ARTICLE

Deep Decarbonization and Nuclear Energy

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Summary

The Deep Decarbonization Pathways Project (DDPP) projects a doubling of U.S. demand for electricity by 2050, even accounting for increased energy efficiency and conservation. In two DDPP scenarios, this demand would be met by significant increases in nuclear, wind, and solar energy by 2050. The High Nuclear Scenario involves more than 400 gigawatts of nuclear, four times current capacity. The Mixed Scenario involves approximately 200 gigawatts of nuclear, or two times current capacity. A sustained national commitment to nuclear energy would be necessary to meet the DDPP goals for either scenario. Advanced technologies exist or are under development that could support a significant, rapid expansion of nuclear energy capacity, but under current conditions, those technologies are not likely to be deployed at the scale required. This Article, excerpted from Michael B. Gerrard & John C. Dernbach, eds., *Legal Pathways to Deep Decarbonization in the United States* (forthcoming in 2018 from ELI Press), highlights various factors that impact nuclear energy, and proposes legal, regulatory, and policy changes to reduce barriers and promote increased use of nuclear generation.

I. Introduction: The Role of Nuclear Energy in Decarbonization

The Deep Decarbonization Pathways Project (DDPP) report calls for fundamental changes in U.S. energy systems, including switching energy end uses such as transportation to electricity and decarbonizing the electricity fuel supply. According to the U.S. Energy Information Administration (EIA), as of 2016, nuclear energy accounted for nearly 60% of the carbon-free electricity generation in the United States.[1] The contribution of nuclear to carbon-free electricity presently exceeds the contributions of hydropower and other renewables combined.[2]

The DDPP report projects a doubling of U.S. demand for electricity by 2050, even accounting for increased energy efficiency and conservation. In two DDPP scenarios—the High Nuclear and Mixed Scenarios—this demand would be met by significant increases in nuclear, wind, and solar energy by 2050. Although there are obstacles to widespread deployment of nuclear energy, the technology offers the clear potential to reach the scale needed to achieve the DDPP goals by 2050.

In 2016, 99 U.S. nuclear power reactors operated at a capacity factor of 92.5% and generated 805 billion kilowatt hours (kWh) of electricity,[3] representing about 20% of electricity in the United States.[4] To put the DDPP goals in perspective, the current installed nuclear capacity in the United States is approximately 100 gigawatts (electric) (GWe).[5] The DDPP High Nuclear Scenario involves more than 400 GWe of nuclear.[6] This is four times current capacity. (The DDPP report shows nuclear at 40.3% of U.S. electricity in 2050 for the High Nuclear Scenario.[7]) The DDPP Mixed Scenario involves approximately 200 GWe of nuclear capacity (27.2% of the increased U.S. electricity supply), or two times current capacity.[8]

This Article therefore focuses on identifying obstacles to achieving those capacities and the policy changes

1. EIA, U.S. Energy-Related Carbon Dioxide Emissions, 2016 (2017).
2. According to the EIA, hydro accounted for 19% of carbon-free generation, while wind and solar combined for 20%. *Id*.
3. EIA, *Frequently Asked Questions—What Is U.S. Electricity Generation by Energy Source?*, https://go.usa.gov/xn4yW (last updated Apr. 18, 2017).
4. *Id*.
5. EIA, *U.S. Nuclear Generation and Generating Capacity*, https://go.usa.gov/xn4y5 (last released Dec. 22, 2017); *see also* World Nuclear Association, *Nuclear Power in the USA*, http://bit.ly/2b0sXpQ (last updated Oct. 2017). Gigawatts measure the capacity of large power plants or of many plants. One GW = 1,000 megawatts (MW) = 1 billion watts. A typical nuclear unit would have a capacity around 1,000 MW. Future units may be larger or smaller, depending on the design and technology. A typical combined-cycle natural gas plant is about 600 MW in size.
6. James H. Williams et al., Energy and Environmental Economics, Inc. et al., Pathways to Deep Decarbonization in the United States, US 2050 Report, Volume 1: Technical Report xiv (2015).
7. *Id*. at 19-20 tbl. 7.
8. *Id*. at 36 fig. 30.

needed to overcome those obstacles. Consistent with the DDPP scenarios, increased nuclear generation would be developed in concert with increased reliance on renewables (whether utility-scale or distributed), as substantial nuclear and renewable contributions are contemplated in both scenarios.

Both DDPP scenarios would likely require preservation of at least some of the existing nuclear fleet. An operating license (OL) from the Nuclear Regulatory Commission (NRC) is initially issued with a term of 40 years.[9] Based on required technical analyses, most operating plants have been granted a renewed license that extends their license terms by 20 years.[10] But even so, by 2040, one-half of the nation's existing nuclear fleet will have turned 60 years old and a renewed license will have expired. For plants still operating at 60 years, NRC regulations allow an application for a second license renewal for 20 additional years.[11] But the regulatory process for second license renewal has not yet been tested. By 2050, absent second renewal, nearly all currently operating nuclear units will be retired.

There has also been a trend in recent years of premature closure of nuclear plants for technical, political, and economic reasons.[12] These closures will make achieving the DDPP goals more difficult. Plants that have permanently ceased, or announced plans to cease, operations since 2013 include Crystal River, Fort Calhoun, Indian Point, Kewaunee, Pilgrim, San Onofre, Vermont, and Yankee, with additional closures predicted in the next few years.[13] The operator of Diablo Canyon in California also announced that it will not renew the OLs for those two units beyond 2024 and 2025, due to a policy preference in California for renewable energy sources.

As long as natural gas generation is needed to make up for intermittency of wind and solar, replacing nuclear generation with a combination of intermittent wind or solar and natural gas leads to far greater emissions than simply maintaining existing nuclear generation. This has been demonstrated by emissions increases in California, Florida, New England, and Wisconsin following closures of nuclear plants there.[14] The same dynamic occurred in Germany, where emissions declines have stagnated following nuclear closures despite a decade of heavy investment in renewables.[15] Preserving existing nuclear avoids taking a backward step on the path to decarbonization.

Regardless of the existing fleet, the nuclear capacity assumptions in both the High Nuclear and Mixed Scenarios require the development of a substantial amount of new nuclear generation capacity utilizing advanced nuclear technology. In the United States, one new nuclear unit (Watts Bar Unit 2 in Tennessee) began operating in 2016—the first new commercial unit to begin operating since 1996. Only four units (two in Georgia and two in South Carolina) have begun construction, and construction had been suspended at two (the units in South Carolina) as this Article went to press, following a bankruptcy filing by Westinghouse, the nuclear vendor and parent of the company responsible for construction. NRC has issued early site permits (ESPs) and combined licenses (COLs) for several other new units, but there are no plans to immediately begin construction on any of those projects. The DDPP projections therefore represent a significant challenge—one that cannot be met with the status quo in nuclear energy economics and public policy.

Advanced nuclear technologies exist or are under development that could support a significant, rapid expansion of U.S. nuclear energy capacity. With appropriate regulatory policies and economic and market conditions, the most optimistic DDPP projections may be challenging, but are achievable. There is precedent. From 1973 to 1988, with the support of the government and industry, France radically altered that country's electricity generation from almost entirely fossil fuels (mostly imported oil) to more than 80% nuclear, at a rate of up to six new nuclear plants per year.[16] And the U.S. renewable industry today is the product of more than a decade of policy choices, portfolio standards, and subsidies, as well as improved technology and rapidly declining costs, rather than pure market forces.

A similar sustained national commitment to advanced nuclear energy in the United States would be necessary to meet the DDPP goals—first for the Mixed Scenario and even more so for the High Nuclear Scenario. In addition to carbon benefits, advanced nuclear could, as a matter of policy, have a role in a generation mix that considers grid stability, fuel diversity, and other social benefits such as the

9. 42 U.S.C. §2133.c.
10. NRC, *Backgrounder on Reactor License Renewal*, https://go.usa.gov/xn4VZ (last updated Nov. 27, 2017). As this Article went to press, 84 of the 99 operating reactors had received renewed licenses.
11. NRC, *Subsequent License Renewal Background*, https://go.usa.gov/xn4V5 (last visited Dec. 23, 2017). NRC explains that there are no specific limitations in the Atomic Energy Act (AEA) or NRC's regulations restricting the number of times a license may be renewed. The decision to grant a renewed license is based on the outcome of an NRC review to assess if the nuclear facility can continue to operate safely during the 20-year period of extended operation.
12. *See* Emily Hammond & David B. Spence, *The Regulatory Contract in the Marketplace*, 69 Vand. L. Rev. 141, 147-48, 190 (2016).
13. *See*, *e.g.*, Jim Polson, *Exelon Shutting Two Nuclear Plants After Legislation Fails*, Bloomberg, June 2, 2016, https://bloom.bg/1Pngzmh.
14. Metin Celebi et al., The Brattle Group, Nuclear Retirement Effects on CO_2 Emissions: Preserving a Critical Clean Resource (2016), http://bit.ly/2yfCzfZ; James Conca, *Are California Carbon Goals Kaput?*, Forbes, Oct. 2, 2014, http://bit.ly/2ifvYrc.
15. Stanley Reed, *Germany's Shift to Green Power Stalls, Despite Huge Investments*, N.Y. Times, Oct. 7, 2017, http://nyti.ms/2g0h4YV.
16. World Nuclear Association, *Nuclear Power in France*, http://bit.ly/2ejXhg1 (last updated Oct. 2017); Jake Richardson, *Why France Went Nuclear*, CleanTechnica, Aug. 6, 2014, http://bit.ly/2zRKKeY.

job creation associated with nuclear equipment manufacture, construction, and operation.[17]

Part II of this Article begins with an overview of recent advances in nuclear technology and a description of the current state and federal legal and regulatory frameworks governing nuclear power. This is followed, in Part III, by an assessment of approaches to preserving existing nuclear capacity in the face of current conditions and trends, including carbon pricing, market reforms, and second license renewal. Part IV then moves into a discussion of dynamics that could spur the major build-out of nuclear power necessary to meet DDPP projections for the High Nuclear and Mixed Scenarios, including initiatives to address the cost of nuclear power and to facilitate necessary financing for individual projects, approaches to supporting and commercializing technological advances, and steps to further assure nuclear design standardization. Part V addresses other major initiatives that could encourage (and even assure) the development of new nuclear power plants, including large-scale public nuclear power development and changes in nuclear waste policy to resolve the long-standing political impasse. Part VI concludes.

II. The Current State of Nuclear Power and Regulation

The technology deployed in U.S. nuclear generation has been relatively stable for decades. In recent years, however, standardized designs with advanced and passive safety features have been certified by NRC. Even more advanced technologies are under development. All of these designs and any new projects will be subject to comprehensive safety and environmental regulatory regimes at the federal and state levels. In addition, new generation technology will be developed within the applicable legal and regulatory frameworks for retail and wholesale electricity sales and distribution. This part discusses the current status of nuclear technology and the various regulatory frameworks that govern nuclear generation.

A. *Advances in Nuclear Technology*

Nuclear energy technology has slowly evolved since it was first developed in the 1950s and deployed in the 1960s. However, in recent years, there has been substantial attention given to new, modular, or advanced nuclear technologies that, at least in concept, offer the prospect of major improvements in the costs, risks, and public perceptions of nuclear energy.

All reactors presently operating in the United States use light water reactor (LWR) technology originally developed for U.S. nuclear Navy propulsion systems in the 1950s and 1960s. LWRs—whether a pressurized water reactor (PWR) or a boiling water reactor (BWR)—use ordinary water to transfer heat generated by the fission process in the reactor to a turbine that produces electricity. The technology has been refined over time. Generation I reactors were prototypes and early commercial plants constructed in the 1950s and 1960s. Generation II reactors were those built in the 1970s and 1980s, many of which remain in operation. Generation III reactors were first developed in the 1990s and reflect advances in safety and operation relative to Generation II reactors. Generation III+ reactors reflect further improvements to reduce capital costs and increase safety and operational efficiency.

The technological developments in LWRs have improved the performance and safety of existing Generation I and Generation II reactors. The power output of nearly all currently operating reactors has been increased through power uprates, which involve equipment modifications or component upgrades that permit the operator to increase a plant's electrical output.[18] Accident-tolerant fuels under development can withstand loss of active cooling in the reactor core for a considerably longer time period than traditional fuels (depending on the LWR system and accident scenario) while maintaining or improving the fuel performance during normal operations.[19] Lightbridge Corporation, for example, is developing a metallic nuclear fuel rod that provides increased safety margins and improved economics for LWRs compared to conventional oxide fuel. The new fuel is expected to extend the fuel cycle for existing plants to 24 months while increasing power output by 10%.[20] Improvements in the use of probabilistic risk assessments also support greater use of risk-informed categorization and treatment of structures, systems, and components, and can lead to improved regulations and significant cost savings.[21]

The four new units that began construction in recent years in Georgia and South Carolina rely on the Westinghouse AP1000 design. (In 2016, Westinghouse entered the bankruptcy process to reorganize its businesses as a result of financial difficulties associated with construction of the four new units.[22] As of this writing, future ownership of the technology remains uncertain.) The AP1000 design is a "standardized" Generation III+ LWR design that has been

17. Nuclear industry data suggest that the average nuclear energy facility pays approximately $40 million in wages, $16 million in state and local taxes, and $67 million in federal taxes annually, in addition to approximately $470 million annually in sales of goods and services in the local community. Nuclear Energy Institute, Job Creation and Economic Benefits of Nuclear Energy (2016), http://bit.ly/2CYJjBj; *see also* Nuclear Matters, *Nuclear Impact Tool* (tool shows benefits of nuclear power for each state), http://bit.ly/2u3pwse (last visited Dec. 23, 2017).

18. NRC, *Backgrounder on Power Uprates for Nuclear Plants*, https://go.usa.gov/xn4dk (last updated Apr. 8, 2016). One common uprate is the measurement uncertainty recapture uprate (typically 1%-2% increase), which is achieved through the use of state-of-the-art flow measurement devices that reduce the degree of uncertainty associated with feedwater flow measurement and in turn provide for a more accurate calculation of thermal power.

19. U.S. Department of Energy (DOE), Development of Light Water Reactor Fuels With Enhanced Accident Tolerance: Report to Congress (2015).

20. Press Release, Lightbridge Corp., Lightbridge Expected to Benefit From EPA Clean Power Plan (Aug. 5, 2015), http://bit.ly/2zRVHgL.

21. *See*, *e.g.*, 10 C.F.R. §50.69.

22. Diane Cardwell & Jonathan Soble, *Westinghouse Files for Bankruptcy, in Blow to Nuclear Power*, N.Y. Times, Mar. 29, 2017, http://nyti.ms/2nu92qe.

certified by NRC.[23] The AP1000 incorporates passive safety systems (i.e., safety systems that do not require operator action or an electric power supply to keep nuclear fuel in a safe condition) and advanced security features (including protection against aircraft threats). And because all four units have essentially the same design, the lessons learned during construction can be leveraged in scale should there be future orders for more units. Other standard Generation III and Generation III+ reactor designs, such as General Electric's economic simplified BWR (ESBWR), have been certified by NRC and referenced in new reactor applications and licenses, but none are currently under construction.

Reactor technology advances have not been limited to increased efficiency at current plants and refinement of large-scale LWR designs. Small modular reactors (SMRs) of varying designs and configurations are in the development phase. SMRs, which are generally in the 25-400 megawatts (electric) (MWe) range, offer several benefits that may facilitate their use in new markets and for different applications.[24] For example, SMRs can be manufactured and assembled at a factory and transported to a site by rail or truck.[25] SMRs may also be more capable of "load-following" and supporting intermittent renewables, and they may further come with reduced capital costs and the ability to be expanded incrementally as load conditions warrant.[26] Unlike large LWRs, SMRs may be used in areas that have lower electricity demands or smaller distribution systems, or where there are constraints on the amount of cooling water available.[27]

Some SMRs are integral LWRs, which have reactor coolant piping and heat transport systems located inside the reactor vessel, and may be designed with fewer overall systems (e.g., natural circulation that eliminates the need for primary coolant pumps). NuScale, for example, submitted a design certification (DC) application to NRC for its 50 MWe design in late 2016.[28] A COL application referencing the NuScale design is anticipated in 2018. NuScale projects a 51-month construction schedule. This implies first commercial operation of an SMR no earlier than the mid-2020s.

The Tennessee Valley Authority (TVA) has also submitted a site approval application to NRC for an unspecified SMR at the Clinch River site.[29] Although the TVA's effort could resolve a number of key technical and regulatory issues surrounding SMR licensing, the time line to eventual construction and operation of an SMR at Clinch River also is no earlier than the mid-2020s. Development of another SMR design, mPower, has been slowed after the owners failed to identify a customer or obtain new investors.[30]

Other concepts using "advanced" non-LWR technologies, or Generation IV designs, are now attracting investment and are under active development. More than $1 billion in private capital has been invested in SMRs and other advanced nuclear technologies.[31] Terrestrial Energy projects that its integral molten salt reactor (IMSR) will be ready for deployment sometime in the 2020s, though no application involving the design is under active review by NRC.[32] IMSR, as with similar designs, relies on a molten salt that is both the fuel and the coolant, effectively eliminating loss of coolant and meltdown accident scenarios.

TerraPower's Generation IV traveling wave reactor (TWR) is also designed to eliminate the possibility of certain severe accidents; it uses depleted uranium for fuel and has features that render it proliferation-resistant.[33] TerraPower hopes to achieve startup of a prototype in the mid-2020s, followed by global commercial deployment in the 2030s. Other reactor designs under development use thorium, rather than uranium, for fuel (e.g., high-temperature, gas-cooled, and fast-spectrum sodium reactors), which can improve proliferation resistance and reduce the radiotoxicity of spent fuel.[34]

The federal government has supported the development of new nuclear technologies. Under the George W. Bush and Barack Obama Administrations, the U.S. Department of Energy (DOE) provided support for nuclear research and development, which to date the Donald Trump Administration has continued.[35] DOE's Office of Nuclear Energy aims to advance nuclear power as a resource by resolving technical, cost, safety, proliferation, and security barriers through research, development, and demonstration.[36] In the past, DOE's support for new nuclear through Nuclear Power 2010—a partnership between the federal government and the nuclear industry to facilitate construction of advanced reactor designs through several pilot licensing projects—was critical to the licensing and current construction of new large LWRs.[37] Based on that model, DOE established a cost-sharing program to support design and licensing of SMRs. NuScale was selected to participate in

23. *See infra NRC licensing process* in Part II.B.1.
24. NRC, *Small Modular Reactors (LWR Designs)*, https://go.usa.gov/xn4vT (last updated Dec. 20, 2017).
25. DOE Office of Nuclear Energy, *Benefits of Small Modular Reactors (SMRs)*, https://go.usa.gov/xn4vD (last visited Dec. 23, 2017).
26. *Id*.
27. *Id*.
28. NRC, *Design Certification Application—NuScale*, https://go.usa.gov/xn4v8 (last updated Oct. 24, 2017).
29. NRC, *Early Site Permit Application—Clinch River Nuclear Site*, https://go.usa.gov/xn4vN (last updated Dec. 8, 2017).
30. Bruce Henderson, *B&W Scales Back Its Small Nuclear Reactor Project*, Charlotte Observer, Apr. 14, 2014, http://bit.ly/2yYBHMw.
31. Samuel Brinton, *The Advanced Nuclear Industry*, Third Way, June 15, 2015, http://bit.ly/1C8Gmma.
32. Terrestrial Energy, *Home Page*, http://bit.ly/2zSeWX9 (last visited Dec. 23, 2017).
33. TerraPower, *Technologies*, http://bit.ly/1snLCl7 (last visited Dec. 23, 2017).
34. Brian Ade et al., NRC, Safety and Regulatory Issues of the Thorium Fuel Cycle 3-5 (2014) (NUREG/CR-7176).
35. *See, e.g.*, Press Release, DOE, Energy Department Invests Nearly $67 Million to Advanced Nuclear Technology (June 14, 2017), https://go.usa.gov/xn4vS; Press Release, DOE, GAIN Announces Second Round of Nuclear Energy Voucher Recipients (June 26, 2017), https://go.usa.gov/xn4wq.
36. DOE, Nuclear Energy Research and Development Roadmap: Report to Congress (2010).
37. DOE, Nuclear Power 2010 Program: Combined Construction and Operating License & Design Certification Demonstration Projects Lessons Learned Report (2012).

the program and received funding to hasten development of its technology.[38]

To accelerate the pace of nuclear innovation and commercialization, DOE also established the Gateway for Accelerated Innovation in Nuclear (GAIN) to provide nuclear developers with access to technical, regulatory, and financial support.[39] GAIN integrates and facilitates efforts by private industry, universities, and national laboratories to test, develop, and demonstrate innovative nuclear technologies, and to fast track the commercialization of these systems. Southern Company Services and X-energy have each won $40 million in DOE funding toward development of their respective advanced nuclear technologies.[40] Of course, any new technology, even one supported by DOE, ultimately must be licensed by NRC, which is the federal agency responsible for public health and safety with respect to radiological hazards at nuclear plants. That process and related challenges are described further below.

Nuclear technology could eventually extend beyond fission. Fusion reactors have long been the "holy grail" of energy technology. Fusion releases more power than fission. Fusion reactors would be fueled by common elements, would not melt down, and would produce very little pollution or radioactive waste.[41] While the technological promise of fusion is substantial, actual progress has been slow. Yet many companies, including both larger established technology companies and smaller startup companies, are experimenting with different fusion technologies and constructing a range of prototypes.[42] There are varying predictions regarding the pace of fusion development, but most do not expect commercially available fusion energy and deployment on a time line that would meet the DDPP goals for 2050.[43]

B. Current Legal and Regulatory Framework

Federal and state agencies regulate electricity generating plants, establishing a comprehensive regulatory framework that encompasses the ownership, siting, operation, and environmental impacts of nuclear power plants; retail and wholesale electricity rates for electric energy and capacity; and energy market structure and operation. A brief overview of the legal and regulatory framework for nuclear power in the United States follows.

1. Federal Regulation (Safety and Environmental)

□ *Role of federal agencies*. NRC is the independent federal agency responsible for regulating civilian nuclear power reactors. The primary statute governing reactor construction and operation is the Atomic Energy Act (AEA).[44] The AEA provides NRC with exclusive authority for the licensing of nuclear energy technologies (designs) and specific plants, and for the oversight of construction and operation of each facility. Accordingly, entities wishing to certify a design or to construct, own, or operate a nuclear power plant must apply to NRC for a DC or license.[45]

In addition to safety reviews of license applications under the AEA, NRC must consider environmental impacts of licensed projects under the National Environmental Policy Act (NEPA).[46] Applications for construction or operation of facilities, or license renewal, require NRC to publish an environmental impact statement (EIS).[47] Other environmental regulations, such as those addressing air and water emissions, wetland fill, and coastal zone management programs, are covered by other agencies, such as the U.S. Environmental Protection Agency (EPA) or the U.S. Army Corps of Engineers (the Corps), with responsibilities frequently delegated to state agencies (e.g., air and water discharge permits).

DOE is an executive agency with the mission to ensure energy security and economic prosperity by supporting transformative science and technology solutions.[48] In this role, DOE conducts or funds research and development related to nuclear energy and has responsibility for promoting the use of nuclear power. The Nuclear Waste Policy Act (NWPA) assigns DOE the additional responsibility to evaluate Yucca Mountain as the geologic repository for spent nuclear fuel, submit a license application to NRC for construction of a repository, and develop and operate the repository.[49] The NWPA also provides for a kWh charge for nuclear electricity that is paid into the Nuclear Waste Fund to pay repository costs.

To date, DOE has defaulted on its obligations to develop the repository and to take possession and dispose of spent fuel. The Court of Federal Claims has repeatedly found DOE liable for breach of contract, and, as a remedy, DOE must reimburse reactor operators the costs associated with

38. Press Release, DOE, Energy Department Announces New Investment in Innovative Small Modular Reactor (Dec. 12, 2013), https://go.usa.gov/xn4wC.
39. A description of the GAIN program is available at https://go.usa.gov/xn4wg (last visited Dec. 23, 2017).
40. Press Release, DOE, Energy Department Announces New Investments in Advanced Nuclear Power Reactors to Help Meet America's Carbon Emission Reduction Goal (Jan. 15, 2016), https://go.usa.gov/xn4wW.
41. Fact Sheet, Princeton Plasma Physics Laboratory, Fusion Power (Oct. 2011), https://go.usa.gov/xn4wK.
42. Dino Grandoni, *Start-Ups Take on Challenge of Nuclear Fusion*, N.Y. Times, Oct. 25, 2015, http://nyti.ms/1LWRs5U.
43. *See, e.g.*, *Fusion Reactors Economically Viable "Within a Few Decades" Say Experts*, FutureTimeline, Oct. 8, 2015, http://bit.ly/2h0By45.
44. 42 U.S.C. §§2011 et seq.
45. 10 C.F.R. §52.54(b) provides that the commission "may issue a standard design certification in the form of a rule," and any such rule "must specify the site parameters, design characteristics, and any additional requirements and restrictions of the design certification rule." Licenses to own, construct, or operate a nuclear plant are required under either 10 C.F.R. pt. 50 or pt. 52. *See id.* §50.10.
46. 42 U.S.C. §§4321 et seq.
47. *See generally* 10 C.F.R. pt. 51.
48. Under the Energy Reorganization Act of 1974, 42 U.S.C. §§5801 et seq., this role was taken from the Atomic Energy Commission (AEC) and assigned to an agency later subsumed by DOE. The same statute abolished AEC and formed NRC to fulfill the licensing and regulatory responsibilities for nuclear power, the nuclear fuel cycle, and civilian use of radiological materials in industry and medicine.
49. 42 U.S.C. §§10141 et seq.

on-site spent fuel storage. The U.S. Court of Appeals for the District of Columbia (D.C.) Circuit has also prohibited DOE from collecting further fees for the Nuclear Waste Fund in the absence of an active repository program.[50]

The Federal Energy Regulatory Commission (FERC) is an independent federal regulatory agency that regulates wholesale sales of electric energy and capacity as well as interstate transmission of electricity. FERC also regulates and monitors interstate energy markets. FERC's primary legal authority is the Federal Power Act.[51] FERC's role with respect to nuclear plants relates to their electrical output; FERC is not involved in licensing or oversight of nuclear operations. However, FERC regulation of competing generation technologies and transmission projects has significant impacts on price and on the ability of existing nuclear plants to compete with other generators.

Other federal agencies, such as EPA and the Corps, may have a permitting role depending on the site and its environmental attributes. Permitting issues are described further below in the discussion of a state's role in nuclear plant siting.

□ *NRC licensing process*. Before an entity can begin construction or operate a nuclear plant, it must obtain NRC approval. Historically, NRC issued construction permits (CPs) and OLs in two distinct steps. Under the older two-step process in 10 C.F.R. Part 50, construction and operation require separate NRC approvals. First, an applicant must seek the CP authorizing construction. NRC reviews the proposed design and assesses its impacts on the environment at the proposed site. If the agency determines that there is reasonable assurance that the plant can be constructed and operated safely, it issues the CP. The CP holder may then begin construction.

During construction, the CP holder must apply for the OL. The OL review focuses on design details that were previously not completed or that changed during construction. The OL review also considers whether the plant has been constructed in accordance with the CP and applicable safety regulations. Both steps involve an environmental review under NEPA. And at both steps, the public is permitted to raise safety and environmental "contentions" regarding the proposed license and adjudicate those issues—that is, intervene in administrative proceedings before NRC's Atomic Safety and Licensing Board.

As demonstrated in the 1980s, the two-step Part 50 process creates significant regulatory risk. For example, CP holders have flexibility during construction to finalize and adapt a plant's design based on the particular needs that arise during construction. CP holders therefore are permitted to design the plant as it is being built and then submit an OL application based on the "as-built" plant. But the relatively limited scope of NRC's CP review and a proliferation of design changes during construction create uncertainty in the outcome of NRC's OL review. CP holders seeking an OL for an already constructed plant confront the possibility that NRC might decline to license the as-built facility or require expensive retrofits. OL reviews are also subject to potential delays due to the NRC hearing process, as many issues are not resolved until late in the licensing process.

The significant variability among plant designs also reflects the two-step Part 50 process. Each plant was essentially a custom design. All design and siting issues were considered anew in each case. And because NRC did not review and approve a complete design in the CP process, resolution of important safety issues was often deferred until late in the construction process. The variation in final designs made it more difficult for NRC to license and oversee the fleet of custom plants.[52]

In 1989, after notorious construction and licensing delays, NRC established alternative licensing processes in 10 C.F.R. Part 52 to improve regulatory efficiency and add greater predictability to the process. Specifically, NRC developed three new approvals: standard DCs, ESPs, and COLs.[53] A COL replaces a CP and the OL, and authorizes both construction and operation.[54] The safety requirements that a plant must meet are essentially the same under Part 50 and Part 52. The fundamental difference between Part 50 and Part 52 relates to the timing of the regulatory approvals, as well as the scope of the opportunity for the public to request a hearing and participate in the process.

In the Part 52 regulations, NRC took steps to encourage standardization in nuclear plant designs. NRC believed that increased standardization would improve regulatory efficiency, reduce licensing time and uncertainty, and more readily permit the sharing of construction and operating experience.[55] The Part 52 licensing regime incorporated a process for reactor designers (usually the vendor) to submit a generic, essentially complete, *design* to NRC staff for review—separate and apart from applications for new units at a specific site.[56] NRC's review of the DC application addresses the safety and compliance issues associated with the design. That DC includes parameters defining the necessary conditions for sites where the design can be deployed. Because the DC is generic and does not authorize construction or operation, DCs do not trigger the NRC hearing process. The DC is approved through a rulemaking.

Separate from an application for a CP or COL, NRC can issue an ESP for one or more *sites*, based on an assessment of certain environmental impacts of construction

50. In *National Ass'n of Regulatory Util. Comm'rs v. U.S. Dep't of Energy*, 736 F.3d 517, 43 ELR 20254 (D.C. Cir. 2013), the D.C. Circuit suspended licensees' obligation to pay the fees, until such time as DOE reengages in addressing its obligations under the NWPA.
51. 16 U.S.C. §§791a et seq.
52. Nuclear Power Plant Standardization, 52 Fed. Reg. 34884, 34884 (Sept. 15, 1987).
53. *See* 10 C.F.R. pt. 52, subpt. A (Early Site Permits); subpt. B (Standard Design Certifications); and subpt. C (Combined Licenses).
54. *Id.* §§50.10(c), 52.71.
55. Statement on Standardization of Nuclear Power Plants, 43 Fed. Reg. 38954 (Aug. 31, 1978); Standardization of Nuclear Power Plants, 42 Fed. Reg. 34395 (July 5, 1977).
56. 10 C.F.R. §52.12.

and operation. ESPs are valid for 10 to 20 years and can be renewed for an additional 10 to 20 years. The NRC review of an ESP application addresses site safety issues, environmental protection issues, and plans for coping with emergencies, independent of a specific nuclear plant design. The ESP confirms that a site is suitable for a reactor whose characteristics fall within certain defined parameters.

A COL is the license for a *specific unit* at a *specific site*. A COL authorizes both construction and operation upfront, similar to a CP, but eliminating the need for a later OL. Under the AEA, there must be a public hearing opportunity for a COL application. A hearing must be completed prior to license issuance and therefore prior to construction. The COL includes inspections, tests, analyses, and acceptance criteria (the ITAAC) to be completed prior to operation.[57] The licensee will use these methods and criteria to verify that a plant has been constructed according to the design.

Once construction is complete and NRC has verified that the acceptance criteria in the ITAAC have been met, the plant can begin operation without further NRC approval.[58] Verification of ITAAC completion is intended to be a confirmatory action and sufficient in itself to verify the quality of construction. Meeting the ITAAC before operation replaces the old OL and the broad hearing opportunity that went with it. There is still a limited hearing opportunity prior to operation, generally constrained to challenging whether a specific inspection, test, or analysis from the ITAAC has not been completed or whether a defined acceptance criterion has not been met.[59]

An application for a COL may incorporate by reference a DC, an ESP, or both. The advantage of this approach is that the issues resolved during the DC rulemaking or the ESP process are not reconsidered at the COL stage. In fact, those issues can theoretically be resolved long before a COL application for a specific site, greatly reducing regulatory uncertainty and economic risk. On the other hand, if an ESP and DC are not referenced in a COL application, NRC will review the technical and environmental information associated with the design and the site during the COL review—much like under the old Part 50 process. As will be discussed further below, based on experience to date with the revised Part 52 process, opportunities to further refine and streamline still exist.

2. State Regulation (Economic and Siting)

Although the federal government maintains complete control of radiological safety and the "nuclear" aspects of energy generation, states retain traditional power "over the need for additional generating capacity, the type of generating facilities to be licensed, land use, environmental permitting, ratemaking, and the like."[60] Current nuclear power plants therefore operate under state jurisdiction with respect to electricity supply planning (e.g., siting and determinations of need for generating capacity) and economic regulation, as well as wastewater and heat discharges. As part of their energy planning responsibilities, states can advance emissions reduction goals, grid reliability considerations, and other factors.

State laws, state siting approvals, and public acceptance at new sites all complicate license extensions for existing units as well as new nuclear construction. On the planning front, many states require entities seeking to construct a large electricity generating plant, such as a nuclear power plant, to obtain a certificate of public convenience and necessity or similar approval demonstrating a need for the new power generation and assessing its impact on reliability, cost, and the environment. In *Pacific Gas & Electric Co. v. State Energy Resources Conservation & Development Commission*, the U.S. Supreme Court upheld a California law imposing a moratorium on new nuclear power plants in the state pending a determination that the United States had approved a demonstrated technology for the permanent disposal of high-level waste.[61] Relying on the avowed economic purpose for the California moratorium, the Court found that the law fell within the state's traditional authorities and that it therefore did not infringe on the federal government's exclusive authority to regulate nuclear safety.

In the wake of the decision, a number of states passed moratoria on new nuclear construction pending resolution of the waste disposal issue (some of which have since been repealed).[62] States may also indirectly preclude the construction of new nuclear plants by withholding state water withdrawal, water discharge permits, wetland fill, or coastal zone consistency determinations. State support is also necessary for NRC-required security programs and for emergency planning and response efforts.[63]

The new units that began operation or that were under construction in the United States in 2017 are all co-located at existing nuclear sites and have, for the most part, been welcomed in the local communities based on the economic benefits. However, exclusive use of existing sites would be inadequate for the proposed capacity to meet the DDPP goals. Although reactors currently exist at more than 60 sites in the United States, not all of the sites are of sufficient size or have the necessary characteristics (such as cooling water supply) for additional units. The DDPP goals would necessitate more than 100 (and potentially several hundred) new nuclear units, outstripping the capacity of the current reactor sites. Legal barriers and potential opposition to new plants at new sites would need to be identified and addressed on a state-by-state and site-by-site basis.

Environmental statutes, such as the Clean Water Act (CWA)[64] and the Coastal Zone Management Act

57. Ordinarily, these will be standard ITAAC that are included in the DC for the reactor being proposed.
58. 10 C.F.R. §52.103(g).
59. *Id.* §52.103(b).
60. 461 U.S. 190, 212, 13 ELR 20519 (1983).
61. *Id.* at 190.
62. *See, e.g.*, *Wisconsin No Longer Bans New Nuclear Power Plants*, Nuclear Energy Inst., Apr. 6, 2016, http://bit.ly/2yZKL1e.
63. 10 C.F.R. §§73.55(e)(10), (m) (security plans), 50.47(b) (emergency plans).
64. 33 U.S.C. §§1251-1387.

(CZMA),[65] are not insurmountable obstacles to license extensions at existing units or deployment of new reactors at additional sites, but they can complicate the state and federal permitting processes and increase capital expenses (e.g., by requiring construction of cooling towers to reduce thermal discharges). For example, §316 of the CWA regulates discharges of cooling water and intake structures at nuclear facilities.[66] These requirements must be incorporated into a national pollutant discharge elimination system (NPDES) permit that is typically administered by the states, with oversight by the federal government.[67]

These requirements must be met for new plants and can lead to the premature closure of existing nuclear plants. For example, New Jersey negotiated a consent order calling for the closure of the Oyster Creek nuclear plant, in lieu of requiring installation of costly cooling towers.[68] For plants located in the coastal zone, operators must also obtain a coastal consistency certification from the state. New York, for example, withheld the required coastal consistency certification for Indian Point, contributing to its premature closure.[69]

With respect to the economic regulation of electricity generation by states, there are generally two types of state-level regulatory environments:

- Traditional cost-of-service rates, subject to state prudency review
- Deregulated or "merchant" electricity markets

In states with traditional regulated environments, a single entity in a geographic area, typically a utility, has responsibility for electricity generation, transmission, and distribution. In those states, the retail sale of electric energy is generally governed by a state or municipal regulatory agency, such as a public utility commission or a public service commission. These entities normally regulate not only electricity rates, but also the terms and conditions of retail sales and distribution of electric energy by utilities. Prudent costs associated with regulated generation are passed on to retail customers in electricity rates.

In deregulated merchant markets, generation, transmission, and distribution of electricity have usually been unbundled, which means that they are priced and sold separately. A utility may still exist, but its primary responsibility is to distribute electricity purchased from third-party generation entities to customers. Generators sell electricity in competitive markets established by the state or FERC, with the costs of energy, capacity, and ancillary services all transparent and known. Deregulation has allowed non-utilities, also known as independent power producers (IPPs), to enter competitive power markets. The types of generation that will be built in deregulated markets are typically not based on policy considerations, but on the economic costs captured in market prices. Electricity revenues can be significantly influenced by market structures as well as by state or federal subsidies for specific generation types.

As discussed further below, changes to market structures or subsidies can improve the economics for existing nuclear plants in certain markets. For example, in recognition of the importance of existing nuclear facilities to meeting their greenhouse gas emissions reduction goals, some states with deregulated electricity markets have adopted laws that compensate nuclear generators for the value of their emissions-free electricity.[70] With respect to new units, given the higher cost of capital in deregulated markets, only a few new nuclear projects have been proposed in deregulated markets and none have received a license.

III. Pathways to Preserving Currently Operating Nuclear Plants

The first renewal (extension) of the terms of NRC OLs has proven to be technically achievable and cost effective. A second license extension is possible, but unproven. Nuclear power plants currently operating in traditional energy markets typically remain economically viable for the foreseeable future. Nuclear power plants in deregulated markets face economic challenges in addition to the uncertainties of second NRC license renewal. About one-half of the U.S. nuclear fleet is located in traditional cost-of-service energy markets, while the other half operates in merchant markets.

Considering both rate-regulated and merchant environments, the following discussion addresses four recommendations to preserve at least some of the current nuclear fleet to 2050 and beyond: (1) a form of carbon pricing to improve the costs of nuclear relative to fossil generation; (2) reforms in deregulated energy markets to capture the full value of nuclear plants, including low-carbon emissions and grid resiliency; (3) immediate economic support for continued operation and tax incentives for investment in uprates and second license renewal; and (4) measures to ensure the viability of the NRC regulatory process for second license renewal.

A. *Federal Carbon Pricing*

Regulatory policies or programs that impose meaningful restraints on carbon emissions from the electricity sector are critical to meeting the DDPP goals. In rate-regulated markets, policy preferences related to generation type and emissions can be expressed in comprehensive energy plans and in individual permitting decisions for generating plants. The one recently completed unit and the four new

65. 16 U.S.C. §§1451-1466.
66. 33 U.S.C. §1326.
67. In cases where the NPDES program has not been delegated, the federal government will issue the permit. However, in that case, the state must still issue a water quality certification under §401 of the Act. 33 U.S.C. §1341. In most cases, a state will also need to issue a §401 certification to support the NRC license.
68. Matthew L. Wald, *Oyster Creek Reactor to Close by 2019*, N.Y. Times, Dec. 8, 2010, http://nyti.ms/2gVN2G9.
69. Vivian Yee & Patrick McGeehan, *Indian Point Nuclear Power Plant Could Close by 2021*, N.Y. Times, Jan. 6, 2017, http://nyti.ms/2z0K5Lw.
70. *See infra* Part III.B.

units under construction are all located in states or regions with a traditional economic regulatory structure. In deregulated markets, energy planning is ceded to markets for the most part, and carbon pricing is therefore necessary to internalize the costs of fossil generation and the benefits of zero-carbon fuels.

In states with a traditional cost-of-service rate regulatory structure, costs of electricity generation are not the sole driver of the choice of fuel, since prudently incurred costs are recovered in rates. A public utility commission may authorize higher rates associated with certain generation units based on factors such as the long-term value of diversity in generation supply as a hedge against future changes in fuel costs or the societal benefits of zero-carbon nuclear power. Moreover, nuclear plants now operating will have recovered a significant portion, if not all, of their original capital costs over their operating life to date, improving the economics for continued operation through any renewed license term.

In contrast, in merchant markets, electricity prices have been driven down by low-cost natural gas and, to a lesser extent, by renewables that are subsidized by production tax credits. State renewable portfolio standards also generally exclude nuclear power, essentially mandating a certain market share for renewables at the expense of other generation sources, even carbon-free nuclear generation. In this setting, a form of carbon pricing, such as a carbon tax or a cap-and-trade system for carbon emissions, may be essential for continued operation of a significant part of the existing nuclear fleet.

Unlike in regulated markets, merchant generators must make decisions based on projections of the economic competitiveness of their generation facilities, taking into account fuel costs, operations and maintenance costs, utilization rates, existing resource mix, and capacity values across a region. Notably, the recently announced nuclear plant closures for economic reasons involve plants located in deregulated markets. Internalizing carbon costs, such as through a federal carbon tax on fuel, would directly improve the economics of nuclear power relative to fossil fuel-fired generation. The federal government—preferably through permanent legislation, but alternatively through an administrative program—should develop a framework for pricing the costs of carbon emissions.

One measure for assessing economic competitiveness is avoided cost, which measures the cost to generate the electricity that would be displaced by a new generation project. Avoided cost can be converted to a level annualized value that is divided by the project's average annual output to develop a levelized avoided cost of electricity (LACE). Although sensitive to fuel costs, environmental regulations, tax credits, dispatch duty cycle (the amount of time a unit is generating electricity), and regional variations, the average levelized cost of electricity (LCOE) of new generation under consideration can be compared to the average LACE for a generation type to give a sense of economic competitiveness of existing generation.

According to the EIA, the capacity-weighted average LACE for unsubsidized advanced nuclear in 2022 is $61.4 per megawatt hour (MWh).[71] However, the capacity-weighted LCOE for conventional combined-cycle natural gas-fired facilities is $56.4/MWh. And the LCOE with tax credits for wind and solar photovoltaics (PV) are $50.9/MWh and $58.2/MWh, respectively. This suggests that nuclear power is more costly at present than natural gas generation given current low natural gas prices and also suffers when compared to new wind and solar PV, particularly given tax credits or other subsidies for those types of generation. An ongoing nuclear industry effort, *Delivering the Nuclear Promise*, may deliver substantial cost reductions at existing nuclear plants through improved efficiency and increased reliability.[72] But in the near term, it would likely take increases in natural gas prices to shift relative costs in nuclear power's direction.

A federal carbon tax would not provide a direct benefit to nuclear power. Instead, it would indirectly benefit nuclear relative to carbon-emitting (principally fossil fuel) generators by increasing the cost of electricity from those sources. Nonetheless, the EIA data suggest that the benefits of a carbon tax may be insufficient to avoid closures of existing nuclear plants so long as other market-distorting subsidies remain in place. For example, the production tax credit for wind generation encourages wind producers to sell electricity at a loss to earn tax subsidies. When demand for electricity is low, this can result in negative pricing. A carbon tax would not necessarily benefit existing nuclear power in this circumstance.[73]

Given that the assumptions for the DDPP High Nuclear and Mixed Scenarios involve substantial amounts of both nuclear and renewable capacity, other policy measures may be needed to prevent renewable generation from causing the closure of nuclear plants (and their replacement by natural gas). Several of these policies are discussed in the next sections. Any remaining economic gap for nuclear would need to be justified by operational and planning considerations, such as the scale of existing nuclear plants, the plant's expected useful life, the desirability of maintaining generation diversity, and the present need for dispatchable (non-intermittent) capacity.

One alternative to a carbon tax is a carbon cap-and-trade system, in which carbon emitters would obtain allowances to emit certain levels of carbon, but could sell or trade the allowances to others that have reached their cap. As the cap shrinks or the load grows, the price of carbon should rise as allowances become more valuable. This too would increase the value of zero-carbon nuclear power relative to fossil fuel-fired generation. But the benefits still may not allow

71. EIA, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016 (2016).
72. Nuclear Energy Institute, Delivering the Nuclear Promise: Advancing Safety, Reliability, and Economic Performance (2016), *available at* http://bit.ly/2z4IguA.
73. Frank Huntowski et al., The NorthBridge Group, Negative Electricity Prices and the Production Tax Credit (2012), http://bit.ly/2hpFQyS.

nuclear to overcome the economic advantages of natural gas, wind, and solar based on low fuel costs, subsidies, and renewable portfolio standards.

The Clean Power Plan (CPP), promulgated by the Obama Administration in 2015, included mechanisms that would tend to help nuclear. But the CPP was stayed by the Supreme Court in 2016 and, as of this writing, the Trump Administration is taking steps to cancel it entirely (though it is possible that a future administration may attempt to revive it). Under the CPP's mass-based approach, a state must simply meet a cap, measured in tons of carbon dioxide. This approach would implicitly recognize nuclear plants' compliance value and would create indirect incentives to preserve existing nuclear capacity.

Under the CPP's rate-based plan, nuclear could play an important role if a state created emission rate credits that included new and uprated nuclear capacity. Sale or trading of emission rate credits could result in additional payments to nuclear plant owners for zero-emission generation. The CPP, however, is insufficient as proposed to provide meaningful support for existing nuclear power plants, much less prompt development of new plants. As discussed further below, either the U.S. Congress or EPA should develop a carbon program even more restrictive than the CPP to spur nuclear to the levels contemplated by the DDPP projections.

In the absence of a federal program that imposes limits on or prices carbon emissions, many existing nuclear plants (particularly those in merchant markets) are likely to retire before the end of their current OLs. This will make achieving the DDPP goals that much more difficult. The federal government should develop a comprehensive program—ideally, a permanent legislated solution—that imposes meaningful restraints on carbon emissions from the electricity sector, which would be a critical step to meeting the DDPP goals.

B. Reforms in Competitive Energy Markets

As discussed above, competitive energy markets do not presently internalize carbon costs. Nor do these markets necessarily pay generators for all the attributes that they provide to the grid.[74] Achieving the DDPP goals will require market reforms to fully value the benefits of nuclear power.

Deregulated energy markets, which account for approximately two-thirds of wholesale electricity sales, were intended to allow market forces to shape energy policy—indeed, much of energy policy is reliant on the market. But these markets have inherent structural inefficiencies and externalities, often the result of public policies that generally favor natural gas and renewables over nuclear generation. It is true that current low natural gas prices are driven by a surge in supply of low-cost shale gas based on technical advances in extraction. These low natural gas prices squeeze out both coal generation, which is positive for decarbonization, and nuclear, which is not.

But it is also true that energy markets do not routinely address valuable attributes of nuclear generation, such as low-carbon emissions, diversity of fuel supply, capacity availability, reliability and resiliency, and the ability to store fuel at sites (e.g., ability to avoid problems with natural gas supply such as those that occurred in the upper Midwest during the Polar Vortex event of January 2014).[75] Renewable portfolio standards and investment or production subsidies (policies imposed on the market) also distort the markets with their narrow focus on wind and solar and exclusion of nuclear.

There are approaches that can be implemented at the state, regional, or federal level to preserve existing nuclear assets in deregulated energy markets. PJM, a regional transmission operator, restructured its capacity market to ensure that generating units perform when needed by enhancing incentives and penalties. This increases the value of reliable nuclear power. In New York, a reliability support services agreement between the operator of the Ginna nuclear plant and Rochester Gas and Electric provided a temporary financial lifeline. And in Ohio, the Public Utilities Commission has repeatedly taken action to help preserve existing nuclear generation in that state.

The federal government is also taking the first steps toward market reforms to value certain attributes of nuclear power. FERC has considered (but, as of this publication, has rejected) a rulemaking proposed by DOE that would require system operators to develop pricing guidelines for "grid reliability and resiliency resources," with a focus on providing additional revenue for generation units, like nuclear power plants, that store more than 90 days of fuel supply on-site.[76] According to DOE, if adopted by FERC, the rule would at least partially rectify the failure of market pricing to capture all of the benefits that nuclear power plants and certain other generators provide to the grid.[77] This proposed rule is controversial and its adoption, at least in the form presented by DOE, is uncertain. But in any event, fundamental market changes are necessary to price all of the benefits of nuclear power and create the conditions needed to achieve the DDPP goals. FERC, regional transmission operators, and states should continue and then complete ongoing efforts to fully value the benefits of nuclear power.

For example, PJM is evaluating various frameworks to reflect the costs of carbon emissions in wholesale energy market prices.[78] PJM concluded that a regional carbon pricing framework is preferred because it maximizes market efficiency, but recognized the challenge of having all states within the PJM footprint agree to take such policy

74. Grid Resiliency Pricing Rule, 82 Fed. Reg. 46940, 46942 (proposed Oct. 10, 2017).

75. Mark Flanagan, *Why Nuclear Is Resistant to Fuel Supply Disruptions in Extreme Weather*, Nuclear Energy Inst., July 22, 2014, http://bit.ly/2z160ji.

76. Grid Resiliency Pricing Rule, 82 Fed. Reg. at 46940.

77. *Id.*

78. PJM, Advancing Zero Emissions Objectives Through PJM's Energy Markets: A Review of Carbon-Pricing Frameworks (2017).

action.[79] PJM also evaluated a subregional carbon pricing framework, which would be characterized by a carbon price subregion that includes states that have elected to implement a uniform carbon price and a non-carbon price subregion where no such policy action has been adopted. The subregional framework can lead to significant complexity and potential implementation challenges.[80]

Similar efforts are underway elsewhere, including in ISO New England and New York Independent System Operator (NYISO).[81] While the nascent regional efforts could eventually lead to markets that reflect the cost of carbon emission, they may not be complete in time to prevent early retirement of existing nuclear units. In fact, the regional efforts have been to some degree in response to state efforts to preserve existing nuclear.

New York developed a program requiring distribution companies to acquire zero emissions credits (ZECs) from economically struggling nuclear plants based on the difference between the social price of carbon and existing electricity prices. Although New York participates in the Regional Greenhouse Gas Initiative cap-and-trade program, allowance prices there fall far below the social cost of carbon and provide insufficient value to the emissions-free attributes of nuclear power. In response, in part, to the announced closure of several nuclear plants, the New York Public Service Commission issued an order in August 2016 adopting a first-of-a-kind clean energy standard.[82] New York State is calling for one-half of all electricity in the state to come from renewable and nuclear sources by 2030.

The clean energy standard promotes all low-carbon generation, including nuclear and renewables. Under the standard, New York's investor-owned utilities and other energy suppliers must provide payments for the intrinsic value of carbon-free emissions from nuclear power plants by purchasing ZECs. This program was aimed at preventing closure of upstate New York nuclear units by providing a 1.7¢/kWh subsidy for nuclear.[83] (The order also provides up to a 4.5¢/kWh subsidy for new renewable generation.[84])

The state of Illinois also created a ZEC program to effectively subsidize nuclear power generation and corresponding sales of nuclear power in the wholesale market. The state's Future Energy Jobs Act grants ZECs to certain qualifying energy-generating facilities, likely to be two nuclear power plants in Illinois.[85] Utilities that sell electricity to consumers must purchase ZECs from the qualifying power plants, and those utilities will pass the costs of ZECs onto their customers. The result is proceeds from the sale of ZECs that will give nuclear units a benefit when pricing energy in the wholesale market relative to competing energy producers that do not receive ZEC payments. Although controversial, the program has worked as intended, leading the operator of two nuclear stations in Illinois to reverse plans to prematurely close those units.[86]

Opponents have challenged both the New York and Illinois ZEC programs in federal court.[87] In both cases, the plaintiffs argued that the Federal Power Act preempts the programs because they intrude on the exclusive authority of FERC to regulate "the sale of electric energy at wholesale in interstate commerce."[88] Under the Supremacy Clause of the U.S. Constitution, states may not interfere with FERC's capacity-auction policies by setting or altering wholesale rates for electricity obtained by in-state generators.[89] The complaints also alleged a violation of the dormant Commerce Clause, arguing that the program benefits only in-state nuclear plants and therefore "disadvantages" out-of-state generators that sell in the interstate electricity market. Under the dormant Commerce Clause, states generally may not favor in-state generation by discriminating against out-of-state generation.[90]

Both challenges failed in federal district court.[91] Though the two courts differed somewhat in their reasoning, they both found the ZEC programs distinguishable from the subsidy program rebuffed by the Supreme Court in *Hughes v. Talen Energy Marketing*.[92] Both courts characterized the ZEC programs as similar to renewable energy programs that FERC earlier had found not to interfere with its jurisdiction over wholesale markets. And both courts viewed the ZEC programs as not discriminating against out-of-state nuclear plants. Though legal uncertainties remain, these early successes with ZEC programs provide a model framework that other states with at-risk nuclear plants should consider in the near term.[93]

79. *Id.* at 2, 5.
80. *Id.* at 5-11.
81. Nicole Bouchez, NYISO's Integrating Public Policy Project Update, Presentation to the NYISO Market Issues Working Group (Jan. 31, 2017), http://bit.ly/2lzf0J9; Mark Karl, ISO Comments on IMAPP: Perspectives and Observations on Stakeholders' IMAPP Proposals, Presentation to New England Power Pool Integrating Markets and Public Policy (IMAPP) Plenary Meeting No. 7 (Jan. 25, 2017), http://bit.ly/2iiRXgQ.
82. Vivian Yee, *Nuclear Subsidies Are Key Part of New York's Clean-Energy Plan*, N.Y. Times, July 20, 2016, http://nyti.ms/2aUDN3a; Press Release, New York State, Governor Cuomo Announces Establishment of Clean Energy Standard That Mandates 50 Percent Renewables by 2030 (Aug. 1, 2016), https://go.usa.gov/xn2cQ.
83. *See* Order Adopting a Clean Energy Standard, New York Public Service Commission, Nos. 15-E-0302, 16-E-0270, at 20 (Aug. 1, 2016) (setting ZEC price at $17.48/MWh for the first two-year tranche), https://go.usa.gov/xn2cE.
84. James Conca, *Cuomo Accepts Nuclear Is Clean for Upstate New York*, Forbes, Aug. 2, 2016, http://bit.ly/2iikP9b.
85. *See* S.B. 2814, 99th Gen. Assem., Pub. Act 099-0906 (Ill. 2016), https://go.usa.gov/xn2xD.
86. Cynthia Dizikes, *Power Play: Energy Legislation Stalled, State's Electricity Future Up for Grabs*, Chi. Trib., June 5, 2015, http://trib.in/2zl0ZoO; Ted Caddell, *Exelon's Crane Reports "Monumental Year,"* RTO Insider, Feb. 8, 2017, http://bit.ly/2z6DXAW.
87. Coalition for Competitive Elec. v. Zibelman, 2017 WL 3172866, No. VEC-16-8164, 47 ELR 20092 (S.D.N.Y. July 25, 2017), *on appeal*, No. 17-2654 (2d Cir.); Village of Old Mill Creek v. Star, 2017 WL 3008289, Nos. MSS-17-1163 and MSS-17-1164 (N.D. Ill. July 14, 2017).
88. 16 U.S.C. §824(b)(1).
89. U.S. Const. art. VI, §2; *see also* Hughes v. Talen Energy Mktg. LLC, 136 S. Ct. 1288, 1297, 46 ELR 20078 (2016) (finding that a Maryland program guaranteeing local generators a minimum price per MW produced infringed on FERC's exclusive jurisdiction to set wholesale energy rates).
90. *See* Wyoming v. Oklahoma, 502 U.S. 437 (1992) (striking down Oklahoma law requiring 10% of electric utilities' coal purchases to be from in-state suppliers).
91. *See supra* note 87.
92. *Hughes*, 136 S. Ct. at 1297.
93. John Funk, *FirstEnergy Nuke Subsidy Testimony Begins, $300 Million a Year at Stake*, Plain Dealer, Apr. 26, 2017, http://bit.ly/2z6Hzmu.

As an alternative to ZEC-like programs, state legislatures or utility commissions could impose a nuclear portfolio standard that would co-exist alongside existing renewable portfolio standards or broaden the scope of existing renewable portfolio standards to incorporate all "clean" energy, including nuclear power.[94] While imposition of portfolio standards that include nuclear would require new legislation in many states, such standards would create strong incentives to retain existing nuclear plants and should improve the economic case for second license renewal.

C. *Tax Incentives*

Given the need for action in each state or region that currently hosts a nuclear plant and the likely opposition to such programs from other generators, a state-by-state or regional approach may be inadequate to retain enough currently operating plants to meet the DDPP goals. As an alternative or supplement to carbon pricing and market reforms, direct federal subsidies or federal nuclear production tax credits for existing plants—similar to the tens of billions of dollars in subsidies and credits currently provided for renewable generation—would provide an immediate economic boost for existing units, no matter the market.[95]

According to the EIA, in 2013, direct subsidies to solar and wind were $2.4 billion and $4.3 billion, respectively, while nuclear received only $0.037 billion in direct subsidies.[96] Solar and wind also received far more in tax-related subsidies (e.g., production tax credits) than nuclear. In total, renewables received 72% of all electricity-related federal subsidies.[97] (The EIA data also show federal research investments in energy technology, including significant investments in nuclear.

The nuclear research investments are principally directed to development of advanced technologies and may be helpful in the future, as discussed later in this Article. But for now, these research and development investments do not reduce the current costs of electricity from nuclear and therefore are not direct subsidies that would influence the current market or current operational decisions.) Congress should consider production tax credits for nuclear generation to prevent early retirements by "topping off" economic returns for nuclear generators. And Congress should also consider investment tax credits to provide an incentive for current operators to invest in both power uprates and second license renewal.

D. *NRC Second License Renewal*

By 2050, absent second license renewal, nearly all currently operating nuclear units will be retired. To meet the DDPP goals, a significant percentage of the current fleet will need to continue operating past 60 years. Beyond the economic case for preserving existing nuclear generation, there is the need to extend the NRC licenses for existing plants beyond the current licensed life. Under the AEA, NRC may grant license extensions for existing units beyond both the original 40-year license term and the 20-year first renewal period.[98] A "second license renewal" will extend the licensed life from 60 years to 80 years. To date, only Dominion and Exelon have announced plans to seek second license renewal for a few select plants, though others are expected to do so.[99] However, it is unlikely that licenses for the entire existing fleet will be extended by second license renewal.

No new laws or policies are necessary for NRC to allow second license renewal; it is permitted by the agency's existing regulations.[100] However, efforts are ongoing to confirm the technical bases for subsequent license renewal, particularly focused on equipment aging issues. Support for research is currently provided by industry through the Electric Power Research Institute's Long Term Operations Program[101] and by DOE through its Light Water Reactor Sustainability (LWRS) Program.[102] Congress should continue and increase funding to DOE and NRC to support research and licensing and regulatory process improvements to reduce the technical, economic, and regulatory uncertainty associated with operation beyond 60 years.

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94. Jessica Lovering, *Can States Expand Renewable Portfolio Standards to Include All Low-Carbon Technologies?*, Greentech Media, June 1, 2016, http://bit.ly/1r2Zu5D.
95. The production tax credits for nuclear power in the Energy Policy Act of 2005 are only available to new nuclear plants, not existing units.
96. EIA, Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013 (2015), *available at* https://go.usa.gov/xn2ar. The requirements in the Price-Anderson Act that apply to nuclear are not subsidies for this analysis. The statute requires nuclear generators to maintain private insurance for public liability in the event of a nuclear incident. The statute sets liability limits, but these have never come into play in the United States. And these limits apply only after a substantial amount of money is available for compensation of injuries through insurance, a secondary layer of retrospective premiums assessed on domestic nuclear generators, and supplementary compensation available from Parties to the international Convention on Supplementary Compensation (to which the United States is a Party).
97. *Id.* at xviii. More than three-quarters of the subsidies going to renewables were direct expenditures or tax expenditures targeting upfront capital investments. *Id.*
98. *See* NRC, *Subsequent License Renewal Background* (explaining that there are no specific limitations in the AEA or NRC's regulations restricting the number of times a license may be renewed), https://go.usa.gov/xn2ag (last visited Dec. 23, 2017).
99. Press Release, Exelon Corp., Peach Bottom Seeks Extended Operating License (June 7, 2016), http://bit.ly/2z2jMC6; Press Release, Dominion Virginia Power, Dominion Informs NRC of Intent to Seek Second License Renewal for Surry Power Station (Nov. 6, 2015), http://prn.to/2h01Q6t. These plants together account for less than 5% of current U.S. nuclear generation.
100. *See* 10 C.F.R. §54.31(d) (stating that, for plants that have already received a renewed license, "a renewed license may be subsequently renewed in accordance with all applicable requirements").
101. According to the Electric Power Research Institute, its Long Term Operations Program is conducting an array of research and development activities to ensure that the public, nuclear plant owners, regulatory agencies, and all interested stakeholders have the information needed to make sound decisions regarding the ability of a nuclear plant to sustain safe, reliable, and economic operations through extended life-spans. A description is available at http://bit.ly/2zkWhHl (last updated Apr. 5, 2017).
102. According to DOE, the LWRS Program is developing the scientific basis to extend existing nuclear power plant operating life beyond the current 60-year licensing period and to ensure long-term reliability, productivity, safety, and security. The program is conducted in collaboration with national laboratories, universities, industry, and international partners. A description is available at https://go.usa.gov/xn2aK (last visited Dec. 23, 2017).

Congress should implement new policies to encourage licensees to make the potentially substantial investments necessary to refurbish or replace equipment in existing nuclear plants. For example, investments in wind, solar, and other renewable energy projects currently benefit from a federal investment tax credit and an election to convert the credit into a cash grant from the Treasury Department. As noted previously, nuclear power plants do not currently benefit from these incentives. Congress could permit advanced depreciation to encourage licensees to invest in long-term operations at existing plants. Production tax credits for nuclear generation under a second renewal term should spur more licensees to seek an 80-year term.

IV. Pathways to Developing New Nuclear Capacity

As noted at the outset of this Article, achieving the DDPP goals for either the High Nuclear or Mixed Scenario will require much more than merely preserving some of the existing U.S. nuclear fleet. Both DDPP scenarios involve deployment of a substantial amount of new nuclear generation capacity to replace retiring capacity and add new capacity. Supported by appropriate economic and regulatory policies and a sustained national commitment, the DDPP goals are challenging but achievable.

The following discussion addresses five recommendations to promote development of new nuclear generation at the scale assumed: (1) improvements in the cost competitiveness of new nuclear relative to fossil generation; (2) legislative changes to increase access to capital for new nuclear construction; (3) substantial investment in development, licensing, and deployment of advanced nuclear technologies; (4) increased standardization and serial construction of new reactors; and (5) continued evolution and refinement of the NRC licensing process.

A. Cost Competitiveness of New Nuclear

Stimulating new nuclear development will require improvements in the cost competitiveness of nuclear relative to other generation. Based on June 2016 LCOE estimates reported by the EIA,[103] advanced nuclear is expensive relative to other energy options.[104] The LCOE for advanced nuclear is significantly higher than that for onshore wind, solar PV, natural gas, geothermal, and hydropower. The economic gap is exacerbated for natural gas with no carbon pricing and for renewables where tax credits are focused exclusively on wind and solar.

Nonetheless, advanced nuclear can be cost-competitive with other baseload generation technologies, particularly when the capital costs of nuclear are considered over an assumed operating life of 60 to 80 years and the social cost of carbon is reflected in the cost of generating electricity with fossil fuels.[105] New nuclear plants (as with current generation nuclear plants) benefit from relatively low and stable fuel costs, as well as significant economies of scale for operation and maintenance costs over a typical operating life. The EIA estimates for advanced nuclear LCOE are substantially lower than for coal with carbon capture and sequestration, utility-scale solar thermal, and offshore wind—particularly before renewable tax credits.[106]

The combination of the now-expired production tax credits for new nuclear plants provided in the Energy Policy Act of 2005[107] and widespread anticipation at the time of a carbon cap-and-trade program led generators within a few succeeding years to apply to NRC for licenses for more than 25 new nuclear units, in both regulated and merchant environments.[108] While most applications were later withdrawn following the failure of proposed federal legislation to establish a cap-and-trade program and the collapse of natural gas prices, this combination of incentives led to NRC licenses being issued for new units at Vogtle in Georgia, V.C. Summer in South Carolina, Fermi in Michigan, South Texas in Texas, W.S. Lee in South Carolina, and Levy County in Florida. This experience demonstrates that there is appetite for new nuclear under the right economic conditions. But to ensure that the large capital investment for a new nuclear plant can be recovered, nuclear developers would need to be able to reasonably forecast economic conditions for at least the initial decades of operation.

As already discussed, carbon pricing—no matter the form—would improve the comparison of new nuclear to fossil fuels. However, the EIA projected that even with implementation of the Obama Administration's CPP (and no other action), nuclear generation would remain flat through 2050—with new plants only offsetting retirements of existing plants.[109] Therefore, Congress—or, less ideally, EPA—should consider a program even more restrictive than the CPP to spur nuclear to the levels contemplated by the DDPP projections.

Federal or state governments should also consider subsidies for nuclear generation comparable to direct subsidies for renewables that improve, if not reverse, the cost comparison relative to renewables.[110] Investment or production tax credits, discussed above for existing plants, also improve the economics of new plants and should be offered to nuclear units. However, the projected price for carbon

103. EIA, *supra* note 71.

104. *But see* Energy Options Network, Energy Innovation Reform Project, What Will Advanced Nuclear Power Plants Cost? A Standardized Cost Analysis of Advanced Nuclear Technologies in Commercial Development (2017) (the average LCOE for advanced reactors is projected to approach $60/MWh for the "nth" of a kind plant), http://bit.ly/2hqLCk2.

105. International Energy Agency & Nuclear Energy Agency, Projected Costs of Generating Electricity 14 fig. ES.1 (2015 ed.); *see also supra* note 71.

106. *See supra* note 71.

107. Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594.

108. NRC, *Combined License Applications for New Reactors*, https://go.usa.gov/xn2af (last updated Sept. 15, 2017).

109. Thad Huetteman & Laura Martin, *Clean Power Plan Accelerates the Growth of Renewable Generation Throughout United States*, Today in Energy, June 17, 2016, https://go.usa.gov/xn2aA.

110. Ted Nordhaus et al., *Carbon Taxes and Energy Subsidies: A Comparison of the Incentives and Costs of Zero-Carbon Deployment*, Breakthrough, Sept. 12, 2012, http://bit.ly/2z1Dm3T.

or the value of subsidies or tax credits would need to be relatively high and certain for an extended period.

B. *Financing Capital Costs of New Reactors*

Capital costs for new nuclear projects relative to new gas generation (including conventional and advanced combined-cycle and combustion-turbine generation) are substantial. Financing the capital costs for nuclear—particularly given the long time line to operation—presents a significant challenge to any entity that would build, own, and operate the facility. Significant reductions in capital costs or improved access to capital at favorable terms would likely be necessary to spur the new nuclear construction needed to meet the DDPP goals.

In the United States, energy projects are typically developed and operated by private entities (usually investor-owned, for-profit ventures). Electricity generation companies, even the current large nuclear fleet operators, do not necessarily have the robust market capitalization that would support highly leveraged, long-term projects, particularly ones that will be viewed as financially risky.[111] This presents a very different scenario than exists in countries like China, India, and the United Arab Emirates, where new nuclear construction is now in progress in furtherance of national policy goals. In these countries, state-backed financing or financing by state-owned entities building the facilities is the norm.

At the state level, in cost-of-service rate-regulated environments, state legislatures and regulatory bodies can ease financing burdens by allowing some form of early cost recovery through rates for new nuclear plant development costs.[112] This includes licensing and financing costs and construction progress costs. Cost recovery was a problem for many current nuclear plants, particularly in the very high interest rate environment that existed in the 1980s. No recovery was allowed until the plant was completed and put into commercial operation. Some states have confronted this issue and allowed cost recovery, subject to prudency review by a public utility commission, for current projects and projects still in development.

For example, Georgia, Florida, and South Carolina have allowed recovery for construction work in progress (CWIP).[113] This authorizes utility companies to collect funds from customers to offset construction costs prior to completion of a project. Recovering costs during construction reduces finance costs and therefore lowers the project cost and the customer rate base once the facility is finished and goes into operation. For the Vogtle project, CWIP is expected to reduce overall project costs by around 10%, saving more than $300 million in financing costs.[114] However, if a project is abandoned before completion, as may be the case at V.C. Summer in South Carolina, ratepayers would be unable to recover the value of construction costs already paid. This dynamic may discourage other states from authorizing CWIP in the absence of additional ratepayer protections.

Where cost-of-service rate recovery is not available, many policy options and financing strategies could be applied to or adapted for new nuclear projects by legislatures, regulatory bodies, utilities, developers, and investors. Possible strategies include tax/equity models used for financing of renewable projects; sale-leaseback models; or other innovative approaches to enhance the ability of developers to obtain financing and to hedge the inherent risks in such large and long leadtime projects. Support for new projects through long-term power purchase agreements would provide investors, operators, and banks some measure of assurance of revenues and hence long-term economic viability.

State legislatures and utility commissions could also adopt other approaches, such as public financing options and infrastructure support, to assist private entities investing in new nuclear projects. This approach is often used for civic enterprises. Similar support for critical infrastructure projects that promote jobs and help to achieve clean air and carbon objectives would be justifiable. These approaches may be particularly useful, and even necessary, for first-of-a-kind technologies.

The federal government has also previously offered loan guarantees for new nuclear projects that use new technologies. This approach was adopted in the Energy Policy Act of 2005.[115] Southern Company negotiated a loan guarantee with DOE for the new units at Vogtle, though this subsidy was not a factor in the company's decision to move forward with the project.[116] The loan guarantees were ultimately limited in scope because of protracted negotiations with DOE and the availability of favorable terms and conditions in the marketplace for rate-regulated projects. Moreover, developers in merchant environments struggled to reach

111. *See More Funds for Loan Guarantees*, World Nuclear News, Dec. 10, 2010 (noting that, at the time, the cost of Southern Company's project to construct Vogtle Units 3 and 4 is $14 billion, while Southern's market capitalization is $32 billion), http://bit.ly/2iiehHr; Moody's Investor Services, Moody's Corporate Finance—New Nuclear Generating Capacity: Potential Credit Implications for Investor Owned Utilities (2008), *available at* http://bit.ly/2A6YT93.

112. There are currently 15 states—California, Connecticut, Hawaii, Illinois, Kentucky, Maine, Massachusetts, Minnesota, Montana, New Jersey, New York, Oregon, Rhode Island, Vermont, and West Virginia—that have imposed restrictions on the construction of new nuclear power plants. Prior to new nuclear construction in those states, the restrictions would need to be satisfied or removed.

113. Robert C. Volpe, *The Role of Advanced Cost Recovery in Nuclear Energy Policy*, 15 Sustainable Dev. L. & Pol'y 28 (2015), *available at* http://bit.ly/2zUIXWF.

114. This is an estimate that has been published by the plant owner, Georgia Power Company, based on initial cost estimates. *See* Georgia Power, *Construction Financials*, http://bit.ly/2yiYMK8 (last visited Dec. 23, 2017). With the increase in construction costs for the Vogtle project, the value of CWIP has also increased.

115. Among other things, the Energy Policy Act of 2005 adopted 42 U.S.C. §16513, which authorizes guarantees for projects that "avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases" and "employ new or significantly improved technologies as compared to commercial technologies in service in the United States at the time the guarantee is issued." *See also* DOE Loan Programs Office, *Section 1703 Loan Program*, https://go.usa.gov/xn2jq (last visited Dec. 23, 2017).

116. Press Release, Southern Company, Southern Company Subsidiary, DOE Finalize Vogtle Nuclear Project Loan Guarantees (Feb. 20, 2014), http://prn.to/2iiYXul.

final loan guarantee agreements with DOE due to stringent cost requirements established by the government's Office of Management and Budget, such as charging a nearly $900 million fee for a $7.75 billion loan.[117] To be successful at the scale contemplated for the High Nuclear Scenario, Congress and DOE should expand the federal loan guarantee program to be far more extensive in scope, more financially aggressive, and less costly for the project developers than the 2005 program.

In the 2005 Act, Congress also provided a limited scheme of "standby support" for project delays for six plants.[118] Under the program, the first two plants to start construction after the 2005 Act are eligible to recover 100% of costs resulting from *government* delay, up to $500 million per plant. The next four plants are eligible to recover 50% of the costs of government delays beyond six months, up to $250 million per plant.[119] Within a regulatory framework where there is some measure of mitigation for significant uncertainties, a developer will be in a much better position to recommend projects to economic regulators, shareholders, and the investor community. The availability of protections for regulatory delay allows the developer to focus on the project's merits—including the scale, reliability, operating lifetime, projected operations and maintenance and fuel costs, and the benefit of no-carbon generation. Congress could expand this program to cover all new nuclear construction.

Minor changes to the AEA could also increase opportunities for investment in and private financing for new nuclear projects. The AEA currently prohibits NRC from issuing a reactor license "to an alien or any corporation or other entity if the Commission knows or has reason to believe it is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government."[120] This was a provision adopted in the 1950s, when the United States had an effective monopoly on nuclear technology. It was designed to prevent the proliferation of nuclear materials and nuclear technology. Although NRC has applied the statute to allow foreign entities to invest in projects, such as by holding interests in a plant or an operator, it has blocked projects that would be indirectly owned by a foreign nuclear operator.[121] Because of the current statutory restriction, NRC also scrutinizes plans for foreign financing for new nuclear plants and transfers of licenses for operating plants.

In today's global nuclear energy market, with international safety, security, and nonproliferation conventions, the AEA foreign ownership, control, and domination provision is outdated and unnecessary to serve its original purpose. The statute unnecessarily forecloses important sources of capital and nuclear operating experience, such as major global financial institutions and major international nuclear vendors and operators. Amendments to the AEA in this area should be part of any initiative to restructure the legal framework to facilitate new nuclear development. Importantly, striking this restriction from the AEA does not eliminate consideration of national security risks. Even with a legislative change, the statute would retain the separate provision that prohibits NRC from issuing a license if it finds that the license would be "inimical" to the common defense and security of the United States.[122]

C. *Advanced Nuclear Technology Development and NRC Certification Costs*

Investment in development, licensing, and deployment of advanced nuclear technologies are essential to meeting the DDPP assumptions for either the High Nuclear or Mixed Scenario. As discussed above, NRC has certified several advanced reactor designs with passive safety systems. To meet the decarbonization goals for 2050, these certified designs are available and would be the most likely to be deployed in the near term. Newer technologies, including SMR technologies as discussed above, may offer even greater potential for rapid and economic deployment. But those technologies are not yet fully developed and licensed. Significant investment in the commercialization and licensing of these new nuclear technologies is still required to realistically support deployment of SMRs by the 2020s and other advanced technologies by the 2040s.

The development of advanced nuclear designs will require investment in technology development, detailed engineering work, comprehensive testing, and, ultimately, marketing. In addition, there are significant up-front costs associated with the NRC DC process. Obtaining investment funding in venture capital markets may be particularly challenging given the long time anticipated before a return on investment. Absent contracts with project developers and clear public policy support for nuclear development, investors will perceive the long-term investments in nuclear power as being very risky.

Some of the risks and costs for SMRs and other emerging technologies can be mitigated by a focus on the regulatory process. The time line for an NRC DC can be daunting. Also, current law requires NRC to recover its DC review costs from the applicant through application fees.[123] NRC's data show that the DC process for the AP1000 took almost four years with application fees (including an amendment) of more than $45 million.[124] For General Electric's ESBWR, the review took more than nine years, with application fees of more than $68 million. To be clear, the fees do not reflect the vendors' own development costs, only

117. *Constellation Rejects Loan Guarantee Terms*, World Nuclear News, Oct. 11, 2010, http://bit.ly/2iQtWSt.
118. 42 U.S.C. §16014.
119. *Id.*; 10 C.F.R. §950.13.
120. 42 U.S.C. §2133.d.
121. *Ownership Issues Block UniStar License*, World Nuclear News, Aug. 31, 2012, http://bit.ly/2xHmqMc.
122. 42 U.S.C. §2133.d.
123. Omnibus Budget Reconciliation Act of 1990, as amended, Pub. L. No. 101-508, 104 Stat. 1388; Independent Offices Appropriations Act of 1952, 31 U.S.C. §9701.
124. NRC, NRC Responses to Requests for Information From Senators James Inhofe and Shelley Moore Capito 30 (2015), https://go.usa.gov/xn2jZ.

their payments to NRC. Administrative measures within the agency to capture lessons learned, reduce the time lines, and increase efficiencies appear to be necessary.[125]

To improve the NRC DC process, Congress could mandate specific time goals for a DC review, from application acceptance to approval (e.g., three years with a one-time, one-year extension in the event the applicant has provided insufficient support for the application). However, such goals may be ineffective and unenforceable. Therefore, amending the law to reduce or eliminate the fee recovery for the government review of new designs could be considered as a public investment in the technology.

On a more modest level, NRC is also considering proposals for phased reviews of advanced non-LWR designs to provide developers with flexibility to gain preliminary or phased NRC feedback to assist in the technical development process as well as financing of the costs.[126] At a minimum, NRC should consider steps to control review costs, consistent with its current statutory obligations. These would include clear time lines for completing agency reviews, elimination of unnecessary requests for additional information, better management of contractor expenses, and more efficient use of staff resources.

In addition, the NRC regulatory framework for newer nuclear technologies is either still under development (e.g., light water SMRs) or nonexistent (e.g., advanced, non-light water technologies). NRC worked with NuScale on a pre-application basis to address regulatory policy issues in advance of its application in late 2016. But the regulatory framework for advanced non-LWR reactors is only beginning to be considered. NRC has suggested internally that a framework might not be available until 2025.[127] If a technology will be ready, this schedule may need to be accelerated to support substantial new deployment by 2050.

Incremental measures may be inadequate. As suggested by a DOE advisory board, direct public funding or public-private partnerships to develop, license, and deploy SMRs and advanced non-LWR technologies would be a more aggressive option, assuming the necessary policy and political support.[128] One example based on that idea would be for Congress to require that some carbon tax or allowance auction revenues or other funding be used to provide initial federal support for deployment of specific SMRs and (later) specific projects utilizing advanced nuclear technologies—in effect, providing support for demonstration plants for first-of-a-kind technologies.

Congress could also increase DOE funding (supplementing private venture capital) to support development and testing of new reactor technologies, as well as detailed design engineering and NRC licensing. As noted earlier, DOE presently provides some support for SMRs and for advanced nuclear through the GAIN program, but this commitment could be increased. National laboratory test facilities could also support the development process. The focus of these initiatives would be on initial technology development and deployment rather than long-term operational subsidies, such as those discussed previously.

D. Design Standardization

An important lesson learned from the current U.S. fleet of nuclear plants, as well as from the serial, low-cost, and on-schedule nuclear construction efforts in Japan, South Korea, and, most recently, the United Arab Emirates, is the importance of standardization (or at least the extreme disadvantages of customization). The present generation of U.S. nuclear plants is an amalgam of LWR designs, of varying models, all customized for each site, and all licensed separately. As discussed above, the licensing process for the current nuclear fleet was notoriously slow and unpredictable. Many projects were abandoned after substantial investment, and in some cases after the plants were nearly or fully completed.[129]

Standard plant designs could significantly simplify licensing and construction of new plants, by allowing new projects to capitalize on the experience of lead projects. If a sufficient number of standard projects move forward in parallel or close succession, there would be synergies and economies of scale. Detailed engineering costs would be reduced. Off-site manufacturing of components could be increased. Construction lessons learned could be captured and applied to subsequent projects. The labor force could be trained and retained for successive projects.

As already discussed, NRC's Part 52 licensing process now supports and encourages standardization through the DC process. But to fully achieve the potential benefits of standard plants produced at scale, the federal government, including NRC, must encourage—or even require—standardization of plant designs to the maximum extent feasible. NRC must provide discipline in the regulatory process to appropriately restrict design changes to ensure that individual DCs remain stable and provide regulatory finality (with design changes only required based on significant operational experience suggesting the need for safety enhancements). Conversely, both the industry and the regulators (NRC and states) must constrain individual developers to adhere to the previously approved configuration rather than making endless customized changes.

A fair question can be raised regarding how many standard designs would be optimal. A market-based approach

125. Memorandum From Jennifer Uhle, Director, Office of New Reactors, to NRC Commissioners (Mar. 18, 2016), https://go.usa.gov/xn2jX.

126. NRC, *Advanced Reactors (Non-LWR Designs)*, https://go.usa.gov/xn2jE (last updated Dec. 22, 2017).

127. Jennifer Uhle, Activities and Planning Efforts for Advanced Non-Light Water Reactors and Small Modular Reactors, Comments at Meeting of NRC and DOE Office of Nuclear Energy (June 20, 2016), https://go.usa.gov/xn2jG.

128. *See generally* DOE, Secretary of Energy Advisory Board Report of the Task Force on the Future of Nuclear Power (2016), http://bit.ly/2fLBGPA.

129. Letter From Nils Diaz, Chairman, NRC, to Joe Barton, U.S. Representative (Feb. 20, 2006), https://go.usa.gov/xn2jh. In the case of the Shoreham plant in New York State, the plant was completed, licensed, and operated at low power before it was abandoned and decommissioned as part of a settlement among stakeholders. Matthew L. Wald, *For Nuclear Industry, Harm Is Already Done*, N.Y. Times, May 27, 1988, http://nyti.ms/2iN6JR1.

would contemplate certification of multiple designs, to allow the market to select the winner(s). In effect, this is anticipated in the current regulatory framework. Any vendor can seek an NRC DC, so long as the vendor pays the NRC license fees. But a multiplicity of "standard" designs would be inconsistent with maximizing construction efficiency, ensuring a consistent supply chain, and promoting operational consistency.

Therefore, another approach might involve deployment of reactors of a selected design by a single, well-funded, and capitalized "builder" of nuclear power plants (whether public or private) that could leverage its experience and supply chain to manage construction costs. The builder would license and construct nuclear power plants and then sell to generators (utilities or a highest bidder) once they were in operation, freeing up capital to reinvest in constructing the next plant. Such a "top-down" mandate for an aggressive and standardized nuclear build-out might incorporate a very small number of designs, intended for a range of applications (e.g., a large baseload unit, a smaller unit such as an SMR) or a limited range of cooling technologies based on access to water (e.g., ocean versus freshwater sources).

A top-down mandate of a limited number of designs may forestall innovation by rewarding an inferior, faster-to-market technology. Another alternative, therefore, would be a hybrid model. Congress could provide incentives for "first-to-market" designs. Once a new design is licensed and has been deployed successfully, subsequent developers may be encouraged to replicate the reference plant through tax incentives or access to low-cost financing. A newer design may be offered similar incentives, putting it on an equal footing in the market.

E. NRC Licensing Costs and Regulatory Uncertainties

The continued evolution and refinement of the NRC licensing process will also be important to create conditions needed to meet the DDPP projections. The protracted nuclear licensing experience of the 1980s is not necessarily applicable for new plants today. The plants of the 1970s and 1980s were custom plants, designed and constructed in a post-Three Mile Island regulatory environment of major change. Interest rates were high and there usually was no allowance for recovery of capital costs until commercial operation. And more germane to the present point, the two-step licensing framework has changed significantly, as discussed earlier in this Article.

More-standardized plants based on previously approved DCs will mean more commonalities in equipment, procedures, and support programs (e.g., security). The approved standard designs provide some measure of regulatory "finality" with respect to design requirements, with controls and limitations on new regulatory requirements. Lessons learned from recent licensing decisions can be incorporated to further improve the licensing process. Nonetheless, for widespread development of new nuclear units to take place, project developers will need to have confidence that the regulator will remain disciplined, efficient, and internally accountable for maintaining a stable regulatory environment.[130]

As discussed above, design issues are now reviewed during issuance of a DC to the vendor. Even with a certified design, the licensing time lines can be long, particularly for the first COL application referencing each new certified design. For example, the COL reviews for the Vogtle and V.C. Summer units (utilizing AP1000 technology) and the Fermi 3 plant (utilizing the ESBWR design) took from four to six years. All were the initial COLs for the designs involved, and improvement for future applications are likely. (In fairness, for both the AP1000 and ESBWR, the COLs were conducted in parallel with reviews, respectively, of an amendment to the existing DC proposed by the vendor and the vendor's application for an initial DC.) But owners and investors may still see the time lines as uncertain. And, as with DCs, NRC costs are recovered in application fees paid by the applicant. Further improvements and cost reductions in the process appear to be needed and achievable.

For example, within the existing regulatory framework, NRC should take steps to streamline design changes during construction by eliminating the Tier 2* designation for certain design-related information in a DC.[131] Changes to Tier 1 information, considered more safety-relevant, require prior NRC approval.[132] Changes to Tier 2 information, which involve less significant design information, can be made without prior NRC approval. A third designation, Tier 2*, was created to minimize the scope of Tier 1 information and, in theory, to provide greater flexibility in making changes to that information. But in practice, changes to Tier 2* information have required levels of effort nearly identical to Tier 1 changes.[133] Experience with AP1000 construction has shown that license amendments during construction could be reduced by nearly 30% by applying the same change process as that used to make changes to a plant during operation.

Other improvements require statutory changes. For example, in accordance with the AEA, a statutory body, the Advisory Committee on Reactor Safeguards (ACRS), must review a COL application. The ACRS review is in addition to the NRC staff's safety and environmental reviews.[134] The ACRS was established by the AEA before NRC was created. The ACRS was intended to provide an independent regulatory body, separate from the atomic energy research

130. Although untested with respect to nuclear power plants, legislation such as Fixing America's Surface Transportation Act, Pub. L. No. 114-94, 129 Stat. 1312 (2015), could improve the way that federal agencies evaluate environmental impacts from, and issue permits for, construction of large infrastructure projects. *See also* Exec. Order No. 13807, 82 Fed. Reg. 40463 (Aug. 24, 2017).
131. *See, e.g.*, 10 C.F.R. pt. 52, app. A, sec. II.F.
132. NRC, SECY-17-0075, Planned Improvements in Design Certification Tiered Information Designations 1-2 (July 24, 2017).
133. Letter From Joseph Pollack, Chief Nuclear Officer, Nuclear Energy Institute, to the Honorable Kristine Svinicki, Chairman, NRC 2 (Oct. 11, 2017) (SECY-17-0075), http://bit.ly/2mnUeKz.
134. 42 U.S.C. §2039.

and promotion functions of the Atomic Energy Commission, the federal agency at the time. In the current statutory scheme, the ACRS review is somewhat duplicative of NRC staff reviews. To reduce redundancy, Congress could modify the statute to better focus the ACRS' role, such as by eliminating ACRS reviews of site and COL applications, and reserve its reviews for DC applications and other generic safety issues.

Another component of the time line and cost of a COL is the hearing required by the AEA before NRC's Atomic Safety and Licensing Board. Even though the AEA does not require on-the-record adjudications under the Administrative Procedure Act,[135] the NRC hearing process is relatively formal (including elements such as mandatory disclosures, discovery in some cases, and cross-examination under certain circumstances). The hearings come late in the licensing process and formal procedures can lead to delays.

There are statutory and regulatory measures that could be adopted to refine and potentially shorten the NRC hearing process. For example, as discussed for DCs, NRC could establish (or Congress could impose) strict time lines for NRC reviews of COL applications referencing a standard DC—to reflect the reduced scope of issues for review. However, again, strict time lines can be viewed with skepticism. The licensing time line for the proposed high-level waste repository mandated by the NWPA has not proven to be effective.

Alternatively, NRC could adopt less formal NRC public hearing procedures. Formal adjudicatory procedures are not necessarily a model in government efficiency and public involvement. Along with slowing down the decisionmaking process, formal and legal procedures may tend to inhibit public participation in agency decisionmaking.[136] NRC therefore could find new ways to solicit and consider relevant input, including contrary data or technical views, short of formal adjudicatory proceedings. At a minimum, there should be renewed focus on lessons learned from the latest round of licensing hearings, with an eye on eliminating redundancies, late-filed issues, and unnecessarily tardy decisionmaking in the hearing process.

NRC also allows administrative litigation of environmental issues under NEPA in its AEA hearing process. This exceeds the public participation required by NEPA itself, as well as the public participation on NEPA issues offered by other federal agencies. In recent years, with design issues resolved by the DC, most issues in the NRC hearing process have been NEPA issues. Because NRC will not complete these hearings until after the NRC staff completes the EIS or supplement, a hearing on environmental issues will be very late in the licensing process. The hearing cannot be completed in parallel with NRC staff reviews; it is "back loaded" in the time line and therefore has the potential to significantly extend the overall time line to a license.

NRC should—consistent with the AEA and NEPA—eliminate contested hearings on NEPA issues (or at least move them forward in the process). NEPA procedures for public comment would continue to apply, but would not create the same potential to delay licensing. Reductions in the formality or scope of administrative hearings would undoubtedly draw opposition from some stakeholders. The challenge, therefore, would be to reduce unnecessary procedures while still allowing meaningful public participation.

Although a post-construction OL is no longer required, there remains additional licensing uncertainty prior to operation. As discussed above, the COL requires successful completion of a defined set of inspections, tests, and analyses and verification that the established acceptance criteria (altogether, the ITAAC) have been met. The ITAAC findings confirm completion of construction and readiness for operation. NRC defines the ITAAC to be objective and readily verifiable, without requiring an exercise of agency discretion.

Nonetheless, NRC regulations allow for a public hearing opportunity on completion of the ITAAC, which would be held over a compressed schedule during the final 210 days prior to the date of intended operation.[137] The threshold for a hearing is high. And the regulations allow at least the possibility that operation can begin before the hearing is completed. But the ITAAC process has not yet been tested, and delay in operation of a new plant due to an 11th-hour hearing on one or more ITAAC could be extremely costly for the operator.

The ITAAC hearing process will be exercised for the Vogtle and V.C. Summer units if and when they approach operation. Congress should reexamine the efficacy of the public participation component of the ITAAC process, which is a legacy of the old two-step licensing process. Utilizing more up-to-date means to ensure transparency of ITAAC close-out and stakeholder input may be equally effective, without the uncertainty. For example, NRC should make greater use of Internet-based reporting, monitoring, and feedback to enhance public participation. NRC should also expand use of the agency enforcement process, rather than prelicensing hearings, to close out ITAAC to reduce regulatory uncertainty associated with the start of operations. And as noted above, similar to the Energy Policy Act of 2005, Congress could provide further financial "standby support" for licensing process delays.[138]

Finally, uncertainty regarding regulatory costs is not limited to initial licensing and construction. NRC regulation is a necessary societal cost of nuclear energy, and the prospect of future new requirements to address operating experience and events around the world is no doubt an essential element of the regulatory framework to ensure ongoing protection of safety and to maintain public con-

135. City of W. Chi. v. U.S. Nuclear Regulatory Comm'n, 701 F.2d 632, 645, 13 ELR 20648 (7th Cir. 1983); Citizens Awareness Network, Inc. v. United States, 391 F.3d 338, 348-50 (1st Cir. 2004).

136. *See* Emily Hammond, *The Flaws of Formality in Risk Regulation*, 2016 Utah L. Rev. 169 (2016).

137. Notice, Final Procedures for Conducting Hearings on Conformance With the Acceptance Criteria in Combined Licenses, 81 Fed. Reg. 43266 (July 1, 2016).

138. Press Release, DOE, DOE Releases Filing Instructions for Federal Risk Insurance for New Nuclear Power Plants (Dec. 21, 2007), https://go.usa.gov/xn2Wf.

fidence in nuclear operations. Nonetheless, NRC has a long history of imposing new, heightened requirements in response to external events. The industry has perceived some of these to be out of proportion to actual risks and safety benefits.

For example, following the terrorist attacks on September 11, 2001, NRC imposed supplemental security requirements that triggered more than $2 billion in security upgrades.[139] In response to the Fukushima nuclear accident, NRC required every plant to conduct costly seismic and flooding hazard reevaluations, and the agency is still considering whether to require licensees to make plant and procedure modifications to address those hazards. Along with voluntary enhancements made by the industry, the post-Fukushima response has cost nuclear operators around $3 billion.[140] Investors will want some measure of assurance that, going forward with advanced designs, any new regulatory requirements will in fact be justified by safety and security risks.

NRC also imposes additional costs on licensees through its licensing and inspection programs by informally setting new standards, such as new design and qualification expectations for safety-related equipment, during compliance inspections. A design feature previously reviewed at licensing may, during an inspection, be cited as a "violation" based on a new regulatory interpretation. Under NRC's existing regulations—principally the agency's "backfit rule"[141]—compliance issues reviewed during licensing should not be reopened during operational inspections and rules should not be reinterpreted by inspectors, absent a specific safety justification in accordance with criteria defined in the backfit rule.

The existing rule is intended to enhance regulatory stability by ensuring that NRC inspectors cannot "impose" new requirements without following procedures consistent with the Administrative Procedure Act. But in practice, the rule is weak, easily circumvented, and rarely invoked successfully by plant operators to avoid imposition of new requirements. NRC—on its own initiative or with congressional prompting—should refine the rule to give future investors and operators greater confidence that new requirements will be carefully controlled and imposed only when there is new experience and a clear safety benefit.

V. Pathways to Support Nuclear Deployment Based on Other Major Federal Initiatives

Because states generally retain power over electricity supply planning and economic regulation, the federal government's role in promoting nuclear development and siting specific projects is constrained. However, as already discussed, the federal government can enact legislation that prices carbon or provides subsidies, tax credits, loan guarantees, or other economic incentives to stimulate a major nuclear build-out. Using carbon tax revenues, the federal government could provide public funding for research or enter into public-private partnerships to develop, license, and deploy advanced nuclear technologies.

These would be major federal steps toward increasing nuclear capacity. But even beyond these proposals, other major federal initiatives could spur development of new nuclear power plants. The following discussion addresses two additional recommendations to advance the prospects of meeting the DDPP goals: (1) direct federal investment to spur large-scale deployment of publicly owned or financed nuclear units; and (2) resolution of the long-standing issue of long-term nuclear waste storage and disposal.

A. *Large-Scale Public Nuclear Power Development*

There is precedent for direct government investment in new electricity generation, including new nuclear plants. Congress created the TVA in 1933 to aggressively build new electricity generation projects, including hydro projects, sell power on the wholesale market, and support regional economic development. The TVA later launched a substantial nuclear energy building program. The completed nuclear projects ultimately fell short of initial plans—many projects were abandoned or mothballed in the 1980s, as electricity demand leveled, construction costs multiplied, and interest rates soared. Nonetheless, after bringing a second unit at Watts Bar online in 2016, the TVA now operates 13 nuclear units with a capacity of 6,700 MW of electricity. Hoover Dam and other western hydro projects of the mid-20th century are similar examples of an active federal role, in those cases intended for electricity generation, flood control, and irrigation.

To address decarbonization, Congress could consider creating a new government administration or corporation to develop nuclear projects, based on the TVA model. The organization could, for example, focus on deploying SMRs at government or military installations.[142] Traditionally, generation siting decisions fall within state discretion and are subject to the availability of (and cost of improving) the transmission system. A federal role in designating available sites, away from population centers and away from external threats such as severe weather and earthquakes, linked to a revitalized transmission system, could preempt state and local permitting and also increase public confidence in safe nuclear energy (e.g., if technical experts were to base siting decisions solely on safety and environmental criteria, without being subject to geographic constraints posed by states, regions, or service areas). Federal support for the transmis-

139. John Funk, *Federal Security Concerns Since 9/11 Have Turned U.S. Nuclear Power Plants Into Armed Fortresses*, Plain Dealer, Aug. 6, 2011, http://bit.ly/2gS8PL6.

140. Steven Dolley, *US Nuclear Industry Spends Billions on Post-Fukushima Upgrades*, Platts, July 31, 2014, http://bit.ly/2zVWBbJ.

141. *See*, *e.g.*, 10 C.F.R. §50.109.

142. Constructing reactors on government property, such as former military bases, could avoid the moratoria imposed on new nuclear construction by a number of states.

sion system to connect sites to population centers may also serve as an indirect stimulus for nuclear build.

Congress or the president could use such a program to build on the existing framework for government procurement of electricity. Executive Order No. 13693, Planning for Federal Sustainability in the Next Decade, issued in March 2015, requires all federal agencies to receive 25% of their electric and thermal energy from renewable and clean, alternative sources by 2025. Importantly, the Executive Order designates SMRs as a suitable "alternative" source of power for achieving these goals. The TVA's application for an SMR at Clinch River reflects one of the TVA's efforts to meet that goal. A similar governmental target for all nuclear power generation, based on either SMRs or large-scale LWRs, could spur large-scale deployment of publicly owned or financed nuclear units.

B. Nuclear Waste Policy

There is no disposal facility in the United States for spent nuclear fuel. Congress established a legal and policy framework for addressing the issue in the NWPA. The federal government, through DOE, has the responsibility to develop the repository and take the spent fuel for disposal, using funds collected from nuclear generators. The Nuclear Waste Fund now totals more than $35 billion, with investment income of more than $1 billion per year. Congress has designated Yucca Mountain as the site for the repository, overriding a veto by the state of Nevada in accordance with the statute.[143]

Nonetheless, in 2009, after years of study, DOE abandoned the Yucca Mountain license application. The decision by the Secretary of Energy was not based on a scientific finding or regulatory conclusion; it was expressly based on the political opposition to the project from Nevada, which led the Secretary to conclude that the plan mandated by the NWPA "is not a workable option."[144] The D.C. Circuit later directed NRC to continue with the licensing process, but only to the extent of appropriated funding.[145]

The lack of a repository for ultimate disposal of spent nuclear fuel creates a public acceptance issue for nuclear energy. Opponents assert that there is no solution to "the problem of nuclear waste." And absent a disposal site, spent nuclear fuel remains in storage at reactor sites—both operating sites and decommissioned plant sites—leading or contributing to local opposition to continued storage or development of new generating capacity. As noted above, the opposition has resulted in moratoria on new nuclear plants in several states, such as California, Connecticut, Illinois, Kentucky, Maine, New Jersey, Oregon, and West Virginia, pending development of a nuclear waste repository.[146]

The safety concerns about waste storage and disposal are based largely on public perception and politics, rather than data.[147] Although spent fuel disposal certainly represents a major challenge and any waste site must be carefully analyzed to ensure very long-term isolation of radionuclides from the environment, the Yucca Mountain site has passed the detailed studies and licensing reviews completed to date. Even after the shutdown of the program by DOE, NRC staff completed a safety evaluation for Yucca Mountain and concluded that in all areas the regulatory performance objectives are satisfied, including regulatory limits for individual protection, human intrusion, and separate standards for groundwater protection.[148]

NRC's environmental review also assessed the potential environmental impacts with respect to potential releases from the repository into groundwater over a *one-million-year period* and concluded that each of the potential direct, indirect, and cumulative impacts from groundwater and surface groundwater discharges would be small.[149] NRC also has completed a rulemaking, supported by a comprehensive EIS, addressing extended storage of spent fuel at reactor sites, and concluded that spent fuel can be stored safely and without significant environmental impacts for an extended period of time past the licensed life for operation of a reactor.[150] NRC's rule and EIS were upheld by the D.C. Circuit.[151]

To increase public support for rapid expansion of nuclear capacity, the federal government must revisit and reanimate the Yucca Mountain project. Indeed, legislation has been proposed that would do that, such as appropriations for the project proposed in the U.S. House of Representatives.[152] Resumption of licensing of Yucca Mountain by DOE undoubtedly would provide a boost to nuclear power proponents. Nonetheless, beyond the appropriations needed, reactivating and licensing the project would

143. Alison Mitchell, *Senate Approves Nuclear Waste Site in Nevada Mountain*, N.Y. Times, July 10, 2002, http://nyti.ms/2z6pgOk.
144. *Statement of Steven Chu, Secretary of Energy, Before the Senate Comm. on the Budget*, 111th Cong. (2009); *see also* Todd Garvey, Congressional Research Service, Closing Yucca Mountain: Litigation Associated With Attempts to Abandon the Planned Nuclear Waste Repository (2011), *available at* https://go.usa.gov/xn2Zb.
145. In re Aiken County, 725 F.3d 255, 43 ELR 20190 (D.C. Cir. 2013), *reh'g en banc denied*, 2013 U.S. App. LEXIS 22003, No. 11-1271 (D.C. Cir. Oct. 28, 2013).
146. *See* National Conference of State Legislatures, *State Restrictions on New Nuclear Power Facility Construction*, http://bit.ly/2ilnY7U (last updated May 2017).
147. The Blue Ribbon Commission on America's Nuclear Future report stated that the consensus within the scientific and technical community is that safe geologic disposal is achievable with currently available technology. Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy §4.3 (2012), https://go.usa.gov/xn2ZR.
148. NRC, NUREG-1949, Vols. 1-5, Safety Evaluation Report Related to Disposal of High-Level Radioactive Wastes in a Geologic Repository at Yucca Mountain, Nevada (2010), *available at* https://go.usa.gov/xn2ZE.
149. NRC, NUREG-2184, Supplement to the U.S. Department of Energy's Environmental Impact Statement for a Geologic Repository for the Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste at Yucca Mountain, Nye County, Nevada—Final Report xii (2016), *available at* https://go.usa.gov/xn2Zv.
150. 10 C.F.R. §51.23; NRC, NUREG-2157, Generic Environmental Impact Statement for Continued Storage of Spent Nuclear Fuel—Final Report (2014), *available at* https://go.usa.gov/xn2Zf.
151. New York v. U.S. Nuclear Regulatory Comm'n, 824 F.3d 1012, 1013, 46 ELR 20105 (D.C. Cir. 2016).
152. Energy and Water Development Appropriations Bill, H.R. 5055, 114th Cong. (2016).

require clear commitment and direction from DOE and Congress. The necessary steps include reconstitution of the DOE project organization, restaffing the regulatory organization at NRC, and completion of NRC's administrative hearing process.

With respect to the latter, at the time the project and NRC proceeding were suspended, NRC's administrative hearing board had admitted 14 parties to the adjudicatory proceeding along with 288 highly technical issues related to the geosciences of the site, the engineering and long-term performance of the repository, handling of fuel, and environmental impacts. As of this writing, the state of Nevada is expected to continue to oppose the project. Congress therefore could consider providing substantial no-strings-attached benefits to the state and to local communities to supplement local economic benefits and mitigate the perceived burdens being placed on the host communities. Even then, engineering and construction would need to be completed, underscoring the long-term political commitment that will be required.

Moreover, if and when finished, Yucca Mountain will not have the capacity for waste from a new generation of nuclear plants. Additional storage capacity and disposal facilities would be necessary to support nuclear development at the levels contemplated by the DDPP goals.[153] Congress therefore should define and initiate the process to identify additional sites and to attract potential host communities as soon as possible. Likewise, Congress may need to revisit the policy choices made in the NWPA (e.g., deep geologic disposal, the licensing process, the existing cap on repository capacity), given the urgency created by climate change. For example, Congress could amend the statute to provide for consent-based siting and licensing of alternative or additional sites.

In the near term, DOE could remove or permit others to remove spent fuel from existing reactor sites and move it to a centralized interim storage or monitored retrievable disposal facility. DOE could be authorized to contract with private waste storage facilities (e.g., current proposed facilities in Texas and New Mexico) to store waste. This would ease local concerns that reactor sites will become de facto permanent storage locations. But site licensing processes still need to be completed. For the longer term disposal issue, Congress could assign the daunting tasks of completing a repository and addressing the need for additional repository capacity to a new "Nuclear Waste Administration" as an alternative to DOE—with a clear mission and consistent funding from the existing Nuclear Waste Fund, divorced from political whim.[154]

The waste disposal issue could also be addressed to some degree by technological innovation. New nuclear technologies offer the potential to reduce the amount of nuclear waste created.[155] In 2010, the Obama Administration created the Blue Ribbon Commission on nuclear waste to evaluate alternatives to Yucca Mountain.[156] The report prepared by that group provides an important, expert analysis of options such as fuel reprocessing to reduce waste disposal needs and offers recommendations for a path forward.[157] New disposal alternatives could also be considered. These opportunities, however, are largely contingent on expansion of the U.S. nuclear fleet or development of advanced nuclear technologies.

To promote public acceptance of nuclear energy and address the additional spent fuel that would accompany an expansion of nuclear energy to meet DDPP projections, the federal government—through DOE and Congress—will need to move forward aggressively on this important and chronic issue.

VI. Conclusions

Expansion of nuclear energy on the scale projected by the DDPP report for either the High Nuclear or Mixed Scenario would require a significant and sustained national policy commitment—one resembling but vastly exceeding the commitment that in the past decade has made possible the establishment and expansion of wind and solar generation in the United States in the face of clear market obstacles. Absent a major technological breakthrough, the DDPP projections for nuclear capacity simply cannot be achieved within the regulatory framework, economic conditions, and electricity markets that exist today. Serious public policy decisions need to be made and the necessary legal and regulatory frameworks would need to be established—sooner, rather than later—for nuclear energy to play what could be a substantial, and possibly necessary, role in meeting decarbonization goals by 2050.

As a first step, at least some existing nuclear capacity in the United States needs to be preserved. This would be facilitated by addressing the current economics of nuclear power in merchant (deregulated) energy markets and by extension of the current OLs. Carbon pricing, clean energy standards, and energy market reforms all would improve the economics in the short term, making extended operation of existing units financially feasible for plant owners. Reintroduction of cost-of-service rate regulation would also allow greater government influence over generation choices, taking into account all relevant considerations rather than only economic costs. A second NRC license renewal would be necessary as well, and this appears to be technically and legally achievable with sufficient industry support and government action. With these steps, some currently operating nuclear assets could operate to 2050 and beyond.

153. *See*, *e.g.*, Michael B. Gerrard, Whose Backyard, Whose Risk: Fear and Fairness in Toxic and Nuclear Waste Siting (1994).

154. *See* Interim Consolidated Storage Act of 2016, H.R. 4745, 114th Cong.; Interim Consolidated Storage Act of 2015, H.R. 3643, 114th Cong.; Nuclear Waste Administration Act of 2015, S. 854, 114th Cong.

155. *See*, *e.g.*, Kevin Bullis, *Safer Nuclear Power, at Half the Price*, MIT Tech. Rev., Mar. 12, 2013 (discussing a reactor design that can run on nuclear waste), http://bit.ly/2xHFbPm.

156. *See supra* note 147.

157. Blue Ribbon Commission on America's Nuclear Future, *supra* note 147, at vii.

Even with extended licenses for some units, much of the existing nuclear capacity will likely need to be replaced by 2050. And the deep decarbonization projections in the High Nuclear and Mixed Scenarios involve an increase in nuclear capacity from two to four times the current level. Achieving the deep decarbonization goals with a significant contribution from nuclear energy therefore will require substantial nuclear new build. Technology exists to meet the most ambitious objectives, in the form of standard reactor designs already certified by NRC and currently being deployed in new builds in the United States and around the world. Development and commercialization of advanced and more economic reactor technologies—particularly SMR technologies—could further facilitate meeting the goals by 2050. But deployment of these technologies would be expensive. Absent an unforeseen nuclear technology that emerges to change the current cost calculus, none of this will occur spontaneously under current market conditions.

Carbon pricing and energy market reforms could spur new nuclear development in deregulated electricity markets by internalizing the costs of fossil fuels and the benefits of nuclear generation. In addition, as with many infrastructure projects, public investment may be essential—in this case to spur technological advances in the safety and economics of nuclear energy and to facilitate expeditious licensing and deployment of new technologies. Investment could be in the form of support for research and development; support for testing, licensing, and first-of-a-kind engineering; financing subsidies or other support for specific projects; or direct investment in deployment of nuclear technologies. A publicly funded entity could be created to serve as the "national" nuclear developer, which would license and construct nuclear power projects and then sell plants (or electricity) to local utilities or IPPs once in operation, allowing the entity to reinvest in the next project. Some of these approaches could utilize revenues from carbon taxes for initial or ongoing support.

The social benefits of new nuclear extend beyond decarbonization and energy planning considerations, and further support the case for public investment. Nuclear projects, even potential SMR deployments, are major infrastructure projects with proven potential for economic development. Nuclear projects would create thousands of construction jobs in the short term and hundreds of high-paying technical jobs throughout the operating life of a plant. It has been estimated that for each 1,000 MW of installed capacity, nuclear creates approximately 5,000 jobs during construction. As of mid-2016, there were reportedly 6,000 workers at the two-unit Vogtle construction site in Georgia.[158] To give perspective, this compares to 1,000 jobs each for natural gas and wind projects per 1,000 MW.[159]

During operation, a nuclear plant provides approximately 800 jobs, compared to only 60 and 90 jobs for natural gas and wind, respectively. (Solar is similar to wind in terms of job creation, though most of those jobs are in rooftop installation or in China related to producing equipment.[160] In contrast, nuclear jobs are domestic and pay the most of any generation type.[161]) Nuclear energy projects also stimulate sophisticated, high-quality equipment manufacturing businesses, as well as jobs in the nuclear fuel cycle, such as uranium mining, conversion, and waste management. And a thriving domestic nuclear industry would support technology vendors and nuclear services suppliers who compete in a growing international nuclear supply and services market.

Ultimately, safe and reliable advanced nuclear energy is assumed in the DDPP High Nuclear and Mixed Scenarios, along with other generation technologies and energy conservation measures. There are many uncertainties related to the development, licensing, and costs of nuclear energy that would need to be overcome to achieve nuclear deployment at the contemplated scale. Legal, regulatory, and policy changes, along with a sustained societal investment, would be needed to overcome the obstacles. But investment in nuclear energy would have substantial benefits for a growing economy, in addition to providing carbon-free electricity at the scale needed to meet the DDPP goals.

158. Damon Cline, *Plant Vogtle Reactor Project Workforce Tops 6,000 Workers, Will Grow*, Augusta Chron., July 27, 2016, http://bit.ly/2aNlLy7.
159. James Conca, *What Do Energy Sector Jobs Do for Us?*, Forbes, Aug. 21, 2012, http://bit.ly/2yiNbLk.
160. Michaela D. Platzer, Congressional Research Service, U.S. Solar Photovoltaic Manufacturing: Industry Trends, Global Competition, Federal Support (2015), *available at* http://bit.ly/2z1ghvF.
161. Donald Harker & Peter Hans Hirschboeck, *Green Job Realities: Quantifying the Economic Benefits of Generation Alternatives*, Pub. Util. Fort., May 2010, http://bit.ly/2z2OJZa.