provide jobs, clean energy and tax revenue, to continue operating.[89] Energy resources that qualify as "renewable" under the Clean Energy Jobs Act, other than solar PV and wind, include solar thermal, geothermal, biodiesel, landfill gas, anaerobic digestion and hydropower that does not involve significant expansion of hydropower or construction of new dams.

4.3.4 Nuclear Operations, Carbon Limits, and Clean Energy in New Hampshire

- The Seabrook Station is the only nuclear plant operating in New Hampshire. It has a total generating capacity of 1,251 MW[90] and produced 57.3% of all power generated in New Hampshire in 2017.[91] Seabrook's operating license was recently extended to 2050 by NRC. A watchdog group in Massachusetts has contested the extension claiming that deterioration of concrete structural components will limit the plant's ability to resist seismic activity.[92]
- In 2018, New Hampshire published a 10-year strategy document[93] containing a set of principles and goals to guide energy policy development. The strategy recognizes the Seabrook Station as a source of zero-carbon energy that is critical for managing carbon emissions on a large scale. The state's strategy does not endorse out-of-market subsidies to accelerate adoption of renewable resources.[94]

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88 Julia Pyper, New Illinois Bill Targets 100% Renewable—Not Just Clean—Electricity by 2050, *Greentech Media*, March 4, 2019, greentechmedia.com/articles/read/illinois-100-renewable-electricity-bill#gs.z7ix62

89 Ibid.

90 Source: Source: U.S. Energy Information Administration.

91 Ibid.

92 Angeljean Chiaramida, *NRC to report on Seabrook Station Nuke Plant,* Seacoast Online, April 11, 2019 seacoastonline.com/news/20190411/nrc-to-report-on-seabrook-station-nuke-plant

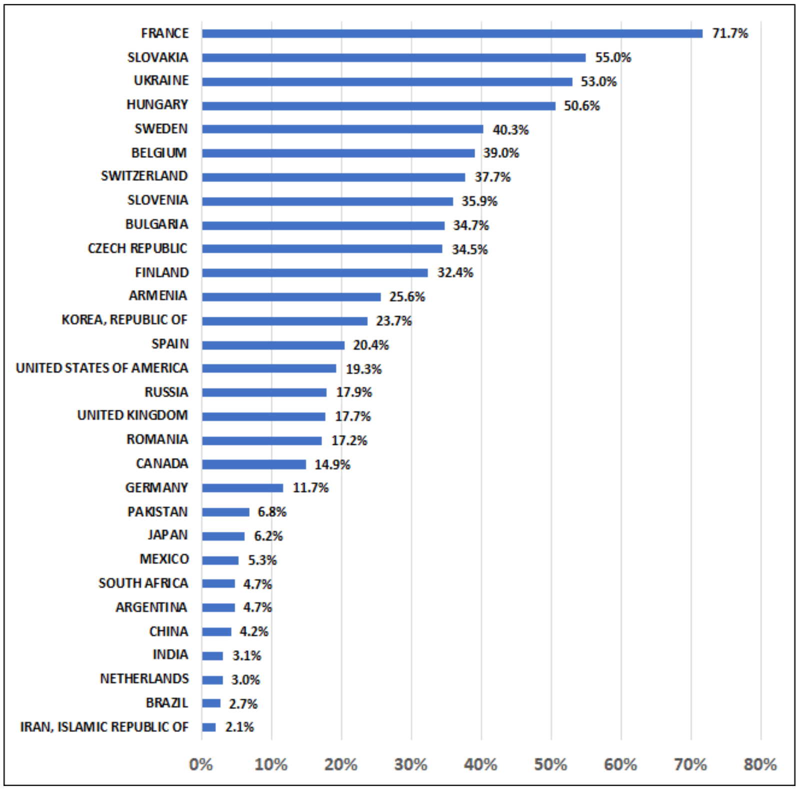
93 New Hampshire Office of Strategic Initiatives, *New Hampshire 10-Year State Energy Strategy*, April 2018, p. 51 , nh.gov/osi/energy/programs/documents/2018-10-year-state-energy-strategy.pdf

94 Ibid. p.16

4.4 POWER SECTOR CARBON DIOXIDE EMISSIONS TRENDS OUTSIDE THE U.S.

The percentage of electricity generated globally in 2017 by nuclear power plants is depicted in Figure 4-14 below. France, Slovakia, Ukraine and Hungary are the only countries in which nuclear power exceeded 50% of total generation. This section will provide an analysis of carbon emission reduction trends and an examination of the extent to which nuclear and renewable energy have been effectively paired to help meet carbon emission reduction goals in each of these four countries.

Figure 4-14 Percent of Total Electricity Generated with Nuclear Power 2018[95]



4.4.1 *France*

Power sector generation and carbon dioxide emissions data for France from 2000 through 2016 are depicted in Figures 4-15, 4-16, and 4-17.[96] Note that:

- Annual power generation has been just over 500,000 GWh from 2000 through 2016.

[95] Source International Atomic Energy Authority, pris.iaea.org/PRIS/WorldStatistics/NuclearShareofElectricityGeneration.aspx

[96] Source: Eurostat database: ec.europa.eu/eurostat/web/energy/data/database

- The percentage of natural gas and oil in the generation supply mix increased from less than 1% in 2000 to 4.5% in 2016. Coal use declined from 4.9% to 1.5% and electricity from renewable sources increased from 13.6% to 16.8% in 2016 throughout this period. Carbon dioxide emissions fell from 25 million metric tons in 2000 to a low of just over 10 million metric tons in 2014 when the renewable energy component of the mix increased to 16% and coal dropped to less than 2%.

Figure 4-15 Annual Power Generation by Source in France, 2000-2016

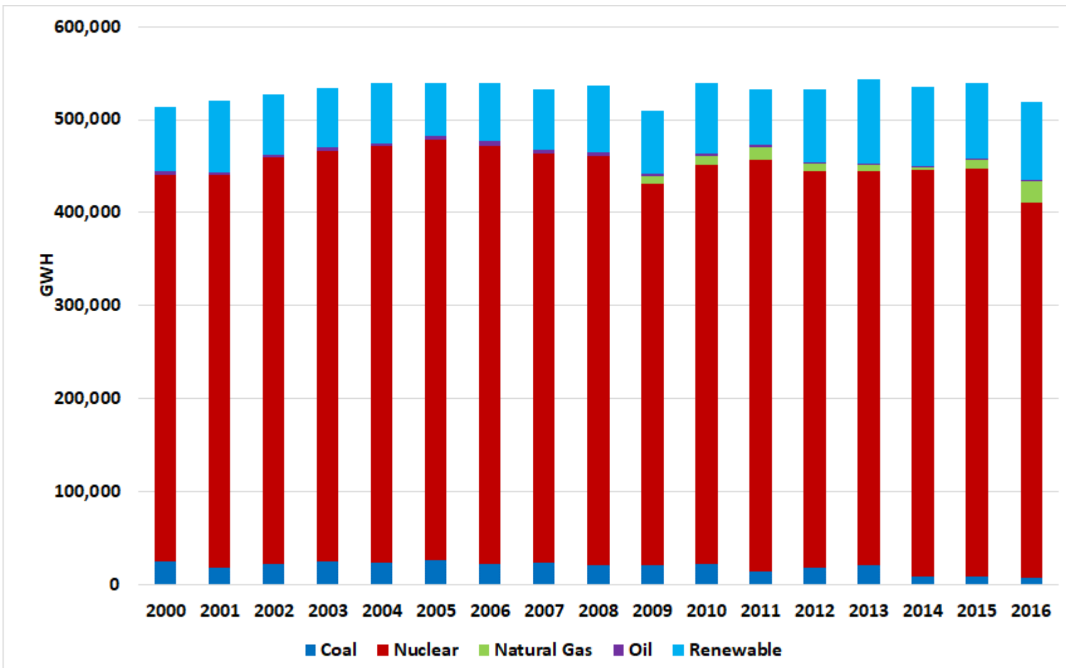
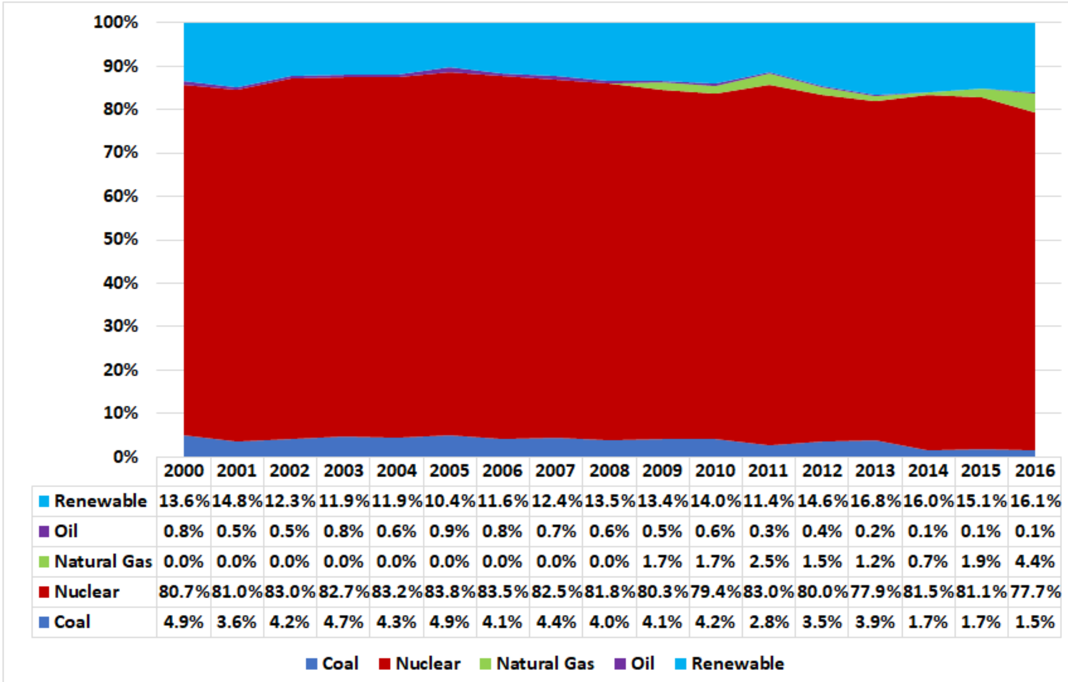
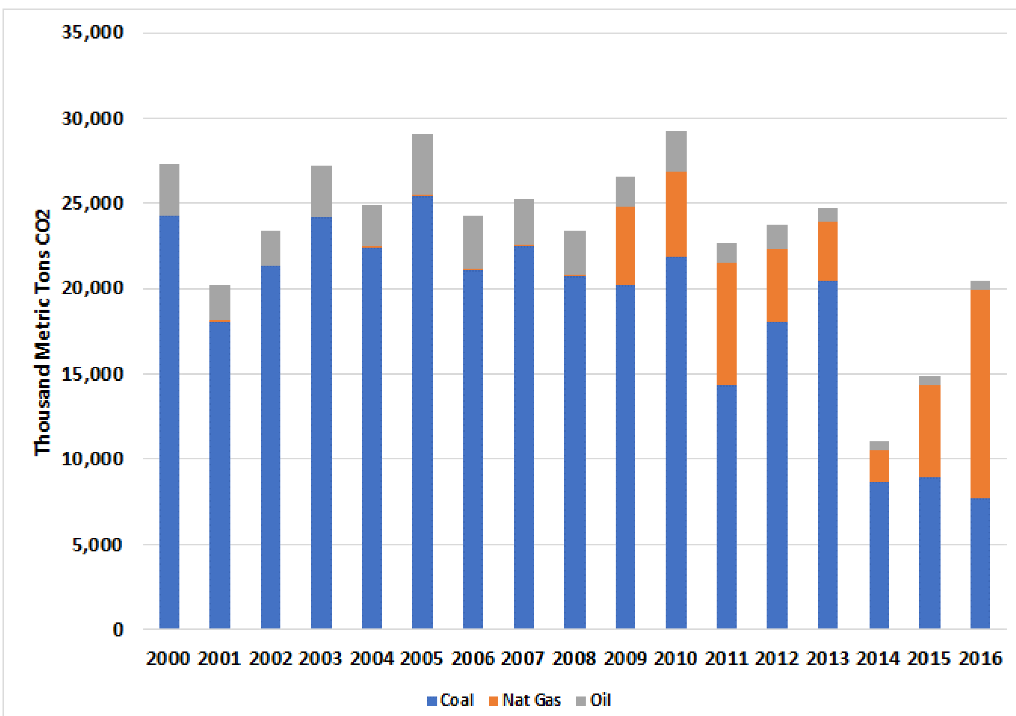


Figure 4-16 Power Generation Resource Mix in France, 2000-2016



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Renewable	13.6%	14.8%	12.3%	11.9%	11.9%	10.4%	11.6%	12.4%	13.5%	13.4%	14.0%	11.4%	14.6%	16.8%	16.0%	15.1%	16.1%
Oil	0.8%	0.5%	0.5%	0.8%	0.6%	0.9%	0.8%	0.7%	0.6%	0.5%	0.6%	0.3%	0.4%	0.2%	0.1%	0.1%	0.1%
Natural Gas	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	1.7%	2.5%	1.5%	1.2%	0.7%	1.9%	4.4%
Nuclear	80.7%	81.0%	83.0%	82.7%	83.2%	83.8%	83.5%	82.5%	81.8%	80.3%	79.4%	83.0%	80.0%	77.9%	81.5%	81.1%	77.7%
Coal	4.9%	3.6%	4.2%	4.7%	4.3%	4.9%	4.1%	4.4%	4.0%	4.1%	4.2%	2.8%	3.5%	3.9%	1.7%	1.7%	1.5%

Figure 4-17 Power Sector Carbon Dioxide Emissions by Fuel Source in France, 2000-2016

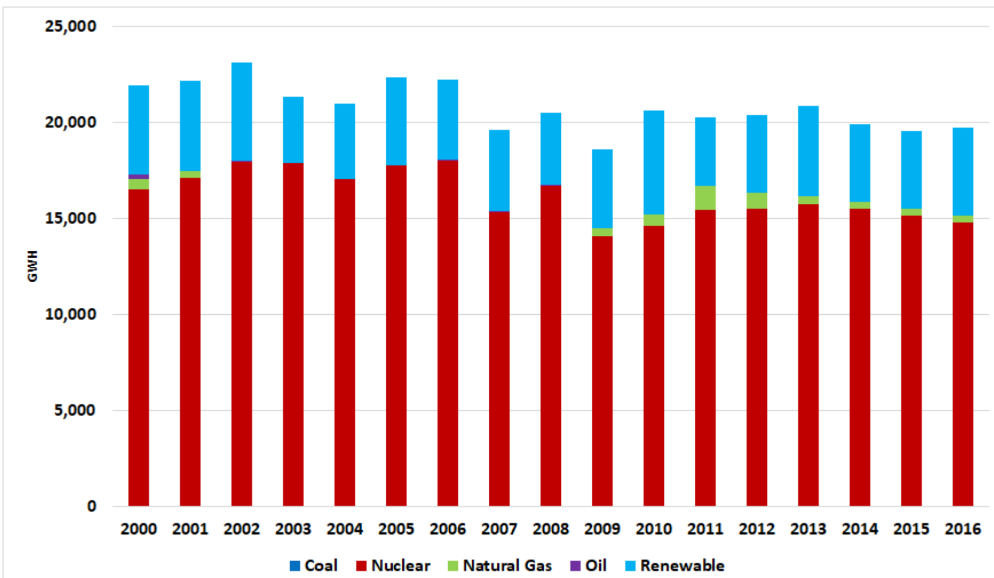


4.4.2 *Slovakia*

Power sector generation and carbon dioxide emissions data for Slovakia from 2000 through 2016 are depicted in Figures 4-18, 4-19, and 4-20.[97] Note that:

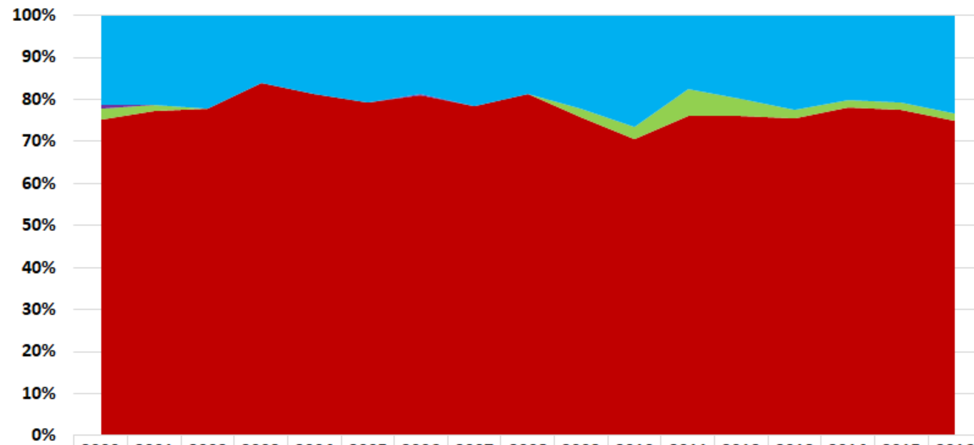
- Total annual power generation declined from a high of 23,000 GWh in 2002 to approximately 20,000 GWh in 2016.
- No coal and nominal amounts of natural gas and oil were consumed in the power sector from 2000 through 2016. Renewable energy ranged from approximately 18% to 23% throughout this period.
- Annual carbon dioxide emissions reflect the modest amounts of fossil fuels consumed for power generation between 2000 and 2016.

Figure 4-18 Annual Power Generation by Source in Slovakia, 2000-2016



[97] Source: Eurostat database: ec.europa.eu/eurostat/web/energy/data/database

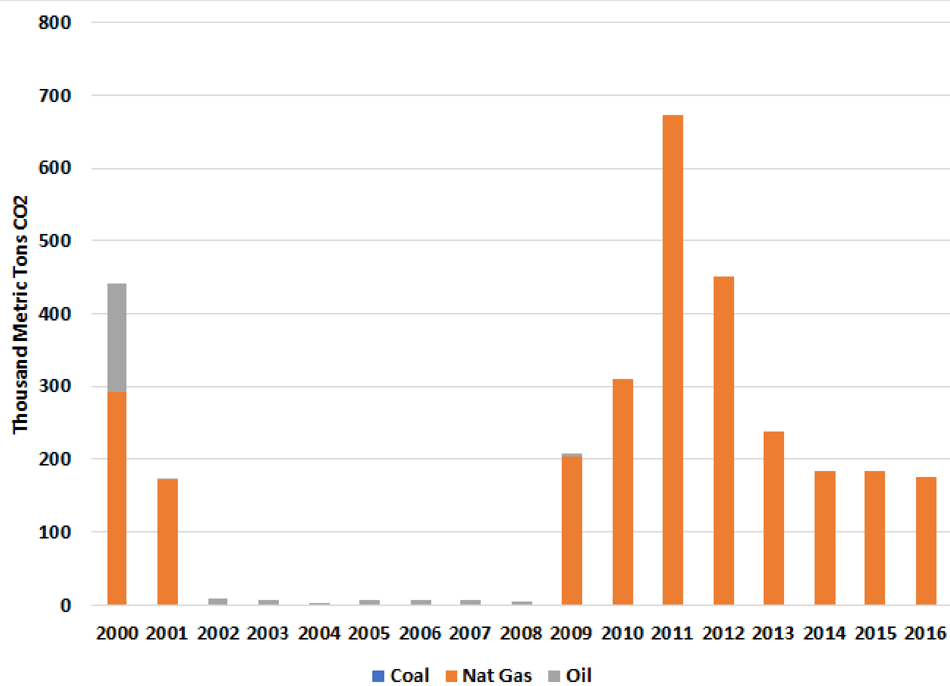
Figure 4-19 Power Generation Resource Mix in Slovakia, 2000-2016



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Renewable	21.4%	21.2%	22.2%	16.1%	18.7%	20.6%	18.8%	21.6%	18.6%	22.2%	26.5%	17.6%	19.8%	22.4%	20.2%	20.7%	23.4%
Oil	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Natural Gas	2.5%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%	2.8%	6.3%	4.2%	2.2%	1.8%	1.8%	1.7%
Nuclear	75.2%	77.3%	77.8%	83.9%	81.3%	79.3%	81.1%	78.3%	81.4%	75.7%	70.6%	76.1%	76.1%	75.4%	78.0%	77.6%	74.9%
Coal	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Coal Nuclear Natural Gas Oil Renewable

Figure 4-20 Power Sector Carbon Dioxide Emissions by Fuel Source in Slovakia, 2000-2016

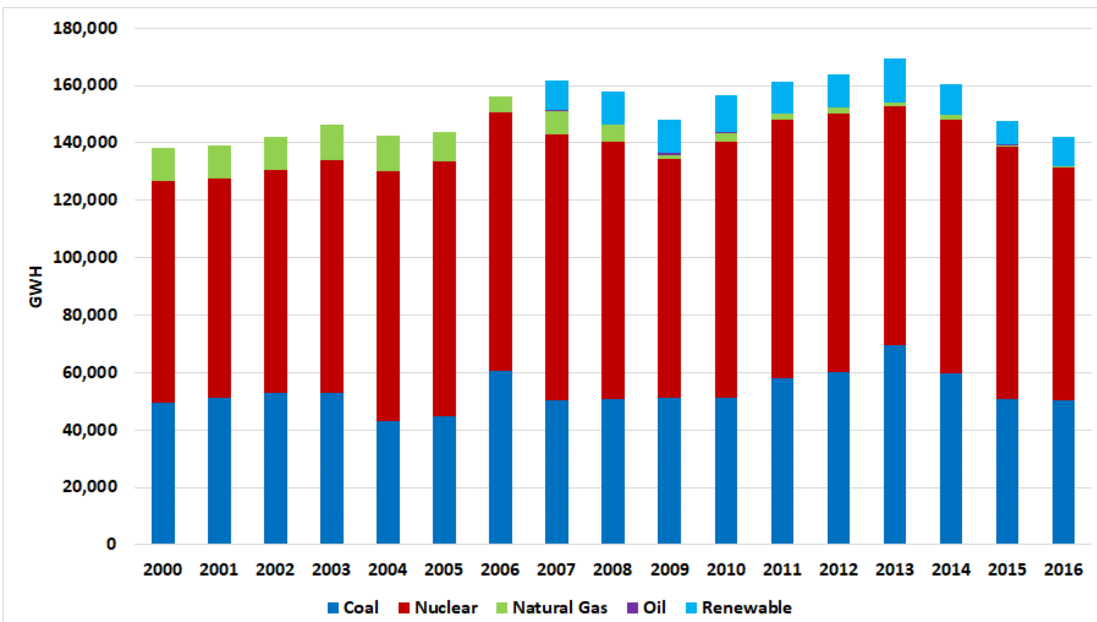


4.4.3 *Ukraine*

Power sector generation and carbon dioxide emissions data for Ukraine from 2000 through 2016 are depicted in Figures 4-21, 4-22, and 4-23[98]. Note that:

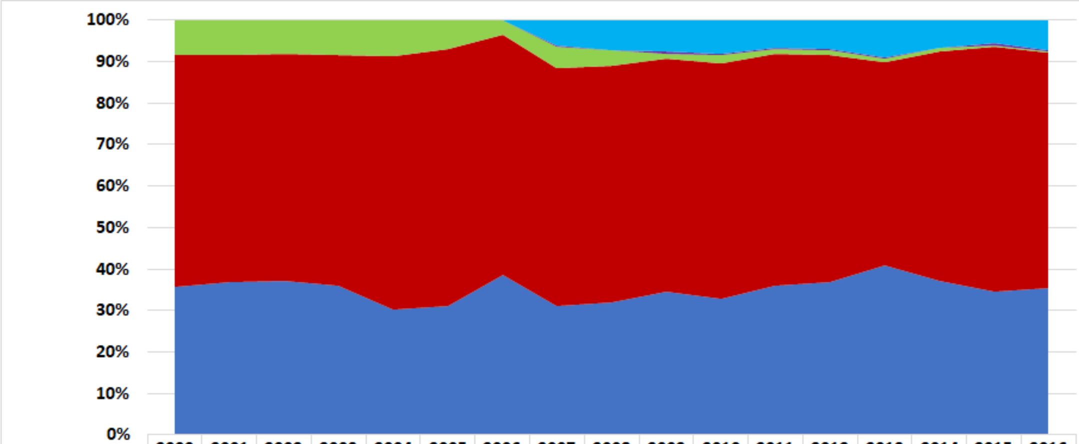
- Total annual power generation generally ranged from 138,000 GWh to 170,000 GWh from 2000 through 2016. Renewable energy entered the supply mix in 2007, largely supplanting power generated from natural gas. Generation from coal remained between 40,000 GWh to 60,000 GWh throughout this period.
- Carbon dioxide emissions ranged from 50 to 60 million metric tons annually throughout the period because the total amount of power generated from fossil fuels remained between 35% and 45% throughout the period.

Figure 4-21 Annual Power Generation by Source in Ukraine, 2000-2016



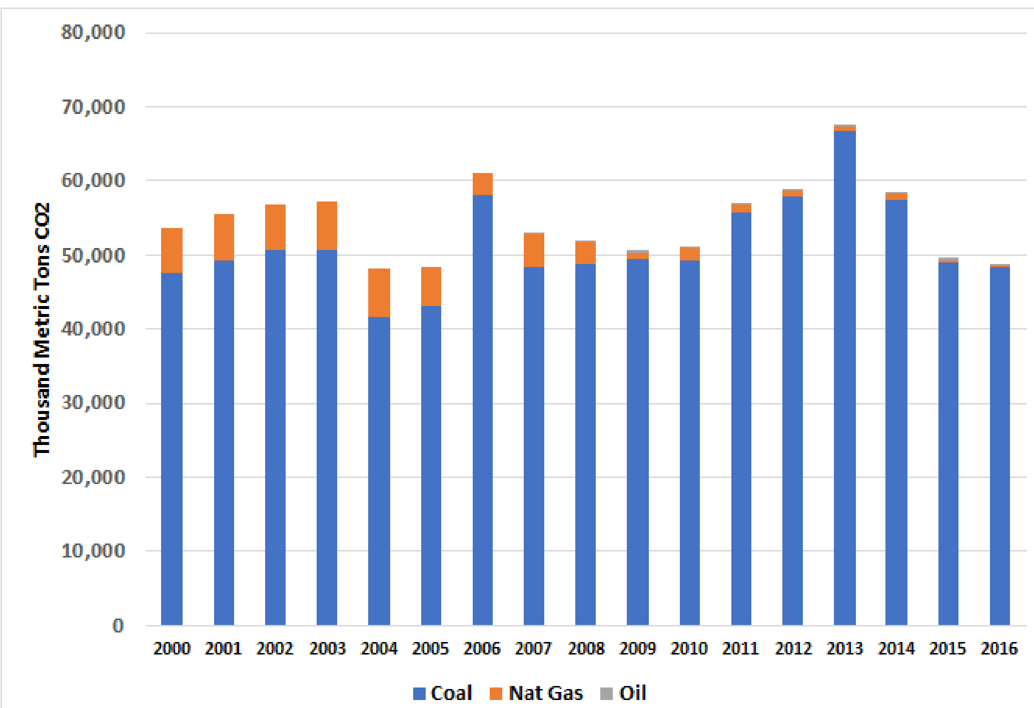
[98] Source: Eurostat database: ec.europa.eu/eurostat/web/energy/data/database

Figure 4-22 Power Generation Resource Mix in Ukraine, 2000-2016



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Renewable	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.2%	7.2%	7.7%	8.2%	6.7%	7.1%	9.1%	6.7%	5.7%	7.3%
Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.5%	0.1%	0.1%	0.1%	0.1%	0.1%	0.3%	0.1%
Natural Gas	8.5%	8.4%	8.1%	8.4%	8.7%	7.0%	3.5%	5.2%	3.6%	1.1%	2.0%	1.2%	1.1%	0.8%	0.9%	0.3%	0.2%
Nuclear	55.9%	54.8%	54.8%	55.6%	61.0%	61.8%	57.8%	57.3%	56.9%	56.0%	56.9%	56.0%	55.0%	49.0%	55.1%	59.3%	56.9%
Coal	35.7%	36.8%	37.1%	36.1%	30.3%	31.2%	38.7%	31.1%	32.1%	34.7%	32.7%	36.0%	36.7%	40.9%	37.3%	34.5%	35.4%

Figure 4-23 Power Sector Carbon Dioxide Emissions by Fuel Source in Ukraine, 2000-2016

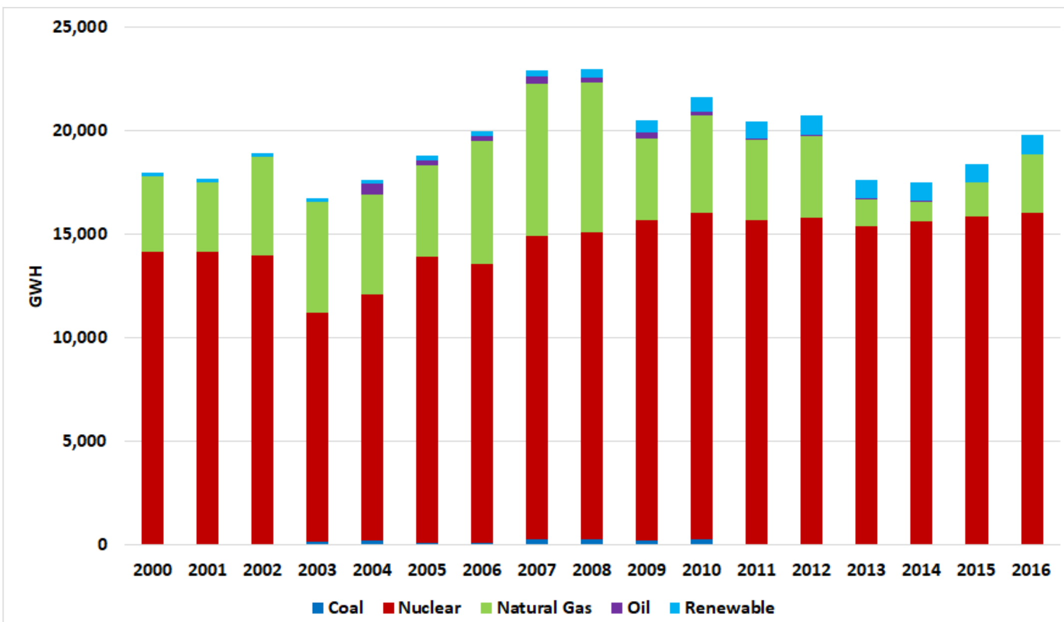


4.4.4 *Hungary*

Power sector generation and carbon dioxide emissions data for Hungary from 2000 through 2016 are depicted in Figures 4-24, 4-25, and 4-26.[99] Note that:

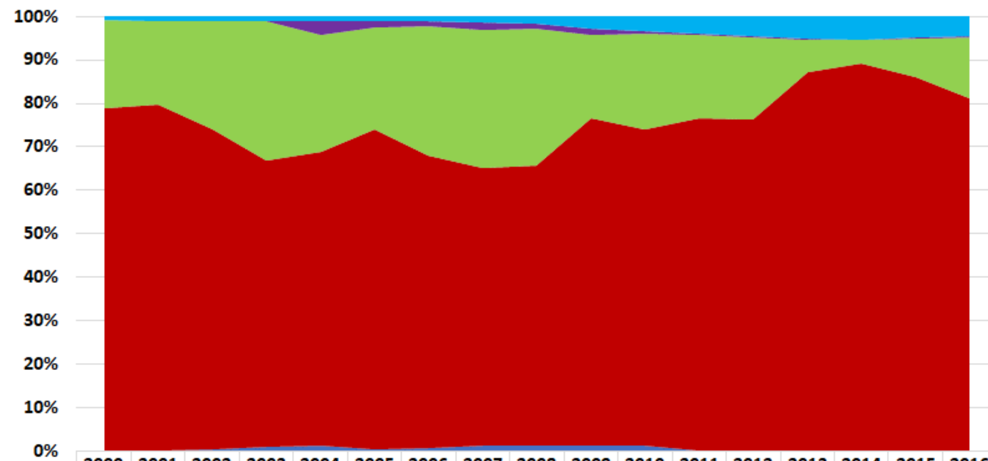
- Annual power generation remained below 20,000 GWh throughout the period except between 2007 through 2012 when generation increased above this level.
- The percentage of nuclear power in the supply mix increased from 79% to as much as 89% in 2014. Natural gas for power generation declined commensurately resulting in annual carbon dioxide emissions falling from a high of over 4 million metric tons in 2007 to 1.5 million metric tons in 2016.

Figure 4-24 Annual Power Generation by Source in Hungary, 2000-2016



[99] Source: Eurostat database: ec.europa.eu/eurostat/web/energy/data/database

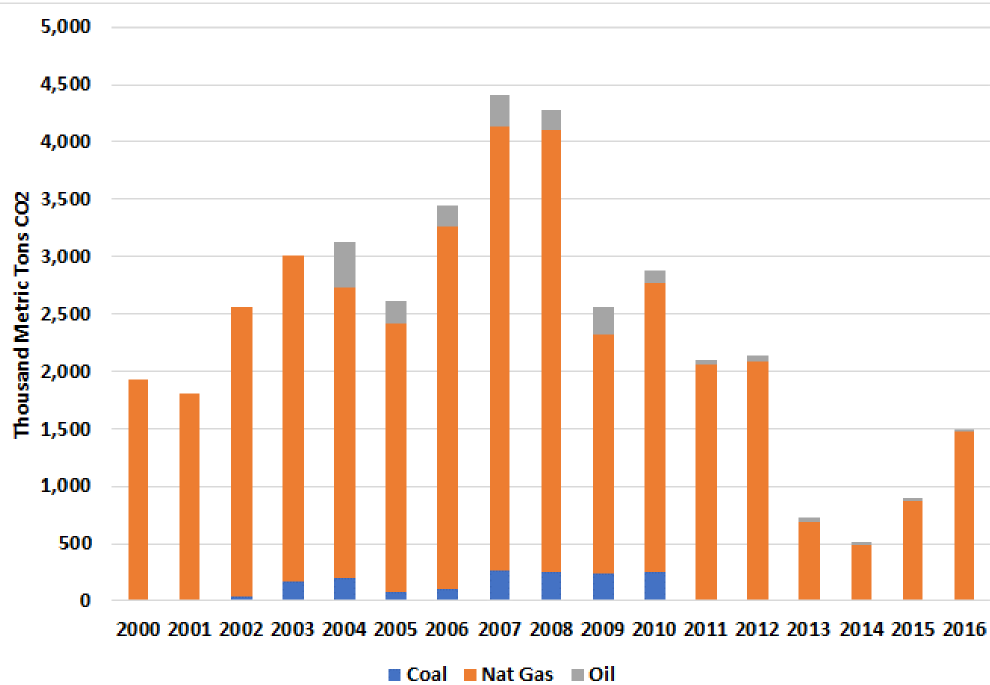
Figure 4-25 Power Generation Resource Mix in Hungary, 2000-2016



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Renewable	0.9%	1.0%	1.0%	1.0%	1.2%	1.1%	1.1%	1.4%	1.8%	2.7%	3.3%	4.0%	4.6%	5.1%	5.3%	4.9%	4.6%
Oil	0.0%	0.0%	0.0%	0.0%	3.0%	1.4%	1.2%	1.6%	1.0%	1.5%	0.7%	0.2%	0.3%	0.3%	0.2%	0.2%	0.2%
Natural Gas	20.1%	19.2%	25.1%	32.1%	27.1%	23.4%	29.7%	31.8%	31.6%	19.3%	22.0%	19.0%	18.9%	7.4%	5.2%	8.9%	14.0%
Nuclear	79.0%	79.8%	73.7%	65.9%	67.6%	73.6%	67.4%	64.0%	64.5%	75.4%	72.9%	76.7%	76.2%	87.2%	89.3%	86.0%	81.2%
Coal	0.0%	0.0%	0.2%	1.0%	1.2%	0.4%	0.6%	1.2%	1.2%	1.2%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Coal Nuclear Natural Gas Oil Renewable

Figure 4-26 Power Sector Carbon Dioxide Emissions by Fuel Source in Hungary, 2000-2016



4.5 PAIRING OF NUCLEAR AND RENEWABLE ENERGY OUTSIDE THE U.S.

4.5.1 *Nuclear Operations, Carbon Limits, and Clean Energy in France*

- There were 58 nuclear reactors operating in France in 2018. These plants generated 395,908,000 MWh in 2018, which represented 71.7% of all electricity generated in the country[100]. France is the world's largest net exporter of electricity. After the oil shocks in 1973, the French government expanded the country's nuclear power capacity for greater energy supply security. France is now one of the lowest cost electricity producers in Europe with extremely low carbon dioxide emissions per capita from electricity generation. Over 90% of electricity is generated from nuclear or hydroelectric.[101]
- The French government issued its Multi-Annual Energy Plan (MAEP) in November 2018 that sets the priorities for energy policy for the period 2019 through 2028. Per the MAEP, the French goals include[102] supplying 23% of energy demand from renewable sources by 2020, reducing the nuclear share in the electricity mix to 50% of power generated by 2025, reducing greenhouse gas emissions 40% versus 1990 by 2030, and complete decarbonization by 2050.[103]
- After 2050 the only sources of electricity in France will be renewable hydro, wind, solar photovoltaic, marine energy, geothermal, wood, biogas, and nuclear.
- The MAEP also states that 14 of the country's nuclear reactors would shut down by 2035; however, the option to build new nuclear reactors remains open.[104] All coal plants will be shut down by 2022.[105]
- After completing the MAEP, the French government has proposed to the Parliament a delay in reducing nuclear power generation to 50% until 2035.[106]

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100 Source International Atomic Energy Authority , pris.iaea.org/PRIS/WorldStatistics/NuclearShareofElectricityGeneration.aspx

101 Nuclear Power in France world-nuclear.org/information-library/country-profiles/countries-a-f/france.aspx

102 *French Strategy for Energy and Climate Multi Annual Energy Plan*, p. 16, ecologique-solidaire.gouv.fr/sites/default/files/0-PPE%20English%20Version%20With%20Annex_0.pdf

103 Ibid., p. 18

104 Ibid., Nuclear Power in France

105 Ibid., French Multi Annual Plan, p. 54

106 Ibid., Nuclear Power in France

4.5.2 *Nuclear Operations, Carbon Limits, and Clean Energy in Slovakia*

- In 2018 there were four nuclear reactors operating in Slovakia. These plants generated 13,789,000 MWh in 2018 which represented 55% of all electricity generated in the country.[107]
- In November 2014, the Slovak government approved an Energy Policy[108] containing targets and priorities through 2035. The objective of the policy is to achieve a competitive low-carbon power sector. High priorities described in the plan include increasing the share of low-carbon and carbon-free electricity generation and using nuclear energy as the main carbon-free source of electricity.
- The power sector in Slovakia has very low carbon dioxide emissions compared to other countries in the European Union because of the high percentage of nuclear generation in the supply mix.[109] The country's goal is to achieve 25% renewable electricity in its supply mix by 2030.[110]
- Wind or photovoltaic power plants are not a priority area for Slovakia.[111]

4.5.3 *Nuclear Operations, Carbon Limits, and Clean Energy in Ukraine*

- In 2018 there were 15 nuclear reactors operating in Ukraine. These plants generated 79,532,000 MWh in 2018 which represents 53% of all electricity generated in the country.[112]
- The Ukrainian government has prioritized development of new nuclear technologies, such as SMRs to replace its existing nuclear plants as they retire after 2030.[113]
- Ukraine's renewable energy policies include increased generation of electricity from renewable sources, sustainable production and energy generation from biomass and increased production of biogas as a fuel for generation of electricity.[114]

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107 Source International Atomic Energy Authority , pris.iaea.org/PRIS/WorldStatistics/NuclearShareofElectricityGeneration.aspx

108 Slovak Ministry of the Economy, *Proposal for an Integrated National Energy and Climate Plan,* December 2018, p.5

109 Ibid., p. 37

110 Ibid, p37 Table 7

111 Slovak Renewable Energy Agency, *Climate and Energy Policy in Slovakia,* November, 2018, p. 14, eko-unia.org.pl/wp-content/uploads/2018/06/mini-report-1_-Slovakia.pdf

112 Source International Atomic Energy Authority , pris.iaea.org/PRIS/WorldStatistics/NuclearShareofElectricityGeneration.aspx

113 Ukraine 2050 Low Emission development Strategy, p.46, unfccc.int/sites/default/files/resource/Ukraine_LEDS_en.pdf

114 Ibid., p. 9

4.5.4 *Nuclear Operations, Carbon Limits, and Clean Energy in Hungary*

- In 2018 there were four nuclear reactors operating in Hungary. These plants generated 14,857,000 MWh in 2018, which represented 50.6% of all electricity generated in the country.[115]
- Two new 1,200 MW nuclear power plants will be constructed by 2030 to allow the phasing out of all coal-based power generation in Hungary. Coal-based energy plants that supply industrial heat and district heating will continue to operate after 2030.[116]
- Hungary unveiled a long-term energy and climate change plan that includes reducing GHG emissions 52% versus 1990 by 2050.[117] Central to the plan is to raise the share of renewable energy production to 20% by 2030 largely by using abundant biomass fuel.
- In May 2019, Hungary lent its support to the European Union's 2050 carbon neutrality goal with the caveat that nuclear power can be used to meet the target.[118]

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115 Source International Atomic Energy Authority , pris.iaea.org/PRIS/WorldStatistics/NuclearShareofElectricityGeneration.aspx

116 European Commission, National Energy and Climate Plan of Hungary, p.38 ec.europa.eu/energy/sites/ener/files/documents/ec_courtesy_translation_hu_necp.pdf

117 bne Intellinews, May 9, 2019, intellinews.com/hungary-unveils-long-term-energy-and-climate-change-plan-160910/?source=hungary

118 Sam Morgan, EURACTIV.com, June 18, 2019, euractiv.com/section/climate-strategy-2050/news/hungary-says-no-climate-neutrality-without-nuclear-but-backs-eu-target/

5.0 *Potential State Initiatives to Support Existing and New Nuclear Power Plants*

States can play an important role in supporting both the continued operation of nuclear power plants and the development of new nuclear plants. Although nuclear power is primarily regulated at the federal level, state and local entities have authority over the siting and taxation of nuclear plants. Additionally, state utility regulatory commissions are responsible for determining whether electric utilities can recover the costs of new or existing nuclear power plants through customer rates, including review of the prudency and reasonableness of nuclear power plant costs. Furthermore, states can provide support to nuclear power through targeted incentives, direct or indirect investments, and guarantees, including loans, purchase agreements, and advanced cost recovery.

Many potential initiatives to support nuclear facilities are already utilized to support other energy technologies. For example, federal or state tax incentives that support emerging or existing renewable energy technologies could be applied to new or existing nuclear power plants. In other cases, potential initiatives are more narrowly directed, such as the creation of zero emission credits (ZECs) to support operating nuclear power plants that face possible closure or otherwise compensate nuclear power for benefits not presently recognized in electricity markets. Additionally, some approaches to support nuclear facilities, like the implementation of carbon pricing, require more significant state or federal environmental policy changes. This section begins with short overviews of specific policies and initiatives that could be applied to nuclear power plants in Maryland. In addition to providing background, each overview also includes examples (as applicable) and a brief listing of strengths and weaknesses.

Implementing any of these potential initiatives is challenging for a variety of reasons, not the least of which is the underlying complexity of the energy sector. Power generators provide an essential service through a complex supply chain that is both highly capitalized and strictly regulated. Maryland's participation in PJM further complicates power provision because the state has ceded control over its power markets to a third-party, independent system operator. Within these complex arrangements, initiatives to support nuclear facilities face an array of political, economic, legal, and regulatory challenges. Thus, to supplement the review of initiatives, this chapter also discusses the overarching challenges facing Maryland policy efforts related to nuclear power.

The feasibility of each prospective initiative depends on the circumstances facing both existing and potential nuclear power plants. Additionally, the appropriateness depends on the goals and priorities of policymakers, some of which involve tradeoffs. Thus, this chapter concludes with a comparison of each potential initiative by various metrics, such as amount of time needed to implement, the ability to target nuclear power plants that need support, cost to ratepayers, and the ease of oversight and administration. This final section also notes which policies might be complementary to each other and which are substitutes.

5.1 *STATE ENERGY PORTFOLIO STANDARDS*

A Renewable Portfolio Standard (RPS) or Clean Energy Standard (CES) require load-serving entities (LSEs) to produce or procure a portion of their power from renewable energy or low-emission sources, usually defined as a percent of total retail sales on an annual basis. LSEs generally comply with these requirements through the retirement of certificates, with each certificate representing a megawatt-hour of energy from certified energy generators, e.g., Renewable Energy Credits (RECs).

Often, energy sources that already exist in the power market, such as nuclear and conventional hydropower, are excluded from these standards. This exclusion is generally due to concerns that nuclear and conventional hydropower are established technologies that do not need financial or policy support, and that such support could be reserved for emerging resources that are not currently economically competitive, such as solar, wind, and biomass. The economic troubles of some nuclear power plants have prompted consideration of whether nuclear power should be included either as part of an existing state RPS, or as a larger CES that includes renewable energy and nuclear power. Additionally, concerns about global GHG emissions have prompted consideration of whether RPS and CES policies could support existing or new nuclear facilities.

Generally, the options available to states fall into one of two buckets: alter an existing RPS structure to include nuclear, or implement a new CES that includes nuclear among a suite of other clean energy resources, including renewables. For either of these approaches, policy design is crucial toward supporting either existing or new nuclear power plants without detrimentally affecting other policy goals such as supporting renewable energy generation. An additional policy option is to exclude nuclear power generation when calculating RPS or CES requirements, which has the effect of accounting for nuclear power without providing additional support. This approach is useful when coupling an RPS with other initiatives to support nuclear facilities. Note that discussion of Zero

Emission Credits (ZECs), a policy approach to compensate existing nuclear generation within an existing or separate state energy portfolio, is reserved for a separate subheading below.

5.1.1 Alter an Existing RPS

State RPS policies are typically structured as either a single, all-inclusive tier, or into multiple tiers that each support different technologies. For a single tier, the overall RPS requirement applies to all eligible technologies without categorical distinction by vintage or technology. A multi-tiered system divides eligible resources into different tiers, with one tier often representing emergent technologies such as wind or solar and lower tiers often reserved for existing resources or mature technologies that would likely cease operation without some form of market support. Primary tier resources are usually eligible for the lower tiers as well. In some cases, these tiers are further subdivided by carve-outs, which typically require a portion of the overall requirement be met by in-state resources. Within either a single or multi-tiered RPS, states can potentially support nuclear by adding it to a tier, or creating a new tier. If states were to include nuclear in either the second or third tier in a multi-tiered structure, nuclear would receive a lower level of state-mandated support. This approach would also, however, prevent it from crowding out high-priority resources in the higher tiers. Alternatively, a state could include nuclear generation in the primary tier of their RPS, allowing it to compete for the highest level of support with other high-priority resources. In this circumstance, nuclear is likely to drive down REC prices unless the overall standard requirement is also increased.

5.1.2 Clean Energy Standard

Rather than adding nuclear power to an existing RPS policy, a state could also implement a CES in lieu of an RPS or as a complementary but separate policy. CES policies are structured similarly to RPS policies in so far as they establish tiers or cutouts for specific resources. The primary difference is that a CES, by definition, includes other carbon-free resources that are often excluded from state RPS policies, such as large hydro and nuclear power, without otherwise redefining eligible renewable energy generation. An alternative policy option for including nuclear in a standard would be to implement a CES in addition to an RPS. In this scenario, the state would implement a CES that operates synchronously with the existing RPS standard, effectively eliminating the competition between the resources included in the CES and traditional renewable resources for RPS funding. This design would function similarly to a multi-tiered approach in which renewables were included in the primary tier and nuclear was included in the lower tiers, except that in this case the CES requirement is exclusive of the RPS requirement.

5.1.3 *Exclude Nuclear Sales from RPS*

A final policy approach is to account for nuclear in an RPS or CES is to net nuclear sales out of total state sales. For example, if generation from in-state nuclear facilities comprises half of a state's retail electric sales requirement, and a state maintained a 50% RPS, then the actual RPS proportion of renewable resources procurement by utilities would only be 25% of retail sales. This approach avoids the direct competition of nuclear and renewables while at the same time recognizing the zero-emission attributes of nuclear. It also avoids compensating nuclear power under RPS mechanisms. Nevertheless, despite not competing directly, this initiative disincentives the development of renewable resources by weighting the overall requirement downward, unless the RPS is increased to compensate.

5.1.4 *Experiences with State Energy Portfolio Standards*

Maryland is one of 29 states and the District of Columbia with an RPS.[119] To date, five states have adopted a 100% Clean Energy or Carbon-free Energy Standard (CES). These are Nevada (2050), New York (2040), California (2045), Washington (2045), and New Mexico (2045). Colorado, Illinois, Maryland, Minnesota, and New Jersey, have also considered 100% CES legislation or initiated studies regarding its feasibility in 2018 and 2019. In this context, several states have adopted or attempted to adopt policy designs that incorporate nuclear power.

Only one state, Ohio, has included nuclear power in its RPS, albeit with limited effect on existing or new nuclear reactors to-date. Ohio's Alternative Energy Portfolio Standard (AEPS) requires 8.5% of retail electricity sold by that state's electric distribution utilities to be generated from alternative energy sources by 2027, including both renewable and advanced energy technology sources, such as nuclear generation. However, qualifying facilities must have been placed in service starting on or after January 1, 1998, which does not apply to any nuclear facilities operating in Ohio. Ohio recently enacted legislation to terminate its RPS at 8.5% by 2026, and to implement a monthly customer surcharge to subsidize two existing nuclear power plants and two existing coal plants.

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[119] Note that several additional states maintain voluntary RPS policies that do not require compliance with renewable energy targets. LBNL (2018). U.S. Renewable Portfolio Standards: 2018 Annual Status Report. eta-publications.lbl.gov/sites/default/files/2018_annual_rps_summary_report.pdf.

Besides Ohio, several other states have proposed legislation to incorporate nuclear into an RPS. In 2015, Arizona considered Senate Bill 1134, which proposed to redefine renewable energy to include "nuclear energy from sources that are fueled by uranium fuel rods that include 80% or more of recycled nuclear fuel and natural thorium reactor resources under development." The bill, which would have allowed nuclear power to be considered alongside solar and wind in Arizona's RPS that consists of a single tier, ultimately failed, as did a ballot initiative in 2018 that would have likewise incorporated nuclear power into an expanded RPS. In 2018, New Jersey introduced Senate Bill 1336, which would have included aneutronic fusion reactors, a type of nuclear generation, within the definition of its Class I renewable energy resources. However, the bill was tabled in favor of the ZEC legislation.

As of August 15, 2019, Pennsylvania had two bills under review in the Pennsylvania General Assembly that would add nuclear generation to the state Alternative Energy Portfolio Standard (AEPS) via a third tier. Both bills would require that Pennsylvania's electric distribution companies buy 50% of the electricity they distribute from alternative energy sources included in Tier III. Tier III eligibility extends to other zero-emission alternative energy sources besides nuclear generation, such as solar, wind, hydropower, and geothermal. However, nuclear generation is expected to dominate Tier III because nuclear generation produces more energy per year, in-state, than any other eligible renewable energy source.

Other states have supported nuclear generation through CES policies. On August 1, 2016, New York established a CES that replaced its previous RPS. The CES has three tiers, with Tiers 1 and 2 constituting a Renewable Energy Standard (RES) portion of the CES, which is comprised of a 50% requirement by 2030 for renewable energy.[120] Tier 1 is designed to promote new RES resources, while Tier 2 promotes existing renewable energy resources. Tier 3, meanwhile, is dedicated entirely to in-state nuclear generation. New York's procurement of nuclear resources as part of the Tier 3 requirement is described further in the "Zero Emissions Credit" section below.[121] On August 11, 2017, Massachusetts created a CES that set a requirement for LSEs to procure a minimum percentage of electricity sales from clean energy sources, beginning with 16% in 2018 and increasing 2% annually until 80% in 2050.[122] The CES, which

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120 The renewable energy component is comprised of: solar, wind, hydropower, biomass, fuel cells, biogas, and tidal energy.

121 DSIRE, New York Clean Energy Standard, Last Updated January 8, 2019, programs.dsireusa.org/system/program/detail/5883.

122 "Fact Sheet: Electricity Sector Regulations." *Massachusetts Department of Environmental Protection, Executive Office of Energy & Environmental Affairs.* Aug. 2017, massdep.org/BAW/air/3dfs-electricity.pdf

complements the state's existing RPS, allows nuclear generation to participate in supplying clean energy. However, Massachusetts's CES restricts the eligibility of nuclear power to plants that commence commercial operation after December 31, 2020.

5.1.5 *Advantages and Disadvantages of State Energy Portfolio Standards for Nuclear Power*

5.1.5.1 *Advantages*

- *Flexible* - RPS and CES policies are adaptable and can serve multiple different policy objectives, depending on design.
- *Perceived as politically feasible* - RPS and CES policies have emerged as one state strategy to support nuclear generation as well as address climate change. The popularity of RPS and CES policies establishes them as a potentially expedient way to incorporate existing nuclear into state energy policies to the extent that policy makers are comfortable and familiar with the RPS and CES as an underlying policy framework.
- *Least-cost approach to supporting low-emission energy sources* - In general, state RPS and CES policies are intended to induce supply-side competition between eligible resources and therefore help control costs.

5.1.5.2 *Disadvantages*

- *Potential zero-sum impact on either renewable energy resources or nuclear power* - A zero-sum impact could result depending on the design and size of the RPS or CES. A lower RPS or CES without tiers could result in output from existing nuclear power plants swamping the RPS or CES obligation, driving down credit prices and significantly eroding, if not eliminating, the financial support for renewable energy resources, particularly the development of new renewable energy projects. Conversely, a RPS or CES could have little impact on maintaining the viability of existing nuclear power plants or supporting new nuclear power plants if they are not economically competitive with other eligible technologies. For these reasons, states have tended to have separate tiers for both renewables and nuclear power to avoid this zero-sum outcome.
- *Incompatibility* - Some proponents of RPS policies see the primary purpose as incentivizing the development of new renewable energy projects rather than sustaining non-renewable resources like nuclear power.

- *Minimal impact on production from existing nuclear plants* - Nuclear power plants generally operate at a high load factor. If an existing nuclear power plant is not facing imminent closure, making existing nuclear plants eligible for an RPS or CES is unlikely to increase power production.
- *May result in financial windfall for existing nuclear power plants* - If a nuclear power plant is already economically competitive, then making such plants eligible for an RPS or CES could simply result in a financial windfall for the owners of such plants.
- *Other policies are likely more important to support nuclear power plants, especially new advanced nuclear power plants* - Existing nuclear and pre-commercialization nuclear power technologies are unlikely to receive sufficient financial support from state standards to support development, absent a separate set-aside or tier. Other policies, such as tax incentives and loan guarantees, may be more effective at facilitating the development of advanced nuclear power plants.

5.2 *ZERO EMISSION CREDITS (ZECS)*

Besides including nuclear as part of an energy portfolio standard, states also can replicate some of the features of a standard in new policies that specifically serve nuclear generation. Some states are targeting nuclear generation for energy portfolio standard support is to implement ZECs. ZECs are similar to RECs in so far as they compensate generating facilities based on specified attributes. ZECs, however, can be restrictively defined to only include certain resources. Presently, ZECs, are mainly deployed to support existing nuclear power plants that are financially at risk of closing before their operating license expires. ZECs are distinguished from RECs because they are generally allocated in advance (i.e., committed based on proposed or average production, rather than actual generation), are not eligible for trading, and serve a closed market.

5.2.1 *Experiences with ZECs*

To date, Illinois, New York, and New Jersey have adopted ZEC initiatives, each with their own pricing mechanisms and distribution conditions. The following overview briefly summarizes the key characteristics of existing ZEC initiative.

5.2.1.1 *New York*

On Aug. 1, 2016, New York became the first state to adopt a ZEC requirement when the New York Public Service Commission (NY PSC) ordered its establishment as part of the state's CES.[123,124] Under the NY PSC order, all six of New York's investor-owned utilities (IOUs) and other load-serving entities (LSEs) in the state are required to purchase ZECs from New York State Energy Development Authority (NYSERDA) based on a percentage of their electric load. The ZEC payments are then distributed among nuclear plants that are selected by NY PSC based upon consideration of:

- The historic contribution of the plant to the clean energy resource mix consumed by retail consumers in New York;
- The degree to which revenues received by the plant from energy, capacity, and ancillary services have been inadequate compensation to maintain operations;
- The cost of adequate compensation in relation to other clean energy alternatives;
- The impacts of such costs on ratepayers; and
- The public interest.

The ZEC contracts for selected nuclear facilities are administered in six, two-year tranches. The total number of ZECs a selected nuclear facility can sell is capped at the total generation output of the facility from July 2015 through June 2016. The price paid for the ZECs, as calculated by the NY PSC, is based on the projected social cost of carbon (SCC) average for each tranche (April through March) minus the fixed baseline portion of the cost that is already captured through the Regional Greenhouse Gas Initiative (RGGI) over the same period.[125,126,127] The NY PSC uses SCC projections from the U.S. Interagency Working Group's July 2015

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123 State of New York Public Service Commission, Case 15-E-0302 and Case 16-E-0270, "Order Adopting A Clean Energy Standard", August 1, 2016.

124 The carbon benefits of preserving the nuclear zero-emissions attributes through the ZEC requirement do not count toward New York's 50% renewable energy by 2030 Renewable Energy Standard (RES) goal. The RES and ZEC programs, however, both contribute to the State's comprehensive greenhouse gas reduction goals.

125 The CES defines the Social Cost of Carbon (SCC) as the nominal price per short ton of carbon dioxide.

126 RGGI is a regional carbon trading system comprised of: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. See the subsequent Carbon Pricing section for further discussion.

127 The CES estimates RGGI values for each tranche using RGGI prices forecasted by the New York Independent System Operator's (NYISO) Congestion Assessment and Resource Integration Study (CARIS) model.

Technical Update.[128] For the first tranche (April 2017 to March 2019), the PSC set a ZEC price of $17.48/MWh.[129] The ZEC requirement has a degree of flexibility built-in which would reduce the value of ZECs if the benefits of carbon-free generation become monetized into energy and capacity prices in New York. If wholesale electricity prices rise to more than $39 per MWh, then the ZEC price would drop correspondingly.[130] However, if electricity prices fall, the ZEC price would likely rise to compensate for the lost revenue.

On Dec. 19, 2016, the NY PSC directed NYSERDA to offer long-term contracts for the purchase of ZECs from FitzPatrick Nuclear Power Plant (FitzPatrick), Robert E. Ginna Plant (Ginna), and two units at Nine Mile Nuclear Station (Nine Mile), totaling 27,618,000 ZECs from the three plants annually.[131] The costs of procuring ZECs will be recovered entirely through a commodity charge on the LSE's customer bills. The total cost to ratepayers from the six tranches is estimated at $7.6 billion, with the first two years of the initiative expected to cost $965 million.

5.2.1.2 *Illinois*

On Dec. 7, 2016, Illinois enacted Senate Bill 2814, or the Future Energy Jobs Act (FEJA). FEJA requires that three of Illinois' LSEs—Commonwealth Edison Company (ComEd), Ameren Illinois (Ameren), and MidAmerican Energy Company (MidAmerican)—purchase ZECs from the state's qualifying nuclear facilities. FEJA's "Zero Emission Standard Procurement Plan" specifies that winning zero emission facilities should be selected based on public interest criteria, including the avoided GHG emissions of continued operation of the zero-emission facility and the cost of replacing nuclear generation with other zero emissions resources.

The procured ZECs will be equal to 16% of the total amount of electric load procured by the Illinois Power Agency (IPA) and delivered to retail customers during the 2014 calendar year for ComEd, Ameren, and MidAmerican, or 20,118,672 ZECs. The IPA selected Units 1 and 2 of the

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128 Interagency Working Group on Social Cost of Carbon, United States Government, "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866", May 2013 (Revised July 2015), obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.

129 The projected SCC for the first tranche is equal to nominal $42.87 per short ton. The nominal RGGI fixed baseline portion for Tranche 1 is $10.41 per short ton. This yields a net cost of carbon of nominal $32.47 per short ton. Using a fixed conversion factor of 0.53846 to convert cost per short ton to cost per MWh yields a ZEC price of $17.48 per MWh.

130 $39/MWh is equal to the New York State Department of Public Service's forecast for long-term avoided power costs.

131 New York Public Service Commission, "Agreement for the Sale of Zero-Emissions Energy Certificates", December 19, 2016.

Quad Cities Nuclear Power Station and the first unit of the Clinton Power Station to receive ZECs through a 10-year contract beginning on June 1, 2017 and expiring on May 31, 2027. The price of each ZEC for each delivery year (DY) is set based on the SCC.[132] The SCC will be $16.50/MWh in the initial DY and will increase by $1/MWh beginning with DY 2023/2024 and each DY thereafter. A "Price Adjustment" is included that reduces the ZEC price to below the SCC by the amount that the market price index exceeds the baseline market price index. If electricity prices increase to the point that the adjustment is greater than the SCC price, then the ZEC price would be zero.

The Zero Emission Standard allows electric utilities to recover all the costs associated with the purchase of ZECs from retail customers through a single, uniform $/kWh charge. The Zero Emission Standard also sets a 1.65% annual cost cap on the amount of total customer costs that can be paid through customer surcharges for the purchase of ZECs. If the amount of ZECs procured results in a cost to the IPA that exceeds the cost cap to customers, then the resulting ZECS will be delivered but will constitute "unpaid contractual volume." This volume will be eligible for payment in a future DY that is not limited by the cost cap but is second in priority to the payments for the ZECs delivered in that year. For the 2018/2019 DY, utilities will purchase 20,118,672 ZECS to utilities, which results in a total ZEC cost of $332 million. Ratepayers will pay only the cost cap of $235 million, which results in 5,886,683 ZECs of unpaid contractual volume.[133]

5.2.1.3 *New Jersey*

On May 23, 2018, New Jersey enacted SB 2313 into law, making New Jersey the third state to enact ZEC legislation. The bill authorized the creation of ZECs and gave the New Jersey Board of Public Utilities (NJBPU) authority to develop the method for selecting recipient nuclear power plants and the mechanism for purchasing ZECs. All New Jersey electric utilities, including the state's four investor-owned electric distribution companies and a municipal distribution company, are required to pay qualifying nuclear plants for the ZECs received during each delivery year (DY), i.e., June 1 to May 30, in the same proportion that they supply electricity to the state.[134] In order to be considered eligible for

[132] Based upon the U.S. Interagency Working Group on Social Cost of Carbon's price in the August 2016 Technical Update.

[133] IPA, "Zero Emission Standard Procurement Plan", October 31, 2017, www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/Zero-Emission-Standard-Procurement-Plan-Approved.PDF.

[134] Exelon's Atlantic City Electric Co., FirstEnergy Corp.'s Jersey Central Power & Light Co., PSEG's Public Service Electric and Gas Co. and Consolidated Edison Inc. (Con Edison)'s Rockland Electric Co., and Butler Municipal Electric Power and Light owned by the borough of Butler, N.J.

ZECs, SB 213 requires a nuclear power plant to demonstrate that the plant makes a significant and material contribution to air quality in the state through minimizing emissions that result from electricity consumption, that the nuclear power plant will cease operations without financial assistance, and that the plant does not currently receive any direct or indirect payment or credit that eliminates the need for the nuclear power plant to retire.

The NJBPU selected the Hope Creek Nuclear Generating Station (Hope Creek) and the Salem Nuclear Power Plant (Salem) to receive 25,300,096 ZECs annually, which is equal to 40% of the electricity (MWh) distributed in the state in the 2017/2018 DY. The plants received ZECs from April 19, 2018 through May 31, 2019 and will continue receiving ZECs for another three years. After this period is over, the NJBPU will review whether the two nuclear plants are eligible for an additional three years. There is no sunset date specified in the legislation. The price of ZECs is determined by dividing the projected annual revenue from ZECs at the end of the DY (estimated at $301.4 million) by the greater of: (1) 40% of the total number of MWh of electricity distributed by electric utilities in the prior DY, or (2) the number of MWh of electricity generated in a prior DY using a DY that is selected by the operating utility. For the 2018/2019 DY, the former is greater and equal to 30,143,748 MWh, resulting in an estimated per ZEC cost of about $10.00. Electric utilities will be allowed to recover the full cost associated with procurement of ZECs through a non-bypassable $0.004/kWh charge imposed on all retail distribution customers of the utility. ZECs are expected to cost all New Jersey electric customers approximately $301.4 million a year, adding an extra $40 per year to each customer's electric bill on average.[135] Based on an estimated price of $10.00 per ZEC, Hope Creek and Salem are expected to receive approximately $253 million in revenue from ZEC sales annually.[136]

5.2.2 *Advantages and Disadvantages of ZECs*

5.2.2.1 *Advantages*

- *Stand-alone-* Once in place, and if treated separately than RECs, ZECs operate independently of RECs upon which they are modeled. As a result, ZEC initiatives that support a CES will not necessarily impact an RPS.
- *Tailored to support existing plants-* ZECs can be designed to support existing nuclear power plants that are otherwise

[135] Ibid. xii

[136] This number could range between $253 million and $301.4 million depending on total electricity distributed. Any excess money produced by the tariff and held by the electric utility that is not used to pay nuclear power plants will be returned to customers at the end of each DY.

uneconomic and are at risk of closing, either by limiting which resources are included in ZEC solicitations or by implementing requirements that preclude other resources that are not intended recipients.

- *Inclusion of financial safety mechanisms-* New Jersey specifies that the pricing mechanism for the ZECs is structured so that the costs are guaranteed to be significantly less than the SCC avoided in order to ensure that the initiative does not place an "undue financial burden on retail distribution customers." Illinois has a "Price Adjustment" factor that similarly reduces ZEC prices to below the SCC by the amount that the market price index exceeds the baseline comparison. New York reduces the price of ZECs if the benefits of carbon-free generation become monetized into energy and capacity prices in New York. Additionally, if wholesale electricity prices rise to more than $39 per MWh (i.e., nuclear generators receive a high level of market compensation prior to ZEC support), then the ZEC price would drop correspondingly.

5.2.2.2 Disadvantages

- *Increases ratepayer costs-* The gross cost, meaning total cost before accounting for benefits, to ratepayers for the New York ZEC initiative is an estimated $633 million annually (on average) over 12 years. The gross cost of the Illinois ZEC initiative to ratepayers is an estimated $235 million annually over 10 years. The gross cost of the New Jersey ZEC initiative to ratepayers will be approximately $301.4 million per year for an estimated seven to 10 years.
- *Administratively complex and time-consuming-* ZEC requirements can be complicated to administer and implement, requiring detailed filings by nuclear plant owners and state regulatory reviews of plant operations and costs to ensure ratepayers are paying the minimum amount necessary to preserve existing nuclear power plants. ZEC procurement can be administered by state utility regulatory commissions, government agencies, or other state entities.
- *Court challenges and dormant commerce clause concerns-* New York and Illinois have faced challenges in federal court regarding ZEC initiatives, although both were ultimately upheld. It is possible that Maryland could face additional legal challenges should the state adopt a ZEC-type initiative and could face different court rulings, depending on the program design.

5.3 CUSTOMER SURCHARGE ACCOUNTS

Customer surcharge accounts are special-purpose accounts intended to support a specific function or initiative that are funded through a non-bypassable, per-kWh surcharge on customer electric bills. These accounts can be implemented to support nuclear energy by directing funds to research and development for advanced nuclear technologies, upgrades at existing nuclear power plants, and/or subsidies to support continued operations. Customer surcharge accounts can be established by legislation or regulation, and when established, the legislation or regulation will specify the broad parameters such as the maximum level of funding (either annually or over a period of time, or both), set a sunset date for the collection of funds, and outline guidelines on how the funds may be utilized. The funds can be administered by a third-party administrator on behalf of a state office or agency, an existing state office or agency such as a utility commission or energy office, or an electric utility.[137]

5.3.1 *Experiences with Customer Surcharge Accounts*

Customer surcharge accounts that benefit nuclear are not common. Mississippi authorizes the Public Service Commission to recover through rates into a customer surcharge account certain costs associated with developing nuclear resources in the state.[138] Likewise, Virginia allows investor owned utilities in the state to petition the State Corporation Commission for specific riders that recover the costs associated with upgrades or licensing that will extend the life of existing nuclear facilities.[139] New York legislators have previously proposed supporting nuclear energy through the New York State Energy Research Development Authority (NYSERDA), including one proposal directing NYSERDA to spend $100 million on an initiative to support struggling nuclear plants (SB 7937) and another authorizing NYSERDA to purchase a plant (SB 8032). Neither initiative proceeded.

One prominent example of a recent customer surcharge account used to support nuclear is Ohio's actions to support two nuclear generation facilities at risk of early retirement, Davis-Besse Nuclear Power Station and Perry Nuclear Generating Station. On July 23, 2019, Ohio Governor Mike DeWine signed into law House Bill 6, "The Clean Air Program," which creates a customer surcharge account intended to support these

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137 Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit,* Clean Energy States Alliance, 2009, Public Benefits Funds," Center for Climate and Energy Solutions, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.;c2es.org/document/public-benefit-funds/.

138 billstatus.ls.state.ms.us/2008/pdf/history/SB/SB2793.xml

139 lis.virginia.gov/cgi-bin/legp604.exe?171+sum+HB2291

plants. The Clean Air Program creates an annual Nuclear Generating Fund equal to $150 million to be disbursed among eligible nuclear generating facilities. The dollar total represents the estimated amount of money needed to meet both plants' revenue requirement. Beginning on January 1, 2021, residential customers will pay up to $0.85 per month while industrial customers pay up to $2,400 per month.

The Public Utilities Commission of Ohio (PUCO) is responsible for determining how the revenue requirement will be allocated to each electric distribution utility and will base the method on some combination of number of customers and relative quantity of kilowatt hour sales. PUCO will also determine how the monthly charge will appear on each customer's bill. The funds are administered and distributed by the Treasurer of the State. Using the Nuclear Generating Fund, Ohio will issue nuclear credits worth $9/MWh to the Davis-Besse and Perry plants. A reduction in the price of a credit will occur if the federal government establishes a monetary benefit to incentivize clean energy production for at-risk nuclear resources, if the plant applies for decommissioning prior to May 1, 2027, or if the funding for nuclear resource credits no longer remains reasonable, i.e., market prices exceed a designated level. In the case of the latter condition, Ohio will adjust the credit price for the 12-month period immediately succeeding May 31 of the subsequent year. The initiative will run from April of 2021 to January 2028, with excess funds returned to consumers.

Maryland does not have an established customer surcharge account for any generation technologies; however, it does have a Universal Service Charge (USC), which is used to fund initiatives for low-income customers, bill assistance, and the retirement of arrearages, and an Environmental Trust Fund, which supports PPRP, Maryland Energy Administration (MEA), and Chesapeake Bay Trust. This USC is assessed to all distribution customers and the Environmental Trust Fund is supported through a surcharge assessed on all non-self-supplied electric customers. A similar mechanism may be possible to raise funds to support nuclear power.

5.3.2 Advantages and Disadvantages of Customer Surcharge Accounts

5.3.2.1 Advantages

- *Flexibility*- Customer surcharge accounts can be designed to fund a variety of initiatives related to nuclear power, including loans, grants, and tax incentives. A customer surcharge account can also be changed in response to market conditions, including returning fund proceeds to customers if they are no longer needed due to more favorable economic conditions surrounding the original recipients.

- *Independent, non-bypassable funding mechanism*- Because customer surcharge accounts are funded separately, they are not dependent on annual state budget appropriations. Additionally, charges are usually assessed to distribution utilities, which are monopolies, or to all consumers (including electric choice customers) based on consumption. This simplifies collection of funds.

5.3.2.2 *Disadvantages*

- *Disproportionate financial benefit*- Although customer surcharge accounts are incurred by all customers, the resulting funds may disproportionately or exclusively benefit one area financially, as would be the case if Calvert Cliffs is the sole beneficiary.
- *Redirection of funds*- Monies raised through a customer surcharge account could be reallocated to the state's general revenue fund to cover other budgetary needs or requirements (unless the legislative language was specifically crafted to prohibit such reallocation).
- *Durability*- Long-term funding assurance is needed, as it can take time to design and launch new initiatives.

5.4 *STATE PROCUREMENT OF CLEAN ENERGY RESOURCES*

States can require regulated utilities to procure power from specific resources. This usually takes the form of competitive procurement processes that guarantee the winning bidder a long-term power purchase agreement (PPA). States can also, however, establish administrative proceedings to select resources that are eligible for a PPA. The costs of PPAs are recovered from ratepayers, either as a separate rider or as part of regulated rates. PPAs provide stability to power plants by committing in advance to a specified contract price over a designated timeframe and therefore offering the power provider some degree of price certainty. Public entities stand to benefit both by encouraging the development of preferred resources and by locking in rates, thereby reducing price risk.

5.4.1 *Experiences with Procurements*

Connecticut recently became the first state to implement a solicitation mechanism that allows for existing nuclear energy to bid for state contracts alongside other clean energy resources. On Oct. 31, 2017, Connecticut enacted Senate Bill 1501, or Public Act 17-3, the "An Act Concerning Zero Carbon Solicitation and Procurement." Public Act 17-3 allowed Connecticut's Public Utilities Regulatory Authority (PURA) and

Department of Energy and Environmental Protection (DEEP) to establish a competitive solicitation process for zero emissions resources, including nuclear power plants, that are found to be in the best interest of ratepayers. In effect, Public Act 17-3 allowed for Connecticut's lone nuclear generating station, Dominion Energy's (Dominion) Millstone Power Station (Millstone), to bid against other zero emissions resources for PPAs.

Dominion bid Millstone into the solicitation as an at-risk resource, i.e., at-risk of early retirement. Under Public Act 17-3, existing resources classified by PURA as "at-risk" were eligible for above market rates (as determined by PURA). The solicitation resulted in a winning 10-year bid for approximately 50% of Millstone's output, or approximately 98.25 million MWh, between Dominion and Connecticut's two electric distribution utilities, Eversource and United Illuminating. The remaining output not sold through the PPA would be sold in the wholesale electricity market at market-price, or through another long-term bilateral contracts not facilitated by the state. The net cost of the PPA will be recovered entirely through a non-bypassable electric charge to all customers.

Maryland recently entered into a PPA with two offshore wind developers to construct projects totally 368-MW nameplate capacity. The procurement process for these resources required a detailed cost-benefit analysis of each proposal. It also required that bidders meet several strict cost control requirements. This process was overseen by the PSC, who conducted its assessment following strict guidelines established in the enabling legislation. Maryland's experience procuring offshore wind may prove useful if the state decides to proceed with future PPAs either to support new or existing nuclear facilities, especially since there is not currently a large number of suppliers to solicit competitive nuclear bids.

5.4.2 *Advantages and Disadvantages of Procurement*

5.4.2.1 *Advantages*

- *Long-term certainty*- PPAs provide a predictable income stream for project owners, which helps to lower the cost of financing and drive rapid deployment for new projects.
- *Reduced price volatility*- PPAs provide stability to power plants by committing in advance to a specified contract price over a timeframe and therefore offering the power provider the ability to hedge against market fluctuations. In the case of short-term PPAs, such as in Connecticut, the reduction in price volatility

helps support the continued operation of existing plants that otherwise face economic difficulty.

- *Flexibility in terms of policy design-* Solicitations can be designed in a myriad of ways. Differences in PPA policy design include eligible resources and technologies; length of contract; adjustment in PPA prices over time; location or application; capacity limits by project, technology, year, or cumulative; and preferential treatment. This flexibility can be used to tailor support for either existing or new nuclear facilities in ways that match state preferences.
- *No upfront public contributions-* PPAs are structured to support resources only if they begin or continue contributing power to the grid. This reduces the risk that customers will provide support to an existing nuclear plant without receiving any power production in return.

5.4.2.2 *Disadvantages*

- *Not necessarily lowest cost-* A technology specific PPA may procure power from generators that are not necessarily the least cost resource available to the grid. Additionally, PPA arrangements with a guaranteed contract term displace alternative resources and lock consumers into receiving power from specific sources.
- *Avoiding legal challenges-* PPAs must be carefully designed in order to avoid possible intrusion on Federal Energy Regulatory Commission (FERC) oversight of wholesale power markets. FERC has previously viewed PPAs that are tied to wholesale markets or impose excessive costs as an infringement on its jurisdiction over interstate markets and wholesale market price regulation.
- *Can be administratively complex-* Overseeing a PPA process can be administratively burdensome when there are several requirements that bidders must meet, or multiple conditions for selecting winners, as was the case in Connecticut.
- *Undermines deregulated markets-* Locking up a share of all power procurement from a single resource discourages the continued development of lower-cost alternatives.

5.5 *ASSIGNING A COST TO CARBON*

A much-discussed means of addressing climate change is imposing a cost on carbon emissions via a tax, fee, or price. Any of these potential approaches would raise the cost of combustion-based generation, as well as raise the clearing price of power generation when carbon-emitting power plants are the marginal resources. Both outcomes would benefit nuclear power, which does not emit carbon. Although there are multiple ways to structure the assignment of a cost to carbon, two methods are popular: a cap-and-trade system, or a carbon tax. Maryland currently participates in RGGI, a cap-and-trade system for CO_2 emissions that includes nine other Northeast states. Maryland's experience with RGGI is reviewed below, following an explanation of the principles of a cap-and-trade system and carbon tax.

5.5.1 Cap-and-Trade

Under cap-and-trade, a "cap," or limit, to total carbon emissions is established. Emitters are then allowed to determine how they will cut emissions in order to get under the cap. Emitters in this system have the option to "trade," meaning purchase and sell carbon emission rights to and from each other. This approach establishes a fixed quantity of emissions, but does not establish a price or value. Over time, the cap can be gradually decreased. As this happens, holders of emission rights, also known as allowances, can continue to trade among themselves. This trading, in theory, results in an efficient outcome in so far as companies that can abate (e.g., implement pollution controls) at the least cost are likely to do so first, as soon the marginal cost of abatement falls below the marginal cost of an emission permit.

Permits can be auctioned to raise revenue, allocated to other parties (e.g., load-serving entities), given away, or some combination thereof. There are several major challenges for setting up a cap-and-trade system, including how best to allocate the initial permits, who to include in the system, whether floor and ceiling prices should be set, and at what level to set the cap. As compared to current or projected carbon emission levels, establishing a cap that is too low could result in high carbon prices and be costly, while setting a cap that is too high could result in low carbon prices, providing minimal incentives for polluting entities to reduce emissions. Additionally, allocating permits for free can result in windfall profits to permit recipients. One concern raised during permit allocation is that customers are essentially paying twice, once for the underlying physical asset and once for the allowance. One downside of a cap-and-trade approach is that, by allowing permit prices to fluctuate, businesses and investors may not have a clear price signal regarding the future cost of carbon. This can hinder decision-making about where to invest to reduce carbon emissions.

5.5.2 *Carbon Tax*

A carbon tax sets a fixed price for emissions and then allows the market to respond to that price signal. If the carbon tax is higher than the marginal cost of abatement, an emitting company will reduce its emissions. If the carbon tax is lower, an entity will continue to emit while also paying the tax. The revenue generated by a carbon tax can be recycled into the economy, including as new incentives for low-carbon resources or as a dividend to consumers.

Among the challenges of setting a carbon tax is deciding at what level to set the initial tax. Establishing a price that is too low will not induce carbon reductions, while setting it too high can impose excessive costs. One downside of a carbon tax approach is that, by not setting firm limits on the desired quantity of emissions, businesses and investors may abate more than what is economically efficient or less than what is socially desirable. However, in the long run, investors and market participants can account for the established cost of carbon and act accordingly.

5.5.3 *Experiences with Carbon Pricing*

Carbon pricing, and related strategies for other air emissions, is already underway for several states and countries. Notably, the federal Clean Air Act in the United States was amended in 1990 to, among other things, allow for the creation of cap-and-trade systems for reducing sulfur and nitrogen oxide emissions that contribute to acid rain. Since the 1990s, the EPA's Clean Air Markets Division has implemented multiple cap-and-trade programs. As a result, sulfur dioxide emissions have been reduced from 11.2 million tons in 2000 to 1.3 million tons in 2017. Similarly, nitrogen oxide emissions have been reduced from 5.1 million tons in 200 to 1.1 million tons in 2017.[140]

Ten Northeast states, including Maryland, formed the Regional Greenhouse Gas Initiative (RGGI) in 2008 to implement a cap-and-trade system for CO2 emissions from electric power plants that generate 25 megawatts (MW) of electricity or more. The 2019 RGGI CO2 allowance cap, which sets a regional budget for CO2 emissions from the power sector, is approximately 60.3 million short tons of CO2. Allowance auctions are administered quarterly by RGGI. At the auctions, participating power plant owners submit confidential bids, which then inform the price of allowances for that auction. Participants are permitted to trade or purchase allowances in a secondary market. RGGI Auction Number 44 was held on June 5, 2019. Bids were submitted across a wide

[140] www3.epa.gov/airmarkets/progress/reports/emissions_reductions.html

range of prices in the auction and CO2 allowances sold for $5.62 per allowance (i.e., $5.62 per short tons of CO2). Through June 5, 2019, RGGI has sold nearly one billion CO2 allowances for $3.2 billion. Through the end of 2017, approximately $2.45 billion in auction revenue was invested in programs, including energy efficiency, clean and renewable energy, greenhouse gas abatement, and direct bill assistance.[141,142]

Although RGGI is contributing to emissions reductions in general, most participating states, except for Maryland and Delaware, are outside of PJM. As a result, RGGI provides a limited advantage to nuclear plants because most competing fossil fuel plants in PJM are unaffected by the cap-and-trade system. That is, RGGI benefits the Calvert Cliffs in Maryland so far as it imposes a cost on other generation sources in Maryland that Calvert Cliffs does not pay. However, Calvert Cliffs competes with resources in other states in PJM that do not face a cost on carbon, reducing the advantage RGGI provides to Calvert Cliffs. Additionally, the current cost of RGGI allowances is low, reducing the cost imposed even on in-state competitors to Calvert Cliffs.

The impact of RGGI on existing and future nuclear power generation in Maryland may change if RGGI participation expands to include other PJM states. New Jersey is slated to rejoin RGGI beginning Jan. 1, 2020, and both Virginia and Pennsylvania have recently considered proposals to join. Additional participation by all these states would potentially enlarge the benefit of RGGI to nuclear in so far as more competing resources face additional carbon costs.

More recently, California implemented a cap-and-trade market for carbon in 2012 that requires California to return to the 1990 GHG emissions level of 431 million metric tons of CO2 equivalent (MMTCO2e) by 2020, and 40% below 1990 levels by 2030. As of 2017, California GHG emissions were reduced to 424 MMTCO2e, or 7 MMTCO2e below the 2020 CO2 limit.[143] The program is linked with Quebec's cap-and-trade system, meaning that businesses in one jurisdiction can use emission allowances issued by the other jurisdiction to meet compliance obligations.[144] The carbon allowance price as of the August 2019 joint allowance auction for Quebec and California was $17.16 per metric ton of CO2.[145]

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141 rggi.org/sites/default/files/Uploads/Press-Releases/2017_10_03_RGGI_Proceeds_Report_Release.pdf

142 acadiacenter.org/wp-content/uploads/2016/07/Acadia_Center_2016_RGGI_Report-Measuring_Success_FINAL_08092016.pdf

143 ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2017/ghg_inventory_trends_00-17.pdf

144 ww3.arb.ca.gov/cc/capandtrade/linkage/linkage.htm

145 ww3.arb.ca.gov/cc/capandtrade/auction/aug-2019/summary_results_report.pdf

No state currently has a carbon tax, although several have unsuccessfully proposed economy wide carbon tax initiatives. The State of Washington, notably, attempted to implement a carbon tax via a ballot initiative both in 2016 and 2018, failing on both occasions. The New York Independent System Operator (NYISO) is considering whether to impose a carbon charge on all energy suppliers in the state, not just the power plants affected by RGGI.[146] The proposed initial carbon charge would be $50/ton of CO2, based upon the SCC for 2022, before netting out RGGI allowance prices.[147] The short-term goal of the proposal is to create a transparent price signal regarding carbon. The long-term goal is to minimize carbon output, while at the same time avoiding cross-subsidization and other cost-shifting. NYISO was expected to file its proposal before FERC in late 2019(it had not done so as of the beginning of 2020).[148] PJM has begun a stakeholder process to consider carbon pricing as well.[149]

5.5.4 *Advantages and Disadvantages of Carbon Pricing*

5.5.4.1 *Advantages*

- *Captures, at least in part, the negative externalities of carbon* - Assigning a cost to carbon emissions shifts, at least in part, the negative social cost of carbon emissions resources from society to generators. In turn, that improves the comparative economic position of nuclear power plants and recognizes nuclear power as a zero-carbon resource.
- *Long-run incentive to support zero carbon-emitting resources* – A carbon tax would provide certainty regarding current and future costs of carbon. This encourages investors to support and/or develop generation resources with low-to-zero carbon emissions, including nuclear power.
- *Revenues can be recycled or returned* - The revenues raised by a carbon tax or by emission allowance auctions can be used to support a variety of state initiatives, including support of nuclear power. Proceeds can also be invested in programs that reduce ratepayer costs in the long run, such as energy

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[146] NY Details Carbon Charge on Wholesale Suppliers, October 23, 2018, rtoinsider.com/nyiso-carbon-charge-billing-wholesale-market-102260/; Carbon Pricing Draft Recommendations, A Report Prepared for the Integrating Public Policy Task Force, August 2, 2018, nyiso.com/documents/20142/2179214/Carbon%20Pricing%20Draft%20Recommendations%2020180802.pdf/575a6d2b-ad09-d8f8-e566-39a0c04f9a43

[147] nyiso.com/documents/20142/2179214/Carbon%20Pricing%20Draft%20Recommendations%2020180802.pdf/575a6d2b-ad09-d8f8-e566-39a0c04f9a43

[148] eenews.net/stories/1060851307

[149] insidelines.pjm.com/pjm-outlines-plan-to-study-market-effects-of-carbon-pricing/

efficiency.[150] Maryland currently utilizes RGGI proceeds for these forms of investment.

- *Relies on market mechanisms to reduce policy costs* – Using price signals rather than mandates encourages energy producers to make efficient choices regarding when to retire existing fossil fuel resources, thereby reducing the overall costs to consumers and minimizing necessary stranded costs.

5.5.4.2 *Disadvantages*

- *Politically challenging* - The process to design and implement carbon pricing, such as determining who participates in a cap-and-trade market or pays a carbon tax, is often politically challenging due to the large number of affected parties and the costs imposed on some stakeholders. Similar challenges would likely face Maryland if it attempted to impose additional costs to carbon beyond those imposed by Maryland's participation in RGGI.
- *Competitive disadvantage* - Unless implemented nationally or in conjunction with carefully designed border adjustments, state initiatives to implement carbon pricing can shift energy production to markets that do not impose a price on emissions, thereby undermining any benefits to zero-carbon resources. Further, a carbon cost that is not applied to all market participants equally has the potential to disproportionately harm emitting generation located in-state.
- *Interstate commerce issues* - States have limited ability to implement carbon pricing that directly affects generating resources located in other states or regions, except by mutual agreement, because of the impact on wholesale power markets, which is the jurisdiction of FERC. Alterations to RGGI must therefore be made by mutual agreement.
- *Not guaranteed to support nuclear power* - If supporting nuclear power is the paramount aim, then carbon pricing is not the most direct mechanism of doing so. Carbon pricing also supports other carbon-free resources, such as renewable energy generation, which may displace nuclear as an alternative to fossil-fuel generation.

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150 According to a recent assessment by the Analysis Group, "local investment of RGGI dollars on energy efficiency and renewable energy offset the impact on electricity prices resulting from CO2 allowance costs." Source: analysisgroup.com/globalassets/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_april_2018.pdf

- *Costly in the short run* - Carbon pricing may have a significant impact on ratepayers when not coupled with a dividend or refund mechanism, or other investments that apply carbon proceeds to the benefit of ratepayers.
- *Concentrated local impacts* - To the extent carbon costs force the closure of carbon-emitting resources, such a measure could adversely impact local economic development and jobs.

5.6 ADVANCE COST RECOVERY

Advance Cost Recovery (ACR) allows utilities to recover the costs of constructing a new power plant prior to project completion. This reduces or eliminates the risks borne by utilities of not recovering their investments in capital-intensive projects, like building a large power plant. ACR also reduces upfront project financing costs and carrying charges by expediting the time frame within which investors can recoup their investment. ACR has been used to support several nuclear projects in the past and is supported by some utilities as a means of reducing regulatory lag. ACR is implemented by legislation and is overseen by state utility regulatory commissions.

5.6.1 Experiences with ACR

South Carolina, Georgia, and Florida have all passed legislation allowing ACR. In all three cases, ACR funded projects have been plagued by issues, including cost-overruns and delays. Three proposed projects in Florida were all ultimately abandoned following expensive licensing processes and construction issues. The projects included a new nuclear power plant in Levy County, Florida, the addition of two new nuclear reactors to the existing two reactors at Turkey Point Nuclear Generating Station (Turkey Point), and repairs to the nuclear reactors at Crystal River Nuclear Generating Station (Crystal River), which have been offline since 2009.

The construction of two new reactors at the Virgil C. Summer Nuclear Generating Station (V.C. Summer) in South Carolina was also canceled in July 2017 by Santee Cooper, a South Carolina state-owned public utility, and South Carolina Electric & Gas (SCE&G), a subsidiary of the SCANA Corporation. The cancellation followed a string of setbacks related to the AP1000 nuclear reactor used in both units. The AP1000 was designed by Westinghouse Electric Corporation (Westinghouse), which was originally hired as the contractor for the V.C. Summer project. In March 2017, Santee Cooper and SCE&G were forced to take over construction when Westinghouse filed for Chapter 11 bankruptcy because of $9 billion of losses from the V.C. Summer project and a similar project at the Alvin W.

Vogtle Electric Generating Plant. The V.C. Summer reactors were originally projected to be completed in 2007 and 2008, respectively, with a total cost estimate of $11.4 billion. By the time V.C. Summer was canceled, the revised estimated cost exceeded $25 billion. As a result of ACR, ratepayers in South Carolina are ultimately responsible for the costs incurred during V.C. Summer's failed development despite the plant never entering service.

Construction of two new reactors at the Vogtle plant in Georgia have faced similar cost overruns, although project development continues. As of September 2018, the project's estimated costs have grown to nearly $23 billion, as compared to the original cost estimate of $14.3 billion. The Vogtle plant is the only commercial nuclear plant under construction in the United States.

5.6.2 *Advantages and Disadvantages of ACR*

5.6.2.1 *Advantages*

- *Potentially reduces project costs*- ACR reduces project upfront finance costs by replacing some portion of investor-funded financing with ratepayer dollars and also reducing investor uncertainty by expediting cost-recovery.
- *Reduces developer risk*- Large capital investments like nuclear generating plants are too financially intensive for all, but the largest companies to undertake on their own. ACR reduces the financial risk to developers and allows for more companies to consider these large investments.
- *Reduces regulatory lag*- ACR expedites the time in which utilities can recover the costs incurred for large capital investments such as new nuclear power plants.

5.6.2.2 *Disadvantages*

- *Transfers risk to consumers*- Under ACR arrangements, the financing and project development risks of developing a power plant are shifted away from investors and onto consumers, who bear the cost of overruns and delays.
- *Does not align utility incentives with the public interest*- Utilities that can recover construction costs prior to project completion do not have a direct financial interest in expediting project development or ensuring the project is completed at a reasonable cost.
- *Does not guarantee project completion*- As illustrated in the abandonment of several nuclear projects subject to ACR, costs

may be recovered from consumers for a project that ultimately does not enter service.

5.7 *FEED-IN TARIFFS*

Feed-in Tariffs (FITs) have been a common approach for increasing renewable energy deployment worldwide.[151] As a policy mechanism, however, FITs are technology neutral and could also be applied to nuclear power. FITs provide a long-term (i.e., 15- to 20-year) purchase agreement for electricity at a specific price. This purchase agreement is also usually paired with guaranteed grid access and, in some cases, priority dispatch. Although there are numerous variants, a FIT generally sets a technology-specific price, and the market responds with an undefined amount of eligible energy capacity (unless program-wide caps or technology-specific caps are imposed).[152]

The value of a FIT for a new nuclear plant could be based on: (1) the estimated levelized cost of a prospective advanced nuclear reactor; (2) a utility's avoided cost of energy plus societal and environmental benefits for a new reactor; or (3) an auction procurement mechanism, under which a government requests bids for the lowest level of incentive needed for developers to build generation projects that would not otherwise be constructed. The primary advantage of auctions is that they introduce competition into the process, which helps to ensure that FITs are not needlessly high. The cost of (non-auction) FITs can be also contained by setting caps on participation, establishing procedures to reduce FIT levels on a regular basis over time, and/or ending FITs when a program's funding ends. However, all these mechanisms introduce uncertainty, which can dampen the overall impact of these initiatives.[153]

5.7.1 *Experiences with FITs*

Other than perhaps the Public Utility Regulatory Policies Act (PURPA), which some consider as one of the very first FITs ever enacted, the United States has had limited experience with FITs. To-date, there are eight states with FITs in effect for renewable energy: California, Alaska, Hawaii,

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151 REN21, *Renewables 2018: Global Status Report*, 2018, ren21.net/wp-content/uploads/2018/06/17-8652_GSR2018_FullReport_web_final_.pdf.

152 Charles Kubert and Mark Sinclair, Distributed Renewable Energy Finance and Policy Toolkit, Montpelier, VT: Clean Energy States Alliance, 2009, cleanenergystates.bluehousegroup.com/assets/Uploads/CESArenewableenergy-FinancePolicy-toolkit2009.pdf.

153 Sadie Cos and Sean Esterly, *Feed-in Tariffs: Good Practices and Design Considerations*, National Renewable Energy Laboratory, January 2016, nrel.gov/docs/fy16osti/65503.pdf.

Washington, Michigan, Indiana, New York, and Vermont. No states use FITs to support nuclear power technologies. There is, however, one relevant international case; some commentators have characterized Great Britain's agreement to support development of the Hinkley Point C nuclear power station as a FIT. The negotiated agreement between the Great Britain government and EDF, the French utility responsible for constructing the project, established an inflation-adjusted fixed price for power from the Hinkley Point C plant over a 35-year period.[154] The project has been criticized for its high costs and long construction delays. The plant, which began construction in 2008, is not expected to enter service until 2025, and will ultimately cost approximately $25.4 billion.[155]

5.7.2 *Advantages and Disadvantages of FITs*

5.7.2.1 *Advantages*

- *Long-term certainty*- FITs that allow for a fixed price provide a predictable income stream for project owners, which helps to lower the cost of financing and drive rapid deployment for new projects.
- *Supportive of new or emerging technologies*- FITs have been utilized in support of new or emerging technologies that would otherwise not be built in a competitive power market.
- *Flexibility in terms of policy design*- FITs can be designed in a myriad of ways. Differences in FIT policy design include eligible resources and technologies; length of contract; adjustment in FIT prices over time; location or application; capacity limits by project, technology, year, or cumulative; and resource intensity (e.g., different rates depending on the site's resource availability).[156]
- *No upfront public contributions*- FITs are structured to support resources only after they begin contributing power to the grid. This reduces the risk that power plants with long lead times, such as large-scale nuclear power plants, impose costs without providing any return.

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154 world-nuclear-news.org/NP-Hinkley-Point-C-contract-terms-08101401.html

155 reuters.com/article/us-britain-nuclear-hinkley/edf-sees-uk-hinkley-c-nuclear-plant-online-by-end-of-2025-idUSKBN1F61QK

156 KEMA, Inc. ―Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options, Final Consultation Report prepared for the California Energy Commission, CEC-300-2008-003-F, 2008, energy.ca.gov/2008publications/CEC-300-2008-003/CEC-300-2008-003-F.PDF.

5.7.2.2 *Disadvantages*

- *Risk of over/under-compensation*- The primary challenge with FITs is setting appropriate levels of compensation, which could be based on a thorough evaluation of the levelized costs of eligible energy technologies. Ideally, FITs should be updated on a regular basis (e.g., annually) to keep pace with technology advancements and market developments. If FIT levels are too high, they can lead to excessive development and impact ratepayers. If FIT levels are set too low, they may not drive the desired investment.
- *Not necessarily lowest cost*- A technology-specific FIT may procure power from sources that are almost certainly not least cost resource without having the intended effect of driving down costs or encouraging additional resource development in the future.

5.8 *GRANTS*

Grants provide partial or full funding for specific projects and efforts, including infrastructure, labor training, and research and development. This mechanism may be particularly useful in the early stages of developing advanced technologies, such as modular nuclear power plants. Grants are generally issued through competitive solicitations or Requests for Proposals, which can be highly structured or left more general and open to encourage innovative project ideas. Grants may also be awarded through reverse auctions to select projects that require the smallest amount of funding.[157]

5.8.1 *Experiences with Grants*

Many states (and the District of Columbia) provide grants to support energy-related initiatives. Maryland has 12 active grant-making programs that provide funds for renewable energy projects, energy efficiency, energy workforce development, and related. In FY18, MEA awarded over 2,700 grants through these programs, providing over $12.5 million in support for renewable energy projects and related activity in the state.[158] Grant recipients include private customers, public organizations, nonprofits, farms, and communities.

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157 Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

158 Maryland Energy Administration, Maryland Strategic Energy Investment Fund: Report on Fund Activities FY 2018, energy.maryland.gov/Reports/FY18%20SEIF%20Annual%20Report.pdf.

DOE frequently funds advanced nuclear technology projects through grants. These funding pathways support demonstration projects as well as provide regulatory assistance (i.e., funding to support the completion of federal safety approval processes). State funding can potentially complement these efforts as well as support nuclear power workforce training, component technology development, and university research related to nuclear power.

5.8.2 *Advantages and Disadvantages of Grants*

5.8.2.1 *Advantages*

- *Addresses up-front costs*- New, advanced nuclear energy projects are largely in the research and development or licensing stage of development. Grants can help overcome these costs and bring new technologies closer to commercialization.
- *Flexibility*- Grants can be designed to emphasize certain technologies, applications, performance outcomes, customer classes, or geographic areas. They can also be used for pilot or demonstration projects, or to support more technologically mature projects. This flexibility can allow Maryland to target its support for nuclear to fit state priorities.
- *Compatibility*- Grants can be combined with private capital. Grantors can also require grantees to secure funding from other sources to preserve grant funds and also to ensure potential grantees have support from other parties.

5.8.2.2 *Disadvantages*

- *High administrative costs*- Preparing and/or reviewing grant applications is time-consuming, both for applicants and grantors.
- *Not self-sustaining*- By definition, grants involve no repayment. Therefore, they require a continual stream of funding, or will be short-lived by design.
- *Imprecision*- The appropriate amount of grant funding can be hard to calibrate; it may be higher than necessary to attract applicants or too small to catalyze the desired activity.

5.9 LOAN PROGRAMS

Loan programs can reduce the upfront capital costs of an energy project by spreading out payments over a long-time frame, effectively making projects more affordable. Additionally, loan programs can reduce the costs of existing debt and equity by refinancing it with public debt at a lower interest rate or financing costs. For nuclear plants, loan guarantees and public sector underwriting can help substantially reduce the underlying risk of investing in otherwise uncertain, pre- or early-commercialization, or very capital-intensive technologies. There are several types of loan programs that have been offered by states, each with varying eligibility requirements and administrative oversight.

5.9.1 Types of Loan Programs

5.9.1.1 Direct Loans

With direct loans, funds are provided directly to the borrower through an institution, such as a government agency or a clean energy bank.[159] Funding for loans is often allocated from state energy funds or through revenues generated from other programs (e.g., RGGI). Other funding allocations come from bond issuances or private capital. As loans are repaid, the loan repayments can be funneled into new loans.

5.9.1.2 Matching Loans

State governments can match loans from private lenders to encourage energy project development. In this case, the state will administer a share of a loan to a project developer at a low interest rate, and a private lender will provide the remaining loan balance. The state's share of the loan is separate from the private lender's, and therefore can offer more flexible repayment terms and interest rates as low as 0%. Unlike direct loan programs, the state and the private lender share underwriting and risk.[160]

5.9.1.3 Interest Rate Buy-down

States can assist private lenders in offering below-market interest rate loans by subsidizing the interest rate through a lump-sum payment to the lender called an "interest rate buy-down." This type of subsidy requires far less capital than the principal amount of a loan and removes the state from underwriting responsibilities and default risk.[161] However, the capital used for an interest rate buy-down payment is not a revolving fund and therefore is not repaid to the state.

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159 Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

160 Ibid.

161 Ibid.

5.9.1.4 *Linked Deposits*

A linked deposit program allows participating banks to make below-market interest payments on state deposits. In return, the bank then uses the funds from the state deposits to provide low-interest loans to energy projects. The state treasurer can establish these programs without legislation. Linked deposits require limited administrative duties such as monitoring deposits and ensuring that applicants for the energy loans are investing in a qualified project. However, like the interest rate buy-down program, the state does forego the earned interest on the funds that are re-loaned to qualified borrowers.[162]

5.9.1.5 *Securitization*

Securitization is a form of loan refinance through which investor-backed utility debt and equity is pooled and then resold as consumer-backed utility equity.[163] This initiative is often used to raise bond money for one-time expenses, such as storm recovery or plant retirement costs. It can also be used, however, to recover funds to buy-down above market power-purchase agreement costs or pay-off financial losses from a power plant. New capital from securitized debt is used to pay off obligations upfront. The new debt, thereafter, is recovered at lower interest rates. This can reduce revenue requirements and produce net present value savings for ratepayers because it substitutes for investor-backed equity costs, reduces interest rates, and eliminates taxes related to the previous revenue requirement.[164]

5.9.2 *Experiences with Loan Programs*

Most states operate at least one energy-related loan program. Maryland, for example, runs two loan programs—the Baltimore Energy Initiative Loan Program and the Jane E. Lawton Conservation Loan Program— that primarily supports energy efficiency and conservation improvements. State loan programs to support nuclear power are uncommon, although several states allow nuclear power projects to be considered as an eligible recipient. Wisconsin, for example, enacted Act 344 in April 2016, which incorporated advanced nuclear power projects into the state's list of priorities when awarding loans and grants. However, nuclear is ranked by the state as a lower priority than energy conservation or renewable energy

162 Ibid.

163 sierraclub.org/sites/sierraclub.org/files/sierra-club-harnessing-financial-tools-electric-sector.pdf

164 saberpartners.com/wp-content/uploads/2019/05/Fichera-NARUC-Electricity-Comm-5-17-19-for-Printing-Indexed.pdf

sources. Several states allow securitization of energy assets.[165] No states to date, however, have deployed securitization to support operating nuclear power plants; rather, it is more often employed to recover the stranded costs of shutting down retired power plants, whether they are nuclear power plants or not.

At a federal level, DOE's loan guarantee program helps encourage private investment in advanced technologies by lowering the cost of borrowing and increasing the availability of credit via loan guarantees. The Vogtle nuclear plant, for example, is supported by DOE loan guarantees. Recreating this form of loan guarantee at a state level for large-scale nuclear projects is generally considered infeasible due to the high costs and the risk that the project may not proceed to completion. Support for smaller advanced nuclear energy projects, such as modular nuclear plants or demonstration projects, however, may be possible. Additionally, states could provide loans to companies conducting research and development in fields related to nuclear power. Finally, states might employ securitization to buy-down the costs of a nuclear plant upgrade, or otherwise recover costs from anticipated plant losses.

5.9.3 Advantages and Disadvantages of Loan Programs

5.9.3.1 Advantages

- *Favorable lending terms*- State loan programs can offer at- or below-market interest rates and longer repayment terms to closely match the expected start of energy production or cash flow of the project over time.
- *Low interest rates*- Many state loans can be formulated to include low interest rates, which significantly reduce the interest expenses for borrowers.
- *Sustainability*- If the program is established as a revolving loan fund (RLF), the principal payments for one loan are used to fund subsequent loans, assuming there are few or no defaults.
- *Provides lender confidence*- State-sponsored loan approvals provide a mark of confidence to other investors or private lenders that could cover the remaining equity gap. This can be particularly important for high-risk or less commercially mature technologies, such as advanced nuclear power.
- *Flexibility*- Loan programs can be designed in a myriad of ways to support existing or new energy technologies or projects.

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165 utilitydive.com/news/securitization-fever-renewables-advocates-seize-wall-streets-innovative-w/555089/

5.9.3.2 *Disadvantages*

- *High capital requirements*- Project loans may need to cover a larger share of the project cost than rebates or grants. This requires up-front financing that must be generated through existing or new revenue sources.
- *Risk of loan defaults*- The loan administrator assumes the risk of defaults. In many cases, loans transfer risk away from investors and onto the loan program and its sponsors. This can be problematic with advanced nuclear power technologies that face greater development and financial risk.
- *Administrative costs*- Loan funds also require ongoing loan servicing and monitoring, and these efforts are often project-specific.
- *Remaining equity gaps*- Loan funds cannot always provide 100% financing to cover all upfront costs and, absent other funding sources, projects may not go forward.

5.10 TAX INCENTIVES

Generally, a tax incentive is designed to encourage certain behavior or actions through a reduction in tax liability. Tax incentives for energy systems provide support through directly reducing investment or ownership costs. At the state level, these initiatives are usually administered by state revenue departments or other state agencies. For nuclear power, tax incentives can offset tax liabilities and bolster investor and financier confidence, thereby facilitating greater project development. This section reviews two prevalent tax options that states and local governments employ: tax credits and tax exemptions.

5.10.1 Tax Credits

Tax credits are a dollar-for-dollar reduction in actual tax owed to the state. For example, if a taxable entity has a tax liability of $300,000 but is eligible for a $300,000 tax credit, their tax goes to zero. Tax credits can either be refundable or non-refundable. A refundable tax credit allows a business to receive the full amount of credit, even if the credit exceeds their tax liability, with the balance received as a tax refund. A nonrefundable tax credit cannot be used to create a tax refund in the event that the tax credit exceeds tax liability. In these cases, many energy development companies will do a "sale-leaseback," where the energy developer sells the project to a company with a sufficient tax liability to offset, then takes the project back once the tax investment has been monetized. Tax credit policies vary widely with respect to system and performance provisions. Investment

Tax Credits (ITCs) and Production Tax Credits (PTCs) are two common types of tax credits for energy systems.

5.10.1.1 *Investment Tax Credit*

ITCs allow businesses to deduct a certain percentage of capital investment costs for an eligible energy project from their state income taxes. The size of an ITC depends on the amount of capital invested in the energy project. An ITC will generally only apply to new or upgraded equipment. Businesses and individuals can claim the one-time ITC in the year it is placed into service. In cases where the ITC is phased down overtime, developers can lock-in an applicable rate when they begin construction so long as they complete the project within a designated time frame.

5.10.1.2 *Production Tax Credit*

The PTC reduces a business' income tax liability based upon the amount, in kWh, of energy generated by an eligible energy project over a period of time, such as 5 or 10 years. The PTC is often capped, although unused credits can be carried forward. The per-kWh rate and length of a PTC will vary based on the energy technology. Similar to the ITC, a PTC can be phased down overtime. Additionally, developers can lock-in an applicable rate when they begin construction so long as they complete the project within a designated time frame.

5.10.1.3 *Experiences with Tax Credits*

The ITC and PTC are both well-established at the federal level. In the case of the PTC, a specific tax credit applies to new nuclear facilities. This PTC allows facilities in service after Dec. 31, 2020, to qualify for specified credits up to a 6 GW cap. Receipt of federal tax credits does not necessarily preclude eligibility for equivalent state level initiatives, although states can adjust the credit amount to account for federal tax benefits. Thirteen states (and the District of Columbia) provide ITCs for renewable energy projects. Only one state, Arizona, offers a PTC for renewable energy projects.[166] Maryland does not currently employ a PTC for renewable energy technologies, and only employs an ITC for energy storage. No states offer PTC or ITC initiatives that support nuclear energy.

The Maryland Energy Storage Income Tax Credit is limited to $75,000 for commercial properties or 30% of the total installation costs, with a cap on

[166] Arizona's Renewable Energy Production Tax Credit began in 2010 and expires on December 31, 2020. It is available as both a personal and a corporate tax credit. Wind, solar, and biomass technologies of at least 5 MW are eligible for between $0.01/kWh and $0.04/kWh based on the technology and output level.

the total available funding. This cap is set annually and is equal to $750,000 in 2019. Maryland had a state PTC from 2006-2018. The Maryland Clean Energy Incentive Tax Credit offered Maryland businesses and individuals a state income tax credit for electricity generated by qualified resources (wind, biomass, landfill methane, methane from wastewater treatment plants, geothermal, MSW, and qualified hydro) of 0.85 cents/kWh, and 0.5 cents/kWh for electricity generated from co-firing a qualified resource with coal. Eligible applicants had to apply for and receive an initial credit certificate from MEA that estimated the amount of electricity that was expected to be produced by a qualified facility over a five-year period. The total amount of the credit specified in the initial credit certificate could not exceed $2.5 million and had to be a minimum of $1,000. Maryland could create similar initiatives for nuclear power plants, although use of the credit would likely be minimal if Maryland limited or capped the amount of the tax credit available to either an individual facility or collectively.

5.10.1.4 Advantages and Disadvantages of Tax Credits

Advantages

- *Easy to administer*- Tax credits do not require an agency to provide oversight duties (other than verifying eligibility), a direct source of funding, or annual appropriations.
- *Flexible to market changes*- Tax credit levels can be adjusted to account for the availability of other federal, state, and local incentives as well as changes in market conditions.
- *Promotes investment*- Tax credits result in a direct reduction in an individual's or business' tax liability, thereby enhancing after-tax cash flows.
- *Rewards performance*- In the case of the PTC, investors only receive the tax credit if the plant continues to be operational.
- *Rewards cost- and time-efficiency*- Fixed value tax credits encourage investors to complete projects as quickly as possible, and do not expose customers to any risk related to delays or cost overruns. This is because the incentive only applies once a project is in service, and does not increase if project costs are higher than expected by the investor.

Disadvantages

- *Financing complexity*– Businesses with insufficient tax liability will enter into complex transactions with entities that do. For example, under a "flip" transaction usually associated with the PTC, a project is sold to another entity (that has tax liability) for

10 years before reverting back to the original owner. The complexity of these transactions limits the pool of available financiers and increases the cost of financing.

- *Setting the incentive level* for ITCs– Determining the proper incentive level to encourage eligible energy technologies may be challenging—too high can lead to a "gold rush," while too low could lead to little or no project development. This is especially challenging for advanced nuclear power technologies, where market deployment costs are still uncertain.
- *Impact on state revenue*- Tax credits can have a greater-than-anticipated impact on state tax revenues unless they are structured with an annual total credit limit and granted on a first-come, first-served basis. Given the capital-intensive nature of nuclear power plants, the impact on state tax revenues could be significant. However, any limitations imposed by a state could quickly render the tax credit unattractive to potential developers of nuclear power plants.
- *Difficult to combine with other state financing initiatives*- Other state financing initiatives, such as upfront rebates, grants, and loans with low interest rates, may reduce the depreciable basis of the project, which is used when calculating one's tax liability. Thus, financing indirectly lowers the tax credit available to a project.

5.10.2 Tax Exemptions

Whereas tax credits reduce the actual tax bill, tax exemptions reduce the pre-tax value of income or holdings upon which taxes are assessed. As a result, tax credits tend to provide greater value to users than tax exemptions. Whereas credits often support new systems, tax exemptions apply to both existing and new generators. Property tax exemption and sales and use tax exemption are two of the most common types of tax exemptions for energy systems. A related initiative is payment-in-lieu of taxes (PILOT), which substitutes an upfront payment in place of future tax obligations.

5.10.2.1 Sales Tax Exemptions

A sales tax exemption excludes certain purchases from accruing sales and use taxes. By releasing the business from its sales tax obligation, the state effectively reducing the upfront costs to the purchase of an energy system.

5.10.2.2 *Property Tax Exemptions*

A property tax exemption allows a business to exclude the added value of an energy system from the valuation of their property for taxation purposes, making it more feasible for a commercial entity to install energy devices on their property. Property taxes are collected at both the state and local level; therefore, state property tax exemptions will give local governments the option to enroll in a state property tax exemption program or offer a blanket exemption. In some cases, states incentivize the placement of energy facilities in certain designated areas, such as brownfields.

5.10.2.3 *Experiences with Tax Exemptions*

Tax exemptions are popular throughout the United States, both at a state and local level, and are commonly used to reduce the costs of various energy efficiency improvements and renewable energy investments.[167] Although less common, a handful of states also include nuclear energy among the technologies eligible for tax exemptions. These include: property tax incentives for nuclear facilities in Alabama, Missouri, Montana, and Kansas; allowances for PILOT arrangement in place of property taxes for nuclear facilities in Mississippi and Ohio; and tax exemptions alongside other corporate tax incentives for nuclear located in an "Enterprise," "Renaissance," or "Opportunity" zones within Georgia, North Dakota, and Pennsylvania, respectively.[168] Idaho recently adopted legislation allowing both property and sales tax exemptions for investments related to the research and development activities of Idaho National Laboratory and small modular reactors.[169]

In 1985, Maryland enacted Title 9 of the Maryland Property Tax Code, which gives local governments the option to allow a property tax credit for buildings equipped with a solar or geothermal device that generates electricity to be used in the structure.[170] At least five counties in Maryland have utilized this option (Anne Arundel, Harford, Baltimore,

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167 cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

168 openei.org/wiki/Property_Tax_Incentive

169 legislature.idaho.gov/sessioninfo/2018/legislation/h0591/

170 MD Tax Property Code, Title 9-203, Effective January 1, 2019, advance.lexis.com/documentpage/?pdmfid=1000516&crid=3dc1fce4-206c-42df-9358-a43afb4c19bc&nodeid=ABJAAKAACAAD&nodepath=%2FROOT%2FABJ%2FABJAAK%2FABJAAKAAC%2FABJAAKAACAAD&level=4&haschildren=&populated=false&title=%C2%A7+9-203.+Energy+devices&config=014EJAA2ZmE1OTU3OC0xMGRjLTRlNTctOTQ3Zi0wMDE2MWFhYzAwN2MKAFBvZENhdGFsb2e9wg3LFiffInanDd3V39aA&pddocfullpath=%2Fshared%2Fdocument%2Fstatutes-legislation%2Furn%3AcontentItem%3A5V2F-RWD0-004F-00F8-00008-00&ecomp=-_57kkk&prid=b793e590-6207-4b35-b680-1edb4aace436.

Montgomery, and Price George's).[171] Similar exemptions may be possible for both existing and new nuclear power plants.

5.10.2.4 *Advantages and Disadvantages of Tax Exemptions*

Advantages

- *Easy to administer*- State or local tax exemption programs do not require agency oversight (other than verifying eligibility), a direct source of funding, or annual appropriations.

Disadvantage

- *Weak incentive*- Tax exemptions provide inadequate support as a stand-alone option to the development of energy systems.

5.11 *OTHER APPROACHES*

5.11.1 *Reliability Support Services Agreement*

In some circumstances, utilities may enter temporary agreements to subsidize nuclear plants on the grounds of reliability. This was the case in New York when Rochester Gas and Electric's (RG&E's) existing long-term contract for power from the Ginna nuclear plant, which is owned and operated by Exelon, lapsed in 2014.[172] Although Ginna was economically distressed, RG&E reached a temporary agreement, referred to as a reliability support services agreement (RSSA), with Exelon in 2015 to continue receiving power from the plant through 2018. The RSSA was intended to ensure continuous reliable power in the area while RG&E completed its preferred alternative, in this case a new transmission line connecting it to other power sources.[173] FERC allowed the agreement on the grounds that it provided essential reliability services. This type of arrangement does not currently apply to Maryland, but could if power flows change and it was found that the state's nuclear power plants provided essential reliability services that could not be replaced.

5.11.2 *State Acquisition and Public Private Partnerships*

Investor-owned, cooperative, and municipal power utilities currently own almost all the nation's operating commercial nuclear power plants, rather than state or federal entities. In contrast, many other countries have more

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171 programs.dsireusa.org/system/program/detail/232

172 power-eng.com/articles/2015/08/r-e-ginna-works-out-temporary-reliability-extension-while-negotiations-continue.html

173 powermag.com/ginna-reliability-deal-draws-fire/

explicit government involvement, including partial or complete ownership of nuclear power plants and related assets. Maryland could potentially support nuclear power by entering into public-private partnerships to develop or own nuclear plants. This type of action would shift financial risk from the private sector and onto taxpayers. It may also, however, support the continued operation and future availability of state-backed plants. This type of arrangement has been proposed in several states in recent years, including legislation (SB 8032) in June 2016 proposing that NYSERDA acquire economically struggling nuclear plants in New York that did not move out of committee.[174] At a federal level, DOE's Gateway for Accelerated Innovation in Nuclear program allows commercial nuclear companies to work in federal laboratories and access national laboratory staff to conduct advanced nuclear research. This form of public-private partnership may be more feasible at a state-level.

5.11.3 *Payment in Lieu of Taxes*

Payment in lieu of taxes (PILOT) is a negotiated payment arrangement that substitutes an upfront payment in place of future tax obligations. These payments are intended to compensate a government for foregone revenue. In the case of energy systems, a PILOT may be negotiated in advance of project development as a way to manage uncertain property valuation, and downstream tax obligations, during project construction. A company might also enter a PILOT to control property taxes, which can increase over time. PILOTs have the advantage of providing investment certainty for developers and guaranteed revenue for governments. A PILOT may also, however, supersede future tax payments that could potentially be larger than the amount recovered upfront through the PILOT. State and local governments in Maryland already have the option to enter PILOT arrangements. Calvert Cliffs, for instance, contributes a PILOT to Calvert County, amounting to about $20 million annually.

5.12 *Challenges to State Nuclear Initiatives*

The subject of state support for nuclear energy resources is controversial. Proponents believe that nuclear energy is crucial to maintaining progress toward reducing carbon emissions while also preserving grid resilience. Furthermore, proponents assert that subsidies for nuclear power plants would protect ratepayers from paying for new fossil-fuel powered plants to replace existing nuclear plants if they were to retire early. Opponents, on the other hand, have raised concerns about the negative impact that preserving nuclear has on other, less-supported resources, and that the

174 nysenate.gov/legislation/bills/2015/s8032/amendment/original

subsidies distort competitive power markets. Apart from the general disagreement surrounding state support for nuclear facilities, there are additional issues being raised in court and administrative proceedings. What follows is a review of four major categories of challenges: legal, regulatory, public perception, and economic. The focus of this section is challenges specifically affecting the implementation of nuclear initiatives, not the broader challenges facing the nuclear sector in general.

5.12.1 Legal

Many of the above initiatives rest on well-established legal precedents that give states the right to determine their own energy policy. Some new policies and innovative policy designs, however, have invited legal challenges, some of which are ongoing. The legal challenges facing the ZEC initiatives in Illinois, New York, and New Jersey as well as the state-required solicitation in Connecticut illustrate some of the prospective legal challenges that Maryland might face should it adopt similar initiatives. These cases are all unique to restructured markets, where state involvement in energy can be construed as interfering in interstate markets or contravening FERC's exclusive jurisdiction over wholesale energy markets.

5.12.1.1 Zero Emission Credits

Immediately following the adoption of the New York and Illinois ZEC initiatives, power producers and consumers filed several lawsuits challenging the legislation in late-2016 and early-2017. Plaintiffs in the ZEC cases argue that the subsidies were contingent on wholesale market participation and violated FERC's jurisdictional authority. Additionally, the plaintiffs in each lawsuit also raised concerns that the programs had violated the dormant commerce clause by discriminating against out-of-state energy producers by allowing only New York and Illinois power plants, respectively, to receive ZECs, and also by burdening interstate commerce through the distortion of market prices.[175] The New York and Illinois cases were ultimately decided by the 2nd and 7th U.S. Circuit Court of Appeals, respectively, in September 2018. Both courts ruled that ZECs were legally similar to other state incentives that support clean energy and have legal precedent. The Illinois and New York proceedings are described further in Appendix 1. Following decisions by the 2nd and 7th U.S. Circuit Courts of Appeals, on April 15, 2019, the U.S. Supreme Court denied certiorari for both states, effectively agreeing with the circuit court rulings and rejecting any future challenges to the ZEC programs in New

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[175] The "Dormant Commerce Clause" refers to the prohibition, implicit in the Commerce Clause, against states passing legislation that discriminates against or excessively burdens interstate commerce.

York or Illinois.[176] This ruling will set an initial precedent for other states to implement similarly designed programs, although further challenges may be considered in the future on different legal grounds.

Legal battles continue in New Jersey. On May 15, 2019, the New Jersey Division of Rate Counsel (Rate Counsel) filed a notice of appeal with the New Jersey Superior Court Appellate Division on the grounds that the NJBPU decision was not supported by the findings of the Eligibility Team, which stated that none of the three nuclear units that applied for ZECs were "at risk" of early retirement.[177] Additionally, the appeal maintained that there was no evidence to support the designated $0.004/kWh rate used to recover the costs of the ZEC program as representing the "emissions avoidance benefits" of the output of the nuclear plants.[178] These issues raised by the Rate Counsel, although specific only to nuclear generation and ZECs in New Jersey, illustrate the potential for legal challenges to ZECs even if they bypass the concerns raised in the New York and Illinois cases.

5.12.1.2 *State-required Solicitations*

Connecticut's state nuclear solicitation, although a first of its kind, has avoided some legal challenges because it is structured in accordance with allowed precedents. The program functions as an extension of the state's 2013 statute that empowered DEEP to solicit proposals for renewable energy, select winners, and direct Connecticut's utilities to enter into PPAs with the winners.[179] The 2nd District Court rejected a lawsuit against Connecticut's solicitation laws in 2014, concluding that the state played no role in determining the price offered to bidders.[180] Courts also dismissed a similar lawsuit against the state in 2015.[181]

5.12.1.3 *Energy Portfolio Standards*

Courts have also determined that RPS or equivalent standards do not violate the dormant commerce clause following several major cases. In

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[176] Supreme Court of the United States, "Order List: 587 U.S." , April 15, 2019, supremecourt.gov/orders/courtorders/041519zor_h3dj.pdf

[177] State of New Jersey Division of the Rate Counsel, "Notice of Appeal and Civil Case Information Statement", May 15, 2019, nj.gov/rpa/docs/ZEC_Rate_Counsel_Notice_of_Appeal_and_CIS_hardcopies_5-15-19.pdf

[178] Ibid. 107

[179] State of Connecticut General Assembly. "An Act Concerning Connecticut's Clean Energy Goals", May 30, 2013. cga.ct.gov/2013/FC/pdf/2013SB-01138-R000879-FC.pdf.

[180] Decision. United States District Court, District of Connecticut. Case 3:13-cv-01874-JBA. December 10, 2014, page 21.

[181] Allco Fin. Ltd. v. Klee, et al., 805 F.3d 89, 2015 U.S. App. Lexis 19452 (2nd Cir. 2015, amended December 1, 2015).

2015, for example, lawsuits were filed in Connecticut, Oregon, and Colorado against their respective renewable energy mandates, all claiming that the programs violated the dormant commerce clause.[182,183,184] Plaintiffs in these cases claimed that each state program protected in-state renewable energy producers and discriminated against out-of-state energy producers. All three cases were ultimately dismissed.

A 2015 lawsuit in Delaware, however, highlights how RPS programs can be in violation of the dormant commerce clause. Delaware's original RPS program provided benefits to in-state fuel cell manufacturers.[185] The plaintiff in a case against the policy claimed that the RPS law discriminated against out-of-state fuel cell manufacturers. The district court ultimately required Delaware to drop the law's geographical requirements and consider any fuel cell "qualified" regardless of the origin of production. Legislators in any states considering implementing or modifying an RPS to include nuclear generation will have to take into consideration this violation in order to avoid this specific legal challenge.

5.12.2 *Regulatory*

To address their concerns about resources receiving subsidies from initiatives such as ZECs, both Independent System Operator- New England (ISO-NE) and PJM have proposed making changes to their respective capacity auctions to essentially separate subsidized and unsubsidized resources. This type of action has the potential to undermine state initiatives to support nuclear energy so far as it reduces any advantages afforded by state-backed subsidies. This, in turn, could perpetuate the need for state support or drive the need for even higher subsidies.

Although ISO-NE does not directly influence Maryland energy markets, recent changes to its market design illustrate one path that PJM might take as it evolves its own market. On March 9, 2018, FERC approved ISO-NE's plan to split its capacity market auctions into two parts.[186] The proposal, titled Competitive Auctions with Sponsored Policy Resources (CASPR), suggested retaining a market for unsubsidized resources, then creating a

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182 American Fuel & Petrochemical Manufacturers, et al. v. Jane O'Keefe, et al., No. 3-15-CV-00467-AA, 2015 U.S. Dist. LEXIS 128277 (D. Or. Sept. 23, 2015).

183 American Fuel & Petrochemical Manufacturers, et al. v. Jane O'Keefe, et al., No. 3-15-CV-00467-AA, 2015 U.S. Dist. LEXIS 128277 (D. Or. Sept. 23, 2015).

184 Energy and Environmental Legal Institute, et al. v. Epel, 793 F.3d 1169 (10th Cir. 2015).

185 John A. Nichols and FuelCell Energy, Inc. v. Jack Markell, et al., No. 12- 777-CJB, (D. Del. Oct. 19, 2015) (order granting settlement agreement).

186 Federal Energy Regulatory Commission, "Order on Tariff Filing", March 9, 2018, iso-ne.com/static-assets/documents/2018/03/er18-619-000_3-9-18_order_accept_caspr.pdf

substitution market for subsidized new capacity. ISO-NE would then hold substitution auctions, whereby subsidized resources can obtain capacity obligations from unsubsidized resources. This market structure would provide a payment to resources that voluntarily retire, while also preserving a competitive basis for capacity prices. For instance, the first capacity auction would operate as normal, but the second auction would transfer capacity obligations from resources that can no longer operate at the lower market price to the new, subsidized resources. Once the unsubsidized plant retires it shifts its capacity obligation to the subsidized resource with no current obligation and pays the subsidized resource for meeting the obligation.

On April 9, 2018, PJM filed a request with FERC to make changes to its capacity market, the Base Residual Auction (BRA), citing specifically the effects of state ZEC and RPS policies on capacity market prices. Specifically, PJM filed two proposals that would address state subsidies.[187,188] Its first proposal, the Capacity Repricing Proposal, proposed a two- stage capacity auction that would allow generators receiving subsidies to enter into a preliminary market where PJM would determine which resources would receive a capacity commitment based upon a clearing price.[189] The second stage would then reprice subsidized resources that had cleared the first stage to eliminate the effect of the subsidy before it could compete with unsubsidized resources.

On June 29, 2018, FERC rejected both of PJM's proposals.[190] In making its decision, FERC noted that the PJM proposals, unlike the ISO-NE capacity market reform which sought to compensate for market impacts of new subsidized resources, focused on existing resources, particularly the ZEC programs in Illinois and New Jersey and solar and wind projects backed by a state RPS. In addition, FERC found the current tariff that governs PJM's BRA to be "unjust and unreasonable" because it failed to mitigate the price-suppressive impacts of out-of-market payments to generators. The commission initiated a proceeding for PJM to design new rules and suggested an alternative to the two-rejected proposals in which changes are made to the Fixed Resource Requirement (FRR) rule within the PJM

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187 Federal Energy Regulatory Commission, "Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of the State Public Policies on the PJM Capacity Market", April 9, 2018, pjm.com/directory/etariff/FercDockets/3576/20180409-er18-1314-000.pdf.

188 PJM's second proposal, the Minimum Offer Price Rule Ex (MOPR-Ex), aimed to mitigate offer prices for subsidized resources by screening subsidized resource offers and requiring these offers to adhere to a minimum price that reflects the cost of that resource without a subsidy.

189 PJM's Base Residual Auction construct is based on auctions for procurement of capacity three years in advance.

190 Federal Energy Regulatory Commission, "Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act" March 29, 2018, ferc.gov/CalendarFiles/20180629212349-EL16-49-000.pdf

tariff that allows utilities to opt out of the capacity market if they can serve demand with their own resources.

On Oct. 2, 2018, PJM filed another two market reform proposals that would remove subsidized resources from the capacity market and institute a strict price floor for unsubsidized resources.[191] The alternative proposals would increase capacity prices for unsubsidized resources in order to combat any price-suppressive effects resulting from the removal of subsidized resources. Unfortunately, both proposals garnered significant opposition that mirrored the same issues that many market participants identified with nuclear subsidies initially. Some generators believed that removing unsubsidized resources from the capacity market would endanger competitive pricing in the remaining market, while consumer advocates felt that boosting prices for unsubsidized resources would burden consumers with unnecessary costs.

On December 19, 2019, FERC issued an order that expanded PJM's price floor, also known as the Minimum Offer Price Rule (MOPR), to include generation, demand-side resources, and energy storage resources that receive out-of-market state subsidies. FERC adopted a broad definition of subsidies that includes any "direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit" to a resources participating in PJM's wholesale capacity market.[192] This definition is inclusive of the support provided by many of the potential state policies described above, most notable ZECs and RECs. In making its decision, FERC exempted existing generation and self generation (or planned generation with an interconnection agreement from PJM); demand response and energy efficiency resources that have cleared past PJM capacity auctions or have a PJM-approved measurement and verification plan; and energy resources, regardless of technology, that do not receive state subsidies. New energy resources whose costs are below the MOPR without state subsidies can petition the PJM Market Monitor for an exemption.

Revising the capacity market to incorporate FERC's changes is expected to result in higher retail electric prices as it will likely reduce the competitiveness of state-subsidized renewable energy, nuclear power, energy efficiency, energy storage, and demand response resources in PJM's capacity markets. Additionally, there will be fewer eligible

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191 Federal Energy Regulatory Commission, "Initial Submission of PJM Interconnection, L.L.C.", October 2, 2018, pjm.com/-/media/documents/ferc/filings/2018/20181002-capacity-reform-filing-w0172181x8DF47.ashx

192 "FERC Directs PJM to Expand Minimum Offer Price Rule," FERC. https://www.ferc.gov/media/news-releases/2019/2019-4/12-19-19-E-1.asp#.XiB2_MhKgdU

resources participating in PJM's capacity market, putting upward pressure on capacity prices. Estimates of the price impacts of FERC's order vary between $2.4 billion per year and $5.6 billion per year.[193] If the latter estimate is accurate, it would represent a 60% increase in capacity market costs.[194] These ongoing matters continue to create uncertainty surrounding the potential benefits of nuclear support policies, as well as their need.

5.12.3 *Public Perception*

The politics of supporting nuclear initiatives are complex. This stems in part from the long history of concern about the health, safety, and environmental risks of nuclear plants. These concerns were magnified in recent history by the Fukushima Daiichi nuclear accident in 2011, which forced a mass evacuation. Although nuclear plants in the United States face strict safety standards, some parties argue that the prospective risk of an accident, no matter how small, outweighs the benefits provided by nuclear generation. This line of argument suggests that the existing nuclear fleet should be retired in an expedient and safe manner, and no new nuclear plants should be deployed. This perspective undermines support for any form of nuclear initiative besides those that help fund one-time retirement expenses, such as securitization.

Besides health and safety concerns, nuclear has also faced uncertainty due to its economic prospects. The expensive, much delayed process to develop new nuclear plants in South Carolina and Georgia has soured some parties to the feasibility of developing any new nuclear plants in the United States. Additionally, the increased availability of low-cost alternatives like natural gas and renewables has raised concerns about whether the existing, operational nuclear fleet warrants support. This line of argument suggests that the existing nuclear fleet should compete solely on its economic merits without any further support. This perspective suggests that large-scale support initiatives, such as ZECs, are not warranted. Relatedly, it also undermines the case for initiatives with high up-front costs or minimal performance requirements, such as loans. However, it may be compatible with production-based tax incentives and

[193] Commissioner Richard Glick, dissent, FERC, Calpine Corporation, et al, versus PJM Interconnection LLC, 169 FERC ¶ 61,239, December 19, 2020, https://www.ferc.gov/whats-new/comm-meet/2019/121919/E-1.pdf (for the $2.4 billion) and Michael Goggin and Rob Gramlich, Consumer Impacts of FERC Interference with State Policies: An Analysis of the PJM Region, Grid Strategies LLC, August 2019, https://gridprogress.files.wordpress.com/2019/08/consumer-impacts-of-ferc-interference-with-state-policies-an-analysis-of-the-pjm-region.pdf.

[194] Michael Goggin and Rob Gramlich, Consumer Impacts of FERC Interference with State Policies: An Analysis of the PJM Region, Grid Strategies LLC, August 2019, https://gridprogress.files.wordpress.com/2019/08/consumer-impacts-of-ferc-interference-with-state-policies-an-analysis-of-the-pjm-region.pdf.

related initiatives on the grounds that not-yet-commercial technologies may eventually provide cost savings.

A related challenge for prospective initiatives is that the benefits and costs are unlikely to be evenly dispersed. Some benefits of sustaining existing nuclear plants, like local employment and tax receipts, are highly concentrated in specific communities. In contrast, the costs of potentially supporting nuclear plants are dispersed among all ratepayers or taxpayers. Potential initiatives must address concerns of cross-subsidization and corporate welfare at the expense of the broader state economy. This challenge undermines targeted initiatives, such as state-required solicitations.

5.12.4 Economic

The economic challenges facing nuclear plants, including the low costs of power from competitors and the high costs of relicensing and other regulatory requirements, are well documented in the preceding sections. One downstream consequence of these economic threats is that they potentially raise the costs of prospective initiatives to support nuclear power, especially in the case of subsidies for existing plants. This, in turn, creates conflicts in terms of state priorities. In the case where a support initiative requires general funds, the costs of subsidizing nuclear may come at the expense of funding alternative priorities. Relatedly, including nuclear alongside renewables in existing programs, has the potential to undermine state support (i.e., transfer resources from renewables to nuclear).

There are also economic risks specific to policies that support advanced reactors. Prior to mass commercialization, the full costs of licensing and development of an advanced reactor design are relatively unknown. State initiatives that provide “blank-check” type support, such as advanced cost recovery, run the risk of incurring substantial costs if a project becomes more challenging to develop than expected. There are also costs to absorbing private sector risk, as in the case of loans. Although the state may be better suited to manage large liabilities, excessive liabilities can raise a state’s cost to borrow. When determining the magnitude of support, states must ultimately decide whether the prospective value received by supporting nuclear outweighs both direct and indirect costs. These sorts of questions invite a great deal of scrutiny from a wide array of stakeholders, including consumer advocate groups and commercial and industrial interest groups.

5.13 *COMPARISON AND RECOMMENDATIONS*

The above initiatives differ along many significant dimensions. Notably, they vary in terms of prospective cost, principal beneficiary (i.e., new or existing nuclear plants), and time frame to design and implement. These differences are the basis of the comparison provided in the summary table below (starting on page 121), which also includes a short summary of each policy. Because each of these factors can vary depending on policy design, these dimensions are necessarily simplified in the table. Prospective costs are summarized using a six-part ordinal scale that ranges from low (1) to high (5) cost (zero means it is not applicable). This comparison is divided into separate scales for the cost to ratepayers versus the cost to taxpayers. Time frame to design and implement is grouped into three categories—short, medium, and long—depending on the typical complexity and burdens involved in initiating or administering each policy. The principal beneficiary is characterized as either new plants or existing nuclear power plants.

A couple of external factors could be kept in mind when considering the policy initiatives discussed in this report. First, Maryland adopted retail electric competition with the idea that generation is a competitive market that needs little or no government oversight or regulation. Providing financial subsidies to generators is seen by some as interfering with the operation of competitive power markets, and indeed, PJM has proposed substantial power changes to its capacity market in an attempt to counter moves by states to subsidize generation technologies such as nuclear power and renewable energy. Second, nuclear power plants based on currently available technologies are large and capital-intensive, and the amount of capital necessary to develop new nuclear power plants likely exceeds, or at the least, strains the ability of state budgets to back and support these investments. Third, while there are advanced nuclear power technologies in various stages of development that promise reductions in capital costs, these technologies are at least a few years away from being market-ready. States typically do not play a direct role in supporting research and development in the power sector, leaving that to the private sector or to federal government agencies such as the DOE. That said, Maryland has research and development capabilities at the University of Maryland campus that could be brought to bear should Maryland decide to make research and development investments.

There are many other characteristics not reviewed in Table 1 that might also influence the feasibility or desirability of implementing each policy in Maryland. For example, these policies have varying impacts on renewable energy, entail different levels of risk and costs to ratepayers and taxpayers, and differ in terms of magnitude of support to the nuclear industry. They also face distinct legal, regulatory, economic, and political challenges, as detailed above. Additionally, some policies in this table are compatible with each other while others are not.

If Maryland decides to implement a policy to support existing or new nuclear facilities, it should first identify its priorities and goals along dimensions, including cost, time, specificity (i.e., how targeted should the initiative be, and to which beneficiaries), and more. These priorities will likely depend on the context applicable to Maryland at the time. For example, Calvert Cliffs is expected to remain financially solvent, meaning estimated revenues exceed estimated costs, through 2021 according to an assessment by Monitoring Analytics, who is PJM's market monitor. Monitoring Analytics found, on the basis of planned capacity payments, estimated energy payments (from forward markets), and estimated plant costs (from NEI's 2017 data), Calvert Cliffs is expected to obtain the highest revenue surplus of nuclear power plants in PJM from 2019-2021.[195] Thus, Maryland may not want to pursue policies, such as ZECs, that are primarily intended to support financially imperiled existing plants until which time they are deemed necessary, if that happens at all. The state might instead take incremental, low-cost steps to recognize the low-emission attributes of nuclear power but not compensate them, such as by excluding generation from nuclear power plants in Maryland from electricity sales in Maryland that are subject to the Maryland RPS.

Several broader recommendations apply to all efforts to responsibly and efficiently support Maryland's nuclear energy industry. These recommendations can be subdivided between policies intended to support existing reactors, and those intended to support emerging nuclear energy technologies. For existing reactors, effective policies include features designed to internalize existing benefits provided by nuclear, such as low-emission generation, and, at the same time, also control costs. The most direct way to internalize a benefit is to assign a value to it, as is the case through a carbon tax (i.e., a cost to carbon) or through cap-and-trade (i.e., a property right to emit). Maryland can also indirectly assign a value, however, by procuring (or otherwise funding) generators based on their attributes, as is the case with RPS policies, ZECs, state-mandated solicitations, and other targeted funding initiatives. Ideally, any internalized costs or benefits will be applied broadly across all existing and potential generation sources, thereby leveling the playing field for those resources should they compete head-to-head in markets or for state subsidies.

[195] monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf

Controlling costs, meanwhile, is facilitated by a handful of strategies. First, states can implement cost caps, which are a useful way to ensure state or ratepayer resources are not expended in excess. Caps can take the form of alternative compliance payments (if nuclear generation is added to an RPS as a carve-out, or within an existing tier), hard limits on financial expenditure by the state or ratepayers, exhaustible funds, or other limits based on production milestones. Second, states can help drive down costs by fostering competition among both existing and potential technologies. For example, nuclear power can be required to compete against renewable energy based on its ability to provide low- or zero-carbon power. A competitive procurement process can ensure that an intended outcome, such as a decarbonized grid, is met without also locking Maryland into a specific resource mix. This approach helps ensure Maryland is still open to future innovation under the right conditions.

Third, states should consider their objectives before subsidizing existing nuclear power plants. Notably, regulators in Illinois and New York required plant owners to open their books before receiving ZECs to demonstrate and determine need. In contrast, Connecticut did not impose all equivalent requirements. Finally, policymakers could periodically reassess whether initiatives to support existing nuclear plants are necessary and prudent by creating rules that automatically account for market conditions. For example, funding may be tied to the relative financial position of a plant given energy, capacity, and other market revenues versus costs. States can also make initiatives temporary or short-term ensuring that a periodic reevaluation occurs before a program is extended.

The goal of controlling costs and internalizing benefits also applies to new nuclear power plants. In the case of new projects, however, several additional best practices apply. First, funding or other support could be dispersed based on the achievement of milestones in a timely fashion. At the front end of project development, this could include obtaining regulatory approvals. Second, co-funding could be required from companies seeking state financial support. For example, policymakers might divide licensing or research and development costs, thereby making sure both the public and private sector have "skin in the game." Finally, funding could focus on rewarding performance. This can take the form of contingent subsidies or incentives that are only available on the basis of actual generation/production, not investment. All of the above strategies have the effect of ensuring that state resources are tied to tangible outcomes and facilitate forward progress.

Based on the above recommendations, new nuclear power projects stand to benefit the most from policy initiatives like grants, loans, tax incentives, and public-private partnerships. For example, Maryland might want to create designated areas that are pre-approved and licensed for prototype deployment, testing, and operation, i.e., "reactor parks."[196] This would help reduce the upfront costs of initiating work on new nuclear reactors. Maryland might also make production tax credits available as a downstream incentive for developers to eventually build productive generators, with a sunset date for the incentive and yearly or total cost caps to limit taxpayer costs.

Maryland may also proactively prepare for future challenges to the financial solvency of existing nuclear power plants by establishing standing support mechanisms that are contingent. For example, Maryland could establish a process to review specific nuclear power plant financial information, to be provided at the discretion of plant owners in the event of insolvency. After demonstrating need, policy initiatives should allow for competition on the basis of desired attributes. This can take the form of ZECs or state procurement processes. This support could be of limited duration or otherwise subject to revaluation for need. For example, in New Jersey, the PSC is required to reassess whether nuclear plants are eligible for ZECs every three years.

[196] "The Future of Nuclear Energy in a Carbon-Constrained World." MIT Energy Initiative, 2018.

	Summary	Cost to Taxpayers	Cost to Ratepayers	Time to Implement	Principal Beneficiary
Alter an Existing RPS (State Energy Portfolio Standards)	Within either a single or multi-tiered RPS, states can potentially support nuclear by adding it to a tier or creating a new tier.	0: Minimal additional admin costs	1: Low if nuclear included in secondary tier and/or competes with other resources 4: Mod./High if a there is a nuclear power carve-out	Short: MD can utilize existing RPS constructs as foundation or borrow from other states that have a separate tier for nuclear power.	New or existing plants: Competition among eligible resources likely disadvantages new nuclear and constrains benefits to existing nuclear, except in the case of carve-outs.
Clean Energy Standard (State Energy Portfolio Standards)	A CES includes other resources that are often excluded from RPS policies such as nuclear power. States can support nuclear power by implementing a CES in lieu of an RPS or as a complementary policy.	0: Minimal additional admin costs	1: Low if nuclear competes with other resources 4: Mod./High if there is a nuclear power carve-out	Short: MD can utilize existing RPS constructs as a foundation or borrow from other states with a CES.	New or existing plants: Competition among eligible resources likely disadvantages new nuclear power and constrains benefits to existing nuclear power, except in the case of carve-outs.
Exclude Nuclear Sales from RPS (State Energy Portfolio Standards)	This approach accounts for nuclear power in an RPS or CES by netting nuclear generation out of total electric sales. Doing so avoids compensating existing nuclear power plants that may not need financial assistance while also recognizing nuclear power's carbon-free attributes.	0: Minimal additional admin costs	0: No ratepayer costs	Short: Requires minimal changes to the RPS. No RECs are provided.	Existing plants: Recognizes the carbon-free attributes of nuclear but does not provide compensation. Could sharply reduce the Maryland RPS requirement for renewable energy unless the target is increased.
Zero Emission Credits	ZECs provide compensation for financially challenged nuclear facilities. ZECs differ from RECs because they are generally allocated in advance, are not eligible for trading, and serve a closed market.	0. Minimal additional admin costs	2: Low/Mod. if designed to meet short-term financial need or subject to financial controls such as cost caps 4: Mod./High if set equal to social cost of carbon or provided irrespective of need	Long: ZECs are administratively complex; require time to design and implement; require regulatory oversight; and regulators must design a system for recipient selection and ZEC allocation.	Existing plants
Customer Surcharge Accounts	A special-purpose account that supports a specific function or initiative, such as nuclear power research and development, plant upgrades, or subsides to sustain operations. These accounts are funded through a non-bypassable, per-kWh surcharge on customer electric bills.	1: Admin costs	3: Mod./High if collected to pay a known cost (e.g., previous year losses) 5: High if collected for open-ended use	Medium: Surcharges are a common, existing funding mechanism. However, the distribution of account funds can be administratively complex and is often politically controversial.	New or existing plants: Fund can be tailored to meet the financial requirements of economically imperiled nuclear plants, to support nuclear power research and development, or to fund upgrades at existing plants.
State-Required Procurement of Clean Energy Resources	A requirement that regulated utilities procure power from specific resources, usually via a PPA. Resources are selected either via a competitive procurement process or an administrative proceeding.	1: Admin costs	2: Low/Mod. if procurement process is competitive 4: Mod./High if administratively selected or if solicitation process is not competitive (i.e., limited to single	Medium: PPAs are common. However, solicitations can be designed in a myriad of ways. Overseeing a PPA process can be time-consuming if there are many selection criteria, many bids to evaluate, or	New or existing plants: Competition among eligible resources likely limits opportunities for new and financially challenged existing nuclear power plants. unless above-market-cost resources are specifically allowed.

	Summary	Cost to Taxpayers	Cost to Ratepayers	Time to Implement	Principal Beneficiary
			technology or does not have large number of bidders)	if losing bidders challenge the bidding results.	
Cap and Trade (Assigning a Cost to Carbon)	An initiative that limits total carbon dioxide emissions and allows emitters to determine how they will get under the cap. Emitters have the option to purchase and sell emission rights to and from each other.	3: Moderate up-front costs from admin. Set-up; low after that if market is well-functioning	2: Low/Mod. from the passthrough of supplier costs (depending on carbon prices). Can be reduced via refunds to ratepayers.	Medium/Long: Identifying an emission cap, allocating permits, and designing a trade system can be time intensive. Requires market monitoring to ensure markets are competitive and well-functioning.	Existing plants: Limiting emissions or imposing a price for emissions provides a cost advantage to low-emission nuclear power.
Carbon Tax (Assigning a Cost to Carbon)	An initiative that sets a fixed price for carbon emissions and then allows the market to respond.	2: Low/Mod. costs from admin, management of taxes and tax revenues	3: Moderate costs from the passthrough of supplier costs. Can be reduced by recycling tax payments.	Medium: Can utilize existing tax collection systems. Identifying appropriate tax level and who it applies to can be challenging.	Existing plants: Limiting emissions or imposing a price for emissions provides a cost advantage to low-emission nuclear power.
Advance Cost Recovery	A regulatory construct that allows utilities to recover the costs of constructing a new power plant prior to project completion.	0: No taxpayer costs	4: Mod./High costs as a result of risk shifted onto ratepayers (historically)	Short: Changes regulatory processes, but has few other admin burdens	New plants: Designed to expedite cost recovery during the development and construction of new plants, making these projects more attractive to investors.
Feed-in Tariff	A policy approach that provides a long-term purchase agreement for electricity at a specific price, usually paired with grid access and priority dispatch, or a premium above a spot market price	1: Admin costs	2: Low/Mod. cost if tariff price is set low (but may have little positive impact on power plant development) or if cost caps are in place; high if technologies are not commercially mature or if technology cost reductions exceed projections	Medium/High: Can be designed in a myriad of ways. Requires extensive monitoring to provide corrective action if necessary.	New plants: Designed to incentivize the development of new plants on the basis of production-based payments. Limited experience in U.S.; more prevalent overseas.
Grants	Partial or full funding for specific projects and programs, including infrastructure, labor training, and research and development.	0: No or limited taxpayer costs..	2: Low/Mod. assuming funding is from a systems benefit charge, especially if potential recipients compete.	Short-Moderate Common approach to funding and can be.easy to administer unless new initiatives or solicitations have to be put in place. Flexible to change	New or existing plants: Grants provide funding that supports all stages of development and operation. Grants are especially beneficial during the early stages of developing new or commercially immature technologies.
Direct Loans (Loan Programs)	Loans provided directly to the borrower through an institution, such as a government agency or a third party, such as a clean energy bank.	0: No or limited taxpayer costs.	5: High,assuming funding is from a systems benefit charge. High capital requirements. State	Short: Already a common approach to loans for large projects	New plants (primarily): DOE loan program helping construction of nuclear owner plants. Could apply to existing plants, but not common.

	Summary	Cost to Taxpayers	Cost to Ratepayers	Time to Implement	Principal Beneficiary
			absorbs the risk of default. Some ongoing servicing and monitoring costs		
Matching Loans (Loan Programs)	State loans that match loans from private lenders in order to encourage energy project development in the private sector as well.	0: No or limited taxpayer costs	2: Low/Mod. assuming funding is from a systems benefit charge. Moderate capital requirements. State absorbs some risk of default. Some ongoing servicing and monitoring costs	Short: Already a common approach to loans for large projects	New plants.
Interest Rate Buy-Down (Loan Programs)	States work with private lenders in offering below-market interest rate loans by subsidizing the interest rate through a lump-sum payment.	2: Moderate capital requirements. Funding not recycled. State has no underwriting responsibilities or default risk	0: No ratepayer costs	Short: Already a common approach to reducing financing costs	New plants: Reduces the cost of bank loans during the construction phases of new nuclear power plants.
Linked Deposits (Loan Programs)	Allows participating banks to make below-market interest payments on state deposits. In return, the bank then uses the funds from the state deposits to provide low-interest loans to energy projects.	2: Low direct cost (admin), but indirect costs through reduced earned interest payments.	0: No ratepayer costs	Short: No legislative action needed	New plants: Reduces the cost of bank loans during the construction phases of new nuclear power plants.
Securitization (Loan Programs)	Form of loan refinance through which investor-backed utility debt and equity is pooled and then resold as consumer-backed utility equity.	1: Admin costs	3: Moderate: Debt is paid by ratepayers, who also absorb risk. Usually only covers a portion of total costs, however, and is of limited duration	Medium: Less common in energy sector, may require new laws. Some administrative requirements to establish collection mechanisms, transfer debt, etc.	New or existing plants: Can help collect funds to support existing plants, help finance research and development or to support costs for new plants.
Investment Tax Credits (Tax Incentives)	Credits that allow businesses to deduct a certain percentage of capital investment costs from their state income taxes for investments in eligible energy projects.	3: Costs incurred after investment. Limited direct cost (admin), but indirect costs through reduced tax receipts. Annual, cumulative, or per-project cost or credit caps can limit impact on government tax revenues.	0: No ratepayer costs	Short: Already a common approach to support new generators. Easy to administer, flexible to change	New plants: Can be targeted toward investment in new nuclear power plants. Companies without or with minimum tax liability will not be able to take full advantage of the tax credit unless it sells or leases projects to other companies or investors.
Production Tax Credits (Tax Incentives)	Credits that reduce a business' income tax liability based upon the amount of energy generated by an eligible energy project over a period of time.	3: Costs incurred after production. Limited direct cost (admin), but indirect costs through reduced tax receipts. Annual, cumulative, or	0: No ratepayer costs	Short: Already a common approach to support new generators. Easy to administer, flexible to change	New plants: Targeted to incentivize capital investment in new nuclear power plants. Companies without or with minimum tax liability will not be able to take full advantage of the tax

	Summary	Cost to Taxpayers	Cost to Ratepayers	Time to Implement	Principal Beneficiary
		per-project cost or credit caps can limit impact on government tax revenues.			credit unless it sells or leases project to other companies or investors.
Sales Tax Exemptions (Tax Incentives)	Exemption that excludes certain purchases from sales and use taxes.	1: Low cost if limited in scope. No direct cost, but indirect costs through reduced tax receipts	0: No ratepayer costs	Short: Already a common way to incentivize certain purchases. Easy to administer, flexible to change	New or existing plants: Reduces current and future tax liability for expenditures related to development of nuclear power plants. Not considered enough of an incentive to stimulate action by itself.
Property Tax Exemptions (Tax Incentives)	Exemptions that allow a business to exclude the added value of an energy system from the valuation of their property for taxation purposes.	1: Low cost if limited in scope. No direct cost, but indirect costs through reduced tax receipts	0: No ratepayer costs	Short: Already a common way to incentivize relocation. Easy to administer, flexible to change	New or existing plants: Reduces current and future tax liability to develop a new project or continue to operate an existing reactor in a specific area.
Reliability Support Services	In certain circumstances, utilities may enter temporary agreements to subsidize power plants (including nuclear power) on the grounds of reliability. These arrangements are generally subject to FERC review.	0: No taxpayer costs	3: Moderate cost if ratepayers are obligated to pay for noncompetitive production at the minimum level necessary to support operation	Medium: High degree of legal and regulatory involvement. Arrangements can be implemented during the review process.	Existing plants: Tailored to meet the minimum financial requirements of economically imperiled power plants.
State Acquisition and Public-Private Partnerships	An arrangement that involves more direct government involvement in power production, including partial or complete ownership of nuclear power plants and related assets.	2: Moderate cost if government shares risks (i.e., partnership) 5: High cost if risk and costs are shifted onto government in full (i.e., ownership)	0: No ratepayer costs if plant production is unchanged after acquisition 4: Mod./High cost if ratepayers are obligated to pay for noncompetitive production	Long: Introduces legal issues. Administratively complex. Must design one-off arrangements for ownership, management, etc.	New and existing plants: Government helps absorb some project risk and costs, either by acquiring an existing plant or developing a new plant.
Payment-in-Lieu of Taxes	A negotiated payment agreement that guarantees an upfront payment, often recurring, in exchange for exemption from regular tax assessment and related obligations.	1: Low cost if limited in scope. No direct cost, but indirect costs through reduced tax receipts	0: No ratepayer costs	Short: Already a common approach to taxes for large projects, especially at the local level.	Existing plants: Reduces uncertainty regarding future tax obligation for plants once they are in service.

Illinois

In February 2017, a group of wholesale non-nuclear generators and retail customers filed complaints against the Illinois ZEC statute in the U.S. District Court for the Northern District of Illinois, Eastern Division of (Illinois District court).[197] The plaintiffs argued that the Federal Power Act preempts the program and that it should be disallowed because it: (1) replaces wholesale prices and intrudes on FERC's exclusive jurisdiction over wholesale sales, and (2) conflicts with FERC's regulatory authority by distorting the outcomes in FERC-regulated markets. The plaintiffs also argued that Illinois violated the dormant commerce clause and the equal protection clause by favoring in-state plants and imposing additional costs on Illinois consumers. On July 14, 2017, the Illinois District Court rejected the plaintiff's argument and determined that ZECs were legally similar to other state incentives that support clean energy and have legal precedent. The Illinois District Court granted a motion by the defendants and Exelon to dismiss the case.[198] On Aug. 24, 2017, the case was appealed to the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit). On May 29, 2018, FERC and the Department of Justice (DOJ) filed a joint legal brief with the 7th Circuit Court of Appeals in support of the Illinois program which maintained that the Federal Power Act does not pre-empt the program to award ZECs because it does not require participation in FERC-jurisdictional markets and is focused, instead, on the ability of the plant to not emit carbon dioxide, which does not interfere with FERC procedures.[199] On Sept. 13, 2018, the 7th Circuit Court concluded that the claims of the Plaintiffs were unfounded because they had failed to identify a "tether" under the *Hughes* case between the ZEC program and the wholesale market participation, and they could not identify any clear damage to FERC goals.[200]

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197 The consolidated plaintiffs include: Commonwealth Edison Company delivery service customers (Village of Old Mill Create, Ferrite International Company, Got it Maid, Inc., Nafisca Zotos, Robert Dillon, Richard Owens, and Robin Hawkins), Electric Power Supply Association, Calpine Corporation, Dynegy Inc., Eastern Generation, LLC, and NRG Energy, Inc. The defendants were the Illinois Power Agency and the Illinois Commerce Commission.

198 United States District Court for the Northern District of Illinois, Case 1:17:cv:01164 Document 107, Memorandum Opinion & Order, July 14, 2017, statepowerproject.files.wordpress.com/2017/02/il-zec-decision.pdf.

199 United States Court of Appeals for the Seventh Circuit, "Brief for the United States and the Federal Energy Regulatory Commission as Amici Curiae in Support of Defendants- Respondents and Affirmance", May 28, 2018, gallery.mailchimp.com/0554cc7ed0bda904329a48c93/files/de89e366-f825-4579-9cae-a04d764e58bb/2018_05_29_FERC_ZEC_Brief.pdf

200 United States Court of Appeals for the Second Circuit, Case No. 17-2654, August Term 2017, blogs.edf.org/climate411/files/2018/09/NY-ZEC-2nd-Circuit-Opinion.pdf.

New York

On Oct. 19, 2016, a coalition of non-nuclear generating companies filed a lawsuit in the U.S. District Court Southern District of New York (New York District court) against New York's ZEC program with supporting briefs from anti-nuclear, environmental, and consumer advocate groups.[201] The plaintiffs complained that New York intruded on the exclusive authority of FERC over "the sale of electric energy at wholesale in interstate commerce" as defined in the Federal Power Act.[202,203] On July 25, 2017, a U.S. District Judge rejected the plaintiffs' argument and determined that ZECs were legally similar to other state incentives that support clean energy and have legal precedent. The Court granted a motion filed by the defendants and Exelon to dismiss the case.[204] On Aug. 24, 2017, the case was appealed to the U.S. Court of Appeals for the Second Circuit (Second Circuit). On Sept. 27, 2018, the Second Circuit affirmed the decision in Illinois' Seventh Circuit court and the FERC and DOJ joint legal brief and concluded that the claims of the Plaintiff were unfounded for similar reasons as used in the IL Seventh Circuit decision.[205]

[201] The plaintiffs include: Coalition for Competitive Electricity, Dynegy Inc., Eastern Generation, LLC., Electric Supply Associates, NRG Energy, INC., Roseton Generating LLC, and Selkirk Cogen Partners, L.P. The defendant was the New York Public Service Commission.

[202] The Federal Power Act gives the Federal Energy Regulatory Commission (FERC) exclusive authority to regulate sales of electricity at wholesale in interstate commerce.

[203] United States District Court Southern District of New York, Case 1:16-cv-08164 Document 1, Complaint, October 19, 2016.

[204] Ibid., Document 159, Memorandum Opinion & Order, July 25, 2017, statepowerproject.files.wordpress.com/2014/03/ny-ces-opinion.pdf.

[205] United States Court of Appeals for the Second Circuit, Case No. 17-2654, August Term 2017, blogs.edf.org/climate411/files/2018/09/NY-ZEC-2nd-Circuit-Opinion.pdf.

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