U.S. House of Representatives, Committee on Energy and Commerce, Subcommittee on Energy and Power
Hearing on "Building a 100 Percent Clean Economy: Advanced Nuclear Technology's Role in a Decarbonized Future"

The Honorable Jeffrey S. Merrifield Commissioner, U.S. Nuclear Regulatory Commission (1998-2007)
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Chairman Rush, Ranking Member Walden and members of the Subcommittee, it is an honor to testify before you today on a topic of critical importance to the United States, our global environment and the future of our civilization: the vital role that nuclear power can play in our efforts to decarbonize our economy. I am appearing here today in my role as the Chairman of the Advanced Nuclear Task Force of the U.S. Nuclear Industry Council ("USNIC"), although my full- time occupation is as a Partner in the nuclear energy practice group of Pillsbury Law Firm.

USNIC is the leading U.S. business advocate for the promotion of nuclear advancement and the American supply chain globally. USNIC represents over 80 companies engaged in nuclear innovation and supply chain development, including technology developers, manufacturers, construction engineers, key utility movers, and service providers.

During an earlier part of my career, I served on the staff of the Senate Environment and Public Works Committee and was involved in the 1992 Reauthorization of the Clean Air Act which was the first major legislation to include provisions addressing the impacts of global climate change. Since that time, it has become increasingly apparent that we must seek a wide range of technological innovations to reverse the global production of greenhouse gasses or risk further environmental impacts associated with the release of carbon into our atmosphere.

As a former Commissioner of the U.S. Nuclear Regulatory Commission, I am very familiar with the critical role that nuclear energy plays in U.S. clean energy production with the existing 96 nuclear units supplying nearly 60% of our nation's carbon-free generation. These critical facilities operate at over a 92% capacity factor and are a vital component in avoiding a further increase in U.S. carbon generation.

Last May, members of the U.S. Nuclear Industry Council had the opportunity to attend the Clean Energy Ministerial 10 in Vancouver where we heard a powerful presentation by Faith Birol, the Executive Director of the International Energy Agency, in which he unveiled their report - "Nuclear Power in a Clean Energy System." Over the past 50 years, the use of nuclear power has reduced CO_2 emissions by over 60 gigatonnes – the equivalent of nearly two years' worth of global energy-related emissions. As the report points out, "nuclear power is the world's second-largest source of low-carbon electricity today, with 452 operating reactors providing 2700 TWh of electricity in 2018, or 10% of the global electricity supply. Yet, without policy changes, advanced economies could lose 25% of their nuclear capacity by 2025 and as much as two-thirds of it by 2040." According to their analysis, failing to enable lifetime extensions of existing nuclear plants could add an additional 4 billion tons of annual CO2 emissions.[1]

The IEA report goes on to state that "it is considerably cheaper to extend the life of a reactor than build a new plant, and costs of extensions are competitive with other clean energy options, including new solar PV and wind projects." They note that market conditions are a barrier to lifetime extension investments: "An extended period of low wholesale electricity prices in most advanced economies has sharply reduced or eliminated margins for many technologies, putting nuclear at risk of shutting down early if additional investments are needed. As such, the feasibility of extensions depends largely on domestic market conditions."

Since I left the NRC in 2007, almost a dozen nuclear plants have either shut down or are scheduled to do so – about two-thirds of which were due to many of the same economic conditions cited in the IEA report. In many cases, the choice to close these plants was due to market conditions caused by the deployment of highly subsidized renewable generation, the plummeting price of natural gas, or a combination of both. In the end, these closures have or will result in increased reliance on fossil fueled generation, with increased carbon emissions.

As the committee may be aware, a great deal of attention has been focused on Germany, which has taken the dual policy of seeking significant renewable deployment at the same time it is seeking to shut down its 17 nuclear power plants. A December 2019 study conducted by researchers at Carnegie Mellon University, UC Berkeley and UC Santa Barbara, funded by the National Bureau of Economic Research, focused on uncovering the hidden costs of denuclearizing Germany. Using machine learning to analyze reams of data gathered between 2011 and 2017, the researchers found that "nuclear power was mostly replaced with power from coal plants, which led to the release of an additional 36 million tons of carbon dioxide per year, or about a 5 percent increase in emissions." Additionally, the researchers estimated that "burning more coal led to local increases in particle pollution and sulfur dioxide and likely killed an additional 1,100 people per year from respiratory or cardiovascular illnesses."[2]

Recognizing the vital role our existing nuclear plants play in avoiding increased carbon emissions, as well as their high reliability, several states, including Illinois, Ohio and New Jersey took steps to adopt forms of zero emissions credits that would protect nuclear generation that was at risk of economic shutdown. Unfortunately, a recent decision by the Federal Energy Regulatory Commission in December of 2019, which expanded the minimum price offer rule ("MOPR") will have the effect of eroding the efforts of these states to keep these important assets and could have a consequence of further reducing the vital carbon-free generation provided by these nuclear plants. I would note, the MOPR could also make it more difficult to deploy advanced nuclear generation in the areas impacted by FERC's decision.

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[1] "Nuclear Power in a Clean Energy System", Fuel Report, International Energy Agency, May 2019.

[2] "The Private and External Costs of Germany's Nuclear Phase-Out", National Bureau of Economic Research, December 2019.

Please do not take my remarks the wrong way. I am a firm believer that wind, solar and other renewable resources are critically needed in our efforts to reduce U.S. carbon emissions. My point is that they are not the only solution to our future generation needs and the increase in their deployment must be conducted in a manner that it is complementary with the carbon free generation provided by nuclear. Consistent with that view, I would note a recent report authored by four researchers at the Massachusetts Institute for Technology titled: "The Role of Firm Low-Carbon Electricity Resources in the Deep Decarbonization of Power Generation." In it the authors note that "firm low-carbon resources – including nuclear power, bioenergy, and natural gas plants that capture CO2 – consistently lower the cost of decarbonizing electricity generation. Without these resources, costs rise rapidly as CO2 limits approach zero. Batteries and demand flexibility do not obviate the value of firm resources…and for zero emissions cases without firm resources, the total required installed generation and storage power capacity in each system would be five to eight times the peak system demand."[3]

Clearly, a host of technologies will be needed to get to 100% carbon free energy generation.

On a related note, the U.S. Nuclear Regulatory Commission, in December 2019, issued its first subsequent license renewal which would extend the operating license at Turkey Point Units 3 and 4 in southern Florida from 60 to 80 years. This is very positive news and it is USNIC's view that the majority of the existing 96 U.S. nuclear plants could also qualify for this life extension process which would provide a significant contribution to avoiding increased carbon emissions.

Turning to advanced nuclear, USNIC has over 20-member companies that are developing advanced nuclear technologies including small modular light water, high temperature gas, molten salt and liquid metal reactors ranging in size from micro-reactors of a few megawatts to large gigawatt size reactors. Many of these reactor designs, which have their origins at U.S. national laboratories from the 1950's and 1960's, have made tremendous progress toward deployment in the last five years and feature enhanced safety features and improved economics when compared to existing reactors. Given those capabilities, these advanced reactors could replace some of the nuclear units that will be retiring in the U.S. over the next 20+ years. Also, their reduced footprint could allow them to be deployed for a wider range of additional sites and applications such as replacing existing coal-fired or gas-fired power units while continuing to use those sites and the electrical lines that connect to them. Additionally, due to their high temperature operations, many of these advanced reactors could replace carbon-based generation for desalination, provide process heat for chemical and manufacturing systems, and in some locations, enable district heating.

This Committee has made vital contributions to the advancement of these technologies through the many pro-nuclear bills it has favorably passed over the last several years. Further, the financial investments that Congress and the Administration have made in increasing appropriations for the Department of Energy's Office of Nuclear Energy over the last few years have been a critical factor in this success of these technologies.

In this regard, the Nuclear Energy Leadership Act ("NELA"), H.R. 3306, has been referred to

[3] "The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation", Joule 2, 1-18, October 17, 2018.

this Committee, and we are aware of parallel efforts on the part of the House Science Committee to address elements of the legislation subject to their jurisdiction. As a general matter, USNIC believes that NELA would significantly enhance the ability of advanced reactor developers to deploy their technologies in the United States. The advanced reactor demonstration programs and long-term federal power purchase agreement changes included in the legislation would be particularly helpful in providing needed assistance to facilitate the deployment of these promising technologies. USNIC encourages this Committee to work expeditiously with its House counterparts to facilitate the prompt passage of this important legislation.

In a previous appearance before this Committee several years ago, I testified on the need for High-Assay Low Enriched Uranium("HALEU") – with enrichments up to 19.75% - which will be needed by many of the advanced nuclear reactors currently under development. While we recognize that the Idaho National Lab, which is engaged on the processing of used fuel to provide some HALEU, and Centrus, which been tapped by DOE to establish centrifuge enrichment capabilities for the same purpose, both provide positive steps forward. Despite this progress, USNIC believes that this Committee will need to continue to closely monitor this matter. Given the potential civilian, military and space needs for HALEU, both here and in Canada, continued attention to this matter is critical. Not only does this relate to ensuring sufficient, multiple sources of HALEU for the advanced reactor community, but also the needed infrastructure to process and manufacture this fuel as well as the necessary cannisters that will be needed for transportation of these materials.

USNIC appreciates and complements the action undertaken by the Chairman and Ranking Member of this Subcommittee that resulted in the swift passage of the "Advanced Nuclear Fuel Availability Act" sponsored by Representative Flores. We believe this legislation is a positive step in the right direction to address the need for HALEU and quite appropriately focuses on key issues such as the need to have DOE create an inventory of this material, the need for criticality information to develop and license transportation packages, and the need for the NRC to develop an appropriate and timely licensing framework. We hope your Senate colleagues follow the leadership of the House and promptly move toward its enactment.

Over the last thirty years, the United States has gone from being the pre-eminent leader in nuclear exports, to the point today where we trail Russia, France, Korea and China in international nuclear deployments. Advanced nuclear and the dozens of innovative companies that are developing and deploying the next generation of clean and cost-effective nuclear technologies are putting our country in a position to regain a leading position in nuclear exports. Additionally, due to their smaller size, these reactors are deployable in locations and areas which cannot support the large, gigawatt sized reactors that were the only market offering the U.S. possessed several years ago.

Last October, I was a member of U.S. Nuclear Industry Council delegation to Africa where we met in Nairobi, Kenya with the leaders of over a dozen sub-Saharan countries who are investigating the potential to deploy nuclear generation. In meeting with the leaders of these programs, we heard a number of clear messages which I will paraphrase:

> "We need nuclear generation to provide clean, carbon-free economic growth for our countries or else we will be forced to buy coal or other fossil plants because renewable energy will not be enough. We want American nuclear technologies and American nuclear assistance, but we keep asking ourselves "where are the Americans?"

The advanced nuclear community I represent today provides a clear opportunity for the U.S. to be a leading presence in the deployment of nuclear technologies in Africa and beyond.

During the last twenty years, I have travelled to over 40 countries on nuclear related matters. Many, many of these countries want our technology, they want our technical support, and they seek the assistance of the U.S. government because they trust Americans and our technology. They do not have the same level of trust in others. With the current and future status of advanced reactor technologies, we as a country possess the best potential opportunity since President Dwight D. Eisenhower to retake the lead in this area. This development will spur exports, create jobs, strengthen our international relations and security and do so in a way that will provide clean, safe, carbon free technology around the world.

There is one export related matter I would like to raise with you today that is not directly within the jurisdiction to this subcommittee but is vital to efforts to utilize nuclear energy as part of a 100% decarbonization plan: the issue of international finance institution opposition to nuclear financing. With the recent adoption of the Build Act, Congress authorized the newly created International Development Finance Corporation to engage in lending and equity investment on behalf of the U.S. Government. While its predecessor, the Overseas Private Investment Corporation, did not undertake nuclear projects, we believe the development of small modular and advanced nuclear reactors provides an opportunity for the IDFC to reverse its prior stance on nuclear financing and enable the deployment of these vital carbon-free technologies.[4] We would urge this Committee to actively work with your counterparts in the Foreign Affairs Committee to encourage a more active policy in support of nuclear exports consistent with strong environmental standards.

Additionally, similar anti-nuclear policies at other international financial institutions including the World Bank, the Asian Development Bank and others are based on an outmoded and ill-considered understanding of the clean energy benefits of nuclear power. Developing countries, including those in Africa with whom I have met, very much want to deploy nuclear technologies to provide clean, reliable and carbon-free energy. We urge Congress to use the power at its disposal to reverse these anti-nuclear policies and enable the use of these critical carbon avoidance technologies.

Thank you for allowing me to testify for the U.S. Nuclear Industry Council on this important subject.

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[4] **<u>See</u>**. World Nuclear News, "Financing Nuclear Projects in Developing Countries", Elina Teplinsky and Sid Fowler, Pillsbury Law Firm, 27 January 2020.

Development Financial Institution Financing for Small Modular Reactor (SMR) Projects: A Mechanism to Address Climate Change Crisis and Meet Sustainable Development Goals by Facilitating SMR Deployment in the Developing World

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Corresponding Presenter: Elina Teplinsky

Over the next decade, the world faces two significant interrelated challenges. First, developing countries must increase electric generation to provide their citizens with access to affordable, reliable energy. Access to energy is necessary for economic development and prosperity,[1] fundamental for economic growth,[2] and critical to enabling societies to achieve basic levels of health,[3] education,[4] and social development.[5] Although only one of the United Nation's seventeen Sustainable Development Goals (SDG 7) focuses specifically on energy access,[6] it is widely recognized that without such access many of the other SDG will not be met.[7] The United Nations recently warned that "[w]ithout urgent action, the world will fall short of achievement of SDG 7 and consequently other SDG."[8]

Second, all nations face the urgent need to rapidly and dramatically reduce carbon emissions. The Intergovernmental Panel on Climate Change's (IPCC) most recent report predicts catastrophic environmental and economic impacts unless the increase in global temperatures is limited to less than 1.5 degrees Celsius.[9] SDG 13 attempts to address this crisis.[10] While achieving this goal is possible, "doing so [will] require unprecedented changes."[11]

The conflux of these demands presents developing nations with a dilemma, as increasing traditional (i.e. fossil) generation to meet energy needs further contributes to climate change.[12] This dilemma is exacerbated by the fact that developing countries are often the most vulnerable to the effects of global warming.[13] As a result, some developing nations are looking to nuclear power to meet growing demand. Nuclear power offers the benefits of traditional generation by providing reliable baseload power while producing virtually no carbon emissions. Many countries in developing regions have shown interest in civil nuclear power programs.[14] However, construction of a traditional large nuclear power plant may not be a viable fit for many developing countries, due to reasons such as a lack of human capital, GDP, or geography (e.g. lack of sufficient cooling water).[15] The long lead times for traditional nuclear plant construction may also be a hinderance to developing nations, as this can increase project risk and financing costs.[16]

.In addition, developing nations may lack a sufficient grid to support the amount of power a large traditional nuclear power plant would produce, as no single plant should exceed ten percent of the grid's capacity.[17] A 2009 IAEA study found that, based on then-projected 2015 grid size, nineteen of the fifty-four countries studied would only be able to fully utilize a plant of 300 MW or less.[18] The ten percent rule also assumes that all generation is connected to a single grid – an assumption which does not hold in some developing nations which have fragmented grids.

However, small and medium-sized or modular reactors (SMRs) could be a fit for those countries which are unable to support a large nuclear power plant. These reactor designs could be quickly deployed, require less human capital to build and operate (and some of which could be provided by the supplier), and could be sized to match local grid constraints. Many SMRs are designed to operate for many years between refueling, be walkaway safe,[19] and are highly proliferation resistant,[20] factors which could help overcome public perception and opposition to nuclear power. Further, SMRs could be used in conjunction with other systems to address non-energy needs, such as providing thermal energy for desalination plants, industrial process heat, or for district heating systems.[21] These non-electric functions are not available from most conventional renewable resources and could help developing nations meet other SDGs, such as SDG 6 (clean water and sanitation), SDG 9 (industry, innovation, and infrastructure), or SDG 11 (sustainable cities and communities).

Finally, it is possible that SMRs could replace aging fossil plants, thereby eliminating sources of carbon. Recently the United Nations' multi-stakeholder SDG 7 Technical Advisory Group, when discussing "ways forward to reach climate goals," noted that "[n]uclear is also an option in pathways that assume public acceptance and resolution of the proliferation challenges."[22] For these reasons, SMRs should be fully considered in any plan to address SDG 7 and SDG 13.

One problem facing energy projects in developing countries is lack of financing. Among the reasons SDG 7 is at risk of not being met is the fact that "[f]inancial flows including public and private investments in energy, are . . . falling short of what is needed."[23] Developing nations often turn to development finance institutions (DFIs), such as the World Bank, for financing. DFIs attempt to serve humanitarian ends by providing financing, advising, and technical support to development projects in poorer regions. The World Bank's mission is to "end extreme poverty [b]y reducing the share of the global population that lives in extreme poverty to 3 percent by 2030" and "promote shared prosperity [b]y increasing the incomes of the poorest 40 percent of people in every country."[24] DFIs are heavily involved in financing energy projects and have increasingly moved away from financing projects with high carbon footprints.[25]

DFIs have recognized nuclear energy's "sustainable and operational benefits,"[26] and the United Nations has expressed a willingness to consider nuclear energy as a means to meet SDG 7.[27] However, despite this recognition most major DFIs will not finance nuclear projects. Common reasons given are a lack of institutional expertise on the part of the DFI,[28] that nuclear projects are not an area of comparative advantage for the DFI,[29] and political and financial risk given the scale and nature of nuclear power projects.[30] While some have criticized DFIs' stance on nuclear power, arguing that DFIs are placing politics and ideology ahead of their mission,[31] nuclear financing does present risk to DFIs.

For example, a key risk facing potential lenders for nuclear projects is that the traditional long lead time for nuclear construction requires capital to be outlayed over many years, during which time construction delays or changing political attitudes can derail a project.[32] Similarly, the long construction time means even small delays as compared to the overall project schedule are still significant from a financing standpoint and the long time frame also makes the economics of the project highly sensitive to interest rates.[33] Nuclear generation facilities also have higher upfront capital costs than other energy projects, and so by the time the plant is completed a significant share of the costs are sunk.[34] If a project is abandoned due to changing political views or construction overruns, it is too late for the investor to reverse the investment decision and avoid a significant loss.

However, SMRs obviate many of these risks, and it is therefore time that DFIs revisit their stance and consider financing for SMRs. As discussed earlier, the design of these reactors should allow them to more readily achieve public acceptance thereby addressing DFIs' political concerns.[35] SMRs also obviate the need for organizations like World Bank to develop significant nuclear safety, nonproliferation, and technical expertise because the reactor designs largely mitigate these concerns by being walkaway safe, proliferation resistant, and relying on standardized designs.

Moreover, SMRs resolve the concerns related to large, long-term capital outlays. SMRs' shorter construction time means capital does not have to be committed for as long, reducing the risk that overruns or changing political attitudes would cause a project to be abandoned. Because of the shorter overall project schedule, construction delays would typically be concomitantly shorter. For a multi-unit SMR installation, a delay would often only apply to the first unit thereby having less of an impact on the overall project,[36] and less capital would typically be sunk in a non-complete reactor at any given time.

Finally, helping bring this revolutionary technology to market fits well within the ambit of DFIs. The World Bank, for example has stated that "[t]he long-term shift to a sustainable energy future depends on deep technological innovation and rapid diffusion of new energy technologies" and has expressed a willingness to provide financing if a project "has a high cost and carries high risks but offers strategic potential for the future."[37] Few technologies offer the future strategic potential of SMRs.

It is becoming increasingly clear that DFIs' traditional reasons for refusing to finance nuclear projects do not apply to SMRs. These reactor designs mitigate many of DFIs' concerns about financing nuclear power, and in the context of developing economies can play a crucial role in allowing the attainment of SDG 7, SDG 13, and other developmental goals. However, public financing is critical for developing world energy projects. For this revolutionary technology to be brought online, DFIs must reconsider their anti-nuclear stance and provide financing for SMRs alongside other low carbon sources.

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[1] UNITED NATIONS DEPARTMENT OF ECONOMIC AND SOCIAL AFFAIRS, Accelerating SDG7 Achievement: Policy Briefs in Support of the First SDG7 Review at the UN High-level Political Form 2018, p. 16 (2018) ("SDG7 Policy Briefs") ("No country has gone from poverty to prosperity without making electricity affordable and available in bulk for productive uses.").

[2] THE WORLD BANK, Toward a Sustainable Energy Future for All: Directions for the World Bank Group's Energy Sector, p. 1 (2013) ("Adequate, reliable, and competitively priced modern energy is essential for business development, job creation, income generation, and international competitiveness.").

[3] SDG7 Policy Briefs at 78 ("Inefficient household energy use is a particular health and livelihood risk for women, children and infants.").

[4] SDG7 Policy Briefs at 86 ("Educational facilities require energy for lighting, cooking, heating, cooling, water delivery and purification, as well as information and communication technology . . . . School attendance and performance levels have been shown to increase with increased electrification rates.").

[5] SDG7 Policy Briefs at 92 ("Greater access to energy services can improve women's health and well-being, free up their time and enable their economic empowerment, thereby supporting the achievement of SDG 5.").

[6] UNITED NATIONS, Transforming our world: the 2030 Agenda for Sustainable Development, *Resolution adopted by the General Assembly on 25 September 2015* ("UN 2030 Agenda") ("Goal 7: Ensure access to affordable, reliable, sustainable and modern energy for all.").

[7] SDG7 Policy Briefs at p. 64 ("SDG 7 is a condition for economic development, poverty alleviation (SDG 1) and reducing inequalities (SDG 10).").

[8] SDG 7 Policy Briefs at 5.

[9] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, Global Warming of 1.5 °C (2018) ("IPCC Report").

[10] UN 2030 Agenda ("Goal 13: Take urgent action to combat climate change and its impacts").

[11] Quote by Jim Skea, Co-Chair of IPCC Working Group III, https://www.ipcc.ch/2018/10/08/summary-for-policymakers-of-ipcc-special-report-on-global-warming-of-1-5c-approved-by-governments/

[12] As the Asian Development Bank has explained, rapid growth in energy demand among developing Asian countries "is not sustainable" if the growth is met by fossil fuels as this would "significantly increase greenhouse gas emissions. . . . Scientists have documented a rise in atmospheric temperature and other significant climate changes, some of which have serious consequences for Asia and the Pacific." ASIAN DEVELOPMENT BANK, Energy Policy, p. 1 (2009) ("ADB Energy Policy").

[13] The IPCC Report found that many of the world's most vulnerable populations, including "small island developing states, and Least Developed Countries" are particularly at risk from the impacts of climate change and that "limiting global warming to 1.5°C, compared with 2°C, could reduce the number of people both exposed to climate-related risks and susceptible to poverty by up to several hundred million by 2050." IPCC, IPCC Report Summary for Policy Makers, B.5.1 (2018)

[14] *See*, *e.g.*, INTERNATIONAL ATOMIC ENERGY AGENCY (IAEA), Common User Considerations (CUC) by Developing Countries for Future Nuclear Energy Systems: Report of Stage 1, p. 1 (2009) ("IAEA 2009 CUC") (discussing 54 countries with developing economies which had expressed an interest in "considering, introducing, or expanding their nuclear power programmes").

[15] JESSICA JEWELL, Ready For Nuclear Energy?: An Assessment of Capacities and Motivations for Launching New National Nuclear Power Programs, 39 Energy Policy 1041 (2011); *see also* M.V. RAMANA AND PRISCILLA AGYAPONG, Thinking Big? Ghana, Small Reactors, and Nuclear Power, 21 Energy Research & Social Science 101, p. 105 (2016) ("Historically, Pakistan is the only country to have successfully introduced nuclear power with a GDP of less than 50 billion US dollars.").

[16] As demonstrated by a number of abandoned projects, this is a problem in first world countries as well. However, the risk is greater in a developing nation where a single plant is a larger portion of the country's GDP and ratepayers may not be able to repay investors for an abandoned project.

[17] The IAEA recommends that no single plant "exceed 10% of the total electricity capacity in a country. . . . [t]he value of 10% of the grid capacity is a rule of thumb commonly accepted to be the upper limit for the capacity of any single additional unit of any type in order to prevent instability and unreliability of the grid system." IAEA 2009 CUC.

[18] *Id.*

[19] ABIGAIL SAH ET AL., Atoms for Africa: Is There a Future for Civil Nuclear Energy in Sub-Saharan Africa?, Center for Global Development Policy Paper 124, p. 19 (Apr. 2018) ("Each [microreactor] is expected to be walk-away-safe and have a lifespan of 12 years, after which the fuel can be recycled at the central manufacturing facility to be used for another 12 years in another unit of the reactor.").

[20] IAEA 2009 CUC at p. 11 ("Some SMR designs may reduce obligations of the user for spent fuel and waste management and possibly offer greater non-proliferation assurances to the international community.").

[21] *See* Sah, *supra* n. 19, p. 19.

[22] SDG7 Policy Briefs at 158.

[23] *Id.* at 5.

[24] https://www.worldbank.org/en/who-we-are

[25] In 2018 the World Bank delivered over $20 billion in climate-related finance. WORLD BANK, Press Release No. 2019/008/CCG: World Bank Group Exceeds its Climate Finance Target with Record Year (July 19, 2018). The World Bank also recently announced that as of 2019, absent special circumstances it no longer provides financing for upstream oil and gas projects. WORLD BANK, World Bank Group Announcements at One Planet Summit (Dec. 12, 2017) http://www.worldbank.org/en/news/press-release/2017/12/12/world-bank-group-announcements-at-one-planet-summit.

[26] ADB Energy Policy at p. 14.

[27] *See* SDG7 Policy Briefs at 158.

[28] World Bank *supra* n. 2 at p. 14 ("Although all options will be considered for sector assessment and longer-term planning purposes, the WBG [World Bank Group] will not finance nuclear power generation or provide specific technical assistance for its assessment and development because safety of nuclear facilities and non-proliferation are not in the WBG's areas of expertise, nor will the WBG build internal capacity in matters related to nuclear power generation.").

[29] AFRICAN DEVELOPMENT BANK, Energy Sector Policy of the AfDB Group, p. 22 (2012).

[30] NUCLEAR ENERGY AGENCY, ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT, The Financing of Nuclear Power Plants at p. 48 (2009).

[31] *See, e.g.*, THE HERITAGE FOUNDATION, Issue Brief: The U.S. Should Appoint a World Bank President Committed to Energy Prosperity, p. 3 (Jan. 29, 2019) ("If the World Bank [w]ere [s]erious [a]bout [r]educing CO2 [e]missions, [i]t [w]ould [c]onsider [n]uclear [e]nergy.").

[32] NUCLEAR ENERGY AGENCY, ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT, The Financing of Nuclear Power Plants at pp. 23, 32 (2009).

[33] FABIENNE P. LUCET, Conditions and Possibilities for Financing New Nuclear Power Projects, 12 Journal of World Energy Law and Business 21-35 (2019).

[34] *Id.*

[35] *See supra* nn. 19-21.

[36] SARA BOARIN AND MARCO E. RICOTTI, An Evaluation of SMR Economic Attractiveness, Hindawi Publishing Corporation Science and Technology of Nuclear Installations Volume 2014, Article ID 803698, pp. 3-4 (2014).

[37] WORLD BANK *supra* n.2 at p. 14.

Nuclear Power in a Clean Energy System

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2019

Abstract

Nuclear power and hydropower form the backbone of low-carbon electricity generation. Together, they provide three-quarters of global low-carbon generation. Over the past 50 years, the use of nuclear power has reduced carbon dioxide (CO_2) emissions by over 60 gigatonnes – nearly two years' worth of global energy-related emissions. However, in advanced economies, nuclear power has begun to fade, with plants closing and little new investment made, just when the world requires more low-carbon electricity. This report, *Nuclear Power in a Clean Energy System*, focuses on the role of nuclear power in advanced economies and the factors that put nuclear power at risk of future decline. It is shown that without action, nuclear power in advanced economies could fall by two-thirds by 2040. The implications of such a "Nuclear Fade Case" for costs, emissions and electricity security using two *World Energy Outlook* scenarios – the New Policies Scenario and the Sustainable Development Scenario are examined.

Achieving the pace of CO_2 emissions reductions in line with the Paris Agreement is already a huge challenge, as shown in the Sustainable Development Scenario. It requires large increases in efficiency and renewables investment, as well as an increase in nuclear power. This report identifies the even greater challenges of attempting to follow this path with much less nuclear power. It recommends several possible government actions that aim to: ensure existing nuclear power plants can operate as long as they are safe, support new nuclear construction and encourage new nuclear technologies to be developed.

Foreword

As the leading energy organisation covering all fuels and all technologies, the International Energy Agency (IEA) cannot ignore the role of nuclear power. That is why we are releasing our first report on the subject in nearly two decades in the hope of bringing it back into the global energy debate.

We are highlighting the issue at a critical time. The failure to expand low-carbon electricity generation is the single most important reason the world is falling short on key sustainable energy goals, including international climate targets, as we have highlighted repeatedly this year. The question is what nuclear power's role should be in this transition. Put another way: Can we achieve a clean energy transition without nuclear power?

For advanced economies, nuclear has been the biggest low-carbon source of electricity for more than 30 years, and it has played an important role in the security of energy supplies in several countries. But it now faces an uncertain future as ageing plants begin to shut down in advanced economies, partly because of policies to phase them out but also under pressure from market conditions and regulatory barriers.

Our report, *Nuclear Power in a Clean Energy System*, assesses its current role and considers its mid- and long-term outlook, especially in competitive electricity systems.

This report is part of an expanding view the IEA is taking of the global energy system. In June, we will be releasing another analysis on the future of hydrogen, at the request of the Japanese presidency of the G20 this year. We are also holding various high-level meetings to underscore the critical elements needed for a successful transition – including a high-level ministerial conference in Dublin next month on energy efficiency and another ministerial meeting on systems integration of renewables in Berlin in September 2019.

Government policies have so far failed to value the low-carbon and energy security attributes of nuclear power, making even the continued operation of existing plants challenging. New projects have been plagued by cost overruns and delays.

These trends mean nuclear power could soon be on the decline worldwide. If governments don't change their current policies, advanced economies will be on track to lose two-thirds of their current nuclear fleet, risking a huge increase in CO2 emissions.

Without action to provide more support for nuclear power, global efforts to transition to a cleaner energy system will become drastically harder and more costly. Wind and solar energy need to play a much greater role in order for countries to meet sustainability goals, but it is extremely difficult to envisage them doing so without help from nuclear power.

Some countries have decided to refrain from using nuclear power, and their choice is well respected. However, those that aim to continue using it represent the majority of global energy use and CO_2 emissions. As governments seek to achieve a diversified mix in their energy transitions, the IEA remains ready to provide support with data, analysis and real-world solutions.

Dr Fatih Birol
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International Energy Agency

Executive summary

Nuclear power can play an important role in clean energy transitions

Nuclear power today makes a significant contribution to electricity generation, providing 10% of global electricity supply in 2018. In advanced economies,[1] nuclear power accounts for 18% of generation and is the largest low-carbon source of electricity. However, its share of global electricity supply has been declining in recent years. That has been driven by advanced economies, where nuclear fleets are ageing, additions of new capacity have dwindled to a trickle, and some plants built in the 1970s and 1980s have been retired. This has slowed the transition towards a clean electricity system. Despite the impressive growth of solar and wind power, the overall share of clean energy sources in total electricity supply in 2018, at 36%, was the same as it was 20 years earlier because of the decline in nuclear. Halting that slide will be vital to stepping up the pace of the decarbonisation of electricity supply.

A range of technologies, including nuclear power, will be needed for clean energy transitions around the world. Global energy is increasingly based around electricity. That means the key to making energy systems clean is to turn the electricity sector from the largest producer of CO_2 emissions into a low-carbon source that reduces fossil fuel emissions in areas like transport, heating and industry. While renewables are expected to continue to lead, nuclear power can also play an important part along with fossil fuels using carbon capture, utilisation and storage. Countries envisaging a future role for nuclear account for the bulk of global energy demand and CO_2 emissions. But to achieve a trajectory consistent with sustainability targets – including international climate goals – the expansion of clean electricity would need to be three times faster than at present. It would require 85% of global electricity to come from clean sources by 2040, compared with just 36% today. Along with massive investments in efficiency and renewables, the trajectory would need an 80% increase in global nuclear power production by 2040.

Nuclear power plants contribute to electricity security in multiple ways. Nuclear plants help to keep power grids stable. To a certain extent, they can adjust their operations to follow demand and supply shifts. As the share of variable renewables like wind and solar photovoltaics (PV) rises, the need for such services will increase. Nuclear plants can help to limit the impacts from seasonal fluctuations in output from renewables and bolster energy security by reducing dependence on imported fuels.

Lifetime extensions of nuclear power plants are crucial to getting the energy transition back on track

Policy and regulatory decisions remain critical to the fate of ageing reactors in advanced economies. The average age of their nuclear fleets is 35 years. The European Union and the United States have the largest active nuclear fleets (over 100 gigawatts each), and they are also among the oldest: the average reactor is 35 years old in the European Union and 39 years old in the United States. The original design lifetime for operations was 40 years in most cases. Around one-quarter of the current nuclear capacity in advanced economies is set to be shut down by 2025 – mainly because of policies to reduce nuclear's role. The fate of the remaining capacity depends on decisions about lifetime extensions in the coming years. In the United States, for example, some 90 reactors have 60-year operating licenses, yet several have

[1] Advanced economies consist of Australia, Canada, Chile, the 28 members of the European Union, Iceland, Israel, Japan, Korea, Mexico, New Zealand, Norway, Switzerland, Turkey and the United States.

already been retired early and many more are at risk. In Europe, Japan and other advanced economies, extensions of plants' lifetimes also face uncertain prospects.

Economic factors are also at play. Lifetime extensions are considerably cheaper than new construction and are generally cost-competitive with other electricity generation technologies, including new wind and solar projects. However, they still need significant investment to replace and refurbish key components that enable plants to continue operating safely. Low wholesale electricity and carbon prices, together with new regulations on the use of water for cooling reactors, are making some plants in the United States financially unviable. In addition, markets and regulatory systems often penalise nuclear power by not pricing in its value as a clean energy source and its contribution to electricity security. As a result, most nuclear power plants in advanced economies are at risk of closing prematurely.

The hurdles to investment in new nuclear projects in advanced economies are daunting

What happens with plans to build new nuclear plants will significantly affect the chances of achieving clean energy transitions. Preventing premature decommissioning and enabling longer extensions would reduce the need to ramp up renewables. But without new construction, nuclear power can only provide temporary support for the shift to cleaner energy systems.

The biggest barrier to new nuclear construction is mobilising investment. Plans to build new nuclear plants face concerns about competitiveness with other power generation technologies and the very large size of nuclear projects that require billions of dollars in upfront investment. Those doubts are especially strong in countries that have introduced competitive wholesale markets.

A number of challenges specific to the nature of nuclear power technology may prevent investment from going ahead. The main obstacles relate to the sheer scale of investment and long lead times; the risk of construction problems, delays and cost overruns; and the possibility of future changes in policy or the electricity system itself. There have been long delays in completing advanced reactors that are still being built in Finland, France and the United States. They have turned out to cost far more than originally expected and dampened investor interest in new projects. For example, Korea has a much better record of completing construction of new projects on time and on budget, although the country plans to reduce its reliance on nuclear power.

Without nuclear investment, achieving a sustainable energy system will be much harder

A collapse in investment in existing and new nuclear plants in advanced economies would have implications for emissions, costs and energy security. In the case where no further investments are made in advanced economies to extend the operating lifetime of existing nuclear power plants or to develop new projects, nuclear power capacity in those countries would decline by around two-thirds by 2040. Under the current policy ambitions of governments, while renewable investment would continue to grow, gas and, to a lesser extent, coal would play significant roles in replacing nuclear. This would further increase the importance of gas for countries' electricity security. Cumulative CO_2 emissions would rise by 4 billion tonnes by 2040, adding to the already considerable difficulties of reaching emissions targets. Investment needs would increase by almost USD 340 billion as new power generation capacity and supporting grid infrastructure is built to offset retiring nuclear plants.

Achieving the clean energy transition with less nuclear power is possible but would require an extraordinary effort. Policy makers and regulators would have to find ways to create the conditions to spur the necessary investment in other clean energy technologies. Advanced economies would face a sizeable shortfall of low-carbon electricity. Wind and solar PV would be the main sources called upon to replace nuclear, and their pace of growth would need to accelerate at an unprecedented rate. Over the past 20 years, wind and solar PV capacity has increased by about 580 GW in advanced economies. But in the next 20 years, nearly five times that much would need to be built to offset nuclear's decline. For wind and solar PV to achieve that growth, various non-market barriers would need to be overcome such as public and social acceptance of the projects themselves and the associated expansion in network infrastructure. Nuclear power, meanwhile, can contribute to easing the technical difficulties of integrating renewables and lowering the cost of transforming the electricity system.

With nuclear power fading away, electricity systems become less flexible. Options to offset this include new gas-fired power plants, increased storage (such as pumped storage, batteries or chemical technologies like hydrogen) and demand-side actions (in which consumers are encouraged to shift or lower their consumption in real time in response to price signals). Increasing interconnection with neighbouring systems would also provide additional flexibility, but its effectiveness diminishes when all systems in a region have very high shares of wind and solar PV.

Offsetting less nuclear power with more renewables would cost more

Taking nuclear out of the equation results in higher electricity prices for consumers. A sharp decline in nuclear in advanced economies would mean a substantial increase in investment needs for other forms of power generation and the electricity network. Around USD 1.6 trillion in additional investment would be required in the electricity sector in advanced economies from 2018 to 2040. Despite recent declines in wind and solar costs, adding new renewable capacity requires considerably more capital investment than extending the lifetimes of existing nuclear reactors. The need to extend the transmission grid to connect new plants and upgrade existing lines to handle the extra power output also increases costs. The additional investment required in advanced economies would not be offset by savings in operational costs, as fuel costs for nuclear power are low, and operation and maintenance make up a minor portion of total electricity supply costs. Without widespread lifetime extensions or new projects, electricity supply costs would be close to USD 80 billion higher per year on average for advanced economies as a whole.

Strong policy support is needed to secure investment in existing and new nuclear plants

Countries that have kept the option of using nuclear power need to reform their policies to ensure competition on a level playing field. They also need to address barriers to investment in lifetime extensions and new capacity. The focus should be on designing electricity markets in a way that values the clean energy and energy security attributes of low-carbon technologies, including nuclear power.

Securing investment in new nuclear plants would require more intrusive policy intervention given the very high cost of projects and unfavourable recent experiences in some countries. Investment policies need to overcome financing barriers through a combination of long-term contracts, price guarantees and direct state investment.

Interest is rising in advanced nuclear technologies that suit private investment such as small modular reactors (SMRs). This technology is still at the development stage. There is a case for governments to promote it through funding for research and development, public-private partnerships for venture capital and early deployment grants. Standardisation of reactor designs would be crucial to benefit from economies of scale in the manufacturing of SMRs.

Continued activity in the operation and development of nuclear technology is required to maintain skills and expertise. The relatively slow pace of nuclear deployment in advanced economies in recent years means there is a risk of losing human capital and technical know-how. Maintaining human skills and industrial expertise should be a priority for countries that aim to continue relying on nuclear power.

Policy recommendations

The following recommendations are directed at countries that intend to retain the option of nuclear power. The IEA makes no recommendations to countries that have chosen not to use nuclear power in their clean energy transition and respects their choice to do so.

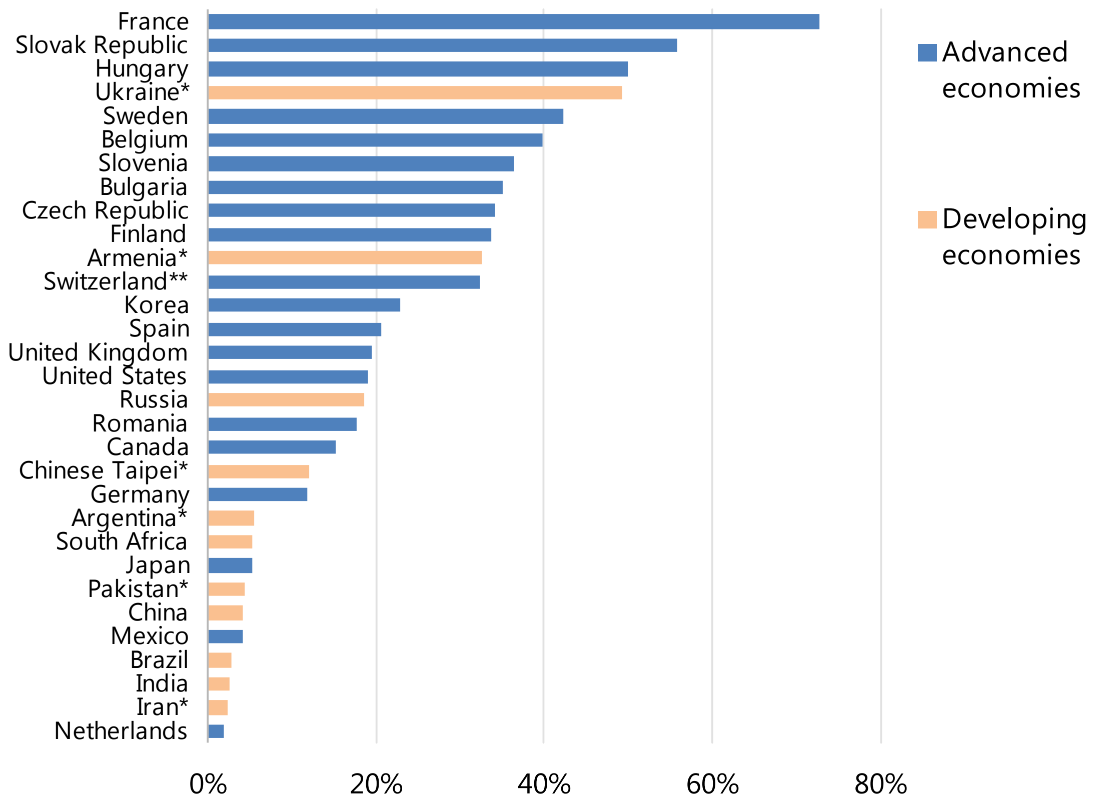
- **Keep the option open:** Authorise lifetime extensions of existing nuclear plants for as long as safely possible.
- **Value dispatchability:** Design the electricity market in a way that properly values the system services needed to maintain electricity security, including capacity availability and frequency control services. Make sure that the providers of these services, including nuclear power plants, are compensated in a competitive and non-discriminatory manner.
- **Value non-market benefits:** Establish a level playing field for nuclear power with other low-carbon energy sources in recognition of its environmental and energy security benefits and remunerate it accordingly.
- **Update safety regulations:** Where necessary, update safety regulations in order to ensure the continued safe operation of nuclear plants. Where technically possible, this should include allowing flexible operation of nuclear power plants to supply ancillary services.
- **Create an attractive financing framework:** Set up risk management and financing frameworks that can help mobilise capital for new and existing plants at an acceptable cost, taking the risk profile and long time horizons of nuclear projects into consideration.
- **Support new construction:** Ensure that licensing processes do not lead to project delays and cost increases that are not justified by safety requirements. Support standardisation and enable learning-by-doing across the industry.
- **Support innovative new reactor designs:** Accelerate innovation in new reactor designs, such as small modular reactors (SMRs), with lower capital costs and shorter lead times and technologies that improve the operating flexibility of nuclear power plants to facilitate the integration of growing wind and solar capacity into the electricity system.
- **Maintain human capital:** Protect and develop the human capital and project management capabilities in nuclear engineering.

1. Nuclear power today

Role of nuclear power in global electricity supply

Nuclear power makes a significant contribution to global electricity generation, providing 10% of global electricity supply in 2018. As of May 2019, there were 452 nuclear power reactors in operation in 31 countries around the world, with a combined capacity of about 400 gigawatts (GW). Nuclear power plays a much bigger role in advanced economies, where it makes up 18% of total generation. In 2018, it provided over one-half of the power in France, the Slovak Republic and Hungary (Figure 1). The European Union obtained 25% of its electricity supply from nuclear reactors. Korea and the United States similarly relied on nuclear power for about one-fifth of their electricity. In Japan, nuclear power made up about 5% of electricity generation in 2018. Before the accident at Fukushima Daiichi in 2011, it had been on an equal footing with coal and gas as the largest sources of electricity in Japan at around 30%.

Figure 1. Share of nuclear power in total electricity generation by country, 2018

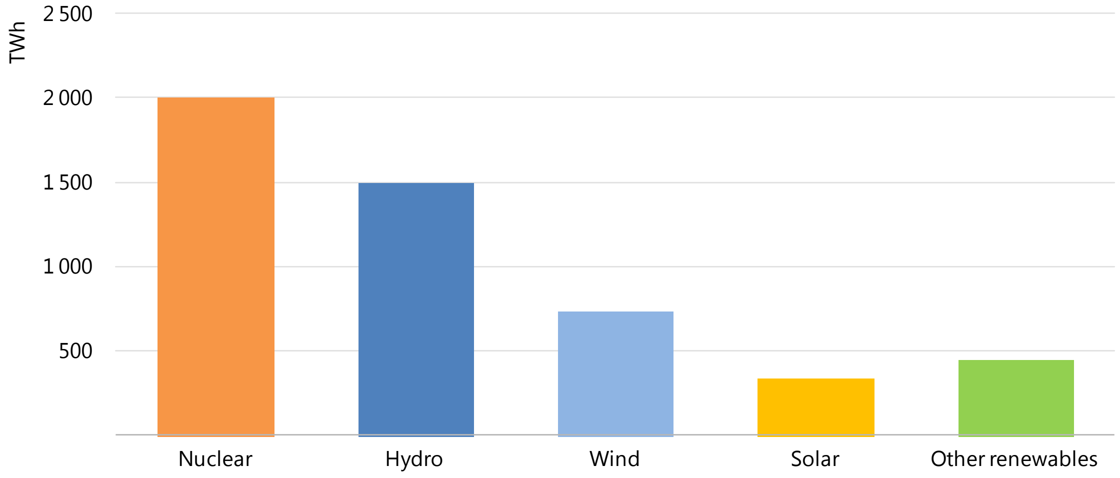


*2016 data; **2017 data.

Nuclear power is an important low-carbon source of electricity in many advanced economies.

In advanced economies as a group, nuclear power is the largest low-carbon source of electricity, providing 40% of all low-carbon generation (Figure 2). Nuclear generation totalled just over 2 000 terawatt hours (TWh) in 2018, outstripping hydropower by one-third, and representing nearly double the combined output of solar and wind projects. Nuclear power is the largest low-carbon source of electricity in 13 individual advanced economies: Belgium, Bulgaria, the Czech Republic, Finland, France, Hungary, Korea, the Slovak Republic, Slovenia, Spain, Sweden, the United Kingdom and the United States.

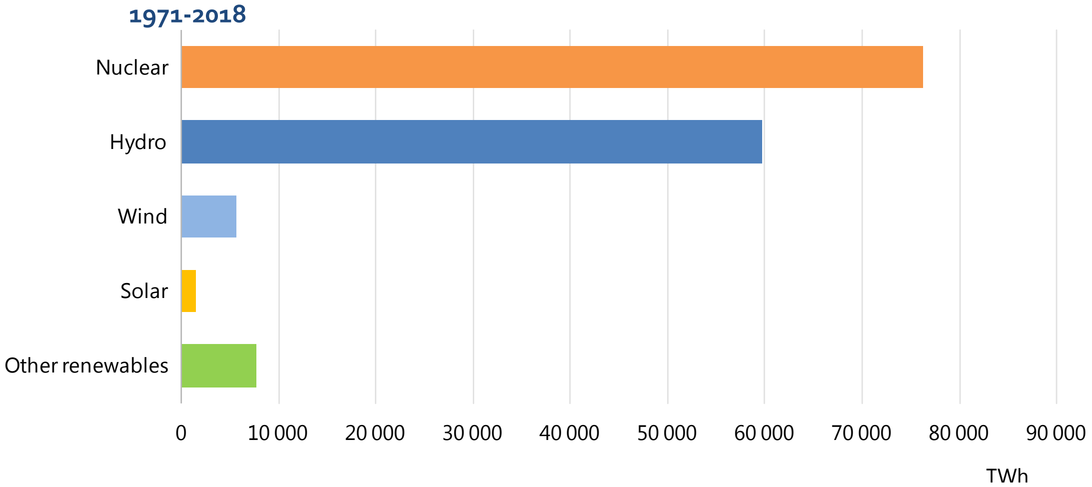
Figure 2. Low-carbon electricity generation in advanced economies by source, 2018



Nuclear power is the leading low-carbon source of electricity in advanced economies today.

Over the past 50 years or so, nuclear power has provided around one-half of all low-carbon electricity in advanced economies. During the period from 1971 to 2018, nuclear power provided some 76 000 TWh of zero-emissions electricity – more than ten times the total output of wind and solar combined (Figure 3).

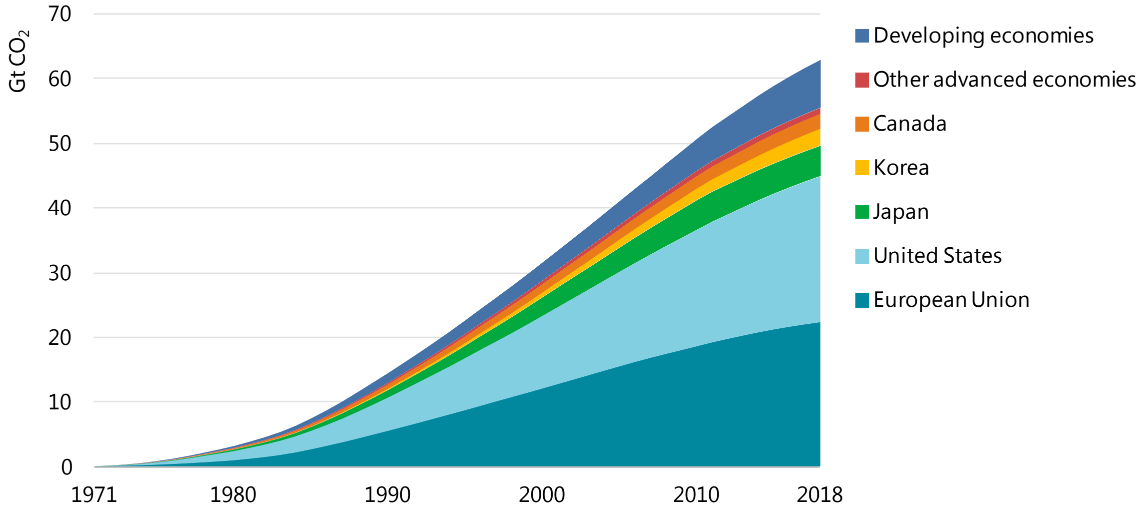
Figure 3. Cumulative low-carbon electricity generation in advanced economies by source, 1971-2018



Nuclear power and hydropower account for 90% of low-carbon electricity since the 1970s.

Nuclear power has helped to slow the long-term increase in emissions of carbon dioxide (CO_2) over the last half-century, particularly in advanced economies. Globally, nuclear power output avoided 63 gigatonnes of carbon dioxide ($GtCO_2$) from 1971 to 2018 (Figure 4). Without nuclear power, emissions from electricity generation would have been almost 20% higher, and total energy-related emissions 6% higher, over that period. Nearly 90% of the avoided emissions were in advanced economies. The European Union and United States each avoided about 22 $GtCO_2$ – equal to more than 40% of total power sector emissions in the European Union and one-quarter in the United States. Without nuclear power, emissions from electricity generation would have been 25% higher in Japan, 45% higher in Korea and over 50% higher in Canada over the period 1971-2018.

Figure 4. Cumulative CO_2 emissions avoided by global nuclear power to date

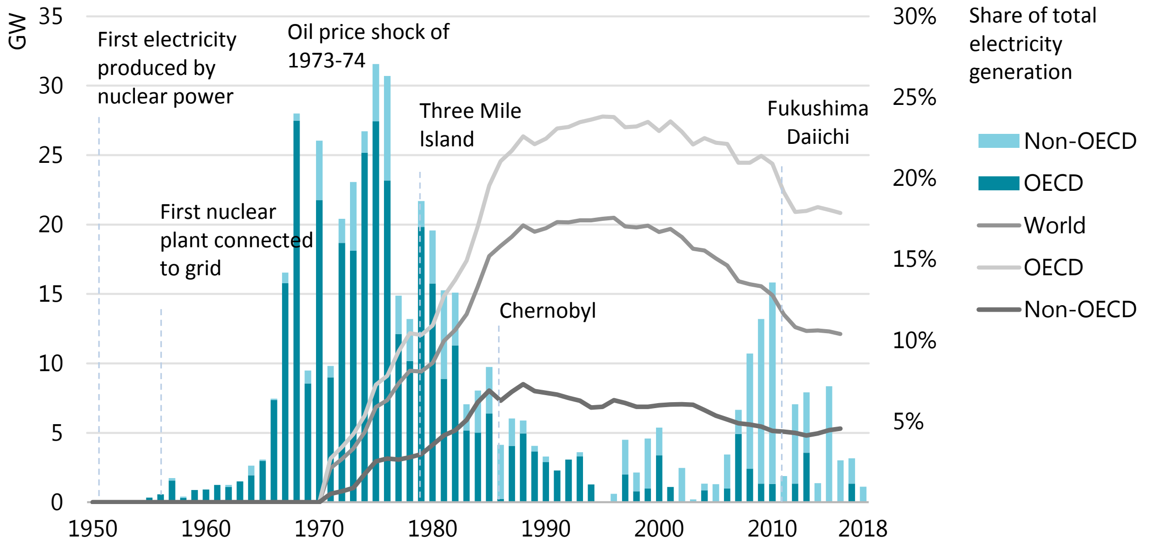


Without nuclear power, global CO_2 emissions from electricity generation would have been almost 20% higher over the last half-century.

Nuclear reactors in advanced economies are ageing

With a sharp slow-down in the rate of commissioning of nuclear reactors in advanced economies in recent years, the average age of the world's fleet of reactors has been rising, despite increased capacity in the developing economies. Most of the nuclear power plants now in operation in advanced economies were built in the 1970s and 1980s. In the early 1970s, nearly 80% of electricity generation came from coal, oil and gas, with hydropower making up most of the rest. The construction of nuclear reactors world wide surged in the 1960s and 1970s (Figure 5). In the peak years of 1974-75, over 30 GW per year was added – equivalent to nearly 3.5% of total global electricity demand at the time and about twice the share that electricity generated from renewable sources of energy (renewable electricity) is adding today. Most of this capacity was built in advanced economies. This wave of construction resulted in a rapid increase in the share of nuclear power in the overall electricity generation mix. By the mid-1990s, the share reached 18% world wide and 23% in advanced economies.

Figure 5. Reactor construction starts and share of nuclear power in total electricity generation



Note: OECD = Organisation for Economic Co-operation and Development.
Sources: IAEA (2019), Power Reactor Information System (PRIS) (database); IEA (2018a), Electricity Information 2018 (database).

Most of the nuclear reactors in operation today in advanced economies were built before 1990.

The number of construction starts for new nuclear power plants slowed dramatically in the 1980s, particularly in advanced economies outside Japan and Korea, and had slowed to a trickle by the late 1990s. Construction has picked up since then, with most new projects being located in developing economies, led by the People's Republic of China ("China") and India. There are now 54 reactors under construction (Table 1), of which 40 are in the developing economies, led by China, with 11 units, India (7), the Russian Federation ("Russia") (6) and the United Arab Emirates (4). In advanced economies, Korea has the most units under construction (4), followed by Japan (2), the Slovak Republic (2), the United States (2), and Finland, France, Turkey and the United Kingdom (1 each). The recent wave of construction starts in the developing countries is on a smaller scale than that in advanced economies four decades earlier, so the share of nuclear power in the generation fuel mix in the developing economies has grown more modestly, reaching 6% in 2018.

Table 1. Nuclear power generating gross capacity by country, May 2019

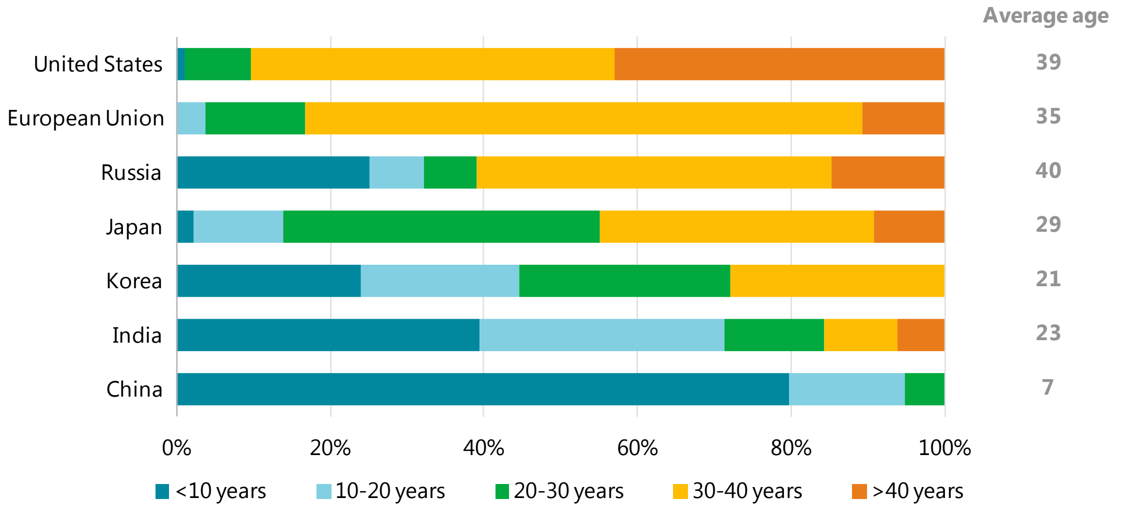
Country	Existing gross capacity (GW)	Gross capacity under construction (GW)
Advanced economies	**312**	**18**
Belgium	6	0
Bulgaria	2	0
Canada	14	0
Czech Republic	4	0
Finland	3	2
France	66	2
Germany	10	0
Hungary	2	0
Japan	39	3
Korea	25	6

Country	Existing gross capacity (GW)	Gross capacity under construction (GW)
Mexico	2	0
Netherlands	1	0
Romania	1	0
Slovak Republic	2	1
Slovenia	1	0
Spain	7	0
Sweden	9	0
Switzerland	3.5	0
Turkey	0	1
United Kingdom	10	2
United States	105	2.5
Developing economies	**110**	**41**
China	46	12
India	7	5
Russia	30	5
Other developing economies	27	19
World	**422**	**59**

Source: IAEA (2019), Power Reactor Information System (PRIS) (database).

The world's nuclear fleet is ageing due to the large construction wave in the 1970s and 1980s and the more modest rate of construction in recent years. Globally, the average age of nuclear capacity stands at 32 years. In advanced economies, it is 35 years. Outside Japan and Korea, nearly 90% of the nuclear reactors in advanced economies are more than 30 years old. By contrast, the average age in developing economies is just 25 years. Excluding Russia, most reactors in those developing economies are less than 20 years old. China, which accounts for most of the nuclear power plants built during the past two decades, has a particularly young fleet (Figure 6).

Figure 6. Age profile of nuclear power capacity in selected countries/regions



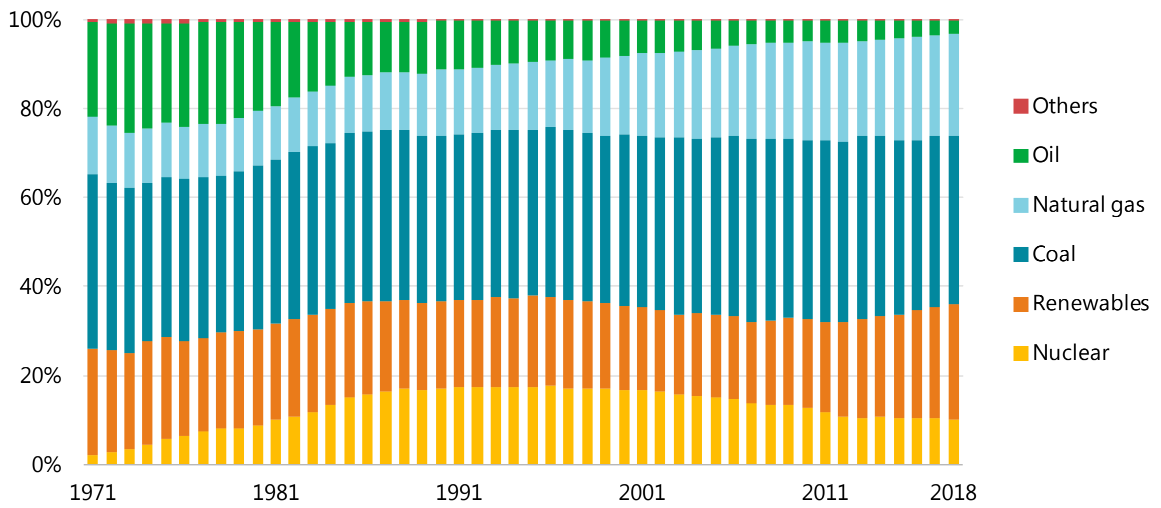
Source: IAEA (2019), Power Reactor Information System (PRIS) (database).

Most nuclear power plants in the European Union and the United States are more than 30 years old, while plants in developing countries – notably China – are much younger.

The operators of many older nuclear plants have been investing in improvements in their operational performance and extending their operating lifetimes. In some cases, this has involved increasing capacity. The lifetimes of several plants have already been extended well beyond those originally planned, and many others will soon face extension decisions. Most nuclear power plants have a nominal design lifetime of 40 years, but engineering assessments have established that many can operate safely for longer. In most cases, such extensions (typically to 50 or 60 years) require significant investment in the replacement and refurbishment of key components to allow units to continue to operate safely.

In the United States, where 90 of the 98 reactors in operation have already had their operating licences renewed from 40 to 60 years, the Nuclear Regulatory Commission (NRC) and the industry are focusing on "subsequent license renewals", which would authorise plants to operate for up to 80 years. The NRC has developed guidance for staff and licensees specifically for the subsequent renewal period. In Europe, several plants have recently obtained licence extensions or are on the verge of obtaining them. For example, plants recently obtained 20 year extensions in the Czech Republic, Finland and Hungary, while three reactors in Belgium have had their operations extended by ten years. In France, licences have so far been renewed for ten years on a rolling basis where they meet safety requirements. France's nuclear safety authority plans to issue a generic ruling on lifetime extensions for the 900 megawatt (MW) series of plants operated by state-controlled Électricité de France (EDF) by the end of 2020, given that final approvals would be further issued on a reactor-by-reactor basis. In Sweden, decisions have recently been taken to extend the operational lives of five reactors. In Canada, operators are pursuing lifetime extensions for most of the country's nuclear fleet.

Figure 7. Share of energy sources in global electricity generation



The decline in nuclear power's share in electricity generation has entirely offset the growth in the share of renewables since the late 1990s.

The share of nuclear power in the world's electricity generating fuel mix has fallen steadily in recent years, from a peak of around 18% in the mid-1990s to 10% in 2018 (Figure 7). This has slowed the transition towards a low-carbon electricity system. Despite the impressive growth of solar and wind power output in recent years, the overall share of low-carbon energy sources in total electricity supply in 2018, at 36%, was the same as it was 20 years earlier. In other words, the eight percentage point fall in the contribution of nuclear power over the past two decades entirely offset the increase in the share of renewables.

Nuclear power helps to bolster energy security

Nuclear power can contribute to energy security in three main ways. First, nuclear power provides diversity in electricity supply and in primary energy supply. For countries lacking their own domestic energy resources, reliance on nuclear power can reduce import dependence and enhance supply security. For example, in Japan, which must import all its fuels for non-renewable power generation, it is estimated that fuel imports over the period 1965-2010 were reduced by at least 14.5 trillion yen (USD 132 billion [United States dollars]) due to the development of nuclear power. Several countries in Central and Eastern Europe see nuclear power as an important means of enhancing their energy security (Box 1). Second, the relatively low fuel cost of nuclear power means that the operating costs of plants are less subject to fuel price volatility than fossil fuel plants, which are the other conventional source of power (a 50% rise in the fuel cost results in a mere 5% increase in the overall cost of generating electricity with nuclear power). Third, nuclear power plants provide reliability services as a dispatchable form of generation, i.e. output can be dispatched to the system as and when required.

Box 1. Nuclear power and energy security in Central and Eastern Europe

Several countries in Central and Eastern Europe have robust policies to support nuclear power. The share of nuclear power in electricity generation is above 30% in the Slovak Republic, and over 50% in the Czech Republic and Hungary – among the highest shares in the world. The policy stance is also supportive in Bulgaria and Romania. Nuclear power does not yet play a role in Poland, but there are plans to build the country's first reactor. There are some common factors that make nuclear power an attractive option across the region.

Coal-fired generation is expected to decline. Six countries (the Czech Republic, Hungary, Poland, Romania, the Slovak Republic and Slovenia) make up just 13% of total European Union (EU) electricity demand but over one-third of coal-fired generation. Their coal-fired plants are covered by EU climate policy, notably a carbon penalty under the European Union Emissions Trading System (EU-ETS), which raises questions about plant long-term viability, especially as most are old and inefficient. Given EU climate goals, there is no realistic prospect of any major investment in new coal-fired plants, so the region is set to lose a substantial amount of dispatchable coal capacity over the next two decades.

Gas supply security concerns. The region remains highly dependent on imports of gas from Russia. Apart from in Romania, there is little prospect of new domestic production. Disruptions in the supply of Russian gas through Ukraine in 2006 and 2009 highlighted the region's energy insecurity. While major progress has been made since then in building new gas interconnectors, reverse flow capability and increasing access to liquefied natural gas (LNG), governments in the region still regard their gas import dependency as an energy security risk. This limits the policy appetite for gas-fired power generation. Phasing out nuclear power and replacing it with gas would increase gas consumption by 37%, all of which would need to be imported.

Limited renewable energy resources. Prospects for the expansion of renewables are less encouraging than in the rest of Europe. There has been significant investment in wind power on the Black Sea coast of Romania, and the Czech Republic experienced one of the earliest booms in solar investment in 2010/11. But large parts of the region, including the Czech Republic, Hungary and the Slovak Republic, have a weak wind potential. Northern Poland has better resources, but there are considerable barriers related to land use and social acceptance. While the share of renewables in electricity generation will undoubtedly grow, official energy strategies in the region tend to regard 100% renewables as unrealistic and envisage nuclear power making a sizeable contribution to decarbonisation.

Social acceptance. Public opinion remains broadly supportive of nuclear power across the region; in most countries, there is a cross-party pronuclear stance. This makes it more feasible to implement nuclear projects that span several political cycles.

Domestic nuclear capabilities. In the Czech Republic, Hungary and the Slovak Republic, nuclear power plants have operated for many years. Consequently, there is a skilled workforce and well-developed expertise on nuclear engineering and operations. In particular, the Czech Republic has long-standing capabilities in manufacturing and supplying components for nuclear power plants. In contrast, there is virtually no manufacturing of renewable equipment anywhere in Central or Eastern Europe; nearly all the wind turbines and solar panels in use are imported. The existence of human capital and an industrial base makes it more attractive for governments in the region to retain nuclear in their energy mix.

The dispatchability of nuclear power makes it valuable to the electricity system. Dispatchable capacity contributes to system reliability and adequacy (the power system's ability to meet demand in the long term, ensuring there will be enough supply to meet demand with a high degree of certainty at all times). In practice, the relatively low fuel costs of nuclear power plants compared with plants that run on fossil fuels mean that, in many markets, they are better suited for baseload generation, providing power at full output in a continuous fashion throughout the year (except during maintenance shut-downs) rather than modulating their production according to the demand for electricity. However, nuclear power plants can be operated in a flexible manner, although this may require minor changes in plant design. In France, the cost-competitiveness of nuclear generation led to it attaining a high share in the overall generation fuel mix (around 75% since the 1980s) and has thus encouraged the incorporation of flexibility into reactor designs to allow some plants to ramp up and down their output quickly at short notice. German nuclear power plants also have these capabilities, allowing them to accommodate increasing shares of variable renewable energy (VRE). Such capabilities will become increasingly important as the overall share of VRE continues to grow (see below).

Prospects for existing plants in advanced economies

Policy decisions remain critical to the fate of ageing reactors

The rate at which the existing nuclear fleet of nuclear reactors in advanced economies is retired relies on policy and regulatory decisions, as well as economic factors (see the next chapter). As of May 2019, there were 318 reactors operating in those countries with a total capacity of 315 GW. This capacity is set to decline as retirements gather pace with ageing of the fleet:

around one-quarter of capacity is set to be shut down by 2025. Phase-out policies are responsible for most of the recent retirements and those scheduled for the next few years. Over 15 GW of nuclear capacity is in the process of being phased out due to political decisions in Belgium and Germany. Switzerland has also decided to phase out nuclear power, although no dates have been set yet. Korea has set limits on the lifetime of existing plants that would see 12.5 GW retire by 2040. An agreement among Spanish utilities would see all the country's nuclear power plants close between 2028 and 2035 (Box 2). France, which has the largest nuclear power capacity in Europe, envisages a continuing long-term role for nuclear power, but it is seeking to reduce its share in the generation fuel mix to 50% by 2035.

Box 2. Agreement to close nuclear power plants in Spain

Spain has seven reactors with a total capacity of 7.4 GW (see the table below). Most of the reactors are co-owned by Spanish utilities, mainly Endesa and Iberdrola, which together hold 90% of the nuclear capacity. Following lengthy discussion about the future of existing reactors in Spain, an agreement was reached in March 2019 that all nuclear power plants would close between 2027 and 2035 – effectively limiting lifetimes of all the plants to 44-47 years. The deadline for deciding on an extension for the Almaraz I plant was March 2019, which led the utilities to seek a decision on extensions for all the plants. The agreement has a clause whereby the plants could shut down early should the Nuclear Safety Body impose onerous conditions on the investments needed. In addition, the new government that took office in May 2018 appears less favourable to nuclear power. Unless something unexpected occurs, this calendar will be respected by all stakeholders.

Agreed closures of nuclear power plants in Spain

Unit	Gross capacity (MW)	Year commissioned	Year scheduled for closure
Almaraz I	1 049	1983	2027
Almaraz II	1 044	1984	2028
Ascó I	1 032	1984	2030
Cofrentes	1 092	1985	2030
Ascó II	1 027	1986	2032
Vandellós II	1 087	1988	2035
Trillo	1 066	1988	2035

The decision to seek limited lifetime extensions was motivated partly by economic factors. In December 2012, in the middle of discussions about lifetime extensions, the Spanish Parliament approved new taxes on the production and storage of spent nuclear fuel and radioactive waste. These taxes came on top of existing levies aimed at funding the management of nuclear waste and the decommissioning of nuclear facilities. Due to the increased tax burden and low wholesale electricity prices, the economic case for investing in the plants to obtain lifetime extensions has been called into question. Despite this, an analysis prepared by the Massachusetts Institute of Technology suggests that it would bring economic and environment benefits.

Regulatory decisions about approvals required to extend operations at plants from the central regulatory bodies and local authorities will affect the rate of closures. Some 40 GW of nuclear power capacity in advanced economies is vulnerable to regulatory risks in the near term (Table 2). In the case of France, of the country's 58 reactors, which have a combined capacity of 66 GW, one-third must pass their fourth ten-year safety inspections before 2025 to continue operating and two-thirds must do so before 2030. In addition, concerns about the safety of old plants could lead to longer outages, as has occurred in recent years at plants in Belgium, France, Korea and the United Kingdom.

Table 2. Near-term regulatory decisions for existing nuclear reactors by country

Country	Decision type	Comment	Capacity (GW)
United States	Extension of operating licence	Operating reactors yet to receive initial 20 year extension: three more applications are expected	4.9
France	Extension of operating licence	Eighteen reactors must pass inspection before 2025 to continue operations	17
Japan	Pending decisions to restart reactors	Ten reactors are under review to restart operations	9.4
Mexico	Extension of operating licence	Application submitted in 2015 pending for Laguna Verde	1.5
Spain	Extension of operating licence	Operating licences for all eight reactors expire by 2025	7.4

In the United States, the length of time that operations at ageing nuclear power plants can be extended is a major uncertainty. There are 98 reactors in operation with a total capacity of 105 GW and an average age of nearly 40 years. By 2030, 24 GW (nearly one-quarter) of this capacity will need to obtain extensions to operating licences or shut down; another 62 GW will reach the end of its operating licences by 2040. Eight reactors have not yet received an initial 20 year operational lifetime extension: one decision is pending and three further applications are expected soon. As of May 2019, six reactors had submitted applications to extend operations beyond the end of their current second licences that expire in the early 2030s, which would allow operations until 80 years.

In Japan, the central question on the future of existing nuclear power plants is how many of the 55 nuclear reactors that were taken off line shortly after the accident at Fukushima Daiichi in 2011 will ever be allowed to restart. Nine reactors have already been brought back into operation having received Nuclear Regulation Authority approval; another six have obtained the approval but have not yet been restarted. Two others are under construction. If no other reactors are brought back on line, the share of nuclear in electricity supply in Japan is expected to rise from 3% in 2017 to about 10% in 2030. In this case, achieving the target of a 44% share of zero-emissions energy sources in power generation in the same year under the Fifth Strategic Energy Plan (updated in 2018) will be difficult. Of the 44% share, 20-22% is expected to come from nuclear power. Another ten reactors with a combined capacity of 12.2 GW that are under regulatory review could provide an additional 80-90 TWh of electricity per year (7-8% of the total supply), making the zero-emissions target much more achievable. This level of output still falls well below the historical contribution of nuclear power: in the decade before the accident in 2011, nuclear power provided 26-31% of electricity supply each year. Even if all this capacity were brought back on line, without further operational lifetime extensions, nuclear power would provide just 2% of the electricity supply in 2040, as more than one-half of the nuclear fleet was built before 1990. An additional nine reactors with a combined capacity of 8.8 GW have not yet applied for licences to restart.

Owing to longer outages, Japanese nuclear power plants have had relatively short operating hours than those of the same age in other countries. Considering the long period that they were required to be off line after the Fukushima Daiichi accident, Japanese nuclear power plants would end up with much shorter operating periods than those in other countries if required to retire at 40 years. From a technical point of view, the ageing of the reactor vessel is primarily determined by the period when chain reactions are taking place in it; an idle reactor ages slower than one that is operated continuously.

Market pressures may lead to early retirements

Economic factors (notably electricity market conditions) are affecting the continued operation of existing nuclear power plants, particularly in the United States. Economic pressures on power generators in advanced economies have increased in recent years with the introduction of competitive wholesale electricity markets. Nuclear plants, like other conventional power plants in these markets, are now exposed to market conditions. Many plants were built and brought into operation at a time when the price of wholesale power was regulated, usually on the basis of cost, which protected them from the risk of unexpectedly low prices and short-falls in revenue.

Across advanced economies, weak electricity demand, rapid growth in renewables-based power supply and low natural gas prices in the United States are putting pressure on the financial performance of existing conventional power generators, including nuclear plants. Although the operating costs of nuclear plants are relatively low compared to other types of power plants, significant ongoing investments are often required (especially to obtain an extension to an operating licence), which operators may not be able to recover if wholesale prices are too low. In the United States, two nuclear units have been retired over the past three years and as many as nine more units could be retired in the next three years, largely for economic reasons. In some cases, the introduction of carbon pricing and rising carbon prices has provided some respite to nuclear power generators. The impact of competition in electricity markets on nuclear plants is explored in more detail in the next chapter.

Barriers to investment in new nuclear power plants

The prospects for new nuclear power projects remain highly uncertain. Some countries have decided to prohibit investment in new projects and phase out existing capacity in a progressive manner, though the timing of the closure of plants remains unclear in some cases. Others envisage a long-term role for nuclear power in their energy system. The countries that fall into the second category account for most of the global electricity demand and the CO_2 emissions, suggesting considerable potential for nuclear power to contribute to the transition to a clean energy system.

The prospects for building new nuclear capacity are of considerable importance to achieving the transition. Even if most existing reactors had long operational lifetime extensions, the share of nuclear power in electricity generation will eventually fall to zero if no new plants are built. A slow-down in nuclear phase-out programmes and longer extensions would reduce the need to ramp up the use of renewable power. However, without new construction, nuclear power can only ever be a bridging fuel.

There are major hurdles to investment in nuclear power, even in those countries that have retained the option to develop new capacity. Overcoming these hurdles represents a major challenge for policy makers and the nuclear power industry. The greatest barrier concerns the ability of nuclear power to compete with other generating technologies on cost, especially in countries that have introduced competitive wholesale markets (discussed in detail in the next chapter). This is exacerbated in power sectors where nuclear's low-carbon nature is not recognised, either through policies such as carbon pricing or wholesale market designs and mechanisms supporting investments in low-carbon technologies in general. However, even where investors are confident that future electricity and carbon prices will be high enough to cover the cost of new nuclear projects, some risks specific to the nature of the technology may prevent investment from going ahead. The main obstacles relate to the sheer scale of investment and related time horizons, the risk of construction problems, delays and cost overruns (project management risk), and the possibility of future changes in policy (policy risk) or in the electricity system itself (disruption risk). In terms of project lead-times, economic lifetimes and complexity of stakeholder management issues, the current nuclear projects are closer to major infrastructure projects than most other power generation technologies.

Huge capital needs and long time horizons increase project risk

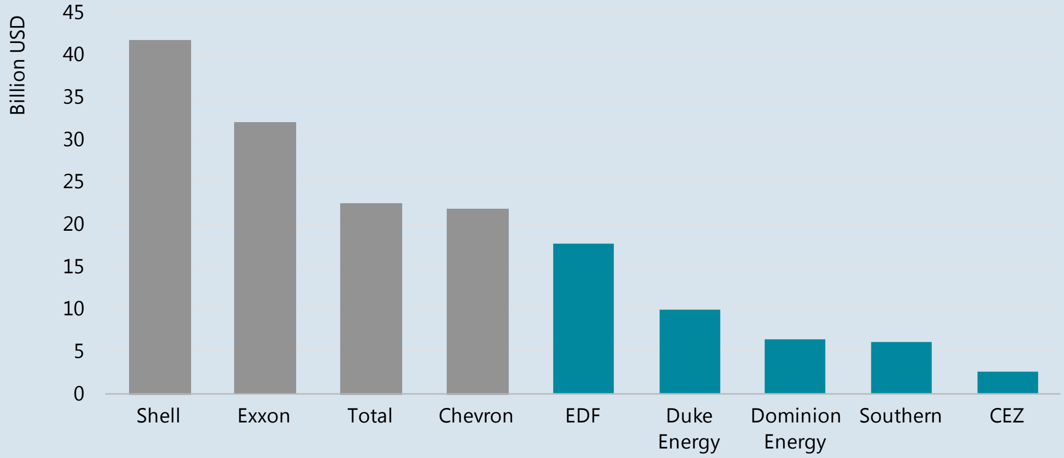
The construction of new nuclear power plants using current technology calls for huge amounts of capital for large-scale projects. Projects launched in the past decade in Europe and the United States involve advanced (or Generation III) pressurised water designs: the AP1000, developed and sold by Westinghouse Electric Company in the United States, and the European Pressurised Reactor (EPR), developed by France's EDF and Framatome (formerly Areva and now an EDF subsidiary) and Germany's Siemens. Both designs are intended for large-scale units with capacity exceeding 1 GW and require investment of several billion USD over a few years. For example, the cost of the 1.63 GW EPR being built by EDF in Flamanville in France has ballooned to over USD 12 billion. These projects are among the biggest energy projects in the world. The nuclear projects under way in developing economies, which primarily use Chinese and Russian designs, are also on a large scale. Globally, the average size of new construction starts in recent years has been above 1 GW.

Given the sheer size of investment needed in a nuclear power plant, financing can be difficult. In general, the liberalisation of wholesale electricity markets has increased investment risk for power generation projects and turned investment preferences towards less capital-intensive technologies such as gas turbines. The large individual project size of a nuclear plant reinforces the effect of market risk. Few private electricity utilities have the financial capabilities to support such an investment on their own. Investment in LNG projects can be on a similar scale to that in nuclear power projects, but there are important differences that make financing of LNG projects much easier in practice (Box 3).

Box 3. Size matters – investing in nuclear power is different to investing in LNG

The capital needs of a third-generation nuclear power plant are comparable to that of a large LNG facility. Both are susceptible to delays and cost overruns. However, there are important differences that affect the nature of the investment and the ease of financing. LNG projects are typically developed by large international oil companies, which have significantly larger financial strength than even the largest electric utilities of advanced economies (see the figure below). In addition, project risk is normally spread, with finance coming from several companies; the project developer often has a minority share only. For example, the largest LNG project in history, Gorgon in Australia, cost over USD 50 billion, but represented less than 20% of the capital spending of Chevron – the project developer – during its construction. As a result, despite cost overruns exceeding USD 17 billion, Chevron was able to maintain attractive returns on its entire corporate portfolio.

Financial performance* of selected major oil companies and large utilities involved in nuclear power, 2017



* Earnings before interest, taxes, depreciation and amortisation.

In theory, this approach to diversifying risk is possible in the case of nuclear power plants. However, in practice, it is hard to put in place due to a scarcity of potential investors and difficulties in allocating the complex risks of a nuclear power project. A new nuclear project would absorb nearly all the entire capital budget of most large utilities, so the stakes are higher for the company to bet on a single project. Developing a new fleet of nuclear power plants, which would enable the owner to take advantage of learning by doing to decrease unit costs, would be even more daunting.

Because of the sheer scale of the investment required, all but 7 of the 54 nuclear power plants under construction globally are owned by state-owned companies and all but one of the projects in private hands (all of which are in advanced economies) are subject to price regulation, which reduces risks to investors (Table 3). This is unlikely to change soon. In the current policy and market environment, it is difficult to see any privately owned utility embarking on a Generation III project in Europe or in North America without strong government support to minimise financial risks to investors. In developing countries, state-owned companies are responsible for all new nuclear investment.

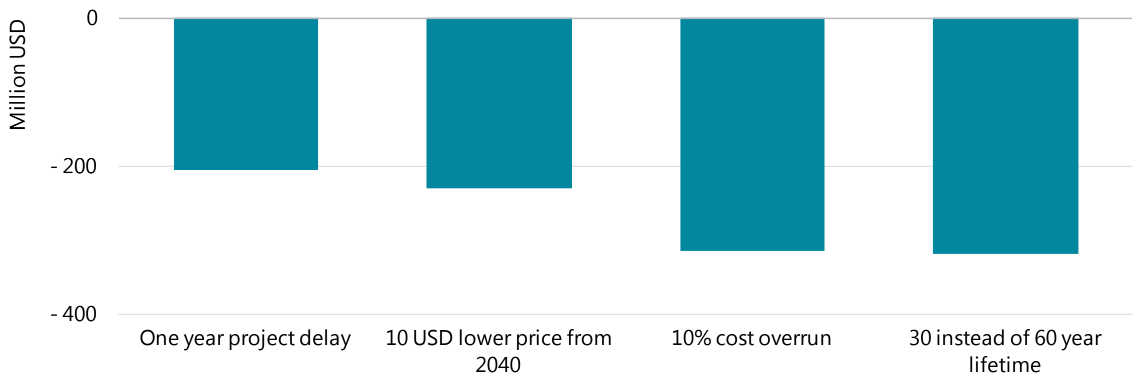
Table 3. Nuclear power plants under construction by ownership and region

Economy type	Number of plants	State-owned operator	Private operator – regulated environment*	Private operator – wholesale market
Advanced economies	14	7	6	1
Developing economies	40	40	0	0
World	**54**	**47**	**6**	**1**

* Includes plants where construction began before the opening of wholesale markets.
Sources: IAEA (2019), Power Reactor Information System (PRIS) (database); Platt's Nucleonics Week Statistics Monthly (database).

The project development lead-time of a modern nuclear project designed for a 60 year lifetime is several years at a minimum and often exceeds a decade – even without project delays. This is well beyond the usual time horizon of normal business planning or even policy analysis. This increases the uncertainty about whether the plant, once commissioned, will be able to generate an acceptable return on investment, as revenues cannot be forecast with a high level of certainty. For example, cutting the average electricity price assumption by USD 10 per megawatt hour (MWh), in 2040 lowers the net present value (NPV) of a nuclear project launched today by over USD 200 million (Figure 8).

Figure 8. Impact of various risks on net present value of a 1 GW nuclear power project with guaranteed revenues to 2040



Note: All the sensitivities are compared with a "best-case" nuclear project, which assumes an investment cost of USD 4.5 billion per GW, a six year project construction time frame, a 60 year lifetime and a 7% cost of capital.

Economic viability of a large-scale nuclear power plant is highly sensitive to project delays, future electricity prices, cost overruns and plant lifetime.

In principle, the price risk associated with long lead-times can be reduced through long-term contracts with electricity buyers. Such contracts do exist in electricity markets among private players, but usually run for no more than 10 to 20 years, which is insufficient for nuclear power projects.

Another approach is to share the risk with electricity consumers. Public utilities in the regulated markets of North America can recover their costs associated with generation, networks and supply through regulated tariffs from end users. Even in liberalised retail markets, given the inertia of small consumers and their reluctance to switch suppliers, building a sizeable retail portfolio can be seen as a form of "virtual vertical integration". The sustainability of such an approach is questionable, as new digital solutions and the spread of decentralised solar generation make even retail revenues less predictable than before and carry the risk that government policy may require changes in market structure in the future. As a result, the impact of vertical integration as a means of reducing market risk is lessened. Contracting with or direct equity participation by energy-intensive consumers – an approach that Finland has pioneered – can also help manage price risk, but it is unclear to what extent this can be replicated in other jurisdictions.

In some cases, direct government intervention has been used to support private sector investment in nuclear power in electricity markets. The United Kingdom has been innovative in this regard. It has provided a contract for differences at a rate of GBP 92.50 (pound sterling) per MWh for 35 years for the Hinkley Point C plant. Following an extensive negotiation, the United Kingdom was not successful in obtaining new nuclear investment at the Wylfa site, despite its offer to provide one-third equity participation, the provision of debt financing required for the project and a contract price of up to GBP 75 per MWh. The United Kingdom is considering a Regulated Asset Base model, whereby the generator receives payments during the construction phase and during operations. This approach allows investors to see a return before the plant starts generating electricity. This has two effects on the financing cost of the project: first, it begins paying off the investment earlier, thus reducing the impact of compound interest, and second, it reduces the risk that investors see no return on investment so they may be willing to invest at a lower financing rate.

Disruption and policy risks are growing

Having been a technologically stable industry for many years, the electricity sector – from power generation, through transmission and distribution (T&D), wholesale and retail supply, to consumption – is now undergoing a profound technological transformation. This is having far-reaching effects on the way the sector operates and business is done. The rapid growth in wind and solar power is just one aspect of this transformation. Major changes are also occurring in the way the network is managed and operated, as well as in the way end users are consuming electricity, due to technological advances specific to electricity and the spread of digital technologies.

Future technological changes and associated changes in market structure could undermine the ability of investors in existing and emerging generating technologies to recover their investments. This "disruption risk" is growing because the future evolution of the electricity system and market structure is increasingly uncertain. One factor that is expected to undergo profound change is the provision of electricity system flexibility – modifying generation or consumption patterns to meet demand at any given moment. Up to now, flexibility has largely been provided through supply-side solutions, i.e. adjusting supply to meet a given level of demand by ramping up or down output at power stations. If deployed on a large scale, batteries and other forms of energy storage would have a major impact on price formation and thus on the returns of a nuclear power investment or other conventional technologies. Similarly, growth in the use of digitalised demand-side response, whereby consumers adjust their electricity consumption in real time in response to price incentives, or the use of electric vehicles (EVs) as storage to meet demand at peak, could have major implications for the way the industry operates and provides revenues to nuclear power and other conventional generators.

Emerging power generation and flexibility technologies generally have much shorter project lead-times and involve smaller projects than Generation III nuclear units. This makes them far more attractive to private investors, as the initial capital needs are smaller and investment strategies can be fine-tuned. Even the largest offshore wind farms[2] are far smaller than nuclear power plants; they use modular technology and are developed in stages.

A rational response from energy companies to increasing uncertainty over the future technology mix and business model is to focus on smaller, modular and short lead-time projects that benefit from learning by doing and enable a flexible rearrangement of the company's asset portfolio. Recent IEA research has documented the parallel decline of average project size and project lead-times in the oil and electricity sectors. Small modular reactors (SMRs), should they become technologically mature, would fit this overall investment approach far better than the Generation III units (see the last chapter).

Nuclear power plants are also subject to considerable policy risk, i.e. the risk that government policy on nuclear power will change at some point in the future. Such a change can include a decision to phase out the use of the technology entirely. Given long construction times, the introduction of a nuclear phase-out policy even 30 years after the original investment decision would still wipe out a substantial proportion of the anticipated revenue of the project (see Figure 8). This is the time frame between the strong pronuclear policies of the early 1980s and the decisions taken after the Fukushima Daiichi accident that have led to early decommissioning and phase-out policies in some countries. Licensing risk is a major concern for new nuclear technologies, and can have a significant impact on projects that are under construction or even in operation if nuclear regulators change the rules. In Japan, the uncertainty related to the timing of restart of idle nuclear power plants is perhaps the biggest uncertainty facing the electricity market.

Policy risks can also take other forms. The main attraction of nuclear power from a policy perspective is its ability to produce large volumes of low-carbon dispatchable power. Climate policies would therefore be expected to favour nuclear power. However, the future ambition and the design of climate policies are uncertain. Even an ambitious climate policy can be detrimental to the economic viability of nuclear power if it includes even stronger incentives for other emissions abatement options. For example, direct support for specific types of renewable energy sources, as opposed to an emissions target, has the tendency to depress wholesale prices and carbon prices, undermining the financial viability of nuclear power plants. Policy risk in advanced economies is discussed in more detail below.

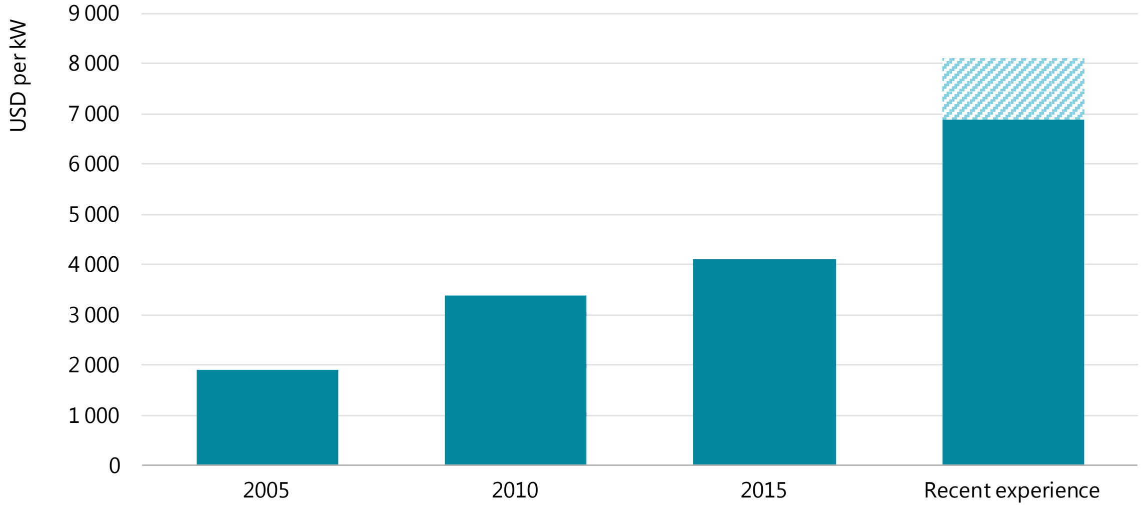
Construction problems, project delays and cost overruns are scaring off investors

The most important reason for the collapse of investor appetite for new nuclear projects in Europe and the United States is the project management track record of the last decade. The two EPR projects in Europe (Finland and France) and the two AP1000 projects in the United States were supposed to herald a renaissance in nuclear power. Instead, they have all encountered major delays, and large cost overruns. In 2017, the construction of two 1.1 GW AP1000 reactors at the Virgil C. Summer plant in South Carolina was cancelled, and USD 9 billion of investment written off because of cost overruns. Work on the other three is continuing, with an average cost overrun of more than 300% compared with assessments made at the time of the investment decision and an average project delay of over five years. It is unlikely that any of these projects will ever generate an attractive return on investment for their owners. The construction cost of these Generation III projects is generally now estimated at

[2] Investment of around USD 2 billion is needed for a 0.5 GW project, with a typical lead-time of four to five years.

around USD 7 000 to 8 000 per kilowatt (kW) – roughly four times the cost estimated in 2005 (Figure 9). Experience in Korea has been better, but even so, recent projects have taken longer to complete than planned.

Figure 9. Projected overnight construction cost of nuclear power capacity and recent United States and Western European experience



Source: IEA analysis based on IEA/NEA (2005, 2010 and 2015 editions), Projected Costs of Generating Electricity.

Construction costs of new nuclear power plants in the United States and Western Europe have turned out to be much higher than projected.

Soaring construction costs in recent years have affected technology suppliers. The EPR consortium in Europe provided guarantees on the construction costs of the new facilities being built in Finland, and Westinghouse did the same in the United States. The guarantees proved damaging to these companies. In 2017, Westinghouse filed for bankruptcy because of the liabilities associated with the AP1000s, and Areva had to be bailed out by the French government.[3]

A comparison between the unfavourable European and North American experiences and the much more successful Korean programme, as well as the historical lessons from the wave of construction in the 1970s, suggests that a sustained and consistent programme of nuclear reactor construction might be able to overcome some of the problems that led to the cost overruns and delays:

The repeated construction of a standardised design, especially multiple reactors on the same site, can lead to gains in efficiency through learning by doing and economies of scale.

- While the AP1000 and the EPR were marketed as fully mature commercial designs suitable for a fixed price contract, they inevitably had some "first-of-a-kind" characteristics. In the case of all four projects, major design modifications (which are often a source of project management problems) occurred during construction. A complete detailed engineering design before construction starts typically reduces project risks substantially.

[3] Areva, which is majority owned by the French state, is responsible only for the liabilities related to the Olkiluoto 3 EPR project in Finland. The rest of its nuclear reactor construction business was sold to EDF in 2017.

- Accumulation of industrial experience and know-how is a main contributor to the more successful new construction programmes outside Europe and North America. Lack of recent experience, a depleting industrial ecosystem and an ageing workforce have been major problems in building the AP1000s and EPRs. There had been no new nuclear construction activity for more than a decade in either Western Europe or the United States before construction of these plants got under way.

However, under existing policies, the chances of the wave of nuclear construction of the 1970s being repeated in Europe and North America appear slim. Given the lack of private sector appetite for investing in nuclear power, the first few projects would need to be underwritten by governments, representing a massive financial commitment. And the capacity additions involved would probably exceed actual needs. Given the large individual project sizes, the capacity built during this learning-by-doing phase would represent a substantial proportion of the electricity demand of a medium-sized system. For these reasons, SMRs, by the nature of their technology, may eventually prove a more attractive option, depending on technological progress.

2. Economics of nuclear power in advanced economies

Impact of competition in electricity supply

The establishment of competitive wholesale electricity markets – a central pillar of the wave of restructuring of the electricity supply industry that has been under way around the world since the late 20th century – is having a major impact on the nuclear power sector. That process, which has transformed the way the electricity sector functions, began in Chile and the United Kingdom in the 1980s, and has since spread to most advanced economies and many developing ones. Today, 53% of the world's electricity production is sold on competitive short-term markets that optimise operations among multiple participants whereby a single spot price is set according to bids from retailers and end users and offers from competing generators for the supply of energy over a specific time period (typically half-hourly or hourly blocks), before being supplied to end users via the grid. In many cases, short-term markets in energy are complemented with other instruments, such as capacity markets, to encourage investment. Competitive mechanisms have also been put in place for ancillary services needed to maintain reliable operations of the interconnected transmission system, including reserves (short-term back-up capacity in case of need), as well as markets for transmission congestion and financial derivatives such as electricity futures and options. Some countries have extended competition to the retail market, allowing all end users (including households in some cases) to choose their supplier.

Those reforms have generally proven successful in improving the efficiency of operations and investment decisions in the countries and subnational jurisdictions where they were implemented. Key to this success is the ability of competitive markets to exert constant downward pressure on the costs of operating, maintaining and developing the electricity system to meet the needs of consumers. Competition for the various services involved in electricity supply has encouraged innovation by market participants, responding to financial incentives to find the cheapest way to supply them, through new ways to operate the plants, by refurbishing them or by investment in new assets.

Although most of the nuclear power plants now operating in advanced economies were designed and built before competition was introduced, that development did not require any major changes to the way nuclear assets were operated. Nevertheless, it has boosted incentives to operate plants in a more efficient manner. Between 1992 and 1998 in the United States, nuclear plants in restructured markets experienced an additional 9.1% improvement in nuclear capacity factors compared to those in markets that did not restructure. Applications for uprates – an authorisation from the regulator for a nuclear plant to increase its output, usually by modifying or replacing certain components – have also been more common in restructured markets.

In countries that have restructured their electricity sector, nuclear power plants (existing and potential new ones) have to compete directly with other types of generators, including renewables and thermal fossil fuel plants. Recent market and policy developments have had a profound impact on the competitive position of nuclear power. This chapter assesses the factors affecting nuclear power's competitive position generally, reviews how nuclear power is faring in Europe and the United States, and assesses how various government support mechanisms are helping nuclear power to compete.

Costs of lifetime extensions and new plants

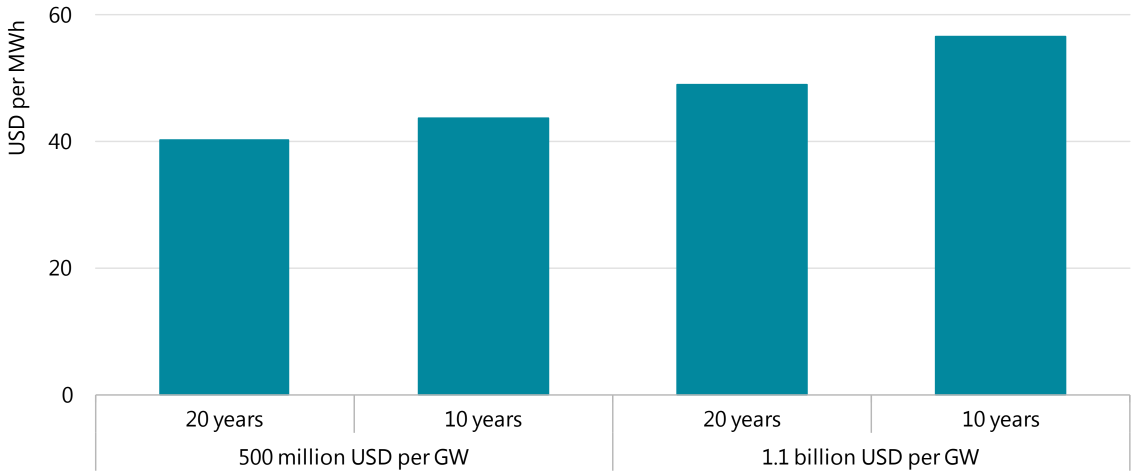
Lifetime extensions are cost-competitive source of electricity

In many cases, carrying out the investment required to obtain authorisation from the regulatory authorities to extend the operating lifetime of a nuclear reactor is an economically and financially attractive option compared with building other low-carbon technologies. The amount of investment varies considerably according to the type of reactor, the length of the extension and the location. In the case of light water reactors, that investment – though often substantial in absolute terms – has often proved less onerous than might have been expected, making it economic, especially where those investment have involved capacity uprates.

The capital cost of extending the operational lifetime of light water nuclear power plants generally ranges from USD 500 million per GW to USD 1.1 billion per GW (Figure 10). Process systems, including safety upgrades to meet regulatory requirements and other non-safety and conventional system upgrades, make up a large share of the total. This category includes work on the reactor itself, shut-down systems, turbo-generators, emergency systems, water circulation, instruments and controls, and cooling and electrical systems. Risk assessment activities and reviews of the operation and maintenance (O&M) procedures can cost more than USD 100 million per GW. Other costs, which cover activities related to aspects of the plant including the original design, operating conditions and maintenance practices since the start of operations, vary widely by plant; they can be as little as USD 50 million or as much as USD 500 million. The duration of lifetime extensions is most often between 10 and 20 years. Regular safety inspections, commonly performed every 10 years, are essential to ensure the continued safe operation of nuclear reactors.

Recent estimates for nuclear lifetime extension costs in France and the United States – the two largest markets for lifetime extensions – fall within the range described above. An OECD Nuclear Energy Agency analysis published in 2012 estimated that the cost of refurbishment of a 1 GW plant was lowest in Korea, at around USD 500 million, and highest in France, at USD 1.1 billion. A later survey of EU nuclear operators estimated the average cost at around USD 650-700 million for a plant of the same size. In the United States, 88 reactors have already started their extended period of operation or will do so within the next decade. A recent report estimated that the associated investment needs for these plants average USD 70 million per year per GW, or USD 700 million per GW over ten years. In France, it was estimated that the Grand Carénage programme of plant retrofits covering the country's entire fleet of reactors will require an annual investment of around EUR 4 billion (euros) over the 2014-25 period to extend the operational life of 64 GW of capacity beyond 40 years.

Figure 10. Indicative levelised cost of electricity (LCOE) for nuclear lifetime extensions



Note: LCOE is based on an 8% weighted-average cost of capital (WACC), 85% annual capacity factor, two year refurbishment period and USD 170 per kW annual O&M costs. LCOE is the average total cost to build and operate a power plant over its lifetime divided by the total energy output of the plant over the same period.

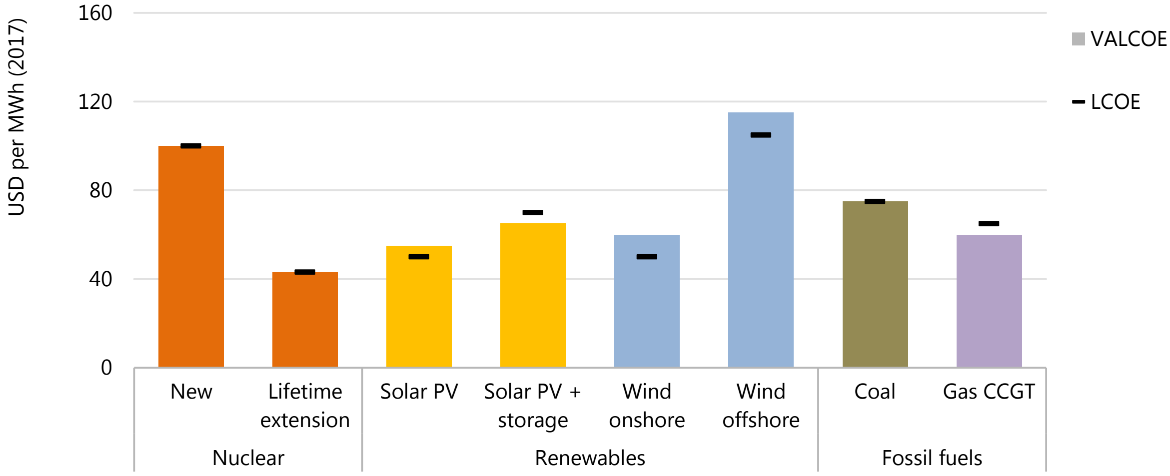
A refurbished nuclear plant will have a levelised cost in the range USD 40-55 per MWh.

Nuclear lifetime extensions are one of the most cost-effective ways of providing low-carbon sources of electricity through to 2040. The levelised cost of electricity (LCOE) associated with a nuclear lifetime extension generally falls in the range USD 40-60 per MWh, based on an investment of USD 500 million to USD 1.1 billion and an extension of 10-20 years (Figure 11). For example, a 20-year extension costing USD 1.1 billion would result in an LCOE of around USD 50 per MWh assuming an 8% weighted-average cost of capital (WACC). For comparison, the average LCOE of new solar photovoltaics (PV) or wind projects are projected to remain above USD 50 per MWh in the European Union and United States under the same financing conditions. This is despite a projected continuing decline in solar and wind power costs. Solar PV costs fell by 65% between 2012 and 2017, and are projected to fall by a further 50% by 2040; onshore wind costs fell by 15% over the same period and are projected to fall by another 10-20% to 2040.

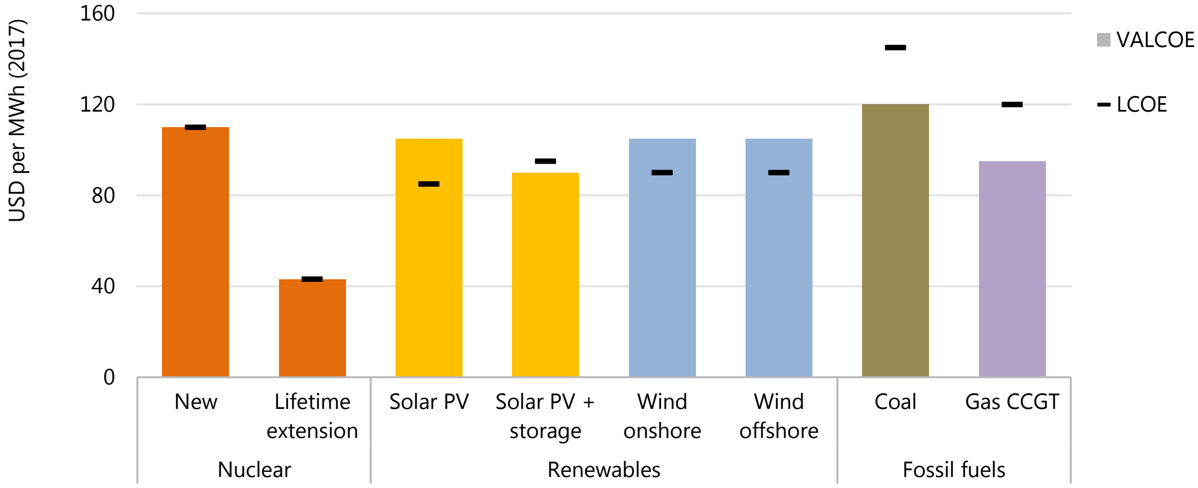
Lowering the cost of capital is an effective means of reducing the LCOE of capital-intensive technologies, including many renewable energy technologies, nuclear power and, to a lesser extent, coal-fired power plants. For example, reducing the WACC from 8% to 4% decreases the presented LCOE of solar PV and wind projects by about 30% and the LCOE of nuclear lifetime extensions by 5-10%. One way of reducing the cost of financing is to reduce the risk related to the project. Long-term power purchase agreements at a specified price, which reduce revenue risk, are a common approach. Competitive auction schemes are an increasingly popular way of driving down the price of electricity supply, having resulted in low prices for solar PV and wind in a growing number of markets. Loan guarantees are another instrument available to policy makers to lower financing costs.

Figure 11. Projected LCOE and value-adjusted LCOE by technology, 2040

a) United States



b) European Union



Notes: VALCOE = value-adjusted levelised cost of electricity; LCOE = levelised cost of electricity; PV = photovoltaics; coal = coal supercritical; CCGT = combined-cycle gas turbines. Nuclear lifetime extension LCOE is based on 1.1 billion USD investment to extend operations for 20 years. Storage paired with solar PV is scaled to 20% of the solar capacity and 4-hours duration. LCOEs are calculated based on an 8% weighted-average cost of capital for all technologies. Other cost assumptions are from the World Energy Outlook 2018 and are available at https://www.iea.org/weo/weomodel/.

Nuclear lifetime extension is competitive with any generation of new build in the United States, and more so in the European Union.

The competitiveness of nuclear plant extensions is even more favourable when the full value of nuclear power as a dispatchable low-carbon source of electricity is taken into account. The LCOE is the most common metric for comparing the competitiveness of power generation technologies, but considers only the costs of generation and does not take into account the value that each technology may provide to the overall electricity system in ensuring flexibility and reliability. A more complete picture of competitiveness requires these values to be considered. The value-adjusted LCOE (VALCOE), a new metric presented for the first time in the *World Energy Outlook 2018* (IEA, 2018b), combines a technology's costs with estimates of these values. Using this measure, nuclear lifetime extensions outperform solar PV and wind power by a wider margin than by simply using LCOE, mainly due to the rising energy costs of solar PV and wind and the increasing costs associated with enhancing system reliability and flexibility as the share of variable renewables in total generation increases.

The economics of new nuclear are difficult today, but could improve in the future

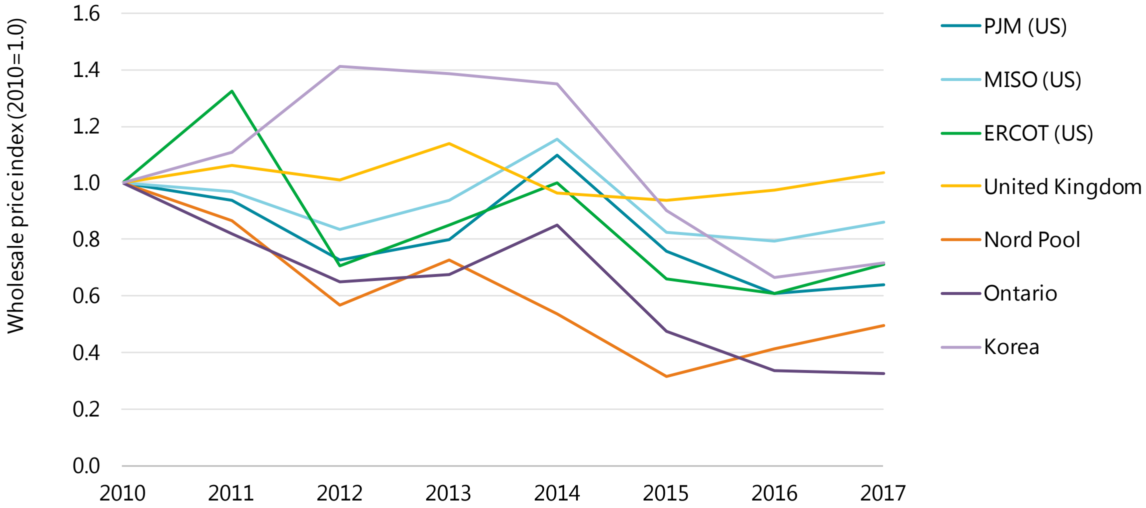
The competitiveness of constructing new nuclear power plants is much less favourable than for lifetime extensions at existing units. In practice, costs vary across countries, sites and type of technology, so projections of the cost of new plants should be considered as indicative of the average. Today, the high capital cost of nuclear makes it significantly more costly on a levelised cost basis than wind power or gas-fired generation in both the European Union and United States. By 2040, in the United States, the LCOE for nuclear power is projected to be around USD 100 per MWh, double that of solar PV and wind. In the European Union, the gap is smaller as nuclear's LCOE averages about USD 110 per MWh compared with wind and solar PV in range of USD 85-90 per MWh.

Using the VALCOE metric reduces this gap in the United States but does not change the picture. It is a different story in Europe, where the VALCOE metric suggests that nuclear power, provided capital costs decrease by one-third from today's levels, would be broadly competitive with solar PV and wind (onshore and offshore). The metric suggests that by 2040, solar PV with four hours of storage will be the most competitive generating technology in Europe (given the generation mix, fuel and CO_2 prices in the New Policies Scenario).

Factors affecting wholesale energy revenues of nuclear power plants

Market conditions in the electricity sector, especially in advanced economies, have changed significantly in recent years, largely because of a slow-down in the growth of electricity demand and the rapid expansion in generating capacity based on VRE. In some markets, notably the United States, a fall in the price of natural gas has also played a role. The net impact of these three factors has been a fall in the wholesale electricity price in all advanced economy markets with nuclear power plants, with the notable exception of the United Kingdom (Figure 12). This section discusses the factors behind the decline in wholesale prices, trends in other sources of electricity revenue for nuclear power plants, implications for existing nuclear power plants in North America and in Europe, and recent policy measures that aim to support nuclear power plants.

Figure 12. Wholesale electricity prices in selected advanced economy markets



Notes: PJM, MISO and ERCOT are independent system operators in the United States.
Source: IEA (2018b), World Energy Outlook 2018.

Electricity prices in almost all markets have fallen significantly since 2010.

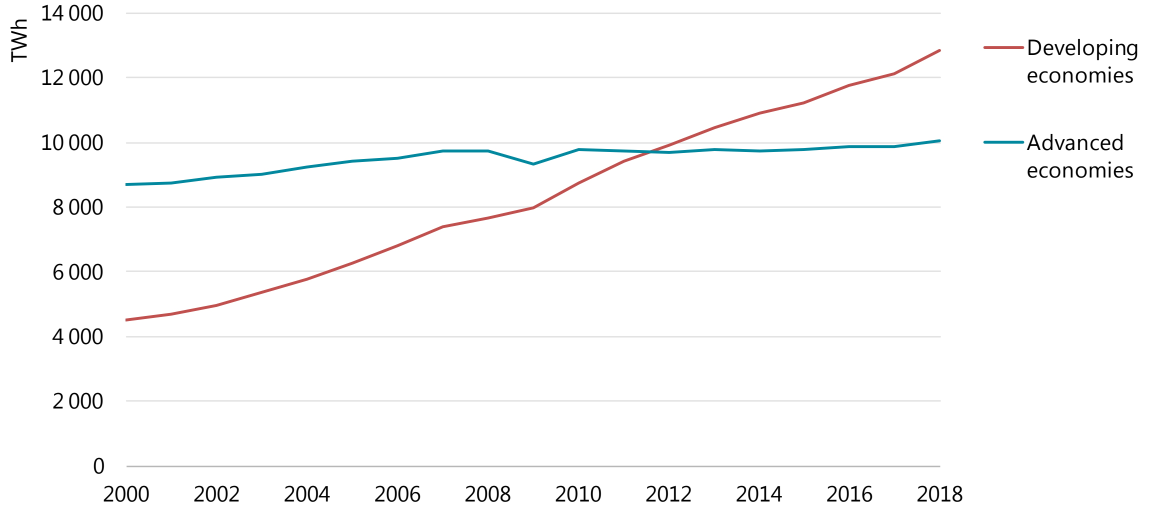
The shift in market conditions is generally affecting the prospects for new construction far more than the operations of existing plants. This is because capital costs represent a large share of the overall cost of nuclear power generation. The variable cost of nuclear power generation is low compared with other types of thermal plants as fuel costs are relatively low. Therefore, existing plants are usually still able to cover their operating costs most of the time, ensuring that nuclear plant is dispatched ahead of all but those renewable energy technologies that have zero variable costs (wind, solar and hydro power). Nonetheless, some existing nuclear plants are struggling to cover their operating costs, notably in the United States (see below).

Demand for electricity is slowing

Electricity consumption has remained about the same or even fallen in most advanced economies in recent years (Figure 13). Between 2010 and 2017, demand grew by 0.3% per year on average – less than one-third of the rate of the previous decade. During this period, electricity demand fell in 18 of the 30 IEA member countries. By contrast, electricity demand has continued to expand rapidly in developing economies as a group.

Several factors have slowed growth in electricity demand in advanced economies, the most important of which is gains in energy efficiency. Efficiency improvements have outpaced new sources of electricity demand growth such as digitalisation, particularly in industry (which accounted for 40% of overall efficiency improvements between 2010 and 2017), lighting and household appliances. Changes in economic structure, involving a stagnation in energy-intensive heavy manufacturing, have also been important. Strong economic growth, rapid industrialisation and a shift in energy use towards electricity has continued to drive electricity consumption in the developing economies ever higher, despite energy efficiency gains.

Figure 13. Electricity consumption in advanced and developing economies



Electricity demand is flat-lining in advanced economies, largely due to gains in energy efficiency.

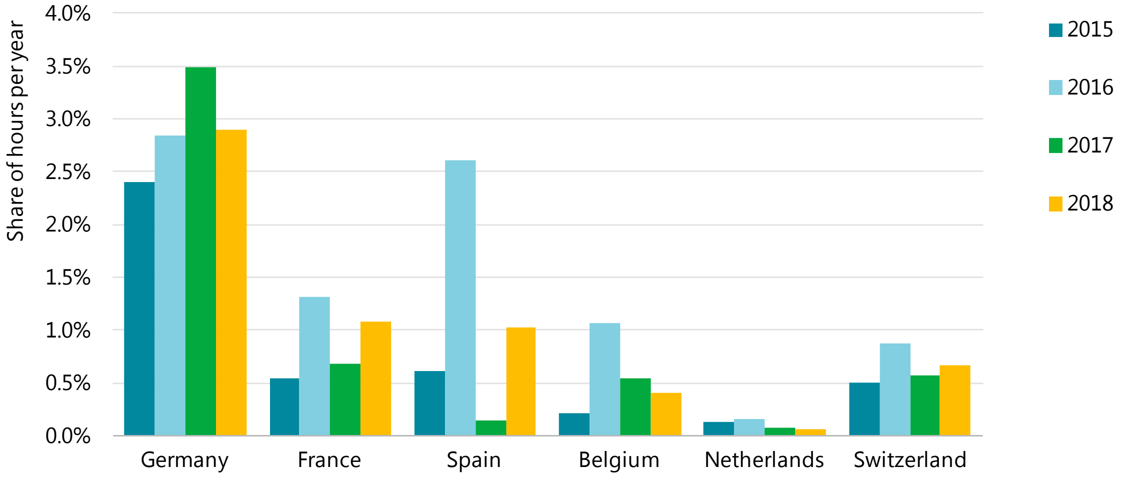
Rapid renewables growth is shrinking the market and depressing wholesale prices

Despite slow electricity demand growth, investment in electricity generation in advanced economies has been growing in recent years. This is primarily due to the growth in investment in renewable electricity generation, particularly wind power and solar power, both of which are types of VRE. Strong government support has been key to this growth, raising the share of the two energy sources in total generation in advanced economies from less than 1% in 2005 to 10% in 2018. Because their variable operating costs are close to zero, nearly all this additional wind and solar production is dispatched ahead of conventional generating plant (including nuclear power) in the merit order, thereby shrinking the market for conventional generation plants.

While the levels of investment in renewables have stabilised in recent years, prospects for continued growth in renewables capacity and production remain good. Continued cost reductions and policy support are set to continue to drive the deployment of wind and solar power world wide. Policy support remains strong, with higher targets for renewables recently adopted in the European Union, Japan, Korea and some US states. According to Renewables 2018 (IEA, 2018c), renewables-based electricity production in advanced economies is projected to rise from 2 870 TWh in 2018 to 3 550 TWh in 2023, an increase of 680 TWh – more than twice the projected growth in electricity demand. Generation from other sources will need to fall to compensate.

The increasing shares of wind and solar power are having an indirect and, increasingly, a direct impact on wholesale electricity prices. The *indirect* impact arises from the displacement of output from conventional resources with higher fuel costs, thus lowering the market price at any time when new resources are available. The effect on prices can be magnified: wind resources and solar resources are often highly correlated within individual markets, i.e. when the wind blows strongly or the sun shines brightly, all generating units produce at or close to full capacity. This means that even in an electricity system where the share of VRE in total generation is low over the course of a year, in any given hour, the share of VRE can be large and can occur during periods of low demand. At these times, the wholesale market price can fall below the marginal fuel price of nuclear power, such that the use of VRE *directly* lowers the prices. Nonetheless, such events are still rare for now. For example, in Europe, where the share of VRE in total production is high, wholesale prices have been below the estimated variable (fuel) cost of nuclear power less than 1% of the time in most countries over the last four years (Figure 14).

Figure 14. Share of hours in each year when wholesale prices are lower than the estimated variable cost of nuclear power in selected European countries



Note: Average variable cost of nuclear power generation is estimated at EUR 8 per MWh.
Sources: European Network of Transmission System Operators for Electricity (ENTSO-E) (2019), ENTSO-E transparency platform (database), and Nuclear Energy Institute (2019) NEI Statistics.

While low prices are a feature of markets with an increasing share of VRE, wholesale prices are still above the average variable fuel cost of nuclear power plants most of the time.

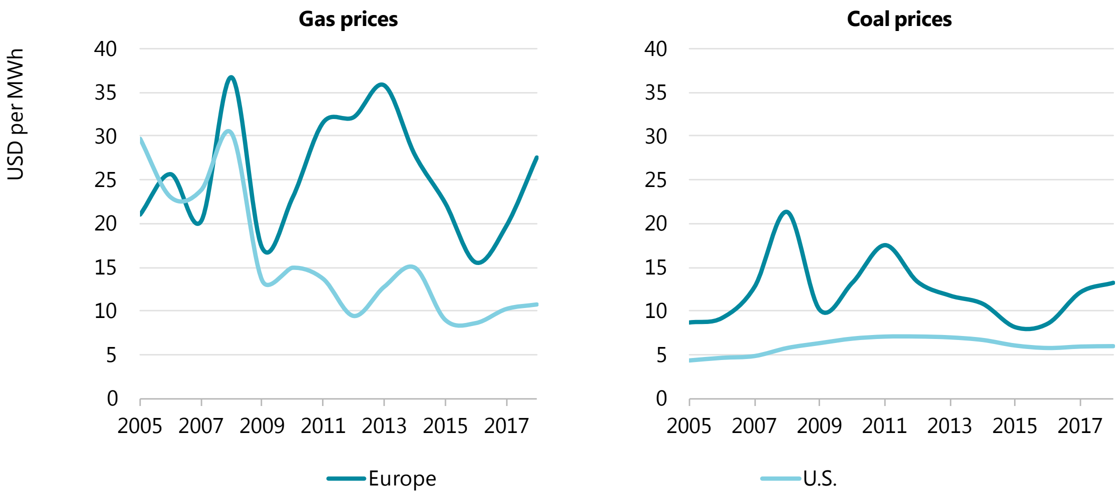
The shift in the position of nuclear power in the merit order in the wholesale electricity market due to the increasing share of VRE also applies to services other than the supply of pure energy. In particular, the prices of ancillary services have also changed due to changes in the merit order. The cost of providing ancillary services, especially operating reserves,[4] is mainly the opportunity cost or lost profit of generating energy at a market price. It thus differs for each plant and type of technology, i.e. the lower the variable cost, the larger the differential between the market price and the variable costs, and the more expensive it is for the system to reduce generation to have enough reserves. This is the main reason why nuclear power plants (with the notable exception of those in France), which have low variable costs, are generally not used to provide many of these services and are typically at the end of the merit order for ancillary services.

4 Operating reserve is the generating capacity available to the system operator at short notice to meet demand in case a generator suddenly goes off line. The operating reserve is made up of the spinning reserve – the extra capacity that is available by increasing the power output of generators that are already connected to the power system – and the non-spinning or supplemental reserve – the extra capacity that is not currently connected to the system but can be brought on line after a short delay.

Low natural gas prices are reducing wholesale electricity prices in North America

In North American and some other markets, the decline in natural gas prices over the last decade has had a significant impact on electricity market conditions, driving down average wholesale prices. This came about largely due to the boom in US shale gas production. As a result, gas has become much more competitive with coal in existing plants and with all other types of thermal generation for new construction, reshaping electricity markets across the continent. The situation in Europe is more complex, as natural gas prices increased earlier in the decade with higher oil prices (oil indexation in long-term gas supply contracts is still widespread) before falling back as oil prices fell and nascent US gas exports helped to decrease international LNG prices (Figure 15). Gas prices in Europe have since picked up. In both markets, the price differential between gas and coal has trended lower since the mid-2000s. Lower gas prices have helped to decrease wholesale electricity prices, as gas-fired power plants are often marginal sources of generation.

Figure 15. Average natural gas and coal prices in Europe and the United States



Note: Gas Henry Hub and Title Transfer Facility (TTF) prices, Coal API2 and IEA estimates.

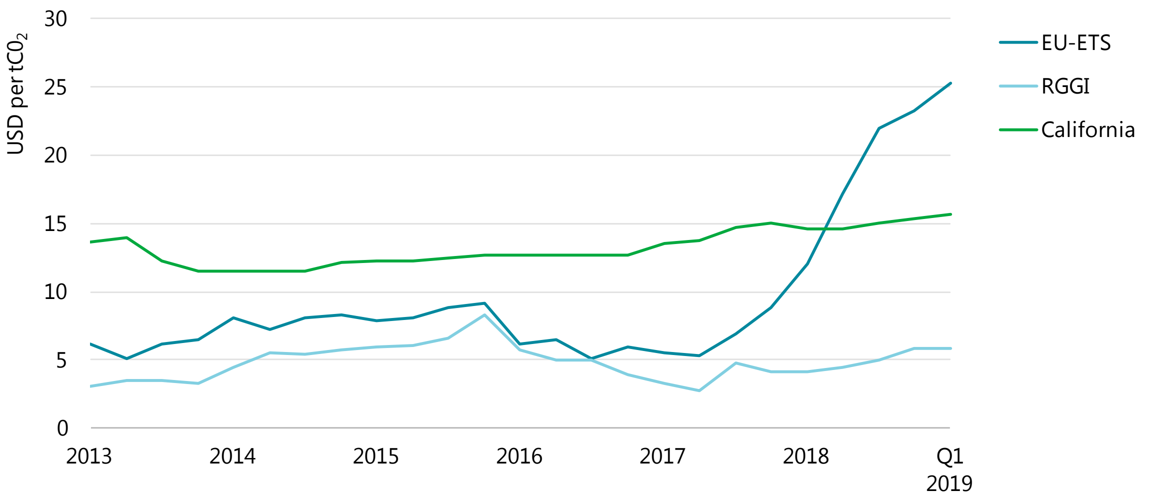
Sources: US Energy Information Administration (2019), Natural Gas Prices; Gasunie Transport Services B.V.(2019), Gas price reconciliation

Due to the shale revolution, the fall in US natural gas prices has reshaped the US electricity market.

Carbon prices are still too low to boost the economics of nuclear power

While the above factors put all types of existing generating plant under financial pressure, fossil fuel generators face greater cost pressures in those jurisdictions where there is carbon pricing, which favours nuclear power and renewables. Globally, nearly 20% of greenhouse gas emissions are already covered by carbon pricing systems such as emissions trading and carbon taxes. Carbon emissions trading systems have been implemented in several electricity markets, including in the EU-ETS and systems in a group of north-eastern US states and California. Power generation is included in all three systems. However, until recently, carbon prices in these systems have been low, meaning that they have had a modest impact on wholesale electricity prices (Figure 16). Prices have risen steadily in Europe since 2017, largely in anticipation of the effects of reforms eventually agreed in early 2018 for the period 2021-30, which limit the future availability of carbon allowances.

Figure 16. CO_2 prices in emissions trading systems in Europe, northeast United States and California



Notes: Q1 = quarter 1; RGGI = Regional Greenhouse Gas Initiative.

Sources: European Energy Exchange, EU-ETS (2019), Spot Market Price, The Regional Greenhouse Gas Initiative (RGGI) (2019), Auction Results, California Air Resources Board (2019), Summary of Auction Settlement Prices and Results.

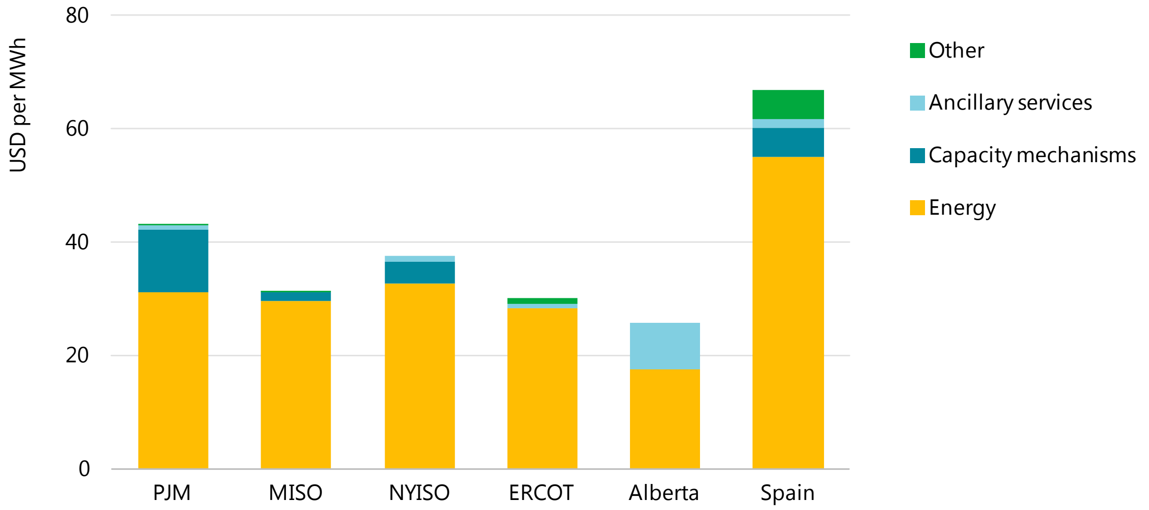
Carbon prices have remained relatively low, except for the recent surge in Europe.

Other market sources of revenue for generators

Revenues from capacity markets and ancillary services generally remain small

While sales of energy only on the wholesale market remain the main source of revenue for nuclear and other power generators in advanced economies, there are other electricity market services with potential to provide additional revenues. One such source of revenue is capacity mechanisms, which have been adopted in several markets as a way of attracting investment in new capacity. Capacity mechanisms remunerate generators for making available capacity from existing and future plants. They are common in US markets and have been introduced in some European countries, including Spain and the United Kingdom. However, revenues from capacity mechanisms make up a small portion of total revenues in most cases (Figure 17).

Figure 17. Sources of revenue for power generators in selected markets, 2017



Note: ERCOT = Electric Reliability Council of Texas; MISO = Midcontinent Independent System Operator (United States); NYISO = New York Independent System Operator; PJM = Pennsylvania, Jersey and Maryland Interconnection (regional transmission operator in north-east United States).

Source: IEA (2018b).

Energy provides most of the revenue earned by generators, even in systems with capacity markets.

The other source of revenue for generation is ancillary services (e.g. the provision of load following, reserve capacity and similar services). Flexible resources are needed to provide these services. Most of today's nuclear power plants were built before competitive electricity markets were established. Nuclear power's low variable costs mostly ensured it was dispatched as part of the baseload fleet of generating plant. The large fleet of nuclear reactors in France, which requires some nuclear power plants to operate flexibly, is the main exception to this (Box 4).

It is technically feasible to operate most types of nuclear reactor in a flexible manner, though some technical modifications may be required. Flexible nuclear power plants can typically increase or decrease power by 10% within a few seconds or minutes to control the flow of alternating current (AC) power from multiple generators through the network (frequency control) and by 20-80% within a few hours to meet load variation. Ramp rates for this type of plant are typically of the order of 2% of the total rated thermal power capacity per minute. While in percentage terms, the flexibility offered by a nuclear power plant is smaller than that of a fossil fuel generating plant, the large size of a nuclear plant means this represents a large source of flexibility in absolute terms. Flexible nuclear operation can complement VRE within a low-carbon energy system, as it is generally possible to forecast renewables output a few days or hours in advance with a reasonable degree of accuracy.

Box 4. France's flexible nuclear fleet

The nuclear reactors in service in France are designed primarily to provide baseload capacity, but have a considerable amount of built-in flexibility, facilitating the accommodation of intermittent generation sources such as VRE. Of the country's fleet of 58 nuclear reactors with a combined net capacity of 63 GW, all of which are operated by EDF, up to 21 GW can be ramped up and down within 30 minutes. One example of a flexible plant is Belleville in central France (see the figure below). Flexibility is also provided on a yearly basis thanks to smart management of periodic refuelling outages. Flexibility was built into the plants in the design phase by various players in the country's nuclear industry – designers, suppliers and operators – as it was anticipated at an early stage that nuclear power would account for most of the country's generating capacity.

Production at Belleville 1 nuclear reactor, 2-4 April 2019

Source: European Network of Transmission System Operators for Electricity (ENTSO-E) (2019), ENTSO-E transparency platform (database).

French reactors are designed to be able to reduce output to 20% of rated capacity twice a day in under 30 minutes, i.e. a gradient of 30-40 MW per minute, depending on the type of reactor. Electrical output is varied using special control rods composed of materials that absorb less neutrons than the usual ones, making it possible to modulate the chain reactions more precisely. Control room operators receive specific training in this mode of operation on full-scope simulators, which are exact physical replicas of control room equipment. Dedicated operating specifications, validated by the Nuclear Safety Authority, are applied to this function.

In addition to near-term flexibility, the French nuclear fleet can also modulate output on an annual timescale, thanks to the size of the fleet and optimisation of the scheduling of planned reactor outages for refuelling and maintenance. The number of refuelling outages scheduled simultaneously thus fluctuates greatly over the year, with more than 15 reactors out of the 58 shut down for refuelling at the same time during the summer when load is lowest.

EDF is looking at the possibility of varying the composition of fuel reloads. When a reactor is shut down for refuelling, normally just one-third of fuel is replaced; therefore, each fuel element goes through three generation cycles. Adapting the number of fresh fuel elements for a new generation cycle would make it possible to extend or shorten the natural length of the cycle by as much as 50 equivalent full power days, thus enhancing flexibility.

Value of future nuclear flexibility will depend on the costs of other options

The need for flexibility is increasing with the growth of VRE. This represents a potential opportunity for existing nuclear power plants, alongside other potential low-carbon sources of flexibility including interconnections with neighbouring electricity grids, demand-side management (utility programmes to encourage the consumer to use less energy, especially during periods of peak load), storage (e.g. batteries or increased hydro storage) and flexible use of VRE.[5]

By operating flexibly, a nuclear plant may be able to reduce the times when it produces below its variable cost. In addition, flexible operation can generate revenue from ancillary service markets. In addition to France, such operations are already taking place to a more limited extent in the United States in response to the growth of wind power. The revenue from ancillary services must be weighed against the lost revenues from reduced energy sales in baseload operation. For example, in the case of France, the amount of energy that is not produced due to the use of reactors to provide frequency control and load following (ramping up and down briskly to meet daily changes in load) is, at this stage, around 3% of the maximal electrical output possible for the whole fleet. Furthermore, there is a cost involved in making the technical modifications to the existing plant, including the costs of obtaining the necessary safety approvals, to be able to operate flexibly.

The future role of nuclear power in providing flexibility will depend on the demand for flexible operations, the supply of other flexible resources and the way the market is designed with respect to how flexibility services are remunerated. Some studies suggest that there could be net benefits to the owners of nuclear power plants in operating flexibly in competitive markets. A study on the effects of flexible nuclear operation in the south-west of the United States shows that flexible operations can increase a nuclear plant's gross operating margin by two to five percentage points compared with baseload operations, despite reducing total output by 5-6%, while reducing curtailment of wind and solar resources – their forced disconnection due to network constraints – by 2-4% for wind and 11-14% for solar power. In practice, the scope for using nuclear capacity profitably to provide flexibility is likely to be limited for as long as the combined share of VRE does not exceed 40%, given expected falls in the cost of batteries, the growing use of cost-effective demand-side response (utility measures to encourage consumers to adjust their consumption in real time to reduce peak load and system costs) and the often large amount of existing available generating capacity based on fossil fuels. The presence of these other flexibility resources may instead reduce the requirement to curtail nuclear power operations.

The efficient operation and coexistence of nuclear capacity, other thermal generating plants and large shares of VRE will require markets to evolve to provide flexibility in a cost-effective manner through ancillary services and ramping capabilities. Many markets are moving in that direction. For instance, many system operators are increasingly developing mechanisms to take advantage of the capabilities of VRE, splitting traditional ramping services into two different categories: ramping up and ramping down, where ramping down can readily be provided by VRE. This allows VRE resources to reduce their generation, avoiding expensive operations requiring inflexible thermal plants to stop and restart in a few hours. The development of

[5] The potential of such resources is being examined in more depth in the IEA Power System Transformation series, addressing the flexibility of the VRE resources themselves.

efficient markets that accurately reflect scarcity of these services will be a crucial step in the transition to a low-carbon energy system, as a lot of this flexibility requires investments that yield benefits seen only in the longer term.

Support mechanisms for nuclear power plants

In recognition that the environmental and system benefits are not fully reflected in the remuneration obtained by low-carbon generators, some jurisdictions have introduced alternative mechanisms to increase their revenues. Most of those jurisdictions are not covered by economy-wide emissions trading systems or explicit carbon taxes. Some US states have adopted such support measures, notably Connecticut, Illinois, New Jersey and New York, together with Ontario province in Canada, and also Japan and Mexico.

The New York Public Service Commission adopted a Clean Energy Standard in 2016. It is designed to enable the state to meet the environmental goals set out in the New York State Energy Plan, which includes a 40% reduction in greenhouse gas emissions from 1990 levels by 2030. Nuclear power plants are supported by zero-emission credit (ZEC) payments from the New York State Energy Research and Development Authority (NYSERDA) based on the amount of electricity generated by each plant (in MWh).

The price of the New York ZEC is set for two years at a time and calculated according to a formula set out in the policy. It is based on the social cost of carbon, estimated by the federal government in 2015 at USD 42 per tonne (t), and the avoided carbon emissions that the nuclear power plants' generation enables, which is calculated as 15 million tonnes (Mt) per year. The ZEC price is USD 17.48 per MWh. The amount of ZECs each load serving entity (LSE) has to purchase is determined by the actual load from 1 April through to 31 March of the previous year. LSEs must purchase ZECs from NYSERDA in an amount that equals the given LSE share of the total state-wide load multiplied by the total number of ZECs purchased by NYSERDA in the compliance period. The ZEC purchase obligation is separate from any other obligation under the state's Renewable Energy Standard – a requirement that utilities obtain a specified percentage of the electricity they sell from renewable resources. As the load calculation is based on the previous year, after calculating the actual load served in the compliance period, the price of any unneeded ZECs is refunded by NYSERDA.

The policy has allowed Exelon – the owner of two nuclear power plants (Ginna and Nine Mile Point) that were due to be retired for economic reasons – to continue operating them. Exelon was also able to buy the FitzPatrick nuclear plant from Entergy and keep it in business (Entergy had planned to close the facility in early 2017.) New York State plans to implement the ZEC policy for 12 years.

New Jersey also adopted a ZEC programme in May 2018. Plants must be licensed to operate until at least 2030. As a result, the Oyster Creek nuclear plant does not qualify for this financial aid. The two other nuclear power plants in the state, Hope Creek and Salem, will receive about USD 253 million per year in revenue from ZEC sales to public utilities, according to government estimates, based on an average price of around USD 11 per MWh. The costs will be recovered through a fixed tariff of USD 0.004 per kilowatt hour (kWh) that will be added to retail prices.

In Illinois, ZECs for all types of low-carbon generation were introduced under the 2016 Future Energy Jobs Act. Illinois has six nuclear power plants with 11 reactors, which produce 50% of the state's electricity. The ZEC amount to be bought by the utilities is 16% of their output in the previous year. The support is provided on the basis of ten year contracts, requiring the power plants to keep operating during that period, to prevent plant early retirement. As a result, Exelon is expected to be able to keep its Clinton and Quad Cities nuclear power plants open due to USD 235 million in subsidy over ten years. The act sets the value of a ZEC at USD 16.50 per MWh based on the "Social Cost of Carbon" . This rate will increase by USD 1 per MWh in 2023 and each subsequent year.

The state of Connecticut has developed a power purchase agreement approach for zero-carbon resources, for which existing nuclear power plants are eligible. The two nuclear power plants supplying the state (one located in neighbouring New Hampshire) have signed power purchase agreements of up to ten years. Solar and offshore wind projects have also signed agreements.

In 2014, Mexico adopted a definition of "clean energy" that includes renewables, nuclear power, carbon capture, utilisation and storage (CCUS) and energy savings from efficient co-generation.[6] Under a Clean Energy Standard project launched in 2018, retailers are obliged to purchase an amount of energy from clean technologies. Under this system, only new facilities are awarded certificates. The country's only nuclear plant at Laguna Verde, where investment was needed to obtain an uprate, was awarded certificates in 2018.

In May 2018, Japan launched a zero-emissions trading system, which will cover nuclear power and renewables-based generators. It is the biggest certificate system in the country. Non-Fossil Value Certificates for electricity not covered by feed-in tariffs will be introduced during 2019. Retailers will need to obtain certificates to meet their obligation of procuring 44% of their electricity supply from sources that are not fossil fuels. The certificates are traded on a new market called the Japan Electric Power Exchange. As of 2019, when tracking systems for the certificates were introduced, large consumers are able to use the certificates to comply with the goals of RE100 – a global initiative bringing together influential businesses that are committed to buying 100% renewable electricity. The tracking ensures that the consumers are able to prove which plant produced the zero-carbon energy.

The Canadian province of Ontario uses a contract for differences methodology to support lifetime extensions at the Bruce nuclear station, which comprises eight units with a total capacity of around 6 GW. The price of the electricity output from the fleet of units is adjusted according to the expected cost of refurbishment each time a unit requires a lifetime extension. Once the cost has been agreed, any cost overruns are the responsibility of the generator. The government of Ontario is entitled to decline to fund the refurbishment if the planned costs are too high and can also terminate the agreement at specified points, if market conditions change so that the plants to be refurbished are no longer required.

For the most part, these support measures are intended to replace more market-oriented approaches, including explicit carbon pricing systems or capacity mechanisms. Of these two approaches, analysis suggests that implementing a moderate carbon price will have a greater impact on the competitiveness of nuclear power (and other zero-carbon) generation than a capacity mechanism (Box 5).

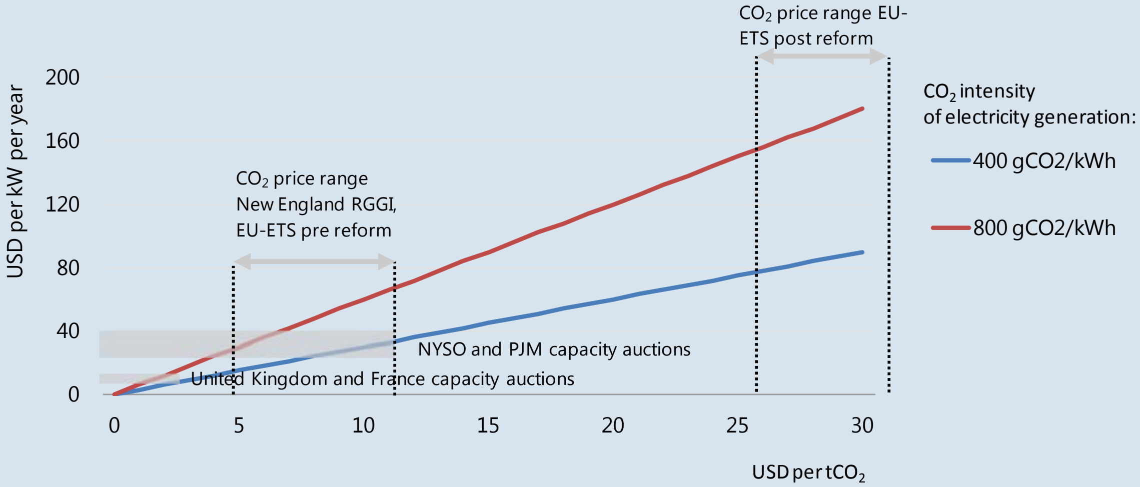
[6] Co-generation refers to the combined production of heat and power.

Box 5. Impact of carbon pricing on competitiveness of nuclear power

Nuclear power does not benefit from the same level of support as renewables in most countries and subnational jurisdictions, despite it being a low-carbon energy source. This reflects policy-maker recognition that VRE technologies, when these incentives were introduced, were not yet mature and that support systems would lead to cost reductions through scale or learning by doing. By contrast, nuclear technology is mature and the low variable costs of existing plants are expected to allow them to earn enough revenue to make continued operations profitable. However, this means that the low-carbon and other benefits of nuclear power are not specifically remunerated.

Carbon pricing is the simplest means of rectifying this imbalance. An explicit penalty on CO_2 emissions would ensure that nuclear power – for existing plants and for future capacity needs – competes on a level playing field with other energy sources and that the generating fuel mix yields the lowest prices for consumers. Only a few markets have adopted an explicit carbon pricing system, either in the form of emissions trading or carbon taxes. With falling wholesale electricity and low capacity prices, the lack of a carbon price and low prices in those markets that have carbon pricing have a significant impact on the competitiveness of nuclear power – much more so than the capacity value or flexibility value that nuclear power is able to provide. In practice, revenues from recent capacity auctions have the same impact on nuclear plant revenues as a modest carbon price – a few USD per t in the case of France and the United Kingdom and USD 4-12 per t in US markets (see the figure below). Following revisions to the EU-ETS in 2018, carbon prices have risen to over EUR 26 per t in anticipation of an EU-wide reduction of carbon allowances in 2019-23. At this price level, revenues to nuclear power producers would rise by USD 70-150 per kW per year – 10 to 20 times more than those from recent European capacity auctions and two to four times more than those in the United States.

Revenues of power generators from CO_2 pricing and capacity payments in electricity systems with moderate and high carbon intensity



Prospects for nuclear power in key markets

Existing conventional generators are losing market share

Existing conventional power generators (including nuclear power plants) in the electricity markets of advanced economies are being squeezed by lower wholesale prices and dwindling market share. Most new renewables-based generators with power purchase agreements or similar mechanisms have not been badly affected by the fall in wholesale electricity or (where they exist) capacity prices in recent years, as other revenue sources entirely or partially offset the impact of low prices. Most existing conventional generators have no such arrangements. With demand set to continue to stagnate and new renewables-based capacity likely to continue expanding in the medium term, it is expected that low prices will persist as the share of low marginal cost renewables increases. In effect, existing generators are facing a game of musical chairs, as an increasing amount of dispatchable capacity is displaced with each round of renewable additions.

This is raising concerns that some nuclear capacity may be decommissioned, reducing back-up capacity, which could undermine electricity security. Nuclear power is normally dispatched after renewables and ahead of other thermal generation plants, as nuclear fuels are of relatively low cost. However, being dispatched does not guarantee financial viability: revenues need to be high enough to pay the fuel costs and the costs of operations, and also to finance ongoing capital expenditures. The ability of nuclear power plants to prosper depends upon particular market circumstances. The rest of this chapter focuses on developments in Europe and the United States.

Low energy and CO_2 prices are making some existing US nuclear plants uneconomic

Electricity market conditions and the viability of existing nuclear power stations in the United States are different to those in Europe. Nuclear plants in the United States are given an operating licence for 40 years, and can obtain a licence extension of 20 years. All but 2 of the 98 nuclear units in operation are over 30 years old, 90 of which have already received the 20 year licence renewal. Each renewal requires significant amounts of capital spending. Fuel and other operating costs have been broadly stable, while ongoing capital investments have declined in recent years as most life extension investments and safety and security upgrades after the Fukushima Daiichi accident have been completed.

The US nuclear fleet is about to experience a wave of retirements. Nine units are due to be retired within the next three years (Table 4). This compares with only two closures in the past three years. In addition, the owner of the last two units operating in California has announced that it will not seek extensions for them and will close them upon expiry of their current licences in 2024 and 2025. In most cases, market conditions have been cited as the main reason for closure.

Table 4. Retirements of nuclear reactors in the United States, 2016-21

Reactor unit	Net capacity (MW)	Closure year	Licence expiry date	Licensed lifetime (years)	Age at closure (years)	Stated reason for retirement		
						Capital expenditure	Market conditions	State policy
Actual 2016-18								
Oyster Creek	619	2018	2029	60	48	O		
Fort Calhoun 1	482	2016	2033	60	43		O	
Planned 2019-21								
Pilgrim 1	677	2019	2031	60	46		O	
Three Mile Island 1	819	2019	2034	60	44		O	
Indian Point 2	1 020	2020	2024	60	45			O
Davis Besse	894	2020	2037	60	43		O	
Duane Arnold	601	2020	2034	60	46		O	
Perry	1 256	2021	2027	40	35		O	
Indian Point 3	1 040	2021	2025	60	44			O
Beaver Valley 1	921	2021	2036	60	45		O	
Beaver Valley 2	905	2021	2027	60	34		O	

Sources: US NRC; IAEA (2019), Power Reactor Information System (PRIS) (database); US Department of Energy (2017), Staff Report to the Secretary on Electricity Markets and Reliability.

There are two main factors undermining the viability of maintaining operations at existing US nuclear power plants. First, revenues from electricity markets appear insufficient to cover costs, including those associated with obtaining operational lifetime extensions, mainly due to the low price of natural gas. According to annual nuclear power cost data published by the US Nuclear Energy Institute, covering capital, fuel and non-fuel operating costs reported by all the operating nuclear units in the United States, average operating costs in 2017 were USD 33.50 per MWh.[7] Given that this is close to the marginal cost of gas plants that set prices in most US power markets, most nuclear power plants are barely able to cover their operating costs let alone the capital costs associated with obtaining operational lifetime extensions. Second, the need for environmental upgrades related to the use of water for cooling, the cost of which has been attributed as a factor in plant closures in California, New Jersey and New York, has added to the cost burden of existing plants. Nuclear power plants are significant users of water for cooling. New regulations require existing plants to upgrade their cooling water systems, which involve a need to invest hundreds of millions of USD. Carbon pricing is not able to compensate for these factors, as a pricing mechanism is not in place in all markets. In addition, where one exists, CO_2 prices are too low to benefit greatly nuclear power (see below).

Nuclear power plants that operate in competitive markets, which make up 64 GW of the total US nuclear capacity of 98 GW, must rely on market revenues unless they have a power purchase agreement. Power plants in those markets have three possible streams of revenue from those markets: revenue from selling energy, revenue from making capacity available (if this is offered by the market) and revenue from ancillary services, which is insignificant for US nuclear power plants. Wholesale electricity prices on competitive markets have been falling in recent years. In the PJM market in the north-east, the average price from 2007 to 2017 fell by nearly one-half,

[7] Costs are generally much lower for plants with two or more reactors. The 36 multiunit plants in the survey have an average generating cost of USD 30.89 per MWh compared with USD 42.67 per MWh at the other 62 single-unit plants.

from USD 61.66 to 30.99 per MWh. The main reason for the decline is a fall in the price of natural gas delivered to power generators, from USD 7.31 per million British thermal units (MBtu) in 2007 to USD 3.52 per MBtu in 2017 – a similar percentage decline as for electricity prices. Revenues from capacity markets, where these exist, can be a significant source of revenue for nuclear and other existing generators. They are important in PJM and Independent System Operator New England (ISO NE) markets, but they either do not exist or are not significant elsewhere.

Table 5. Nuclear power in US organised electricity markets, 2017

Market	Net capacity (MW)	Average energy price (USD/MWh)	Capacity price (USD/MWh)
PJM	33 163	30.99	11.23
MISO	12 420	29.46	-
ISO NE	4 010	35.23	19.00
NYISO	4 820	25.24	2.00
ERCOT	4 960	28.25	N/A
SPP	2 061	23.43	N/A
CAISO	2 894	37.59	N/A

Notes: CAISO = California Independent System Operator; N/A = not available; SPP = Southwest Power Pool. NYISO prices are for the Central Zone, where two nuclear power plants are located.

Source: ISO 2017 Market Monitor Reports.

The independent electricity market monitors in some of these markets have identified the competitiveness of existing nuclear power as a major concern. In the case of PJM (the north-eastern regional transmission system), the market monitor concluded that 9 of 19 plants would have lost money in 2017. This was an improvement over the previous year when 16 out of 19 plants would have done so, but still far higher than in previous years. Similarly, an analysis by the NYISO market monitor found that the market and capacity revenues for the upstate nuclear power plants have fallen significantly in recent years, in part because the plants are located in a zone where supply is plentiful. By contrast, the plant near New York City would appear profitable as it benefits from higher electricity and capacity market prices. In the ERCOT system, the market monitor noted that the average revenue received by nuclear generators, at USD 24.73 per MWh, was well below the average wholesale price, as nuclear power plants run in baseload mode. While it found that nuclear power provides a hedge against a rise in gas prices, such a rise is unlikely to occur in Texas in the short term. The findings of the market monitors – that some plants are competitive even under these market conditions, but others are in difficulty – are consistent with other analyses.

The same underlying pressures on nuclear power producers – falling natural gas prices, stagnant demand and growth of renewable generation – are also apparent in regulated systems. The principal difference is that in organised markets, these factors affect the bottom line of the asset owner, who can then decide to continue operating the plant or to close it. For vertically integrated monopoly utilities, regulators act as a substitute for market signals. Regulators can put pressure on utilities that have excess generation capacity to close the least economically viable plants to reduce the burden on power consumers.

Carbon pricing is offering little respite to US nuclear producers. Not all systems have carbon pricing; where they do, CO_2 prices remain low. There are two regional systems in operation: one in California and a second, the RGGI, covering nine states in the north-east, affecting generators in New England, New York and part of the PJM market. Prices in the California market are highest: the latest auction cleared at USD 15.62 per t, adding about USD 6 per MWh to the cost of gas-fired electricity in California. The latest auction prices in the RGGI, at an average of USD 5.27 per short ton (USD 5.81 per metric t), are roughly one-third of this, implying a cost increase for natural gas generation of just over USD 2 per MWh. While the CO_2 price may have some impact on the competitiveness of nuclear producers in California (e.g. a USD 6 per MWh price rise translates into an extra USD 100 million per year in revenue to the owners of the Diablo Canyon plant), it has not changed the decision to close the plants in the mid-2020s. In contrast, the low CO_2 prices in the RGGI have had little impact on electricity prices in the New England, New York and PJM markets.

Prospects for building new nuclear reactors in the United States remain bleak

If existing nuclear power plants are struggling to cover their costs, the prospects of new nuclear power plants being able to make a profit under current market conditions are even less promising. With recent advances in technology, falling costs and favourable policies, most power generation investment is now going to wind and solar power. Compared with a decade ago, when there was optimism about a nuclear renaissance, a more conservative demand outlook and more bullish prospects for renewables have reduced the expected need for conventional and nuclear generation in 2030 by 1 300 TWh under current and planned policies. This is equivalent to the production of over 170 GW of baseload capacity.[8] Most of this reduction is expected to be met by decommissioning of coal capacity, but the projected call on nuclear power has also been trimmed.

The last application for a new construction licence in the United States was made a decade ago. Eight licences were issued in 2007-09, of which only one (the Vogtle project) is under construction. Three of the remaining seven have been terminated, and it is doubtful that any of the four pending projects will go ahead. These applications were made at a time when US gas production was expected to decline, and LNG imports would stabilise North American gas prices at a permanently high level. As the shale gas revolution was unfolding, gas price expectations for 2030 were revised down from USD 11.3 to 3.8 per MBtu. The difference this has made to the marginal cost of gas-fired generation has effectively cut the NPV of a 1 GW nuclear reactor by USD 5 billion. It would take a CO_2 price of USD 120 per t to compensate for this. The shift in market conditions was cited as the primary reason for cancelling the licence in all three cases. Even without the cost inflation and difficulties in managing the ongoing project, the change in market conditions would have raised questions about the economic viability of new nuclear projects.

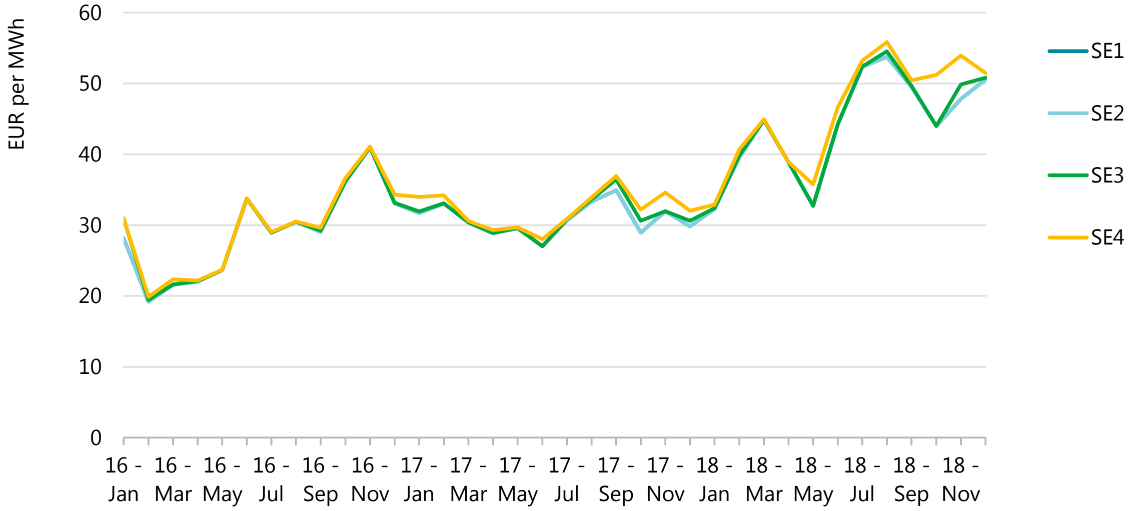
Higher fuel and CO_2 prices are helping existing nuclear plants in Europe to compete…

The competitiveness of existing nuclear power plants on continental European markets has improved recently due to natural gas prices that are structurally higher than in North America, as well as due to explicit pricing of CO_2. EU-ETS CO_2 prices, which had been trading as low as EUR 5 per tonne as recently as 2017, have since rebounded to over EUR 26 per tonne in anticipation of the implementation of reforms to the system that are due to come into effect in 2021. Higher CO_2 prices have increased the marginal cost of generation for a gas-fired CCGT

[8] Projections of the World Energy Outlook 2009 compared with those of the 2018 edition (IEA, 2018b) for 2030 in the central New Policies Scenario.

plant by EUR 8 per MWh, and that of a coal-fired plant by nearly EUR 20 per MWh since 2017. The introduction of a carbon price floor in the United Kingdom in 2015 provided support to wholesale prices in that market. Reliable data on the variable costs of nuclear power in Europe are not available, but at current levels, wholesale market prices are undoubtedly high enough to cover those costs in all cases. Market reforms as part of the EU Clean Energy Package are also expected to level the playing field between nuclear power and renewables.

Figure 18. Average monthly wholesale electricity prices in Sweden by bidding zone



Source: ENTSO-E.

Wholesale electricity prices in Sweden have risen substantially since 2016, in part because of EU-ETS reforms and because of the reduced availability of hydropower due to low rainfall.

The situation is different in the Nordic bidding zones within the European electricity market, where wholesale power prices are generally lower due to the large proportion of hydro and wind power, which have almost zero variable costs. For example, prices in Sweden have risen since 2016, in line with the trend in the rest of continental Europe. However, they remain low, jeopardising the viability of existing nuclear power plants (Figure 18). As a result, a decision was made recently to phase out a tax on nuclear capacity that the plant owners claimed would force them to retire their plants early (Box 6).

Box 6. Abolished nuclear power production tax in Sweden

In 2016, the Swedish government decided to phase out a tax on nuclear power production, introduced in 1984, over a two year period from 2017 to 2019, to discourage the operators of existing plants from retiring them early. The decision formed part of a political agreement that set a goal of producing all electricity from renewables by 2040. In 2017, the tax amounted to around EUR 8 per MWh of electricity produced. Vattenfall, Fortum and Uniper (the principal owners of the nuclear production capacity in Sweden) had previously warned that nuclear power was no longer economic and had threatened to close four reactors by 2020, when additional investment to meet safety requirements will be necessary. Nonetheless, the move to phase out the tax will most likely not improve the profitability of existing plants sufficiently to keep all the plants running, despite higher prices since 2016 due to lower levels of rainfall (which have restricted the availability of hydropower) and higher prices in continental Europe (where the Nordic region exports a lot of power). It is expected that only 6 out of the original 12 reactors in Sweden will continue to run after 2020.* Investment in new power plants remains difficult, as government policy stipulates that they cannot be subsidised either directly or indirectly.

* Of the original 12 nuclear power plants, 2 were closed due to political decisions in 1999 and 2005, and 2 were closed due to financial reasons in 2015 and 2017. Another 2 are expected to close due to financial reasons and will not get the security upgrades allowing them to continue operation after 2020.

… but new nuclear power plants in Europe are not viable for now

Higher carbon and natural gas import prices are making the economics of potential new nuclear power plants more favourable, but financing new construction is extremely difficult in countries that continue to support a role for nuclear power. Due to a combination of the Eurozone crisis and the market impact of rapid growth in renewables, the financial position of the major utilities in Europe is considerably more fragile than that of utilities in the United States. The degree of competition in Europe is also greater: the US projects that have proceeded to new construction – as well as the cancelled ones that survived longest – are all in states that have not deregulated electricity markets.

Competitive wholesale markets effectively make financing of new nuclear projects in Europe unfeasible if they have to rely on market prices. Long-term contracts can be designed for new construction, but they usually apply to actual future production that is several years from the project start. Therefore, during construction, specific financing solutions are needed. Moreover, the risks associated with project management and cost overruns are too high for most electricity off-takers. A significant proportion of the utility industry is "ownership unbundled", i.e. the generating assets are not owned by the companies that own the network assets, so generators do not benefit from the stable and predictable cash flow of the network assets. Even in the case of legal unbundling, where the network assets remain in the same corporate holding, there are strict regulatory restrictions on cross-financing. As a result, the ability of the utilities to undertake large and capital-intensive projects is considerably weaker than in a vertically integrated regulated business model. For unbundled utilities operating in competitive electricity markets, the overarching strategic priority usually is an asset-light business model of retail, energy services and trading activities, coupled with less capital-intensive generation technologies such as gas and wind. Generation III nuclear units are the exact opposite of this business model. As a result, despite higher gas and explicit carbon prices, the new construction outlook in Europe is as pessimistic as in North America, with several prospective projects cancelled or indefinitely delayed – most recently in the United Kingdom.

The prospects for nuclear power remain clouded even in France, which represents nearly one-half of Europe's total nuclear production. The new French long-term energy strategy launched in late 2018 envisages a reduction in the share of nuclear power in the total generation, but leaves the possibility of new construction open as a strategic option. No binding decisions have been made on site selection, pricing or a financing model for any possible new project. This will require a substantial amount of investment by EDF, particularly considering the company's commitments to the construction of Hinkley Point C nuclear plant in the United Kingdom.

European countries with a legally binding phase-out policy – Belgium, Germany and Switzerland – represent only 17% of European nuclear production. However, a further 19% is in countries that have no active policy for new construction and where current operators have no plans to invest in new reactors because of market conditions, financing and cost barriers. Countries where policies support the development of new nuclear capacity, including the Czech Republic, Finland, Hungary, the Slovak Republic and the United Kingdom, account for around one-fifth of European nuclear production. Poland is a special case as a country that does not use nuclear power, but which is planning to authorise the construction of new nuclear plants. No decision has been taken on any particular project in Poland, with the choice of technology and financing still being open questions.

3. Impact of less nuclear investment

Outlook for nuclear power

Electricity market conditions for nuclear power in advanced economies remain difficult. This is because the underlying drivers of low wholesale electricity prices – low demand growth, rising wind and solar power capacity, and low natural gas prices – look set to continue for the foreseeable future. In addition, public concerns about the safety of continued operations at ageing nuclear reactors could lead to a shift in public policy and more stringent regulation, which could render operational lifetime extensions and new construction economically unviable or even impossible. To maintain public confidence, comprehensive safety reviews by independent regulators must be successfully completed before providing lifetime extensions for existing nuclear power plants. Technology and project management risks, highlighted by the ongoing problems being encountered by project developers in Europe and elsewhere, are adding to the uncertainties surrounding prospects for the nuclear power sector.

These uncertainties have never been greater, yet the need for low-carbon sources of electricity has never been more urgent. With the continuing electrification of the world's energy system, decarbonisation of power generation is central to the transition to clean energy. In principle, nuclear power could play a major role. If it does not, reliance on other forms of clean energy, essentially renewables, will have to increase even further to compensate. This could have far-reaching consequences for the way the electricity system operates, for the cost of supplying electricity and for providing the flexibility that will be needed to make the system work reliably and efficiently. This could also, ultimately, impact the likelihood that such an outcome can be achieved.

The latest projections in the New Policies Scenario of the *World Energy Outlook* (IEA, 2018b), which take account of current and planned policies including nationally determined commitments under the Paris Agreement on climate change, showed nuclear power continuing to play an important role in meeting the world's energy needs (Box 7). Output of nuclear power grows by 1.5% per year between 2018 and 2040, though its share in total power generation falls slightly, from 10% to 9%. In a Sustainable Development Scenario, which sets out an energy trajectory that addresses air pollution concerns, provides universal energy access and is consistent with the Paris Agreement's goal of holding the increase in the global average temperature to well below 2°C, the role of nuclear power is much more important: output grows by 2.8% per year to 2040 and its share in the generation mix reaches 13%.

Neither outcome is assured. It is far from certain that even the policies that have already been agreed will be fully implemented, such that nuclear power production could fall short of the levels projected, notably because of barriers to investment in advanced economies. It is even less certain that the ambitious targets in the Sustainable Development Scenario will be achieved, as they require a significant increase in policy support. What would the consequences be for the rest of the energy system if nuclear output fails to rise as projected? To try to answer that question, we have a devised the *Nuclear Fade Case*, in which it is assumed that no new investment in nuclear lifetime extensions or new projects in advanced economies. This case is applied to the New Policies Scenario and the Sustainable Development Scenario. The underlying assumptions in each case are the same, though the outcomes are markedly different, largely because nuclear power plays a much bigger role in advanced economies in the Sustainable Development Scenario. For both scenarios, we investigate the implications for the generating mix and the provision of flexibility services, with emphasis on the Sustainable Development Scenario, which encapsulates the stated environmental and social goals of the international community.

Box 7. The New Policies Scenario and Sustainable Development Scenario

The Nuclear Fade Case set out in this report is applied to two of the main scenarios – the New Policies Scenario and the Sustainable Development Scenario – analysed in the IEA *World Energy Outlook*. The **New Policies Scenario** provides a quantitative assessment of where today's policy frameworks and ambitions, together with the continued evolution of known technologies, might take the energy sector in the coming decades. The policy ambitions include those that have been announced and incorporate the commitments made in the Nationally Determined Contributions under the Paris Agreement, but does not assume any evolution of these positions. Where commitments are aspirational, the measures under development are considered as an indicator of the likelihood of those commitments being met in full.

The **Sustainable Development Scenario** starts from selected key outcomes and then works back to the present to see how they might be achieved. The outcomes in question are the main energy-related components of the United Nations Sustainable Development Goals, agreed by 193 member states in 2015, namely:

- Delivering on the Paris Agreement – the Sustainable Development Scenario is fully aligned with the Paris Agreement's goal of holding the increase in the global average temperature to well below 2°C.
- Achieving universal access to modern energy services by 2030.
- Reducing dramatically the premature deaths due to energy-related air pollution.

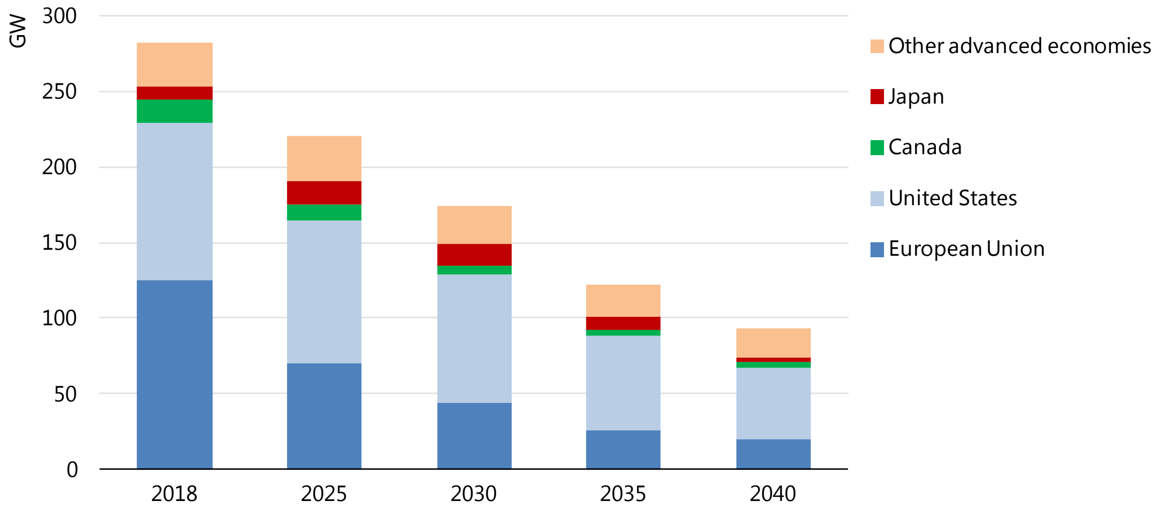
Source: IEA (2018b), World Energy Outlook 2018.

The Nuclear Fade Case

The basic assumption of the Nuclear Fade Case is that no new nuclear power capacity is built beyond those projects already under construction, no further lifetime extensions to existing nuclear reactors are granted and no new investment in existing plants occurs in advanced economies. No change is made to the assumptions about nuclear power development in developing economies on the grounds that the market pressures and uncertainties surrounding the nuclear power sector in those countries are generally less acute (partly because those economies are considering a variety of sources to meet growing electricity demand). In other words, the failure to extend the lifetimes of nuclear power plants in advanced economies is assumed to have no impact on either the extension of the lifetimes of nuclear power plants or on the expansion of the fleet in the developing economies. This is supported because the primary growth markets for nuclear power – China and Russia – will increasingly rely on their own domestic nuclear technology and engineering capabilities (or already do so). However, other developing economies are more likely to rely on international co-operation for technology and project management, which could prove harder if the nuclear industry is in decline in advanced economies. In that way, less nuclear investment in advanced economies could have a negative effect on the expansion of nuclear power in other markets. However, this was not explored in the Nuclear Fade Case.

In the Nuclear Fade Case, the total nuclear capacity in advanced economies declines by around two-thirds to 2040, from 282 GW in 2018 to just over 90 GW (Figure 19). The following 13 countries were considered: Bulgaria, Canada, the Czech Republic, Finland, France, Hungary, Japan, Korea, Mexico, the Slovak Republic, Turkey, the United Kingdom and the United States.

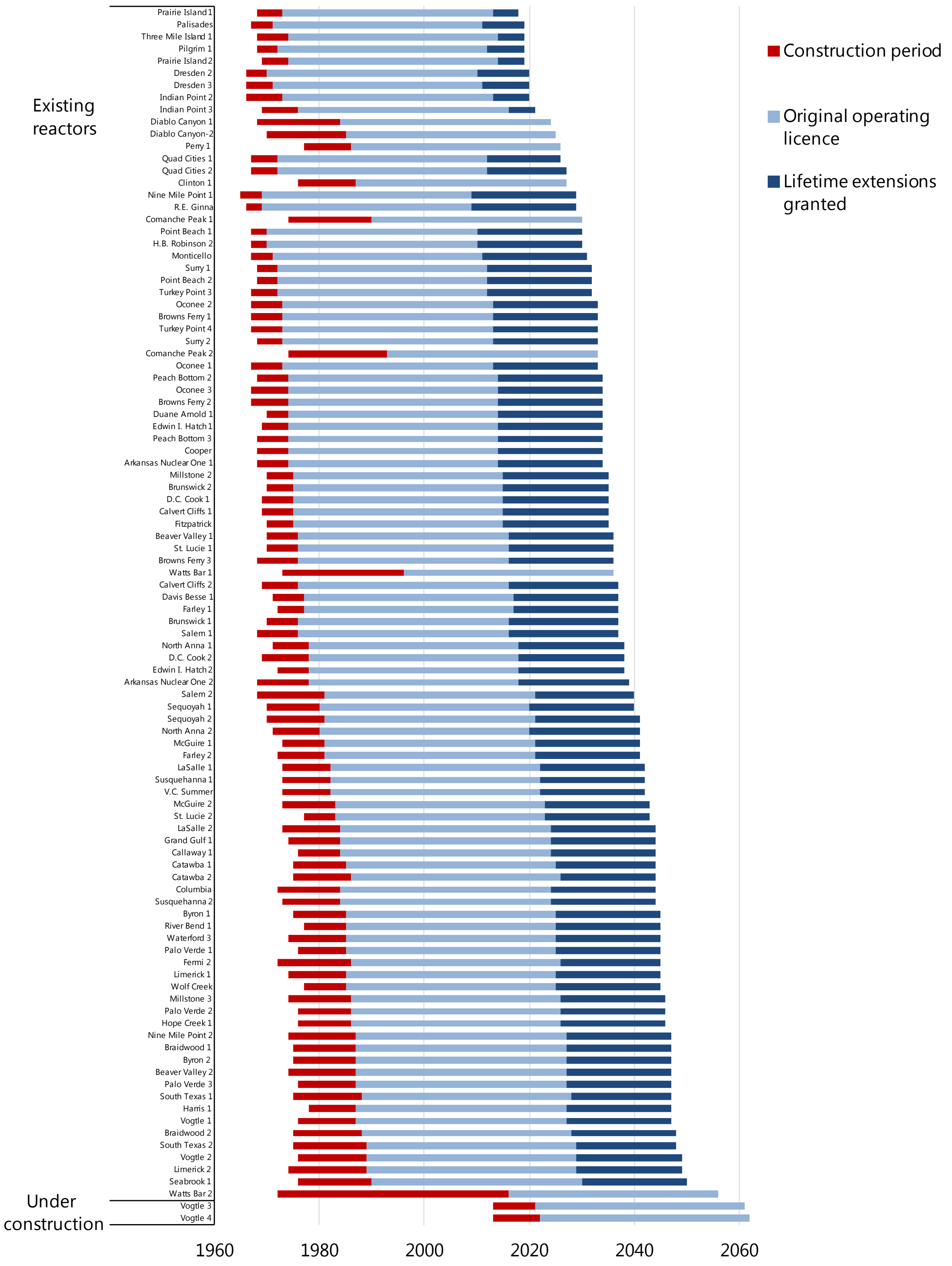
Figure 19. Operational nuclear power capacity in advanced economies in the Nuclear Fade Case



Without new investment in nuclear power, nuclear capacity in advanced economies would decline by two-thirds by 2040.

The European Union sees the largest decline in capacity in absolute terms, at over 100 GW, in the Nuclear Fade Case. Of the 126 reactors in operation, 89 are set to be decommissioned by 2030 without further extensions. By 2040, just 15 of the existing reactors are still in operation, complemented by four reactors that are under construction (Olkiluoto in Finland, Flamanville in France, and Mochovce 3 and 4 in the Slovak Republic). The decline in nuclear capacity in the United States is less severe than in the European Union, because nearly all of the existing fleet has already received initial 20-year lifetime extensions (Figure 20). Even still, nuclear power capacity in the United States declines by about half to 2040.

Figure 20. Current decommissioning dates for nuclear reactors in the United States



Note: Last updated on 20 May, 2019.

Sources: U.S. NRC (2019) ; IAEA (2019), Power Reactor Information System (PRIS).

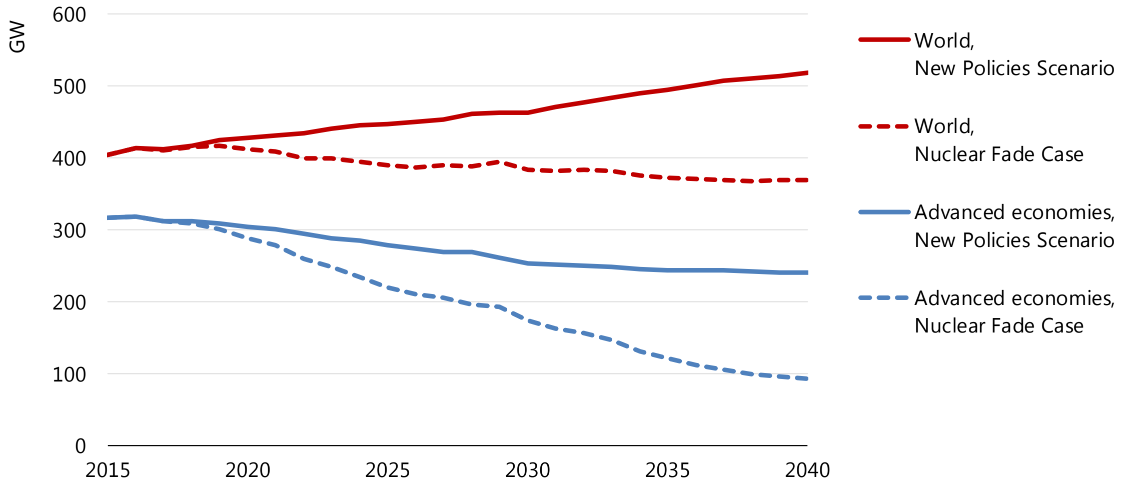
Without further lifetime extensions, 6 out of 10 nuclear reactors in the US would be decommissioned by 2040, even though nearly all have already received 20-year lifetime extensions.

In Japan, restarting reactors that are in temporary shut-down boosts operating capacity over the next few years, before the ageing fleet is rapidly retired. Capacity drops from a peak of around 17 GW in the early 2020s to almost nothing by 2040 when just two reactors (Shimane-3 and Ohma, which are under construction) are still in operation. Korea sees a one-third decline in nuclear capacity over the same period.

Implications of the Nuclear Fade Case in the New Policies Scenario

When the Nuclear Fade Case applied to the New Policies Scenario, global nuclear power capacity declines steadily over the projections period to around 370 GW in 2040 (about 50 GW down on the 2018 level) as the rapid decline in advanced economies more than offsets continued expansion in the developing economies (Figure 21). In the New Policies Scenario, global capacity rises by about one-quarter, with strong growth in China, India and Russia (China becomes the leading nuclear power producer in 2030, overtaking the United States). Capacity falls slowly in advanced economies, levelling off at around 240 GW in 2040 (about 25% lower than in 2018 compared with 70% lower in the Nuclear Fade Case).

Figure 21. Nuclear power capacity in the New Policies Scenario and the Nuclear Fade Case



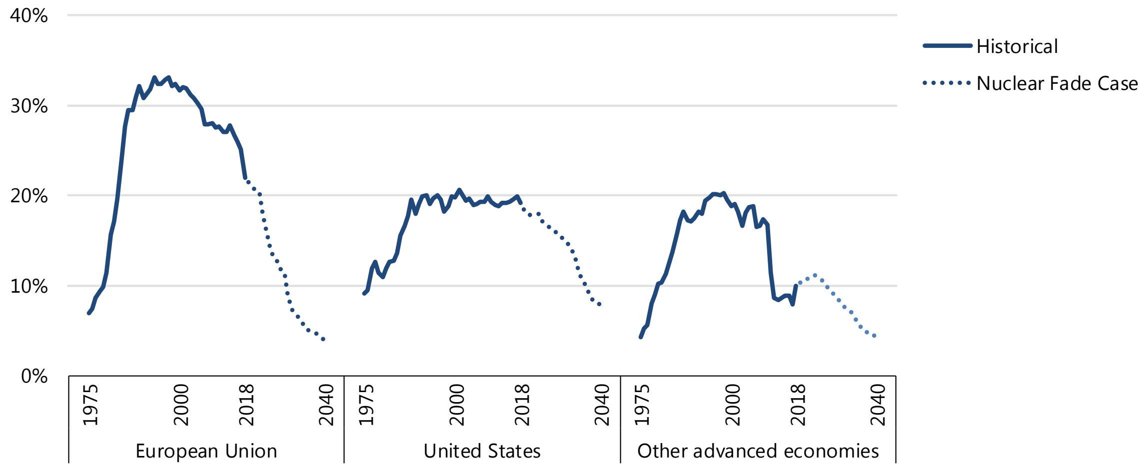
The steep decline of nuclear power in advanced economies in the Nuclear Fade Case outweighs growth in developing economies, driving down global nuclear power capacity to 2040.

Nuclear power will decline rapidly without lifetime extensions

In advanced economies, the share of nuclear power in total generation drops from 18% in 2018 to 5.5% in 2040 in the Nuclear Fade Case of the New Policies Scenario, returning to levels not seen since the early 1970s. This compares with a share of 14% by 2040 in the central New Policies Scenario – the result of an estimated USD 160 billion of cumulative investment in existing reactors, as well as some new builds.Total nuclear generation is about 1 000 TWh lower in 2040 than in the central New Policies Scenario in advanced economies as a whole.

The largest reductions in nuclear output in the Nuclear Fade Case occur in the European Union, where the share of nuclear power in electricity supply falls from 25% in 2018 to less than 5% in 2040– the lowest level since the 1970s (Figure 22). This results in nuclear power falling behind wind power, hydropower, gas, solar photovoltaic (PV), bioenergy and coal to become the seventh-largest source of electricity in Europe; it is the leading source today. In the United States, the share of nuclear drops from 19% to just 8% of total generation in 2040 – the lowest level since before 1975. In other advanced economies, nuclear power's share falls by more than half. Canada sees its share of nuclear power slump by three-quarters to just 4% of electricity supply in 2040; Mexico stops producing nuclear power altogether. In Japan, nuclear power's contribution drop to just 2%. In Korea, with a relatively young fleet and five reactors under construction, the role of nuclear is more stable, its share of total electricity supply remaining close to 20% through to 2040. As a result of these declines in advanced economies, China emerges as the new global leader for nuclear power well before 2030, surpassing both the European Union and United States.

Figure 22. Share of nuclear power in electricity supply in advanced economies in the Nuclear Fade Case of the New Policies Scenario

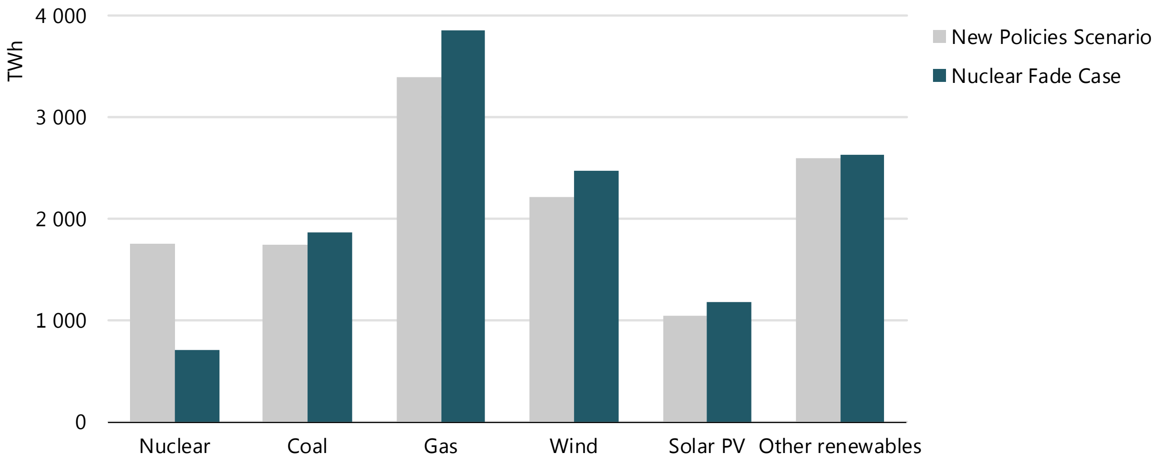


Without further investment, nuclear power will lose its position as the leading source of electricity in advanced economies, providing 6% of electricity supply in 2040 compared with 18% today.

Fossil fuels and renewables offset nuclear power reductions

The rapid decline of nuclear power output in advanced economies in the Nuclear Fade Case must be compensated by other sources, as the total electricity supply remains the same as in the central New Policies Scenario – rising from 11 300 TWh in 2018 to around 12 800 TWh by 2040. Nuclear output falls by 1 300 TWh – slightly more than the fall in coal-fired generation – between 2018 and 2040 in advanced economies. The two sources combined fall from 45% of electricity supply today to 20% in 2040. Most of the loss of nuclear production in the Nuclear Fade Case compared with the central New Policies Scenario is met by increased output from expanded generation from gas-fired and renewables-based power plants; coal-fired generation is only marginally higher (Figure 23). Fossil fuels – mainly gas – provide almost 60% of the increase in output needed to compensate for lower nuclear output; wind and solar power account for most of the rest. Natural gas becomes the single largest source of electricity in advanced economies in the Nuclear Fade Case, reaching 30% of the mix in 2040. The additional gas use in power generation increases overall gas consumption by 4% in advanced economies in 2040, which would put limited upward pressure on domestic and import gas prices. The share of renewables in total generation reaches nearly 50% in 2040, compared with 46% in the New Policies Scenario.

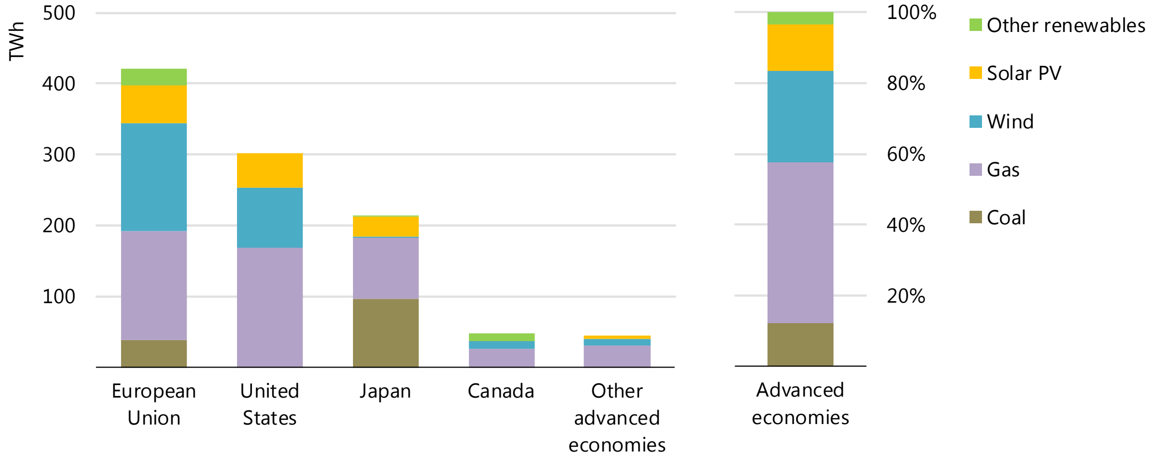
Figure 23. Electricity generation by source in advanced economies in the New Policies Scenario and Nuclear Fade Case, 2040



Natural gas contributes the biggest increase in electricity generation to compensate for less nuclear in the Nuclear Fade Case, with renewables – notably wind and solar PV – adding most of the rest.

The impact of lower nuclear output on other fuels varies by region, according to the policy environment, resource availability and local cost factors. In the United States, cheap gas resources mean it is the primary replacement for reductions in nuclear power (Figure 24). Policy support at the state level for wind and solar PV, along with their improving competitiveness, mean they are next in line to add to the mix. In the European Union, close to one-half of member states have announced coal phase-out plans, so there is limited scope to increase output from coal, making wind power the marginal source of electricity in those countries where nuclear output declines. Gas-fired generation also increases notably in the medium to long term in Europe. In Japan, coal and gas replace lower output from nuclear power in nearly equal measure, with existing capacity running more often and more new capacity being built (24 GW of gas-fired capacity and 12 GW of coal-fired capacity are added by 2040) alongside some additional growth in solar PV. In Canada, where nuclear generation is almost 50 TWh lower in 2040, natural gas offsets more than one-half of this amount, complemented by wind and solar PV.

Figure 24. Electricity supply by source in the Nuclear Fade Case relative to the New Policies Scenario, 2040



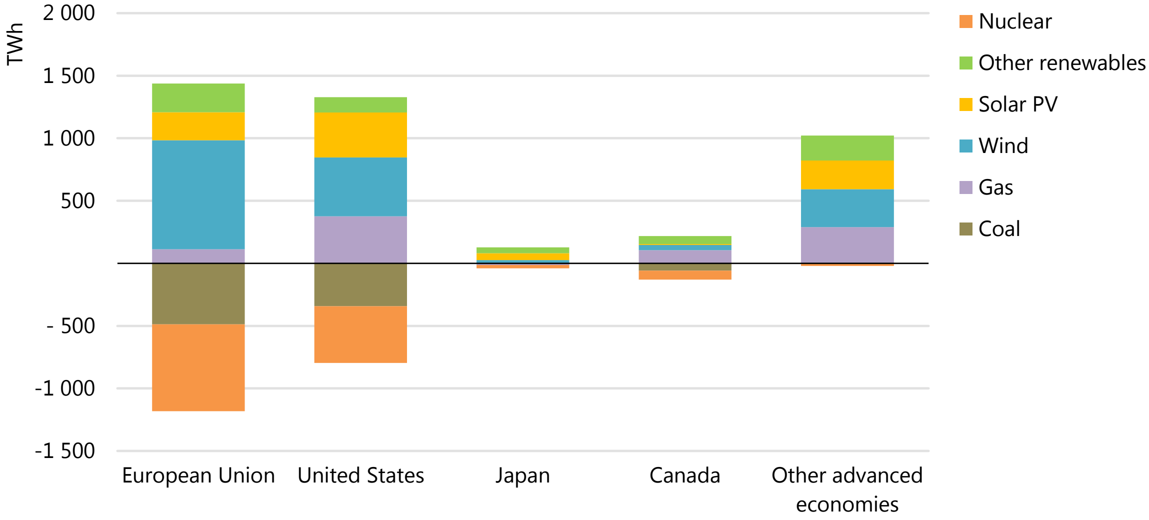
Fossil fuels account for the bulk of the increase in output needed to offset the decline in nuclear power compared with current trends.

Lower nuclear output reinforces the call on renewables

The sharp fall in nuclear output through the projection period in the Nuclear Fade Case means that renewables – especially wind and solar power – grow even more rapidly. Globally, wind power output more than triples between 2018 and 2040, increasing by 1 700 TWh – the biggest increase of any source in absolute terms. This growth comes from new wind farms, with around 720 GW of new wind power capacity added in advanced economies between 2018 and 2040. Of the total capacity additions, almost 400 GW is in the European Union and about 185 GW is in the United States; Korea adds 32 GW, Canada 25 GW, Mexico over 20 GW and Australia about 20 GW. New solar PV projects account for around 950 TWh of additional electricity supply, with about 770 GW of capacity added – 280 GW in the European Union, 230 GW in the United States and almost 90 GW in Japan. Other renewables, including hydropower, bioenergy, geothermal and marine power, add to the growth in renewables capacity.

Despite the increase in the use of gas for power across advanced economies, the amount of generation provided by dispatchable sources falls dramatically in the Nuclear Fade Case of the New Policies Scenario (Figure 25). This changes the nature of the power supply in advanced economies and increases the need for flexibility (see the next chapter). In the European Union, the fall in nuclear and coal-fired power output totals close to 1 200 TWh between 2018 and 2040, equal to one-third of all electricity supply in 2040. Wind power accounts for the lion's share of the compensatory increase in output from other sources and surpasses gas as the largest source of electricity by 2030. The development of offshore sites contributes some 40% of the growth in wind power, concentrated in Belgium, Denmark, Germany, the Netherlands and the United Kingdom. Gas-fired generation also increases in the European Union, but mainly to meet the need for flexibility rather than baseload supply. Solar PV and other renewables expand to 2040 in the region, helping to lift the share of renewables in power from 33% in 2018 to 70% by 2040. With these developments, the CO_2 emissions intensity of electricity supply in the European Union falls by more than one-half, to 1113 grammes of carbon dioxide (gCO_2) per kWh – compared with a 60% reduction in the central New Policies Scenario.

Figure 25. Change in electricity supply by source over time in advanced economies in the Nuclear Fade Case of the New Policies Scenario by region/country, 2018 to 2040



Declines in nuclear and coal-fired generation are mainly compensated by growth in renewables and gas-fired generation.

In the United States, nuclear power generation in the Nuclear Fade Case falls by 470 TWh between 2018 and 2040, with a significant decline also for coal-fired output. Gas-fired generation compensates for one-half of these reductions, and wind, solar PV and other renewables for the rest. These sources also meet the additional 460 TWh of electricity demand projected to 2040. Despite the loss of low-carbon nuclear production, the expansion of renewables and the greater role for natural gas result in the emissions intensity of electricity in the United States declining by one-quarter to 2040. Even so, it remains above 300 gCO_2 per kWh – close to triple that of the European Union in 2040.

In the other advanced economies, nuclear power production drops by 170 TWh between 2018 and 2040 in the Nuclear Fade Case, with coal-fired power output also falling slightly. Renewables play the lead role in offsetting lower nuclear output and meeting growing demand, led by wind and solar PV. Gas also plays a significant role, particularly in Canada and Korea.

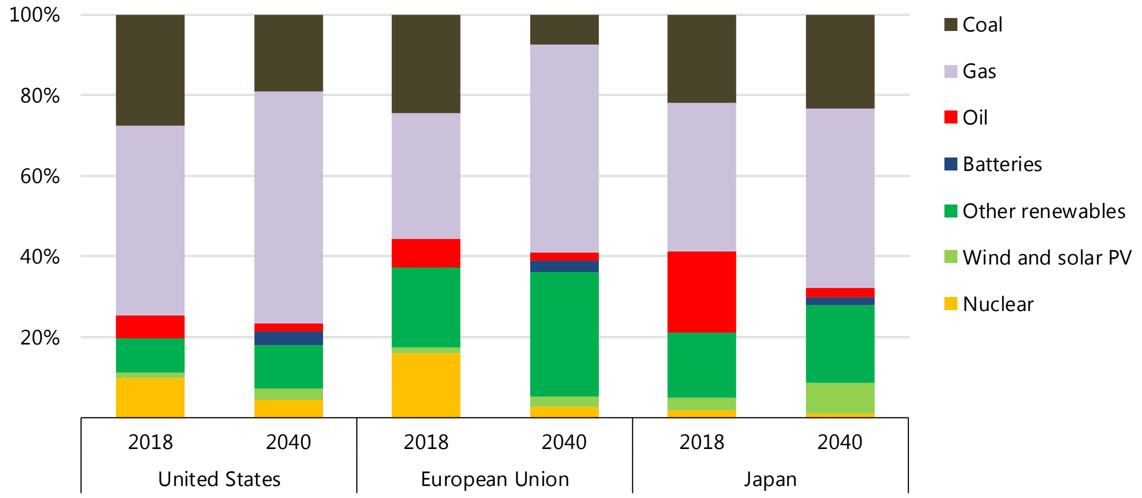
System adequacy relies more heavily on gas

The decline in nuclear power in advanced economies in the Nuclear Fade Case accelerates the shift away from dispatchable capacity. This type of capacity, which includes power plants fuelled by coal, gas, oil and bioenergy, as well as hydropower and solar thermal technologies, accounts for over 80% of installed capacity today. By 2040, the amount of dispatchable capacity remains close to current levels, but its share of the total drops to just over 60%. This occurs in parallel with an increasing need for flexibility in power systems, as variable renewables in the form of wind power and solar PV make up a rising share of capacity. Flexibility, which historically has been provided primarily by dispatchable capacity, would need to come increasingly from energy storage, demand-side response and network interconnections (see the next chapter).

Less nuclear capacity accentuates the decline in dispatchable coal-fired capacity, which also contracts in advanced economies, from 590 GW in 2018 to under 400 GW by 2040 in the Nuclear Fade Case. Policies have recently been established to phase out coal-fired power in 11 countries in Europe, including Germany, Italy and the United Kingdom, and also in Canada. Several other advanced economies are looking to limit the use of coal-fired generation as a way of reducing CO_2 and pollutant emissions. Difficult market conditions are putting financial pressure on the ageing fleet of coal plants. For example, in the United States, competition with gas-fired power plants has accelerated the retirement of old coal-fired stations.

With less nuclear capacity, the reliance on gas-fired power capacity to maintain sufficient flexibility in power generation to maintain the security of electricity becomes more pronounced in advanced economies in the Nuclear Fade Case. Gas is already the primary source of system adequacy in all regions, and this becomes even more the case over the projection period. Variable renewables are less able to provide system adequacy as their capacity is not always available, so other types of capacity are needed to ensure demand can be met at all times. The role of batteries is also projected to grow, though their contribution remains small. Of the capacity added to the system by 2040, gas-fired power makes the greatest contribution to adequacy, as well as flexibility in balancing the system (Figure 26). In the United States, where gas supply is abundant, gas-fired capacity expands by about 60 GW to help meet the growing need for capacity, providing 55% of system adequacy in 2040. In the European Union, gas is no longer the main source of power supply in 2040, but nonetheless, its installed capacity grows by some 100 GW compared with current levels, meeting more than one-half of system adequacy needs by 2040. This is a substantial increase on today's levels and even higher than in the central New Policies Scenario. Difficult market conditions and limited prospects for high utilisation rates raise doubts about how this additional gas-fired capacity would be procured in Europe. Japan adds around 20 GW of gas-fired capacity and Mexico about 40 GW between 2018 and 2040. Aside from nuclear power, other low-carbon technologies also contribute to the adequacy of the system, including dispatchable renewables, notably bioenergy-fired plants, and fossil-fuelled power plants fitted with CCUS.

Figure 26. Contribution to system adequacy in the Nuclear Fade Case of the New Policies Scenario by source and region/country

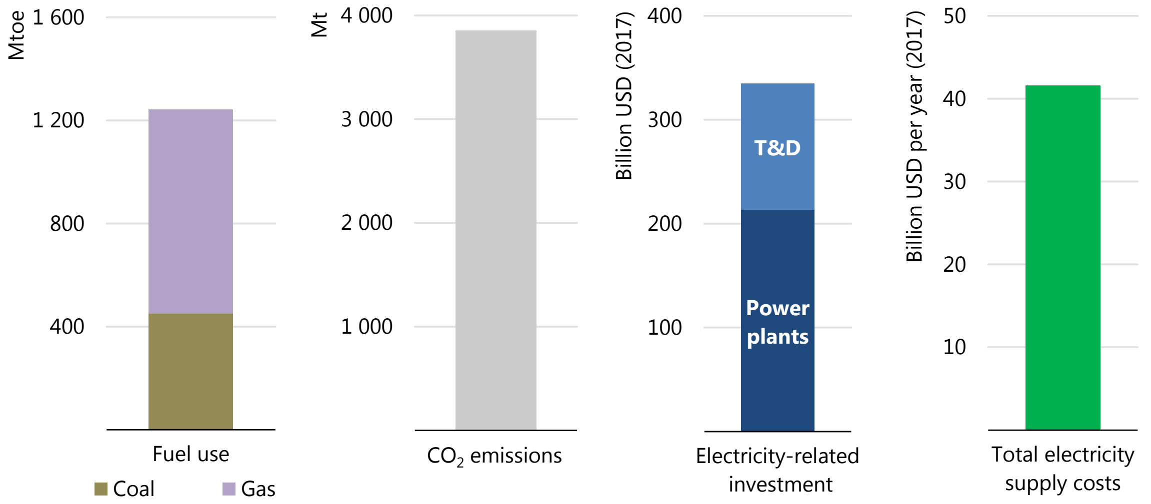


To compensate for the loss of nuclear power, more capacity from other sources – primarily gas-fired plants – is needed to ensure that the total capacity is always adequate to meet peak load.

Lower nuclear output results in higher costs to consumers

The sharp reduction in nuclear power output in advanced economies in the Nuclear Fade Case has wide-ranging implications for the energy system. The amount of coal and gas consumed in advanced economies increases due to higher coal- and gas-fired electricity generation relative to the central New Policies Scenario. Over the period 2019-40, cumulative coal use for power is 4% higher and gas use 7% higher (Figure 27). Most of the increase in coal use occurs in Japan and, to a lesser extent, in the European Union, where coal-fired plants operate at higher capacity factors. The European Union accounts for nearly one-half of the increase in natural gas use.

Figure 27. Change in key indicators in advanced economies in the Nuclear Fade Case relative to the New Policies Scenario, 2019-40



Note: Mtoe = million tonne of oil equivalent.

Lower nuclear would raise fossil fuel use and associated CO_2 emissions, increase power sector investment needs and add an average of 3% to consumer electricity bills.

The increased use of fossil fuels in advanced economies, notably coal in Europe and Japan, drives up CO_2 emissions in the Nuclear Fade Case. Cumulative emissions increase by almost 3 900 Mt, or 5%, to 2040 compared with the central New Policies Scenario. This is nearly equivalent to China's CO_2 emissions from the power sector in 2018. The European Union accounts for more than 45% of the increase, followed by Japan with close to 40%.

Investment costs also increase because of the need to build additional greenfield power plants and refurbish existing non-nuclear plants, as well as to expand or upgrade T&D networks to tap into additional renewable resources. Extending the lifetime of nuclear power plants is generally a cost-effective means of supplying electricity over the projection period. In the New Policies Scenario, some USD 170 billion (in real 2017 dollars) is spent to extend the lifetime or increase the rated capacity of existing nuclear power plants in advanced economies. In the Nuclear Fade Case, lower nuclear investment leads to higher overall power sector investment; over the period to 2040, additional investment is close to USD 340 billion, or 5%, higher compared with the New Policies Scenario. Just under two-thirds of the increase in non-nuclear investment, or around

USD 210 billion, is spent on power plants. The remainder, over USD 120 billion, is invested in networks, with more projects requiring new connections to the grid and many renewables at lower voltages.

The combination of increased use of fossil fuels and higher investment costs results in an increase in the overall cost of electricity supply and higher prices to consumers in advanced economies in the Nuclear Fade Case. The cumulative cost of supply is around USD 950 billion higher than in the New Policies Scenario over 2019-40. As a result, consumers pay an average of USD 43 billion, or 3%, per year more than in the New Policies Scenario over that period. The burden of these additional costs is not equal across advanced economies. The increase in costs is larger in countries with the largest reductions of nuclear power and where imported fuels are needed to compensate for reduced nuclear output.

Implications of the Nuclear Fade Case in the Sustainable Development Scenario

Sustainable development calls for more low-carbon energy

The Sustainable Development Scenario depicts an energy pathway that simultaneously achieves three major United Nations (UN) policy objectives: a trajectory of energy-related CO_2 emissions consistent with achieving the Paris Agreement's goal of holding the increase in the global average temperature to well below 2 °C, a measurable improvement in local air quality and the achievement of universal energy access. Due to the scale of these challenges, the policies and measures that are necessary to meet these objectives go well beyond the policies in place or planned, especially with respect to energy efficiency and ramping up low-carbon energy supply.

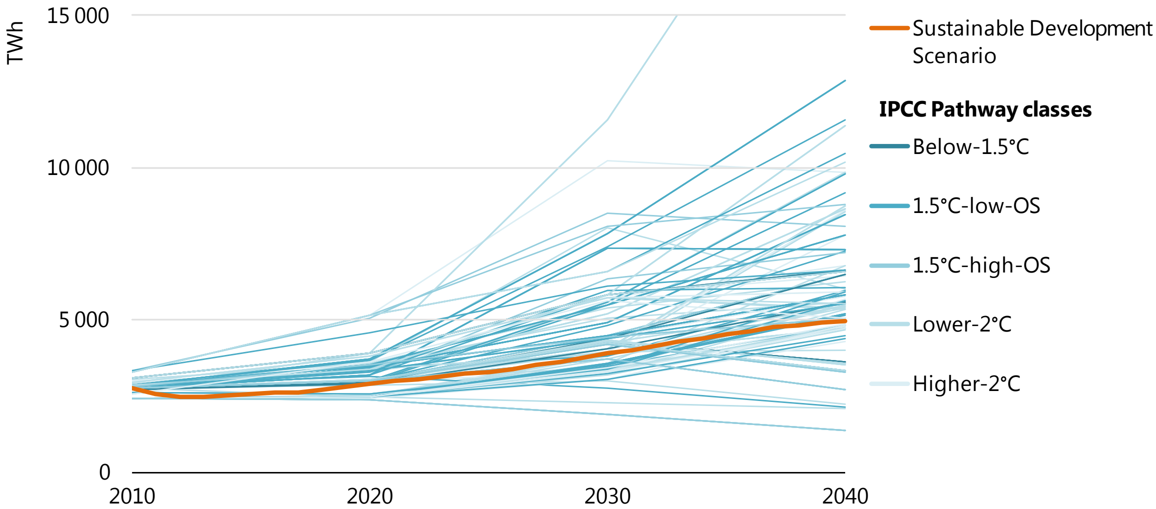
Electrification and the decarbonisation of power generation together play an important role in achieving the multiple UN Sustainable Development Goals, reflecting that the low-carbon sources that are seeing the fastest technological improvements and that can be scaled up most easily are all power generation technologies. Moreover, the use of electricity does not give rise to any pollution at the point of use. While the share of electricity in total energy consumption worldwide has been growing for many years, the rate of increase in that share doubles in the Sustainable Development Scenario, compared with only slightly faster in the New Policies Scenario. The output of low-carbon electricity also increases far more quickly in the Sustainable Development Scenario, tripling by 2040, compared with a 60% increase in the New Policies Scenario. As a result, the global average carbon intensity of electricity, which has fallen by just one-quarter over the past two decades, declines by more than 80% between 2018 and 2040 (compared with 40% in the New Policies Scenario). Wind and solar power, which already account for the bulk incremental generation in the Sustainable Development Scenario, grow much faster, with their combined output expanding by a factor of almost ten between 2018 and 2040.

Nuclear power makes an important contribution to the quicker expansion of low-carbon electricity supply in the Sustainable Development Scenario. As it does not generate any pollution, nuclear power also makes an important contribution to the air quality targets in that scenario. Its impact on energy poverty is much less significant, as most of the world's nuclear fleet will still be in countries where access to modern energy is already universal, or close to being so. Nevertheless, nuclear power plants under construction in countries such as

Bangladesh and India will help provide universal access in those countries. Global nuclear production is projected to reach 4 960 TWh in 2040 – 33% higher than in the New Policies Scenario and 90% higher than in 2018. Capacity reaches 678 GW by 2040, compared with 519 GW in the New Policies Scenario and 422 GW as of May 2019. The largest components of the increase are in China and, to a lesser extent, India, where coal represents most of power generation. Nuclear capacity in the two countries combined jumps from 53 GW in 2018 to almost 250 GW in 2040, compared with about 190 GW in the New Policies Scenario. Nuclear capacity additions there largely replace baseload coal, yielding large emissions reductions without requiring major changes in the electricity system operation.

In advanced economies, nuclear power production increases by around 10% between 2018 and 2040 in the Sustainable Development Scenario, largely due to the restoration of nuclear production in Japan, as well as a combination of more lifetime extensions of existing reactors and some new construction in all regions. This compares with a fall of around 12% in the New Policies Scenario. Nonetheless, the retirement of some plants and legally binding phase-out policies leads to a decline in output between 2018 and 2040 in several countries with a significant amount of nuclear capacity, notably the United States. Nuclear production also falls slightly in the European Union. Yet the share of nuclear in the generation mix declines much less than in the New Policies Scenario, alleviating the challenge of boosting renewables-based generation and integrating it into the electricity system. In Japan, nuclear production recovers almost to the level it was at before the Fukushima Daiichi accident. This would require a major effort to achieve social acceptance, as well as large investments to secure lifetime extensions of much of the idle fleet.

Figure 28. Global nuclear power production in the Sustainable Development Scenario compared with IPCC scenarios consistent with 2°C warming



Note: All IPCC scenarios included for 4 pathway classes: Below-1.5°C, 1.5°C-low-OS, 1.5°C-high-OS and Lower-2°C and Higher-2°C.
Source: Huppmann et al. (2018), release 1.1.

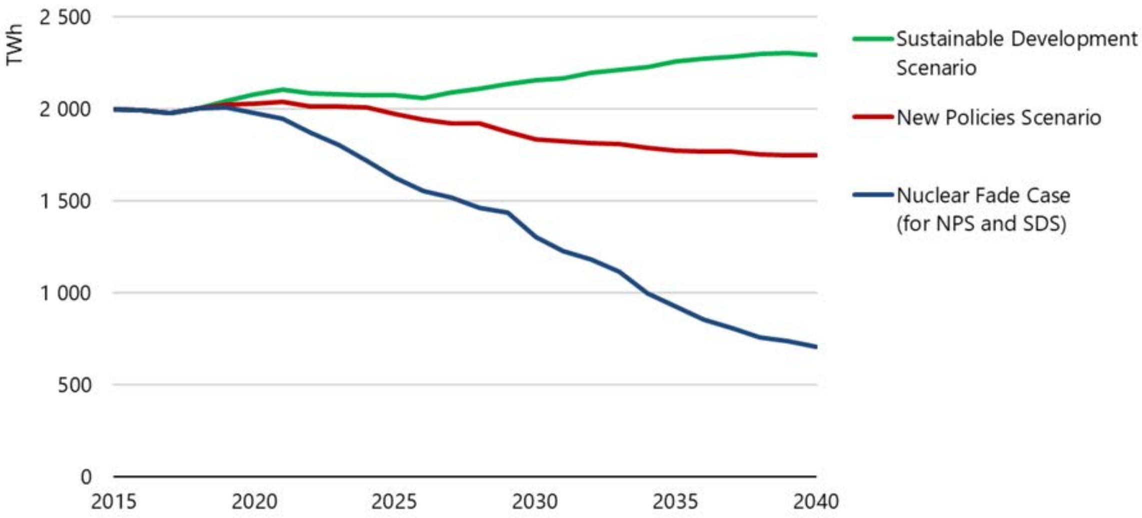
Nuclear power production in most low-carbon scenarios is higher than in the IEA Sustainable Development Scenario.

Nuclear power's potential role in decarbonisation is well established. Among the pathways consistent with 1.5°C to 2 °C – scenarios that limit peak warming to below 2 °C during the entire 21st century with 50% likelihood or higher – reviewed by the Intergovernmental Panel on

Climate Change (IPCC) in its latest Special Report on Global Warming of 1.5°C (SR15) (Rogelj, Shindell, & Jiang, 2018), nuclear power production makes a major contribution to decarbonisation. Indeed, the IEA Sustainable Development Scenario is among the more cautious in terms of nuclear expansion (**Error! Reference source not found.**).

Applying the Nuclear Fade Case to the Sustainable Development Scenario results in a significant short-fall in nuclear output in advanced economies. By 2040, output falls to a level that is 70% below that in the central Sustainable Development Scenario, and 60% below that in the New Policies Scenario (Figure 29). The output gap in 2040 amounts to 1 600 TWh, equal to 13% of total power generation in the Sustainable Development Scenario. To achieve the same pace of emissions reductions, this shortfall must be made up with increased output from other low-carbon energy sources in the Nuclear Fade Case.

Figure 29. Nuclear power production in advanced economies by scenario

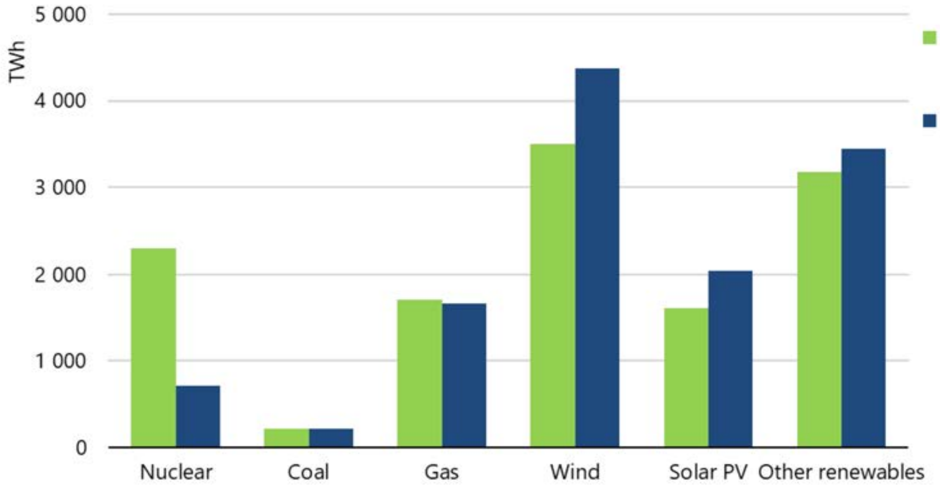


A large shortfall in low-carbon electricity would emerge without nuclear lifetime extensions or new projects, calling on other low-carbon sources to fill the gap to keep to a sustainable energy path.

Wind and solar are best positioned to fill the gap left by lower nuclear output

It is possible to achieve the emissions pathway described in the Sustainable Development Scenario in advanced economies with no new investment in nuclear power, though it is significantly more difficult. Indeed, some countries and jurisdictions have ambitious decarbonisation objectives coupled with a legally binding ban on nuclear construction, or plan to phase it out, and are designing policies to achieve those objectives. In view of the constraints on other technologies, wind power and solar PV plug most of the gap left by reduced nuclear output in advanced economies in the Nuclear Fade Case compared with the central Sustainable Development Scenario (**Error! Reference source not found.**). Increases from other renewables – including hydro, bioenergy, CSP and geothermal – help fill the gap from lower nuclear power production.

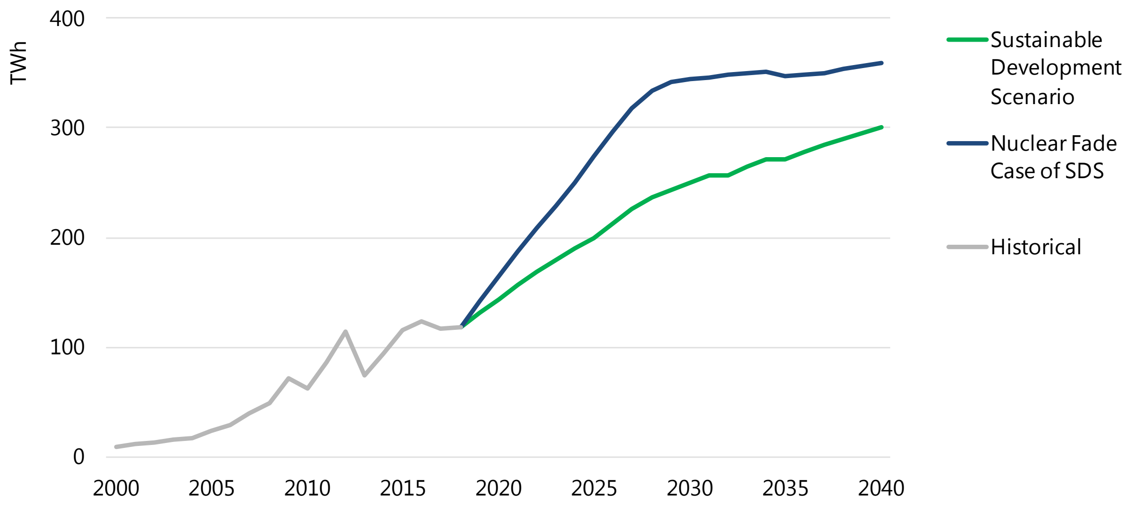
Figure 30. Electricity generation by source in advanced economies in the Sustainable Development Scenario and Nuclear Fade Case, 2040



A combination of wind power, solar PV and other renewables is needed to make up the shortfall in nuclear output in meeting sustainable development goals.

In the Nuclear Fade Case, the rate of increase in wind and solar PV power output in advanced economies to 2040 is roughly one-third higher than in the main Sustainable Development Scenario and three times higher than that of the past decade (Figure 31). This means that power production from wind and solar PV rises six-fold from 2018 to 2040 (instead of five-fold in the Sustainable Development Scenario). Wind and solar PV account for over half of total electricity generation in advanced economies in 2040 in the Nuclear Fade Case, compared with about 40% in the central Sustainable Development Scenario and 10% in 2018.

Figure 31. Combined wind and solar power production growth in advanced economies in the Sustainable Development Scenario and the Nuclear Fade Case



To achieve sustainable energy development, output from wind and solar power would need to expand twice as fast as in the past, and three times as fast in the absence of new nuclear investment.

The increase in wind and solar PV capacities in the Nuclear Fade Case is much greater than the loss of nuclear capacity, because their load factors are far lower. Additions of wind and solar capacities in 2017 in advanced economies amounted to 55 GW, which would be expected to produce around 120 TWh per year under normal weather conditions. This is about one-half the magnitude as power generated by the 30 GW of nuclear capacity added in advanced economies at its historical peak in 1977, which was capable of producing around 250 TWh per year. However, while wind and solar PV capacity additions have continued to increase over the last four years, the energy output from that additional capacity has fallen, as investment has shifted to solar PV, which typically has a lower load factor than wind turbines. The much faster rate of growth in VRE also has important implications for the provision of flexibility (see the next chapter).

There are sufficient geographical resources to accelerate the rate of capacity additions of wind and solar PV in advanced economies to that required in the Nuclear Fade Case of the Sustainable Development Scenario. Both technologies are mature; there is some slack in turbine and PV panel manufacturing capacity globally, and which could be increased sufficiently with enough investment. Learning by doing and economics of scale have been successful in reducing costs to such a degree that, in some regions, the LCOE is often lower than that of either conventional thermal generation or nuclear generation (see the previous chapter). Wind and solar PV are modular technologies that are well suited to high-volume modern manufacturing, offering further opportunities to reduce costs. Potential sites are much more widely available than for geothermal power plants, and there is no feedstock requirement like for bioenergy power plants. While the scale of manufacturing and project management capabilities would need to increase hugely in the Nuclear Fade Case of the Sustainable Development Scenario, the barriers to achieving that are far easier to overcome than those facing the nuclear industry.

Stronger policy support for wind and solar PV would be necessary to scale up deployment to the degree needed. Policies drive nearly all renewables investment. Under long-term capacity auctions, which have emerged as the favoured regulatory mechanism for securing such investment, the amount of capacity added is determined by policy makers, while the auctions determine how much is paid to the investors. Other investment channels that do not involve government support, such as voluntary corporate purchases of renewable energy and wholesale market-based renewables investment, which have been seen in Europe and some regions of North America, have become more important in recent years, but investment levels remain small. For stronger policy support for wind and solar PV to be effective, various non-market barriers would need to be overcome, including public and social acceptance of the projects and the associated expansion in network infrastructure (see the next chapter).

CCUS or dispatchable non-hydro renewables could help fill the gap

There are several alternatives to wind and solar power that could, in theory at least, plug the gap in low-carbon production left by the loss of nuclear power in the Nuclear Fade Case. However, none of them appear to be in a position to expand rapidly soon. The main options are CCUS and dispatchable non-hydro renewables.

In principle, the loss of nuclear output in the Nuclear Fade Case could be offset by the much faster deployment of CCUS at conventional coal- and gas-fired power stations, yielding a similar CO_2 emissions trajectory to that in the Sustainable Development Scenario. This would enable one dispatchable type of generating capacity to be effectively replaced by another, with minimal implications for system flexibility. Retrofitting existing plants could also minimise modifications to network infrastructure as they are already connected. However, deployment of CCUS at an even faster rate than envisaged in the Sustainable Development Scenario would be difficult to achieve. As an emerging technology, there are enormous uncertainties surrounding the technical and economic viability of deploying CCUS on a large scale. The rate of deployment of CCUS is presently running at just 0.15% of that required in the Sustainable Development Scenario by 2040. Recent high-profile projects have suffered similar cost overruns and project management problems as new nuclear projects, and new CCUS projects are facing similar investment barriers. Achieving the rate of CCUS deployment in the Sustainable Development Scenario would already be a major achievement; expecting an even faster rate to compensate for lower nuclear production is probably unrealistic.

There are also limits on how much dispatchable non-hydro renewables capacity – essentially bioenergy (biomass) and geothermal power – could be expanded beyond the rate of increase already projected in the Sustainable Development Scenario. In both cases, electricity is produced by a steam turbine and is able to provide the same capacity adequacy and system services as conventional thermal or nuclear generation. Geothermal plants normally run as baseload capacity, while biomass-fired plants can take advantage of the easy storability of the fuel to ramp flexibly. Nevertheless, there are constraints on the availability of sustainable biomass feedstock. The rate of expansion of bioenergy-based generation already pushes up against ecological constraints in the Sustainable Development Scenario – the projected increase in this type of generation to 2040 is equivalent to 1 billion tonnes of wood per year being burned. That scenario also incorporates a large expansion of biomass heat and liquid biofuels, which compete for the same sustainable ecological potential. Using even more bioenergy to compensate for low nuclear power would put further pressure on feedstock supply.

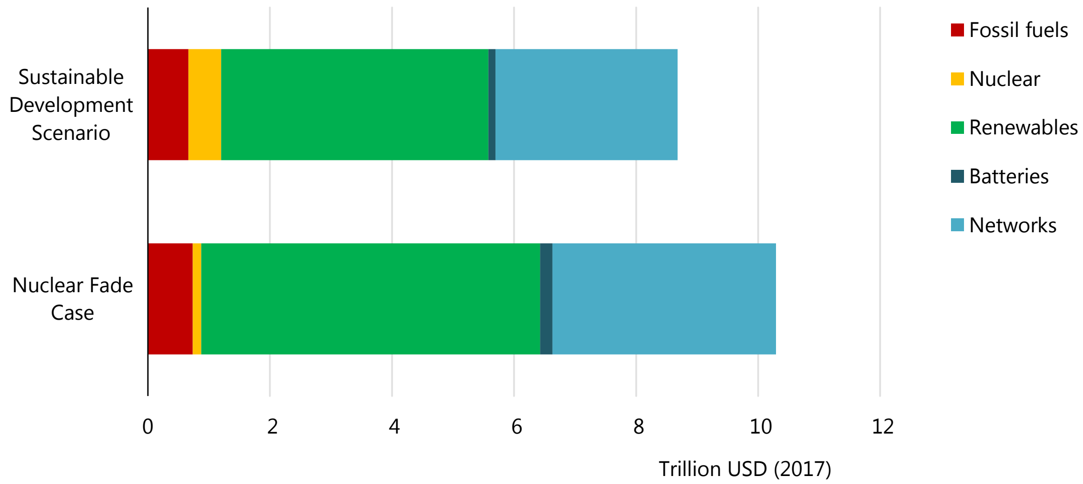
The scope for expanding geothermal power using current technologies is also limited. The potential varies by country and region, but is significant only in active zones such as some countries in Southeast Asia, Iceland and Kenya. Second-generation geothermal technologies based on hydraulic fracturing (fracking) of hot dry rock may allow production to be scaled up considerably, as it could be deployed in many more areas. But it is still at the experimental stage, and costs would probably be high initially. According to the IEA *Geothermal Technology Roadmap*, it might be possible for output to reach a level equal to about 40% of current global nuclear power by mid-century, but only under optimistic assumptions about the rate of technological progress (IEA, 2011).

Achieving sustainability with lower nuclear power production raises investment needs and the cost of the energy transition

Investment needs in power plants and the network in advanced economies increase substantially in the Nuclear Fade Case compared with the central Sustainable Development Scenario. Despite recent declines in wind and solar capital costs, building new renewable capacity requires considerably more capital investment than extending the lifetimes of existing nuclear reactors. Part of the higher cost is due to the need to extend the transmission grid to connect new plants, which are often located in areas where transmission lines are either non-existent or inadequate to handle the extra generating capacity. Lifetime extensions at existing plants require no additional investment in the grid. The much bigger additions of VRE capacity in the Nuclear Fade Case would inevitably mean exploiting less accessible sites.

Over the next two decades, around USD 1.6 trillion more investment would be needed in net terms in the electricity sector in advanced economies in the Nuclear Fade Case than in the central Sustainable Development Scenario (Figure 32). Although investment in nuclear power would be close to USD 400 billion lower, roughly USD 1.2 trillion more investment would be needed in renewables-based generating capacity and around USD 700 billion in network upgrades to integrate the larger renewables fleet. A smaller amount of additional investment in gas-fired capacity (mainly for system adequacy purposes) and in battery storage, totalling around USD 100 billion, would also be needed.

Figure 32. Cumulative electricity sector investment in advanced economies in the Sustainable Development Scenario and Nuclear Fade Case, 2019-40



An additional USD 2 trillion of investment in renewables and in networks would be required to achieve sustainability, far exceeding the USD 400 billion reduction in nuclear investment.

The European Union accounts for the largest share of the increase in power sector investment in the Nuclear Fade Case, calling for an additional USD 560 billion from 2019 to 2040. Renewables account for the bulk of the incremental investment (USD 470 billion) in the Nuclear Fade Case of the Sustainable Development Scenario followed by transmission and distribution networks (USD 240 billion), more than outweighing the USD 210 billion fall in nuclear spending. Average annual wind and solar deployment would need to double the recent pace and be one-third higher compared with the central Sustainable Development Scenario.

Achieving the clean energy transition in Japan without further nuclear investment raises investment needs by USD 540 billion from 2019 to 2040. This is because the restoration of existing nuclear capacity and new plants play a major role in the Sustainable Development Scenario. With the decline in coal-fired power, additional investment in renewables, mostly solar PV, and distribution networks is close to USD 600 billion, more than ten times the fall in nuclear investment (USD 55 billion). Japan is a special case as it recently experienced a wave of investment in solar PV, which proved to be unsustainable. For example, in 2015, generous solar feed-in tariffs stimulated deployment of almost 11 GW, over 20% of global solar PV deployment in the year (Japan represents less than 5% of global electricity demand). This upswing and strong solar PV deployment in other recent years created a significant financial burden on consumers and considerable technical difficulties in integrating the new capacity into the electricity system. This led to regulatory changes to bring solar investment down to more manageable levels. The Nuclear Fade Case of the Sustainable Development Scenario would require a renewed surge in spending on solar and wind power to facilitate a doubling of the rate of deployment. Given the limited prospects for wind power in the near term, the deployment of solar PV would need to be significantly above the 2015 peak.

In the United States, cumulative power sector investment is about USD 370 billion more in the Nuclear Fade Case compared with the central Sustainable Development Scenario. Most of the additional investment is directed towards renewables, where investment rises by over USD 300 billion. Investment also increases in distribution networks (USD 80 billion) and to a lesser extent in batteries (over USD 30 billion) and in transmission (close to USD 20 billion). The fall in nuclear investment is USD 100 billion. The rate of deployment of wind and solar PV in the Nuclear Fade Case is double that observed in recent years. But the need for more renewables is likely to be even greater beyond 2040, when the remaining nuclear plants would shut down. The contribution of nuclear power is still significant in 2040 even in the Nuclear Fade Case, as many plants commissioned in the 1980s with licences to operate until 60 years of age would still be operating. However, by 2040, most of these surviving plants would be within five years of closure.

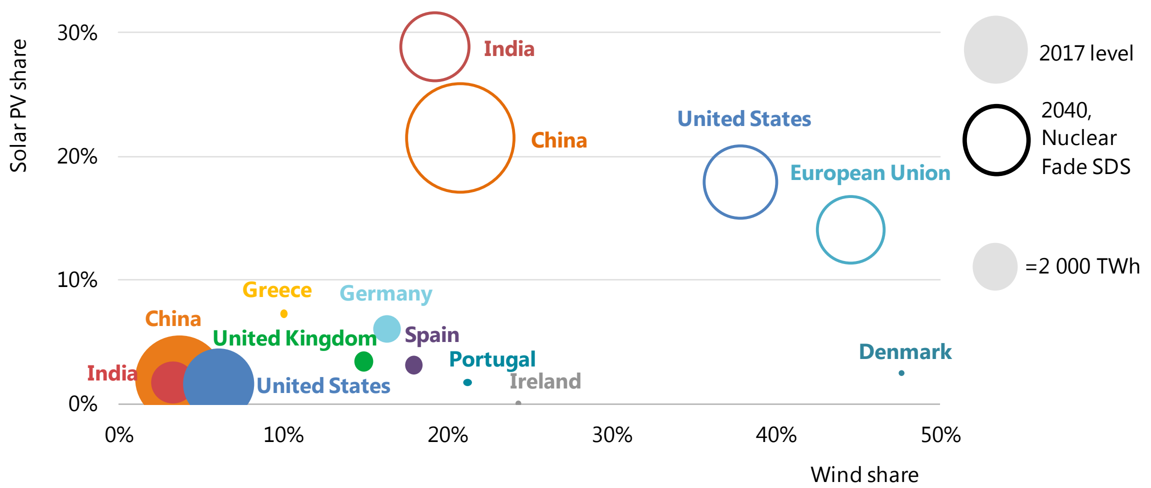
The total costs of electricity supply from 2019 to 2040 are 5% higher in advanced economies in the Nuclear Fade Case of the Sustainable Development Scenario than with nuclear investment. The additional investment required is not offset by savings in operational costs, as fuel costs for nuclear power are low, and operation and maintenance is a minor portion of total electricity supply costs. Electricity supply costs are close to USD 80 billion higher per year on average for advanced economies as a whole. The burden is largest where nuclear power has the potential to play the largest role in the clean energy transition due to modest renewable energy resources, and where fuels are imported. For example, the additional cost of the clean energy transition would be 10% higher in Japan, compared with 6% higher in the European Union and 3% higher in the United States.[9]

[9] Electricity supply cost estimates may not fully capture the network-related system integration costs for the rising shares of wind and solar PV. Detailed grid integration studies would be required in order to accurately estimate the network-related integration costs for the described generation mix.

4. Achieving sustainability with less nuclear power

Boosting renewables-based power generating capacity in advanced economies to fully compensate for the short-fall in low-carbon electricity in the Nuclear Fade Case as applied to the Sustainable Development Scenario is achievable in principle. It would nonetheless require an extraordinary effort by policy makers and regulators to create the conditions needed to bring forth the required investment. However, the challenge concerns other issues in addition to the amount of generating capacity needed. Wind and solar PV are not perfect substitutes for nuclear power in two important respects. First, wind and solar power plants occupy much larger amounts of land than nuclear power stations, which can give rise to constraints on siting. Second, wind and solar power are types of VRE with much lower load factors than nuclear power; this augments the need for flexibility in the electricity system as the share of wind and solar power in the total generating capacity rises. The transition to a clean energy system hinges on overcoming these hurdles. Large electricity systems would have to move to high shares of variable renewables (Figure 33), which is unprecedented historically.

Figure 33. Share of wind and solar in selected electricity systems today and in 2040



Note: Circles are proportional to the system size.

In the Sustainable Development Scenario, especially in the Nuclear Fade Case, large systems would need to overcome land use, infrastructure and flexibility barriers of a high renewable share.

Land use and permitting

Gaining public acceptance of even more renewable energy projects will be hard

Siting is potentially a greater constraint on wind and solar power than on nuclear power. Nuclear power plants are extremely efficient in using land owing to the energy density of nuclear fission. A nuclear facility capable of producing an average of 2 GW at full capacity normally occupies only a couple of hundred hectares (ha) of land, including all the supporting functions. This is far less than the land needed for an equivalent amount of wind or solar power capacity. A 100 MW solar farm located close to the Equator typically requires 100 ha and would operate at best one-quarter of the load factor of the nuclear reactor, resulting in land needs at least 40 times greater for the same annual production.[10] In temperate climates, where most nuclear power plants are located, the land required can be as much as 100 times more. Onshore wind farms require much more space, but unlike solar farms, most of the land can be used for its original purpose once construction has been completed. In the case of solar PV, there is a large potential for using the rooftops of residential and commercial buildings. But, in densely populated areas, such as most Western European countries, Japan and the coastal regions of North America, social and community acceptance of wind and solar power is already emerging as a significant hurdle to siting new projects in many locations. Local and wider populations often object to such projects on the grounds of visual impact, particularly in areas of natural beauty, and in the case of wind, noise and the possible impact on bird populations.

The scale of deployment of renewables in the central Sustainable Development Scenario already implies the need for stringent efforts on the part of policy makers to gain public acceptance. For example, around 150 000 wind turbines are installed across the United States and a similar number in Europe through to 2040. Given that the annual production of a 1 GW nuclear reactor is equal to that of about 2 000 wind turbines, the Nuclear Fade Case implies the need to build 400 000 more turbines across all advanced economies. It is far from certain that social and community objections to this scale of deployment could be overcome with the required speed.

One possible strategy to get around this problem is to concentrate the location of new projects in less densely populated areas, preferably with attractive natural wind or solar resources. In the case of wind, this is already happening in North America: most of the deployment is taking place in the "wind corridor" from North Dakota to Texas, which has a low population density, making access to land much easier and reducing problems of public acceptance. The average load factor of turbines in this wind corridor is close to double the global average. Transmission investment within the region has also been robust. But a rapid scaling up of deployment in this region is likely to encounter problems: the share of wind in total generation in some states in the wind corridor is already around four times the national average of 8%, ranging from 32% to 37% in Oklahoma, Kansas and Iowa. Further increases in capacity would soon result in output frequently exceeding local demand, necessitating large investments in transmission infrastructure to export the surplus electricity to consumption centres outside the region. Obtaining permits for new long-distance transmissions lines can be extremely time consuming, with no guarantee of success (Box 8).

[10] Bioenergy is even more demanding: the biomass needed to fuel a power station to produce the same amount of electricity as a nuclear power plant requires around 10 000 times more land.

Box 8. The Plain and Eastern ultra high voltage direct current transmission project

The proposed Plain and Eastern long-distance transmission project aims to connect the best wind sites in Oklahoma with demand centres in the much less windy south-east United States, which relies heavily on nuclear power, and illustrates the difficulties of replacing nuclear power with renewables. The project is based on ultra high voltage direct current (UHVDC) technology – a maturing technology well suited for point-to-point one-directional flows over distances of more than 500 kilometres (km). UHVDC has been deployed mainly in China up to now, but there is growing interest in North America and Europe. The prospects of the Plain and Eastern line ever being built are still uncertain nine years after the permitting process started. Even if it clears all the remaining legal hurdles and is finally built, it will transport the equivalent of the production of a two-reactor 2 GW nuclear plant, supplying less than 3% of the electricity demand of the south-east region.

Resistance to siting wind and, to a lesser extent, solar farms is a major obstacle to scaling up renewables capacity in many parts of Europe. There is no equivalent of the US wind corridor in Europe. The best onshore wind sites are at or near the coast, where population density tends to be high and tourism is a major economic activity. Public opposition to new wind farms is affecting deployment in some locations such as Brittany in France or the Midlands in the United Kingdom.

Siting wind farms offshore is one solution, but there are cost and infrastructure barriers

With increasing public opposition to wind farms, the focus of investor interest in Europe is shifting to offshore sites, primarily in the North Sea and, to a lesser degree, the Baltic Sea. Recent progress in developing offshore wind projects has certainly been impressive. Due to a combination of successful transition to a new generation of larger turbines, accumulated experience in managing offshore projects and increased investor confidence, costs have fallen sharply, exceeding most investors' expectations. While offshore projects can have an impact on offshore activities like fishing and shipping, gaining public acceptance and permitting are often easier than for onshore projects. In addition, offshore wind output is usually more stable and more predictable, which makes it easier to integrate capacity into the system and reduces the need for modifications to the network. While Europe pioneered the technology, it is also emerging in the north-east United States as a strategic response to barriers to local onshore wind farms and long-distance transmission lines.

However, the large increase in offshore wind capacity called for in the Nuclear Fade Case of the Sustainable Development Scenario raises complex questions about the need for supporting infrastructure. Most offshore wind farms have a point-to-point connection to an onshore grid. If offshore wind power is deployed on a much larger scale, it would be more efficient to build an interconnected offshore grid. This would probably make use of direct current (DC) transmission technology, which is more efficient than AC lines over long distances. Nonetheless, some technological, policy and grid co-ordination obstacles would need to be addressed. While point-to-point DC transmission is mature, interconnected DC grids are still at an early stage of deployment and some technical problems need to be overcome. The capacity of undersea DC cables is far easier to scale up than that of an existing onshore network that uses AC technology. In some cases, the landfall points for new offshore projects are located near to a major load centre, like London, but in others, they are located close to an existing network bottleneck, such as in northern Germany.

Technological advances (e.g. floating wind power) might help resolve some of these problems. There are some promising pilot floating wind projects under development, and innovation is progressing. It could be an important option in regions where onshore wind is limited by land-use constraints and water depth rules out the development of conventional offshore projects. Japan and California fall into this category. The prospects for floating wind power are still uncertain and it therefore plays a minor role only in the Sustainable Development Scenario.

Scaling up solar power massively would call for more transmission capacity

Investment in solar PV faces fewer land-use and public acceptance barriers, although it may prove difficult to expand T&D networks to accommodate the extra capacity for large solar projects and decentralised solar output. There is a considerable potential for decentralised production on top of buildings in advanced economies, though it would not be sufficient to provide all the solar capacity needed in the Nuclear Fade Case of the Sustainable Development Scenario. Installing solar PV panels on top of every single-family house in the United States would generate only around one-half of current nuclear production and meet only 11% of total low-carbon generation needs in 2040.[11] But for ground-based projects, there is a lot of other space that could be used. There are promising initiatives under development world wide for ground-based utility-scale projects using degraded land, such as former industrial and mining sites, where permitting is likely to be much easier.

The key constraint on expanding solar power capacity that might necessitate building more long-distance transmission capacity is the extent to which solar can satisfy winter demand in a given region. The United States is in an advantageous position of having some of the world's best solar potential in close proximity to major load centres like Los Angeles and Las Vegas, where summer peak demand is driven mainly by air conditioning. However, in some northern regions of the United States and large parts of Canada and Europe, electricity demand peaks in winter because of its widespread use for space and water heating. The trend towards electrification of heating in buildings is set to greatly increase the winter-summer discrepancy between solar output and winter load in these regions. In the United States, a substantial proportion of the US nuclear fleet and some of those plants most at risk of premature decommissioning are located in the north-east and the midwest, where the need for renewables production to replace nuclear capacity in the Nuclear Fade Case is greatest. Proposals to build long-distance transmission line to link sunny regions in the south with distant load centres face similar legal and public acceptance barriers as projects to transmit power from the wind corridor.

The imbalance between solar output and winter power demand is pronounced in Europe. At present, around one-half of European solar capacity is in Germany and the United Kingdom, where solar output in the winter is minimal. Even in the Mediterranean region, which has much better solar resources than northern Europe, solar potential is less than in the US Southwest. Improving interconnections within the European Union to address these regional imbalances is

[11] With 56 million single family homes, 5 kW of panels in each home and an average load factor of 17%, total output would be 420 TWh per year, compared with nuclear production of around 807 TWh in 2018.

a policy priority, but progress in linking the Mediterranean with Northern Europe has been slow. In some cases, geographical barriers and competition from other land uses, primarily tourism, has forced project developers to opt for capital-intensive solutions, such as routing cables in tunnels under the Alps from Italy to France and Austria, and laying cables under the Bay of Biscay from Spain to France. The capacity of the north-south interconnection projects that are being held up by permitting problems is an order of magnitude lower than that necessary for Mediterranean solar power to play a meaningful role in meeting winter demand in Northern Europe.

In Japan, improving the limited regional interconnections is a key policy priority. The geography of the country is conducive to undersea DC transmission technology. Better interconnectivity could unlock wind resources in Hokkaido in the north and solar resources in Kyushu in the south, both of which are underexploited because of network bottlenecks. However, given the geography and population density of the country, land use will surely remain a major barrier to the rapid expansion of wind and solar capacity.

Difficulties in permitting new transmission lines could limit the role of renewables

The need for long-distance transmission lines will inevitably grow as the deployment of new renewables capacity rises and the focus of development of renewables moves to more remote locations. It is not possible to predict whether these difficulties would make it impossible to achieve the increase in low-carbon electricity production required in the Sustainable Development Scenario, let alone the Nuclear Fade Case. However, there is a clear risk that legal and public acceptance hurdles could prove insurmountable. While the overall additional investment in networks is less than that in renewables, the infrastructure required is still substantial. Experiences in North America and Europe suggest that even network expansion projects with secured financing often struggle to move ahead due to licensing and permitting issues. There are currently 34 million km of T&D lines in advanced economies, which would need to grow to as much as 48 million km by 2040 in the Sustainable Development Scenario. The scale of investment in lines is uneven across regions. In OECD Europe, 5.5 million km of new lines are needed, of which more than 90% are distribution lines. The United States has 11 million km of network lines, which need to increase to around 14 million km by 2040. However, Japan only needs to add 200 000 km to its current network of 1.55 million km over the same period.

Making the Sustainable Development Scenario a reality, especially in the Nuclear Fade Case, will call for policy measures to address barriers related to land use and permitting. However, the experience in most densely populated democracies is that such measures are highly controversial and politically difficult. Given that the Sustainable Development Scenario would already require potentially controversial measures like high carbon prices, any further increase in the social acceptance bar may prove a step too far politically for many advanced economies. Of course, nuclear power also needs to be accepted by the public if it is to play a role in meeting the need for low-carbon energy. This can be a major obstacle to a greenfield development, and in the case of Japan, to authorising the restart of an existing unit. But public resistance is generally less pronounced in the case of lifetime extensions to allow the continuous safe operation of existing plants. In fact, local communities are often in favour of lifetime extensions because of the employment and economic benefits that nuclear power plants bring. The new nuclear power plants that are built in advanced economies in the Sustainable Development Scenario are predominantly on existing sites that benefit from existing transmission interconnections and where social acceptance is stronger.

System integration of renewables and flexibility

Flexibility of the power system will need to be enhanced

Integrating new VRE capacity – essentially wind and solar power – into the overall electricity system will be critical in making the Sustainable Development Scenario a reality, even more so in the absence of new investment in nuclear power in advanced economies. As the share of VRE grows, the need for flexibility also increases, because VRE is not dispatchable, i.e. it is not always available when needed. An electricity system needs to balance supply and demand at all times. Demand patterns change hourly, daily, weekly and with the seasons; system operators need to follow that by controlling supply, and where available, activating demand-side response. Demand for and supply of electricity are subject to random variability, as they are driven by weather and economic fluctuations as well as unplanned technical outages. Flexibility is needed for the system to be capable of maintaining a constant balance of electricity supply and demand in the face of uncertainty and variability in supply and demand. This is not a new phenomenon; even conventional power systems without variable renewables need flexibility from various sources. These include thermal generation and hydropower capacity, which can be ramped up and down at short notice, together with a combination of pumped storage hydropower, interconnections with other networks that allow electricity to be imported when needed, and demand-side response from large industrial and commercial consumers. These traditional sources of flexibility provide around 375 GW of flexibility world wide (IEA, 2018b).

This paradigm is changing with the growth in non-dispatchable VRE resources. At low shares of these resources in the total generation mix, variability of the wind and sunshine is absorbed into the overall volatility caused by weather affecting demand and conventional production. At higher shares, VRE becomes a major source of power system variation. VRE can provide an element of flexibility beyond simply curtailing output; for example, technology such as "smart inverters", which use digital technologies to control output, can be deployed with solar PV systems to provide a degree of flexibility. And wind farms can also provide a limited range of flexibility services, including spinning reserves by operating a fraction below the capacity that wind conditions would allow and thus maintaining an ability to ramp up quickly. Nonetheless, the projected increase in VRE in the scenarios presented here, especially in the Nuclear Fade Case of the Sustainable Development Scenario, would increase substantially the need for short-term flexibility (reacting to changes within minutes or hours) and for remaining thermal power plants to follow steeper and less-predictable changes in load over longer periods.

The need for flexibility is increasing at different rates across electricity systems according to the rate of penetration of VRE and the degree to which the demand profile matches supply-side characteristics and the size of the system. For example, where VRE output matches demand closely, such as in hot regions where cooling needs and solar PV output largely coincide, and where systems are large, the rate of growth in the need for flexibility tends to be slower (IEA, 2018). Flexibility requirements are also driven by the evolution of electricity demand. In some cases, growing end uses such as EVs, heating or even cooling are accentuating the seasonal peaks in demand, which may not match the availability of VRE. A substantial proportion of demand growth in advanced economies will be applications such as electric cars or digital equipment, which can potentially provide demand-side response if the appropriate regulations and incentives are put in place. There are six distinct phases in the process of integrating renewables into the electricity system (Box 9).

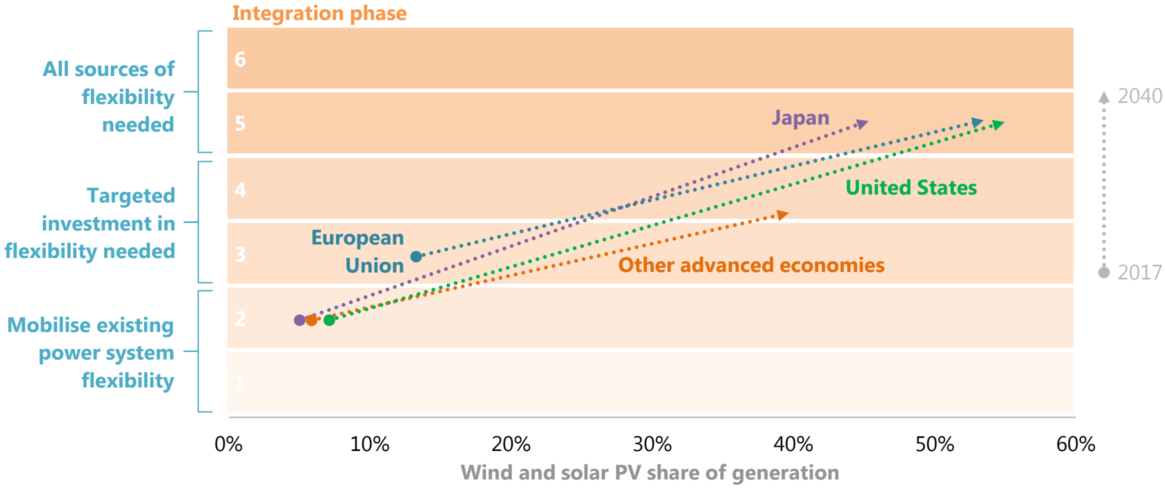
Box 9. Six phases of renewables integration into the electricity system

VRE, such as wind and solar PV, demonstrates a variety of properties that differentiate it from other sources of electricity. The most salient of these is that VRE output fluctuates over time, driven by the changing availability of wind and sunlight. There are six distinct phases of VRE deployment (IEA, 2018b):

- When the capacity of the wind or solar PV plants that are installed represents a small proportion of the total capacity of the system, such that their output and inherent variability have no noticeable impact on the system.
- When the impact of VRE becomes noticeable as capacity grows, but by upgrading some operational practices, VRE capacity can be integrated easily. A reliable forecasting system may need to be established to support efficient balancing.
- When the impact of VRE variability is felt in terms of overall system operation and by other power plants. At this point, power system flexibility becomes important.
- When VRE provides most of the electricity generation during certain periods. This generally requires advanced technical options to ensure system stability, causing changes in operational and regulatory approaches.
- When VRE output frequently exceeds power demand (for days or weeks) and, if left unchecked, these surpluses would result in large-scale curtailment of VRE output, thereby capping further expansion. Enhancing flexibility by means of the electrification of other end-use sectors such as transport and heating with flexible charging and heat storage can mitigate this concern.
- When the structural energy imbalance lasts for long periods, typically due to seasonal imbalances between VRE supply and electricity demand. This creates a need for seasonal storage and use of electricity, such as the production of synthetic fuels or hydrogen, which can be converted back into electricity, or another chemical form that can be stored cost-effectively

The pathway to a truly sustainable energy system inevitably involves a step change in the need to find ways of providing flexibility to integrate VRE into the electricity system. In the Nuclear Fade Case of the Sustainable Development Scenario, the rate of expansion in VRE output is such that Japan, OECD Europe and the United States quickly move into much higher phases of integration (Figure 34). The requirements of managing the system at this level of variable renewables will drive a growing portion of investment needs.

Figure 34. Phases of VRE integration in the Nuclear Fade Case of the Sustainable Development Scenario in selected advanced economy regions/countries



Rising VRE output needs to be accompanied by increased investment in various sources of flexibility, such as batteries, interconnections, electrolysis for hydrogen storage and demand-side management.

Sources of flexibility

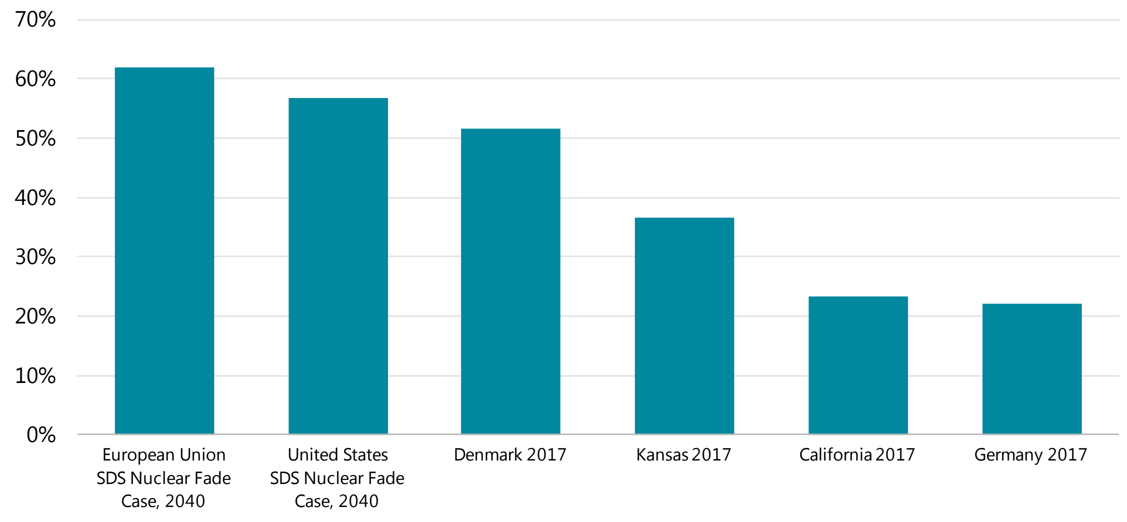
There are several potential sources of flexibility for an electricity system. The appropriate mix of options for a given system depends on local factors and costs. In most cases, dispatchable power plants will remain the primary source. The huge projected increases in wind and solar PV output in advanced economies in the Nuclear Fade Case of the Sustainable Development Scenario would increase the variability of residual demand (demand net of wind and solar production). Dispatchable power plants, including gas-fired ones, could play a central role in dealing with this variability given their ability to adjust output flexibly, particularly in relation to the minimum level at which output remains stable (minimum turn-down), the rate of change of generation output (ramp rate), and the length of time to start or shut-down. The flexibility of existing power plants can be improved by retrofitting equipment or replacing with new more flexible plants (IEA, 2018).

Network infrastructure can contribute to flexibility by balancing the load among different areas, reducing the amount of ramping that needs to be provided by generating plant and by pooling sources of flexibility from neighbouring areas. Exploiting flexibility on the demand side, particularly through demand-side response, is another option, potentially transforming the increased electrification of end uses from a system burden into a system benefit. The potential of demand-side response is projected to increase from around 4 000 TWh today to nearly 9 300 TWh in 2040 in advanced economies in the Sustainable Development Scenario. Baseload nuclear production also benefits from demand response, primarily from shifting consumption from the afternoon peaks to night-time. Some of the largest demand-response programmes in France and Central Europe were historically used to help the system cope with a high share of baseload nuclear production by controlling hot-water boilers. However, a high renewable share will require a different, more dynamic demand response than that historically developed for off-peak nuclear power.

Battery storage is another potentially important source of flexibility. Total battery capacity in advanced economies reaches 400 GW in 2040 in the Sustainable Development Scenario, up from just 4 GW in 2017. This increase is capacity would need to be supported by an appropriate market design to reward such assets for providing flexibility services. Many utility-scale battery installations are likely to be paired with solar PV and wind power to increase their ability to dispatch, to earn revenues from energy arbitrage and to offer ancillary services to the grid. In addition, pumped storage hydropower, which accounts for 97% of global storage capacity, is also projected to continue to expand, but at a slower rate than battery storage, which is expected to become more competitive as costs fall with technological advances. To the extent that geography and social acceptance allow the expansion of pumped storage hydro, it could also play a useful role in expanding flexibility in the Nuclear Fade Case. One of the overlooked consequences of more deployment of storage technologies is a higher overall utilisation of power generation capacity, translating into a lower risk of overcapacity and higher average revenues for generators.

Existing electricity systems that get nearest to the share of variable renewables that would be needed in the Nuclear Fade Case of the Sustainable Development Scenario tend to be small, with a high degree of interconnection across the systems and which benefit from high-quality wind resources. This factor is important: the predictability and high load factor of such resources in places like Denmark or the Great Plains of the United States contribute substantially to lowering the need for flexibility. Strong interconnectivity means that most of the flexibility is provided from outside the system. This is the case in Denmark, which relies heavily on dispatchable hydropower capacity in other parts of the Nordpool system. But this model is not applicable at a continental scale. In the Nuclear Fade Case of the Sustainable Development Scenario, the share of variable renewables in 2040 reaches 55% in the United States and over 60% in Europe, compared with little more than 20% in 2017 in those countries or states that apply rigorous renewables and climate policies on large electricity systems (Figure 35).

Figure 35. Combined share of wind and solar power in total generation in 2040 in the Nuclear Fade Case of the Sustainable Development Scenario and in 2017 in selected countries/regions



Rising wind and solar shares of generation in large geographic regions mean that interconnections may not provide much additional flexibility in the Nuclear Fade Case.

There is a limit to how much flexibility system interconnections can provide

The potential for enhancing connections among electricity systems – a valuable means of providing flexibility – is likely to be limited by geographical factors. Europe and North America are essentially closed electricity systems, so relying on flexibility sources from external systems is not an option in reality. Similarly, an undersea cable from Japan to Korea or the Russian Far East is technically feasible, but even if such a project were built one day, it is unlikely that it would ever play a significant role in balancing the Japanese system. Overland interconnections can also encounter public resistance, as discussed above.

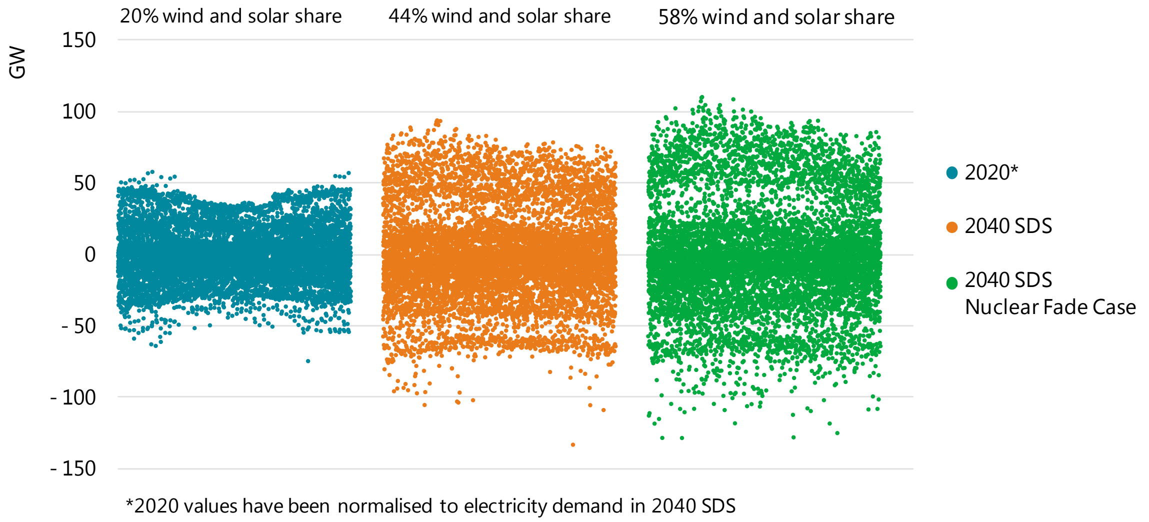
When the share of VRE reaches a high level across an entire region, the scope for interconnections to provide flexibility by tapping into the flexibility resources of neighbouring systems will be reduced. One reason is that all systems will need more flexibility. Another is that the availability of flexibility from an adjacent system may be lowest when the need for flexibility is highest because weather conditions may coincide, even over a large territory.

Continental-scale systems can have the advantage of a fleet of renewables plants spread over different climatic and weather zones. This provides a degree of self-balancing to the extent the output from different generators is uncorrelated. But the degree of correlation for VRE can be high within and across those systems. In the case of solar power, the intensity of sunshine at any given moment can be similar over areas covering several thousand . So, if there is an urgent need to fill the shortfall in output from solar capacity in one system, there is likely to be a similar need in an adjacent system, such that an interconnection between the two would be of limited value to the former. This can also be true for wind power. For example, the North Sea can be affected by weather systems that result in simultaneously high or low levels of production across the whole of northern Europe, from the United Kingdom to northern Germany. Even across countries as far apart and climatically different as Germany and Spain, there is roughly a one-third probability that the hours of low renewables share coincide. This tends to occur during evening peak hours when solar availability is guaranteed to be zero while wind might or might not be available.

The challenges in integrating VRE will be big, even with continuing nuclear investment

The ability of the power systems to deal with output variability as the share of renewables rises has been improving generally across advanced economies. This has resulted from technological innovation, mainly through the widespread digitalisation of grid management. This innovation has been encouraged by changes to regulatory frameworks and market designs. Further improvements, representing nothing less than a profound transformation of the way electricity systems operate, will be necessary make the Sustainable Development Scenario a reality in advanced economies. Without any new nuclear investment, that transformation would need to go even further. Such an outcome is technically feasible. But the difficulties in achieving it should not be underestimated. In the European Union, the flexibility needs to respond to the short-term variability of renewables production more than double. This will necessitate a volatile operation of existing flexibility assets such as gas turbines and investment in new flexibility sources such as battery storage (Figure 36).

Figure 36. Hour to hour ramps needed to fully integrate wind and solar power in the European Union



Increased short-term volatility will put an increasing strain on the existing flexibility assets of the system, necessitating new investment and regulatory reforms for additional flexibility.

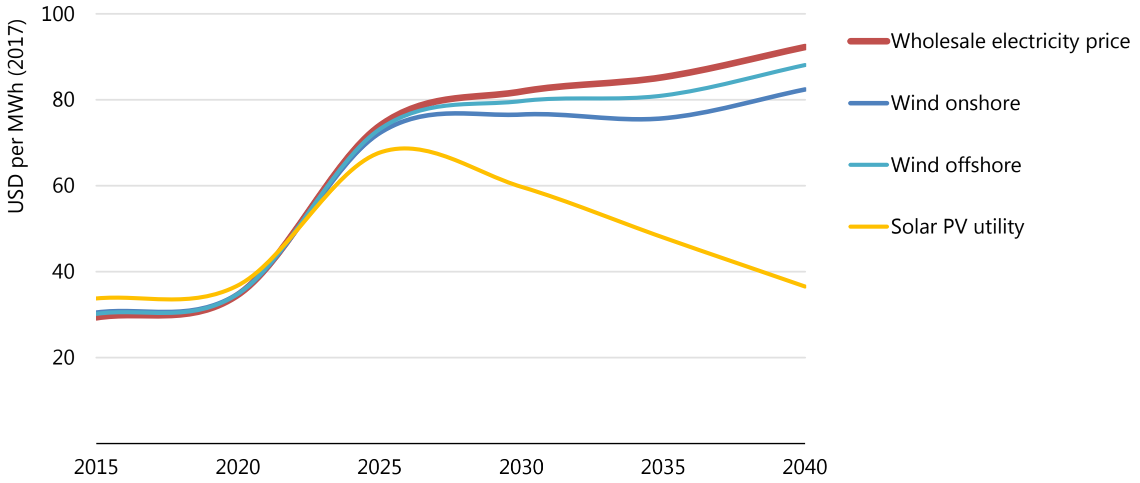
The principal challenges that are likely to be encountered during the system integration of a wind and solar fleet consistent with the Nuclear Fade Case of the Sustainable Development Scenario include the following:

- *Steeper ramp rates and hourly volatility*. As the renewable capacity increases from an already high share, the output from new wind turbines and solar panels will be increasingly correlated with the existing ones. Their production will tend to increase and decrease simultaneously, so flexible assets will have to operate ramping up and down more and more steeply. Natural gas would continue to play a major role in providing flexibility, but the business model for gas-fired plants would be transformed: their average load factor drops to little more than 10% (i.e. they would run for only around 1 000 hours per year, as and when needed for balancing) by 2040 in the Sustainable Development Scenario. The even greater penetration of renewables in the Nuclear Fade Case would depress this factor further. The regulatory framework would need to ensure that these plants are able to make a profit. In addition, demand-side response would need to be exploited to the full, including the potential for using the storage capability of EVs and other appliances. This would need to be coupled with investment in stationary batteries, which have high ramp rates and are well suited to providing frequency control services.
- *Declining system value of renewables*. Even aggregated across a large geographical area, an increase in the average annual share of wind and solar power in total generation to over 40-45% by 2040 in the Nuclear Fade Case of the Sustainable Development Scenario implies a share of up to 70% during the windiest and sunniest hours. The wholesale electricity price could be low at these times, depending on the marginal cost of the next-highest generating plant in the merit order. As the penetration of renewables increases, the average wholesale price they earn is likely to fall, unless the output profile is markedly different to that of existing plants. In fact, every new solar panel or new wind turbine that is installed will tend

to cut the market value of all the solar panels and turbines that have already been installed. This effect varies by technology and region (Figure 37).

- *Need for seasonal storage*. While the cost and performance of batteries have been improving, they still represent an expensive means of providing storage, especially for long periods. The average storage time of utility-scale batteries is only around two hours. A natural consequence of the rising share of wind and solar output in the Nuclear Fade Case of the Sustainable Development Scenario is that a substantial proportion of the additional production occurs during times of the year when total production is close to or over 100% of demand. That surplus power would need to be stored. The need for longer-term storage in each system would be highly dependent on demand and renewable production profiles, but when the share of renewables in annual power generation exceeds two-thirds, the need for storage would almost certainly exceed the technical limitations of batteries. In this case, storage would need to be provided by other technologies, including chemical technologies such as using hydrogen (involving electrolysis and reconversion to power using a fuel cell) or power to gas technologies.

Figure 37. Average energy price received by technology in the European Union in the Nuclear Fade Case of the Sustainable Development Scenario



As the deployment of solar PV rises, the average revenue earned by solar producers falls, despite higher wholesale prices.

In principle, the challenge of integrating the much larger amount of wind and solar capacity in the Nuclear Fade Case of the Sustainable Development Scenario can be overcome. Handling ramp rates and hourly volatility is perhaps the aspect of system integration where the technological prospects are most promising, given the recent declines in the cost of batteries and the projected rapid spread of EVs. Several countries, including those that have renounced nuclear power, are increasing research and development (R&D) into hydrogen and power to gas technologies. Scaling up longer-term storage would help to overcome the loss of the renewables market value that will occur as their market share rises.

However, achieving the goal of a clean energy system could come at a much higher economic cost without continuing reliance on nuclear power in those countries that have retained that option. Nuclear power can play a major role in easing the technical difficulties and lowering the cost of transforming the electricity system. The speed with which that transformation needs to take place, involving a massive increase in production of low-carbon energy over the next two decades, adds to the economic value of maintaining existing nuclear power and building new capacity. In the longer term, some advanced nuclear technologies, notably SMRs, specifically designed for flexible operation might be able to play a role in supporting the required growth in renewable production. The smaller size and negligible land needs of such reactors compared with renewables would allow them to be sited in a way that avoids the need to expand the transmission networks. As a result, their contribution to a clean energy system could be disproportionately greater than their share in the generation mix.

In addition to the physical rigidities that hinder the pace of transformation, there are also institutional rigidities. Implementing a reform of electricity market design or the structure of network tariffs can often take several years, given the complexity of the regulatory process and the diversity of stakeholders involved. A good example is the flexibility that could be provided by EVs: the digital technology for exploiting that potential already exists, but overcoming legal, regulatory and market barriers could take years. This makes a well-designed long-term national strategy for the energy transition all the more important.

Perhaps the biggest uncertainty concerns the prospects for long-term storage of energy, such as hydrogen and power to gas technologies. Most scenarios depicting a low-carbon/low-nuclear future (including the Nuclear Fade Case of the Sustainable Development Scenario in this report) involve the rapid and large-scale deployment of long-term storage. Interest on the part of policy makers and investors is certainly growing, but investment barriers remain daunting. Without nuclear power, long-term storage could make or break the vision of a clean energy system.

5. Policies to promote investment in nuclear power

Policy and regulatory framework

Nuclear power is the largest source of low-carbon electricity in advanced economies as a whole. It makes an important contribution to energy security in all those countries around the world that have nuclear power plants. The declining share of nuclear power in the global energy mix in recent years is one of the main reasons why the rapid expansion of renewables has failed to stop the increase in CO_2 emissions. Several countries have made a decision not to use nuclear energy, and the IEA naturally respects that choice. In others, nuclear power could play a major role in the clean energy transition. However, nuclear power is not on track to fulfil its potential, even where there are strong pronuclear policies. This is partly due to policy imperfections, which can be corrected.

The existing fleet of nuclear power plants in advanced economies is coming under increasing financial pressure, especially where they operate in competitive wholesale markets. This is due to excess capacity, poor market design and a failure to value the environmental and energy security advantages of nuclear power. It is normally technically possible to extend operations at a nuclear plant in a safe manner to at least 60 years. Such a lifetime extension is usually economically attractive and can provide a valuable bridge to a low-carbon energy system that, depending on policy decisions, may contain a new generation of nuclear plants. But it is far from certain that such extensions will always occur in the absence of a supportive policy framework that adequately remunerates plant operators for the incremental investments normally required. Two-thirds of nuclear capacity in advanced economies is at risk of early closure in the next two decades. If this happens, putting advanced economies onto a sustainable development path, involving an extremely rapid growth in renewables, would be difficult.

It is vital that countries which have kept open the option of using nuclear power reform their policies to ensure that nuclear power is able to compete on a level playing field and address barriers to investment in lifetime extensions and new capacity. The most important focus of policies should be on designing electricity markets in a way that values the clean energy and energy security attributes of nuclear power. With regard to the clean energy component, this can be achieved by explicit carbon pricing, clean energy credits and contractual arrangements that reward nuclear and other low-carbon sources of electricity. With regard to the energy security component, the dispatchability and reliability of nuclear power should be rewarded through mechanisms that adequately remunerate plants for flexibility services in a technology-neutral fashion.

These measures would ensure that extending the lifetimes of almost all existing reactors to at least 60 years would be financially viable. Securing investment in new nuclear plants would require more intrusive policy intervention given the high cost of projects and the unfavourable recent experience with construction of Generation III plants. Investment policies aimed at the current Generation III technology need to overcome financing barriers by a combination of long-term contracts, price guarantees and direct state investment. A successful nuclear investment policy should also support learning by doing and accumulation of industrial know-how. It is particularly important to avoid design changes during the construction phase, unless there is a strong safety reason to do so, in view of the impact this tends to have on costs.

The difficulties faced in building large nuclear plants and the evolving needs of the power system have generated interest in advanced nuclear technologies that are amenable to smaller plants, including SMRs. This technology is still at the development stage. There is a case for governments to promote it through funding for R&D, public-private partnerships for venture capital and early deployment grants. While the nature of the SMR technology holds the promise of substantially lower costs through learning by doing, initial costs could be high, deterring its early deployment. As a result, policy makers should consider supportive investment policies such as long-term contracts and price guarantees. Such support should be transitional, with the objective being to compete with other electricity technologies.

Lifetime extensions for existing reactors

Most countries that already have nuclear power have kept open the option of extending the lifetimes of those reactors that are still in operation, including some countries that have ruled out the construction of new reactors. Even where a country's energy policy envisages an eventual transition to 100% renewables, nuclear lifetime extensions can provide a cost-effective means of supporting the transition, allowing more time to put in place policies that accelerate the deployment of renewables and associated infrastructure deployment and transforming system operation. Given the flexibility that nuclear power plants can provide and the often relatively low cost of investing in refurbishment needed to obtain the necessary authorisation, lifetime extensions can also lower the economic cost of the clean energy transition.

In Europe and North America, light regulatory intervention appears to be sufficient for most lifetime extensions, given the limited modifications that are typically required. In general, the investment necessary is likely to be justified by the value of the continued output of the plant, taking into full account the low-carbon and electricity security advantages of nuclear power. In practice, these benefits may be reflected in explicit carbon pricing, ZECs, clean energy contracts or similar measures. In most cases, the shadow price of carbon (an estimate of the value of those benefits over and above the market prices received for the power) incorporated into support schemes for new renewables capacity is considerably higher than the one that would make nuclear lifetime extensions viable. A 20 year nuclear lifetime extension is comparable to the operating lifetime of new renewable assets, so each extension effectively replaces the need for an entire generation of renewables capacity. In Japan, the economic case for lifetime extensions is even more powerful due to high import LNG prices, though social acceptance barriers will need to be overcome and the licensing regime will need to support secure lifetime extensions.

There are legitimate concerns about the ability of electricity market designs to support adequate investment in assets to provide flexibility services. A high share of renewables in the generation mix would require flexibility for the electricity system to operate securely. The appropriate policy approach is to target the flexibility needs of maintaining electricity security rather than the contribution of nuclear capacity on its own. Market reforms will need to be designed in a broad technology-neutral fashion to allow nuclear plant extensions to compete fairly with other options for providing flexibility. In practice, this could make the difference between a lifetime extension and a shut-down.

Supporting new nuclear construction

It has become increasingly clear that the construction of a new wave of large-scale Generation III reactors in all European or North American electricity markets is inconceivable without strong government intervention in view of the policy, technology and project management risks, as well as market and financing barriers. There are some ways in which governments can help to alleviate these risks, at least during the initial and most expensive phases of deployment. The most important measures that should be considered are as follows:

- *Long-term price guarantees*. This measure aims to eliminate the unpredictability of cash flows inherent in the wholesale electricity market. It can take the form of a conventional power purchase agreement. This was the approach used in the case of the Akkuyu plant being built in Turkey. Another option is a contract for difference, essentially a swap between an agreed fixed price and the wholesale market. This is the way future revenues are guaranteed for the Hinkley Point C reactor being built in the United Kingdom. In both cases, the wholesale market risk is transferred to a government entity. The financial liability of the off-taker is potentially large. If Hinkley Point C had already been operational in 2018, the contract for difference would have paid out a short-fall in revenues from the wholesale market of more than GBP 800 million (USD 1 billion) that year. Given the size of the financial risk, the contracting party usually needs to be either a government or a government-mandated entity backed by a sovereign guarantee.
- *Appropriate valuation of low-carbon production.* Carbon pricing is subject to similar problems of volatility and time horizons as wholesale electricity prices. As a result, it is doubtful whether even an ambitious and well-designed carbon pricing regime would be sufficient to stimulate investment in new nuclear capacity. Nevertheless, it can complement well a mechanism that guarantees the price received by the owner of a nuclear plant. Theoretically, once the off-take price is guaranteed, it does not matter whether wholesale prices reflect environmental externalities. However, in practice, by raising the value of clean energy production, payouts can be reduced under contracts for differences, which can improve the social acceptance and reduce the policy risks associated with price guarantees.
- *Sovereign guarantees on borrowing.* Long-term contracts and price guarantees can greatly improve the creditworthiness of a new nuclear project. By doing so, they have traditionally been seen as a precondition of project financing. Unfortunately, in the case of large nuclear projects, technology and project-specific risks may still be considered excessive, even with a price guarantee, primarily due to the risk of cost overruns. As a result, a direct sovereign guarantee on the borrowing for the project can be applied to enable it to tap into cheaper debt finance from banks or bond markets. The Hinkley Point C project has received a guarantee from the British government, though the project company has not yet issued guaranteed bonds. An alternative structure is that adopted in Hungary, where the government borrowed the money directly for a new reactor being built at the Paks power plant, which will be reallocated to the state-owned company that develops the project.
- *Inclusion in the Regulated Asset Base.* Most nuclear power plants operating in advanced economies were built by vertically integrated utilities, a model that is still common in the United States. A regulatory decision to include new nuclear assets in a utility's rate base – the value of all the assets on which a public utility is permitted to earn a rate of return, including network infrastructure, set by the regulator – is an effective way of mitigating project risk by ensuring that it is possible to make a return regardless of market conditions. Often in the United States, the impact on the rate base takes effect from the moment the project is approved, so cash flow is boosted straight away. The downside is that this

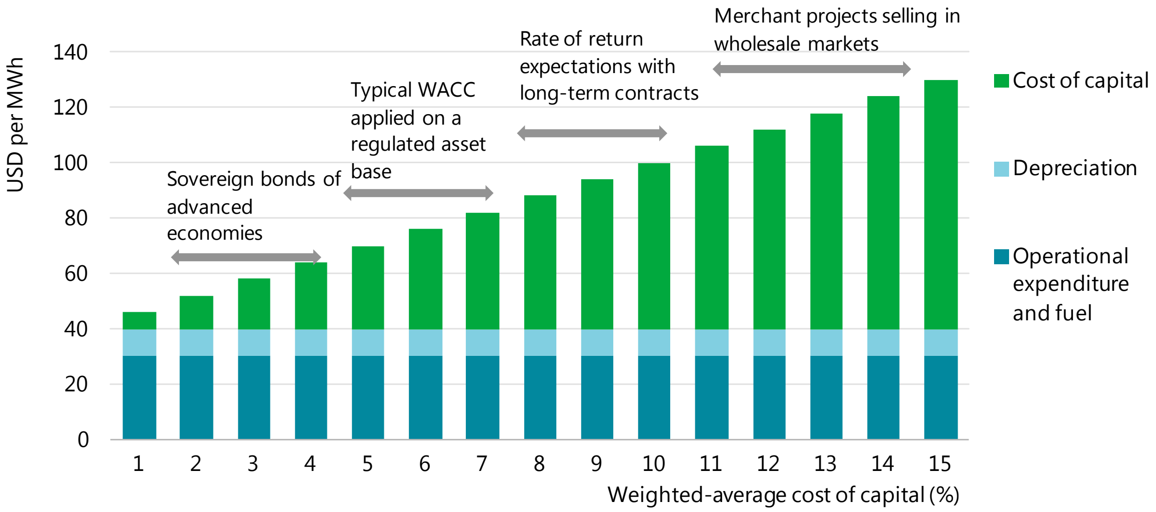
practice, which effectively transfers risk to consumers, can lead to political problems if the project encounters difficulties at a later stage. For example, the Virgil C. Summer project in South Carolina that was cancelled in 2017 resulted in households paying, on average, USD 1 500 for a nuclear power plant that will never come into operation. This has generated a considerable reluctance among regulators elsewhere to adopt similar financing structures. In the European Union, it is unclear whether such a model could be applied without significant changes in energy and competition law.

- *Involvement of the technology provider in equity joint ventures.* This approach would reduce difficulties in raising equity through vertical integration, which mitigates project management risk and provides a powerful incentive for efficient construction. The Akkuyu plant in Turkey applies this structure, and the recently cancelled Wylfa project in the United Kingdom intended to do so as well.
- *Direct investment by state-owned companies.* This is by far the most widespread model of nuclear power plant construction world wide. Even in advanced economies, most of the projects under construction and most of the planned projects that are most likely to proceed are either being led by 100% state-owned project companies, like Paks-2 in Hungary, or majority state-owned corporations, like EDF in France, Polska Grupa Energetyczna in Poland and CEZ in the Czech Republic. In the case of a majority state owned stock market listed corporation, management has a fiduciary responsibility to protect shareholder value under corporate law, so even state-owned companies have to ensure the new plant is financially viable. Most other state-owned companies have profitable existing assets that can support the investment needs associated with a new nuclear power project. As a majority owner, the government can determine the dividend policy and enable the company to recapitalise itself from retained earnings so that new nuclear investment can be financed directly from the balance sheet.

Government measures are crucial in enabling the financing of new nuclear investment at viable interest rates. The cost of capital has a pronounced impact on the competitiveness of nuclear power, because of its high capital intensity. This is generally true for all low-carbon technologies, including wind and solar PV. In the case of renewables, measures to reduce or even eliminate market risk such as feed-in tariffs and long-term fixed price power purchase agreements have played a critically important role in mobilising investment and enabling learning by doing. A fall in the cost of capital, aided by loose monetary policy, is the main reason for the radical decline of renewables auction prices in recent years. In effect, cheaper financing has reinforced the impact of technological innovation and learning by doing. Large hydropower plants are mainly developed by state-owned utilities in the developing economies, most often financed by state-owned or international development banks.

The cost of capital has a pronounced impact on the economics of new nuclear power projects because of the size of the required investment and long project lead-times (comparable to the largest hydropower projects). Investment involving several billion USD needs to be financed during construction for many years before the project can generate electricity and earn revenues. For example, for a new 1 GW plant costing USD 4.5 billion, the LCOE would increase by around USD 5 per MWh for each percentage point increase in the cost of capital. It would double with an increase in the cost of capital from 3% (the typical return on sovereign bonds today) to 13% (the rate that merchant plants selling directly into wholesale markets would normally have to borrow at) (Figure 38).

Figure 38. Illustrative LCOE of a new nuclear power plant project according to the cost of capital



Note: Based on a 1 GW plant with an investment cost of USD 4.5 billion.

Access to cheap capital makes a huge difference to the cost of producing electricity for a new nuclear power project.

The environmental and security benefits of nuclear power provide justification for a more active role for governments in financing new plants, where the technology remains an option. But this may not be sufficient in view of the hurdles facing new projects, especially in advanced economies. The recent cost and project management difficulties faced by projects in several countries have come at a time when the cost of other low-carbon technologies, primarily wind and solar PV, have fallen dramatically. Changes in electricity business models with the spread of competition in wholesale markets has complicated the financing of new large-scale nuclear investments. In addition, the ability and cost of integrating variable renewables into the power system has improved significantly, reducing the comparative advantages of nuclear power in providing flexibility. In fact, wind and solar investment have been moving towards a more competitive, more market-based model. While policy incentives are still essential for renewables in most cases, there has been a move towards so-called market premium models, which expose projects to wholesale market shorter duration off-take contracts. Non-energy companies have also emerged as major buyers of wind and solar power; projects underwritten by such corporate buyers now represent a non-negligible proportion of renewable deployment.

Encouraging investment in small modular reactors

Increasing difficulties in financing the construction of large Generation III reactors, coupled with the need for more low-carbon dispatchable generation, is driving policy and investor interest in small modular reactors (SMRs). This type of nuclear reactor could prove much easier to finance and may be the way forward for nuclear fission technology. SMRs are much smaller than existing reactor designs, have a shorter lifetime and are intended to be built in a modular fashion in factories. Even if the average investment cost per unit of capacity is comparable to the "list price" of conventional large reactors, the smaller project size and shorter lead-times of SMRs promise to make financing easier. Modular design and factory construction mitigates project management risk, which is the single most-important obstacle to financing Generation III nuclear projects. Several SMR designs have inherent advantages in safety and waste management, which could ease licensing and improve social acceptance. In contrast to the collapsing investment appetite by the private sector for large Generation III reactors, SMRs are attracting considerable private venture capital for R&D. Nevertheless, none of the SMR designs under development have yet reached commercial maturity.

SMRs are defined as nuclear reactors with an electrical capacity of less than 300 MW per module. They are usually designed to be built in a factory to take advantage of economies of series and then transported to the site where they are to be installed. They exploit inherent safety features, such as passive safety systems and simplified designs, involving fewer and simpler systems and components. It is expected that they will be deployed in series, using a global supply chain to lower costs. SMRs could be installed as single modules distributed throughout the grid, which may be attractive in countries or regions with less developed networks, in remote regions or as dedicated sources of electricity for industrial complexes, as well as in more traditional large-scale plants by grouping together several modules. In principle, SMRs could be suitable to meet the needs for flexibility in power generation demanded by the electricity systems of the future that combine baseload with increased shares of variable generation. This could be utilised by a wide range of users and for different applications, including energy storage, co-generation and non-electric applications.

SMR designs may use any type of fuel and coolant, and can be coupled with various power conversion systems (steam or gas turbines) or used to produce fresh water, hydrogen and district or industrial heat. Several different types of SMRs are under development (Table 6), a few of them in the United States. Light-water-cooled SMR designs have achieved the highest technology and licensing readiness levels, with several concepts under construction or advanced in the licensing process. The development of liquid-metal-cooled SMRs, molten-salt-cooled and gas-cooled SMR designs (also called Generation IV SMRs) is generally less advanced, but may prove to be more successful as they have the potential to reach higher temperatures to optimise co-generation and non-electric applications, as well as providing fuel cycle services such as multirecycling. This could make them suitable for providing flexibility at Phase 6 of the process of integrating VRE into electricity systems (see Box 9).

A micro modular reactor (MMR) – a new type of SMR – has recently been proposed. MMRs are defined as units with a capacity of less than 10 MW with a rugged design, capable of semiautonomous operation and easy to transport. They could be coupled to ultracompact power conversion systems, such as Stirling engines, supercritical CO_2 cycles or direct conversion devices. They are intended to be used to serve remote communities, seasonal industrial complexes, mining sites, offshore platforms, military bases or expeditionary forces (MIT, 2019).

Table 6. SMRs under development

Design	Net output per module (MW)	Type	Designer	Country	Status
Light-water cooled					
KLT-40S	70	Floating PWR	OKBM Afrikantov	Russia	Pre-commissioning testing
CAREM	30	PWR	CNEA	Argentina	Under construction
SMART	100	PWR	KAERI	Korea	Certified design, feasibility study to construct in Saudi Arabia (desalination)
NuScale	50 (× 12)	PWR	NuScale Power	United States	Licensing process, two projects planned in the United States (Idaho and Tennessee)
SMR-160	160	PWR	Holtec International	United States	Preliminary design
BWRX-300	300	BWR	GE Hitachi	United States	Conceptual design
(no name)	220	PWR	Rolls Royce	United Kingdom	Conceptual design
(no name)	170	PWR	CEA/EDF/Naval Group/ TechnicAtome	France	Conceptual design
Generation IV (non-light-water cooled)					
HTR-PM	210	HTGR	Tsinghua University	China	Under construction
ACP100	100	PWR	CNNC	China	Start of construction planned for end of 2019
SC-HTGR	272	HTGR	Framatome	United States	Conceptual design
Xe-100	35	HTGR	X-energy LLC	United States	Conceptual design
4S	10	LMFR	Toshiba	Japan	Detailed design
EM2	265	GMFR	General Atomics	United States	Conceptual design
IMSR	190	MSR	Terrestrial Energy	Canada	Basic design
ThorCon	250	MSR	Martingale Inc	United States	Basic design

Notes: BWR = boiling water reactor; CEA = Alternative Energies and Atomic Energy Commission; CNEA = Comisión Nacional de Energía Atómica (Argentina); CNNC = China National Nuclear Corporation; GMFR = gas-cooled modular fast reactor; HTGR = high-temperature gas-cooled reactor; KAERI = Korea Atomic Energy Research Institute; LMFR = liquid metal fast reactor; MSR = molten salt reactor; PWR = pressurised water reactor.

Sources: OECD NEA and IAEA.

Box 10. Status of SMR research, development and deployment

In Russia, fuel loading at the two units of the Akademik Lomonosov floating plant (KLT-40S) was completed in October 2018. Start-up of the first unit took place in November 2018 in Murmansk, and the second reactor is expected to follow shortly. The vessel is expected to be towed to its permanent base at Pevek in Russia's Chukotka region in the summer of 2019.

In China, a demonstration plant with two HTR-PM units is on track to be connected to the grid and start electricity generation in 2019. China Huaneng is the lead organisation in the consortium building the demonstration units, together with CNNC subsidiary China Nuclear Engineering Corporation and Tsinghua University's Institute of Nuclear and New Energy Technology, which is the nuclear R&D leader. The reactors will drive a single 210 MW steam turbine, using helium gas as the primary coolant and reaching temperatures as high as 750°C.

In November 2018, the Canadian government released a roadmap (NRCan, 2018) that outlines potential applications for SMRs for the country. It identifies clear roles for SMRs as a clean alternative to coal-fired power stations and as a source of clean heat and electricity to industry, as well as for providing energy to remote communities. In parallel, Canadian National Laboratories (CNL) launched an invitation to proponents of SMR projects to build and operate an SMR demonstration unit at a CNL-managed site. Applicants include Global First Power (GFP), StarCore Nuclear and Terrestrial Energy. In April 2019, the Canadian Nuclear Safety Commission received the first licence application for a type of SMR from GFP, with support from Ontario Power Generation and Ultra Safe Nuclear Corporation. The project involves building an MMR at Chalk River in Ontario. The high-temperature gas reactor would have a power output capacity of 5 MW and heat output of 15 MW.

In the United States, NuScale's SMR technology is undergoing design certification review by the NRC, while Utah Associated Municipal Power Systems is planning the development of a 12 module plant using that technology at a site at the Idaho National Laboratory, to be completed in the mid-2020s. NuScale has also signed memoranda of understanding to explore the deployment of its SMR technology in Canada, Jordan and Romania. In April 2019, the NRC issued an early site permit for the Tennessee Valley Authority to build two or more SMRs at a site in Clinch River.

Owing to their smaller size, SMRs may be deployed in countries or regions with small electricity grids that could not handle large GW-sized reactors or on sites with limited water supply for cooling. SMRs also offer the advantage of scalability of capacity additions. In other words, utilities will be able to add capacity to the grid in smaller increments, allowing them to more easily adapt capacity to changes in electricity demand. Construction lead-times are also expected to be much shorter, thanks to their factory manufacturing and the use of advanced modular construction techniques. The decoupling of civil construction and reactor manufacture processes should also allow plant owners to shift and reallocate financial risk through the plant construction period, due to reduced capital outlays and shorter time to generate a positive cash flow much earlier in the plant life cycle.

As they have smaller cores and, for most SMRs, inherent passive safety features, SMRs may be licensed with smaller emergency planning zones and simplified emergency preparedness procedures. This may facilitate the siting of SMRs, including close to population centres. This attribute could favour the rapid deployment of SMRs in the increasingly distributed electricity grids of the future, including on the sites of existing coal-fired power plants of similar capacity.

SMRs have been designed with load-following capabilities, making them capable of operating effectively in electricity grids with increasing shares of VRE. While this flexibility is highly desirable from a grid stability and reliability point of view, it does not necessarily result in an economically attractive business case for a technology that is optimally designed to operate at full power as baseload like large-scale reactors. However, given their potential use for co-generation and non-electric applications, SMRs may be able to generate sufficient revenue from the production of heat, fresh water, hydrogen or energy (heat) storage, in addition to the revenue from electricity generation, to recover their costs.

Estimates indicate that the LCOE of SMRs could be competitive with larger nuclear units and with other dispatchable generating technologies (NEA, 2016). This will hinge on the development of a global market to establish a robust supply chain and sustainable construction know-how to lower construction costs.[12] In the meantime, prototype and demonstration units are likely to be expensive. O&M costs for SMRs could be lower than for larger nuclear units if the regulators allow SMR licences to take advantage of some of their intrinsic features. For example, several prospective SMR vendors propose to use advanced digital instrumentation and control technologies and advanced digitalisation and automatisation to manage and operate the units. This would allow the plants to be operated with fewer staff in a way that optimises the use of fuel and power output (NEA, 2016).

The flexibility in the size, timing and siting of SMRs may make them a more attractive option than larger nuclear power plants for private investors. First, the total size of the investment would be significantly smaller, making SMRs much more affordable, though not necessarily cheaper on a per MW basis. Financing is expected to be easier because of their lower total cost, shorter period of construction and overall lower construction risk due to factory manufacturing. The ability to add increments of SMR capacity would also facilitate the management of financial risk (Maize, 2010). SMRs may be attractive to countries with no experience of nuclear power, especially those with smaller and less robust electricity grids, due to the overall lower total cost and their simplicity of operation. In many cases, due to grid stability and reliability concerns, SMRs may be the only technically feasible nuclear technology option available to fit the grid (MIT, 2018).

Reform in the licensing process may be necessary to fully take advantage of the inherent advantages of these reactors and lower costs. Exploiting economies of series to the full would require harmonisation of licensing processes for SMRs across countries and regions, though licensing would still require compliance with country and local regulatory requirements (e.g. environmental impact assessments or public consultative processes). This would facilitate the establishment of a global supply chain and a global SMR market.

A clear goal to establish standardised designs is important. While the array of existing SMR designs being developed is a healthy development that will promote innovation at this early stage, this vitality could be dissipated unless focused into a smaller number of promising designs. A fast technological convergence of the various existing conceptual designs, prototypes and first-of-a-kind models into reasonably standardised designs would allow for the value chains to develop, and for the promise of economies of scale and learning by doing to be fulfilled.

[12] www.energycentral.com/c/ec/ge-hitachi-offer-300-mw-smr.

Although the true economics of SMRs are not fully known, there is a large potential for these technologies to represent a complementary way forward for nuclear power development. SMR market development will strongly depend on the successful deployment of prototypes and first-of-a-kind plants. SMRs will become economically viable only in the presence of well-defined and predictable licensing processes. SMR vendors and potential customers will need to work closely with nuclear regulators to quickly resolve various hurdles in deployment of the technology, including validation of innovative safety features and solutions, and factory assembly (NEA, 2016).

The investment policy for SMRs will need to combine the general principles of low-carbon electricity market design with innovation policy to facilitate early deployment. For the first pilot projects, special investment measures, including capital grants, guarantees and tailor-made long-term contracts, could be justified. If the technology matures, policies will need to evolve to incorporate a more market-based approach, whereby generators are adequately remunerated for the value of the low-carbon energy and system services they provide.

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General annex

Abbreviations and acronyms

AC	alternating current
BWR	boiling water reactor
CAISO	California Independent System Operator
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CEA	Alternative Energies and Atomic Energy Commission
CNEA	Comisión Nacional de Energía Atómica (Argentina)
CNL	Canadian National Laboratories
CNNC	China National Nuclear Corporation
CO_2	carbon dioxide
DC	direct current
EDF	Électricité de France
ENTSO-E	European Network of Transmission System Operators for Electricity
EPR	European Pressurised Reactor
ERCOT	Electricity Reliability Council of Texas
EU	European Union
EU-ETS	European Union Emissions Trading System
EV	electric vehicle
GFP	Global First Power
GMFR	gas modular fast reactor
HTGR	high-temperature gas-cooled reactor
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
ISO NE	Independent State Operator New England
KAERI	Korea Atomic Energy Research Institute
LCOE	levelised cost of energy
LMFR	liquid metal fast reactor
LNG	liquefied natural gas
LSE	load serving entity
MISO	Midcontinent Independent System Operator
MMR	micro modular reactor
MSR	molten salt reactor
N/A	not available
NPV	net present value
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator

NYSERDA	New York State Energy Research and Development Authority
OECD	Organisation for Economic Co-operation and Development
O&M	operation and maintenance
PJM	Pennsylvania, Jersey and Maryland
PV	photovoltaics
PWR	pressurised water reactor
Q1	quarter 1
R&D	research and development
RGGI	Regional Greenhouse Gas Initiative
SMR	small modular reactor
SPP	Southwest Power Pool
T&D	transmission and distribution
UHVDC	ultra high voltage direct current
US	United States
VALCOE	value-adjusted levelised cost of energy
VRE	variable renewable energy
WACC	weighted-average cost of capital
ZEC	zero-emission credit

Currency codes

EUR	euro
GBP	pound sterling
USD	United States dollar

Units of measure

gCO_2	gramme of carbon dioxide
$GtCO_2$	gigatonne of carbon dioxide
GW	gigawatt
ha	hectare
km	kilometre
kW	kilowatt
kWh	kilowatt hour
MBtu	million British thermal unit
Mt	million tonne
Mtoe	million tonne of oil equivalent
MW	megawatt
MWh	megawatt hour
t	tonne
TWh	terawatt hour

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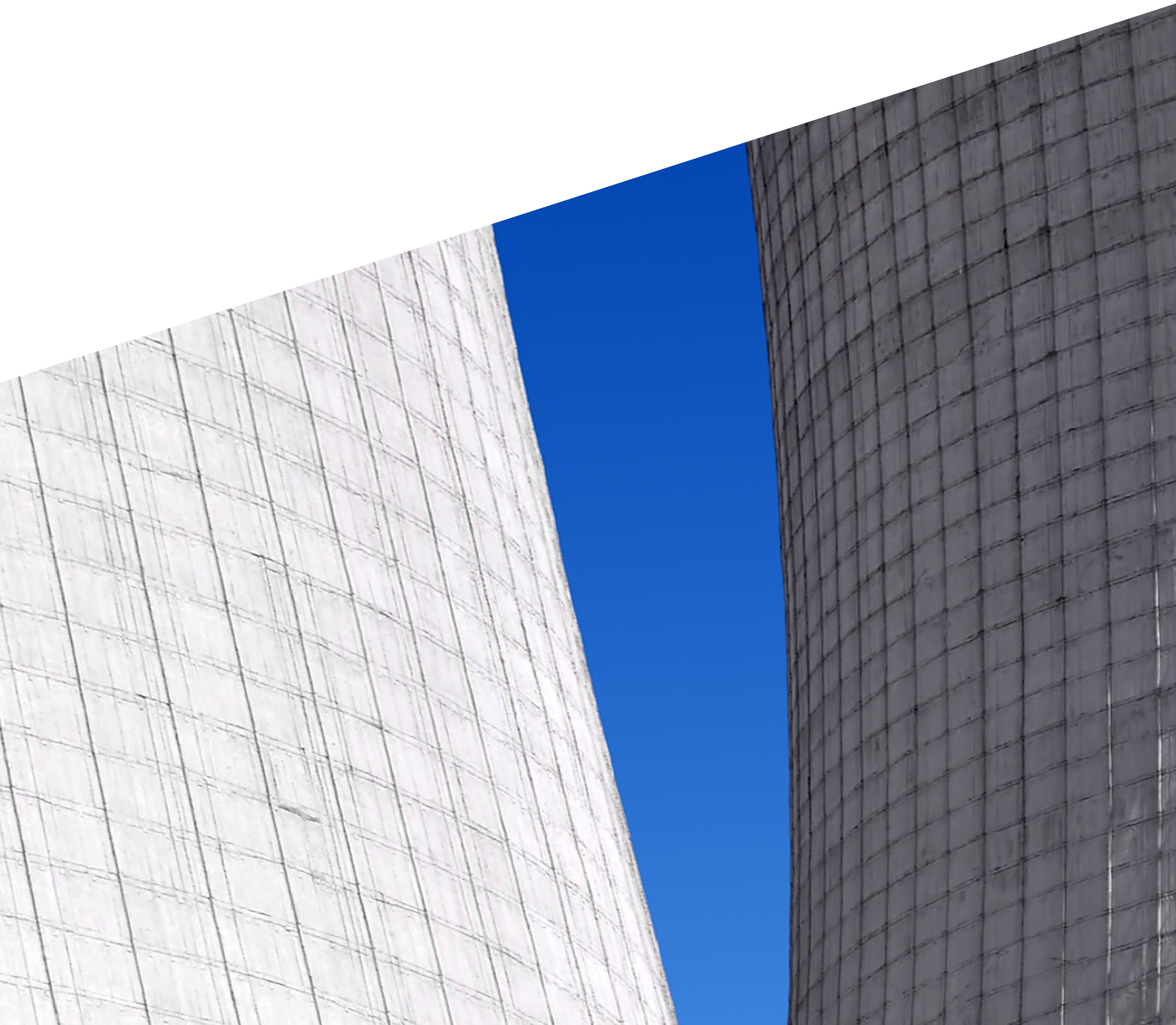

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THE PRIVATE AND EXTERNAL COSTS OF GERMANY'S NUCLEAR PHASE-OUT

Stephen Jarvis
Olivier Deschenes
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Working Paper 26598
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The Private and External Costs of Germany's Nuclear Phase-Out
Stephen Jarvis, Olivier Deschenes, and Akshaya Jha
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ABSTRACT

Many countries have phased out nuclear electricity production in response to concerns about nuclear waste and the risk of nuclear accidents. This paper examines the impact of the shutdown of roughly half of the nuclear production capacity in Germany after the Fukushima accident in 2011. We use hourly data on power plant operations and a novel machine learning framework to estimate how plants would have operated differently if the phase-out had not occurred. We find that the lost nuclear electricity production due to the phase-out was replaced primarily by coal-fired production and net electricity imports. The social cost of this shift from nuclear to coal is approximately 12 billion dollars per year. Over 70% of this cost comes from the increased mortality risk associated with exposure to the local air pollution emitted when burning fossil fuels. Even the largest estimates of the reduction in the costs associated with nuclear accident risk and waste disposal due to the phase-out are far smaller than 12 billion dollars.

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1 Introduction

The Fifth Intergovernmental Panel on Climate Change Assessment Report (IPCC 2013) and the 21st United Nations Climate Change Conference ("COP21") have both recommended that nuclear power should be a part of the global solution to climate change. This is because nuclear electricity generation produces minimal carbon emissions under normal operating conditions (Markandya and Wilkinson, 2007). In contrast, burning fossil fuels to produce electricity is known to emit both global pollutants that contribute to climate change and local pollutants that have negative consequences on human health (NRC and NAS (2010); Jaramillo and Muller (2016); Deschenes, Greenstone and Shapiro (2017); Holland et al. (2018)). Despite this, many countries have substantially decreased the share of their electricity production from nuclear sources. For example, Italy, Belgium, Spain, and Switzerland all have policies in place to phase-out nuclear power entirely. This is due in large part to concerns about long-term solutions for storing nuclear waste and public fears of catastrophic nuclear accidents. These fears intensified considerably following the incidents at Three Mile Island in 1979, Chernobyl in 1986, and Fukushima in 2011.

The decision to phase-out nuclear production in many countries seems to suggest that the expected costs of nuclear power exceed the benefits. Yet, there remains considerable uncertainty about some of these costs and benefits as there is a glaring lack of empirical studies quantifying the *full* range of economic and environmental impacts from large-scale nuclear sector closures.

This paper presents a first attempt at filling this important gap by documenting the impact of the phase-out of nuclear power in Germany on multiple market and environmental outcomes. In particular we focus on the shutdown of ten of the seventeen nuclear reactors in Germany that occurred between 2011 and 2017 following the Fukushima accident in Japan. This context affords us several advantages over previous research studying the impacts of nuclear power plants closures. First, and most importantly, Germany shut down over 8 GW of nuclear production capacity over a few months in 2011, representing close to a 5% reduction in total capacity. By 2017 this had increased to a total of 11 GW of closed nuclear production capacity. This is far larger than the reductions in capacity studied by previous research that focused on the shutdown of a small number of nuclear plants in the United States (Davis and Hausman (2016); Severnini (2017)).

Second, Germany plans to shut down all of its remaining nuclear reactors by 2022. Our study thus provides timely policy-relevant information on the consequences of Germany's nuclear phase-out moving forward. Third, studying electricity markets in the European context gives us the opportunity to examine how cross-border trade was impacted by a large shock to production in one country. Finally, Germany's nuclear phase-out was the direct result of political actions taken following extensive anti-nuclear campaigning in Germany as well as a sudden increase in the perceived risk of nuclear power following the Fukushima accident (Goebel et al., 2015). Importantly, the phase-out was not caused by changes in the economic or environmental conditions pertaining to nuclear production in Germany. This facilitates a causal interpretation of our analysis based on comparing the conditional averages of economic and environmental outcomes before versus after the nuclear phase-out.

This paper adds to the relatively small literature that explores the effects of the nuclear phase-out on the German electricity sector. For instance, both Traber and Kemfert (2012) and Knopf et al. (2014) used mixed economic-engineering models of the power sector to forecast changes to capacity investments, electricity prices and carbon emissions. More recently, Grossi, Heim and Waterson (2017) uses an event study framework to econometrically estimate the impact of the initial nuclear plant closures in 2011 on electricity prices over a three year window between 2009 and 2012. The broad consensus across this small existing literature is that nuclear power was replaced primarily by fossil fuel-fired production, resulting in higher electricity prices and more carbon emissions. However, by focusing on aggregate outcomes, the previous research ignores several important impact margins of the nuclear phase-out. Specifically, we show that much of the social cost of the switch from nuclear to fossil fuels is driven by changes in local air pollution concentration levels around individual power plants before versus after the phase-out.

This paper goes beyond the aggregate electricity sector by estimating the economic and environmental costs of the nuclear phase-out in Germany using rich plant-level data and ambient pollution monitor data. We contribute and expand on the existing literature in several important ways. First, our empirical analysis considers both the initial nuclear reactor closures in 2011 as well as the subsequent incremental shutdowns up until the end of 2017. Second, in addition to electricity prices and carbon emissions, we estimate the spatially disaggregated impacts of the phase-out on production costs, net electricity imports, and local air pollution. This is especially important because the increases in local air pollution as a consequence of shifting production from nuclear to coal represents over 70% of the overall costs of the nuclear phase-out.

To proceed, we develop a new machine learning framework to derive the appropriate counterfactual outcomes under a "no phase-out" scenario. Specifically, our machine learning approach predicts which power plants increased their output in response to the nuclear plant closures. In doing so, this paper contributes a new method that builds on Davis and Hausman (2016) in order to empirically assess how a change in electricity production or consumption at one location propagates throughout the electricity transmission network. This new methodology is useful in a number of different empirical contexts. For example, recent studies have explored how production at different fossil fuel-fired plants responds to changes in electricity consumption at a given location, whether it be plugging in an electric vehicle (Holland et al., 2018), installing a more energy efficient appliance, or siting new wind and solar resources (Callaway, Fowlie and McCormick (2018)). Finally, our paper also contributes to the small but growing literature in energy and environmental economics that integrates machine learning into causal inference techniques (Burlig et al. (2017); Cicala (2017)).

Our novel machine learning approach combines hourly data on observed power plant operations between 2010-2017 with a wide range of related information, including electricity demand, local weather conditions, electricity prices, fuel prices and various plant characteristics. Using these data, we first simply document that production from nuclear sources declined precipitously after March 2011. This lost nuclear production was replaced by electricity production from coal- and gas-fired sources in Germany as well as electricity imports from surrounding countries. We then more formally estimate the impact of the nuclear phase-out on market outcomes using our machine learning algorithm. This algorithm predicts the quantity of electricity produced by each power plant in Germany in each hour-of-sample under two scenarios: one with the nuclear phase-out and one without it. Consistent with the aforementioned descriptive trends, the results of this estimation procedure indicate that the lost nuclear electricity production due to the phase-out was replaced primarily by coal-fired production and net electricity imports.

Finally, we use our predicted changes in plant-level electricity production due to the nuclear shutdowns to calculate the costs of the shift away from nuclear power. We first show that the average operating cost per MWh of German electricity production increased as a consequence of the phase-out. This is unsurprising given that nuclear plants have lower marginal costs than fossil fuel-fired plants. In addition, we find that the switch from nuclear power to fossil fuel-fired production resulted in substantial increases in global and local air pollution emissions. Overall, we estimate that the social cost of the phase-out to German producers and consumers is $12 billion per year (2017 USD). The vast majority of these costs fall on consumers. Specifically, over 70% of the cost of the nuclear phase-out is due to the increased mortality risk from local air pollution exposure as a consequence of producing electricity by burning fossil fuels rather than utilizing nuclear sources.

The nuclear phase-out had benefits as well. In particular, shutting down nuclear plants reduces the risk of nuclear accidents and decreases the costs associated with storing nuclear waste (Dhaeseleer (2013); JECR (2019)). However, even the largest estimates of the benefits of the nuclear phase-out are far smaller than our estimated cost of $12 billion dollars a year. Moreover, consistent with previous work, we find that electricity prices in Germany are higher due to the phase-out. This increase in electricity prices results in increases in the profits earned by most electricity producers but imposes additional costs on German electricity consumers.[1]

Despite the substantial costs to German citizens, the nuclear phase-out still has widespread support. Specifically, more than 81% of German residents were in favor of the phase-out in a 2015 survey (Goebel et al., 2015). Existing evidence suggests that the average person greatly overestimates the expected costs of a nuclear accident, both in terms of likelihood and number of fatalities (Slovic, Fischhoff and Lichtenstein (1979); Slovic and Weber (2002); Slovic (2010)). In addition, the health costs associated with local air pollution exposure may simply be less salient than the risk of a nuclear accident, especially after the Fukishima accident in Japan. Regardless of the underlying causes, widespread anti-nuclear sentiment around the world has made it difficult to set policy pertaining to nuclear power based solely on a dispassionate benefit-cost analysis.

This paper proceeds as follows. The next section provides background on the German

[1]Neidell, Uchida and Veronesi (2019) similarly finds an increase in electricity prices due to the phase-out of nuclear power in Japan following the Fukishima accident. This phase-out-induced increase in prices resulted in a decrease in energy consumption, which in turn caused substantial increases in mortality during very cold temperatures.

electricity sector. Section 3 lists the data sources used for this analysis and presents descriptive trends in electricity prices, production by fuel type, costs, air pollution and other outcomes before versus after the nuclear phase-out. In Section 4, we estimate the impact of the phase-out on plant-level and market-level outcomes using a simple event study framework. We describe how our machine learning approach improves upon this event study approach in Section 5. Section 6 presents our estimates of the economic and environmental impacts of the phase-out. Finally, we discuss the policy implications of our findings in Section 7.

2 Background on Nuclear Power in Germany

The first nuclear power stations were constructed in Germany in the 1960s. Germany's nuclear production capacity expanded rapidly over the next three decades; the last nuclear reactor was commissioned in 1989. Despite no new reactors coming online in the 1990s and 2000s, roughly 25% of Germany's electricity production came from nuclear plants prior to 2011.

Nuclear power has long been controversial in Germany. There were protests as far back as the 1970s at a number of sites where nuclear facilities were either proposed or under construction. However, the Chernobyl disaster in Ukraine in 1986 created a focal point in the politics of nuclear power in Germany. Specifically, radioactive fallout affected much of the country and led to growing public concern. In 1998, the Schröder government took power through a coalition between the Social Democratic Party (SPD) and the Green Party. Over the next two years, the Schröder government banned the construction of new reactors and negotiated a policy of phasing-out nuclear power completely. This plan called for all nuclear reactors to be shut down by 2022.

The center-right Merkel government came to power in 2009. This government renegotiated the original phase-out policy by committing to extending the lifetimes of the newest reactors. This revised policy pushed back the shutdown of the last nuclear reactor into the 2030s. However, the specter of nuclear disaster rose again due to the Fukushima incident on March 11, 2011. In response, public opposition to nuclear intensified again, with an estimated 250,000 people taking to the streets nationwide to protest in the days and weeks following March 11, 2011. The resulting political pressure forced the Merkel government to declare a moratorium on planned extensions at existing nuclear power plants almost immediately after the Fukushima incident. In addition, eight older reactors were taken offline for testing.

By May of 2011, German policymakers decided to return to a version of the original plan: phase out all nuclear power by 2022. Specifically, of the seventeen reactors operating in 2011, the eight reactors already temporarily offline were closed immediately (8.4 GW of capacity), a ninth reactor was closed in 2015 (1.3 GW), a tenth in 2017 (1.3 GW), an eleventh in 2019 (1.4 GW), and the final six reactors (8.1 GW) will close in 2022. Our sample period ends in 2017. Consequently, our empirical analysis focuses on the closure of the nuclear reactors in 2011, 2015 and 2017, but not the subsequent closures in 2019 and 2022.

The phase-out of nuclear power is part of a wide-ranging transformation of Germany's energy sector known as the *Energiewende*. The primary goal of this policy is to reduce Germany's carbon emissions by at least 80% by 2050 relative to 1990 levels (BMWi, 2018). To achieve this, Germany has undertaken major investments in renewable electricity production, transmission grid infrastructure, and energy efficiency measures. The sweeping scope of the *Energiewende* policy highlights the importance of accounting for a host of potential time-varying confounders when assessing the impact of the nuclear phase-out. This motivates the development of our machine learning approach.

3 Data Description and Summary Statistics

This paper brings together the necessary data on the German power sector from a variety of different sources. First, we obtain data on hourly, unit-level electricity production for all power plants with production capacity greater than 100MW. These data are from the European Network of Transmission System Operators for Electricity (ENTSOE) and are only available from 2015-2017. We supplement these data with hourly total production by source (e.g. nuclear, coal, natural gas, oil, etc.) from the European Energy Exchange (EEX) from 2010-2017.

Germany's electricity transmission grid is owned by four different transmission system operators (TSOs) that are each responsible for a different geographical area on the grid: Amprion, TenneT, TransnetBW and 50Hertz. Each TSO reports hourly production from wind and solar sources for the period 2010-2017. The TSOs also provide data on the hourly level of electricity imports and exports in and out of Germany at border points, as well as the hourly total quantity of electricity demanded for their portion of the grid. These TSO data allow us to construct hourly net demand of electricity (total load minus renewable production), as well as hourly generation by source, and net imports at each grid border point.

We construct each plant's marginal cost over time using data on input fuel prices and carbon emission prices gathered from the following two main sources. First, Thomson Datastream provides data on daily natural gas prices in Germany and neighboring countries. The Intercontinental Exchange (ICE) lists monthly coal and oil prices as well as the monthly permit prices for carbon dioxide emissions set by the European Union Emissions Trading System (EUETS).

Our analysis of the environmental costs caused by burning fossil fuels to produce electricity also combines data from multiple sources. The European Environment Agency (EEA) reports annual carbon dioxide emissions for each plant that participates in the EUETS. The EEA also reports annual plant-level data on fuel inputs and local pollution emissions.[2] Station-level weather data comes from Germany's national meteorological service (DWD) and local pollution monitor data are from the German Environment Agency (UBA).

Finally, we compile other electricity sector data and power plant level characteristics from a variety of different sources (Open Power System Data (2018); BNetzA (2018); Egerer (2016)). Most notably, we utilize hourly, Germany-wide wholesale electricity prices from Thomson Datastream.

Taken together, our main estimation sample covers the period 2010-2017 and contains hourly data on wholesale electricity prices, hourly total and net electricity demand, hourly production by dispatchable sources, individual power plant characteristics (including marginal costs of production), and hourly plant-level generation (for the 2015-2017 only).

[Table 1 about here.]

Table 1 provides summary statistics for the electricity sector in 2010 (the first year in our sample) and 2017 (the last year in our sample). The top panel shows that, despite the

[2]These data are collected as part of monitoring for the EU Large Combustion Plant Directive.

closure of more than 10 GW of nuclear capacity between 2010 and 2017, total installed electricity generating capacity grew from 172.2 to 217.6 GW over this period. This is due primarily to rapid growth in renewable production capacity, from 52.1GW in 2010 to 112.5 GW in 2017 (see the bottom panel). Total electricity production increased by roughly 40 TWh between 2010 and 2017. Average wholesale electricity prices also declined precipitously from \$70.70 in 2010 to \$41.80 in 2017 (in 2017 constant USD). Finally, Germany is a net exporter of electricity throughout our sample period; annual net electricity exports increased from 3.5 TWh in 2010 to 33.5 TWh in 2017.

The middle panel of Table 1 reports summary statistics for the major types of power plants in Germany: nuclear, hard coal, lignite, natural gas, and oil. The extent of the nuclear phase-out in 2011 is immediately evident: production from nuclear sources roughly halved after 2011. At the same time, the number of coal-fired power plants (hard coal and lignite) also dropped due to the closure of older and smaller plants. However, production from coal plants remained roughly constant over our sample period; the small decline in hard coal generation was essentially offset by an increase in lignite generation. The marginal cost of production for both type of coal plants fell significantly during the 2010-2017 period, driven by a reduction in the price of coal. The 2010s were also a period of growth for the gas sector: 26 new plants were built and annual total natural-gas-fired production increased from 53.6 TWh to 72.3 TWh. Appendix Figure A.1 presents a more detailed breakdown of the quantity of electricity produced by different types of sources in Germany over 2010-2017.

[Figure 1 about here.]

Figure 1 shows the estimated marginal cost of each power plant in our sample operating in 2011. We assume that biomass, waste, hydroelectric, wind and solar resources have zero marginal operating cost. We also assume that nuclear plants have a marginal operating cost of approximately \$10/MWh (in 2017 USD) based on prior research on Germany's power sector (Egerer, 2016). Finally, marginal costs for fossil fuel plants are calculated as the sum of fuel costs and an assumed amount of variable operating and maintenance costs that differs by fuel type.[3]

[3]Fuel costs are converted to dollars per MWh using the plant's thermal efficiency: how well the plant converts units of input heat to units of electricity output.

Figure 1 highlights that nuclear units uniformly have lower marginal costs than fossil-fuel-fired units. Nuclear power plants also emit virtually no carbon dioxide or local pollutants. We would thus expect that the shutdown of nuclear reactors will lead to increases in both production costs and pollution emissions. We test this hypothesis using a simple event study framework in the next section and our machine learning approach in Section 5.

4 Event Study Regressions

In response to the Fukishima nuclear accident, the German government suddenly and unexpectedly shut down eight nuclear reactors on March 15^{th} 2011. We can thus analyze the impact of these closures on market outcomes using the event study framework formulated in Davis and Hausman (2016) and more recently implemented by Grossi, Heim and Waterson (2017). Specifically, our event study framework estimates how total electricity production by each fuel type i in each hour-of-sample t responds to changes in electricity demand before versus after March 15th, 2011.

The independent variables of interest are equally-spaced bins of net electricity demand interacted with an indicator for observations after March 15^{th} 2011. As in the rest of this paper, "Net electricity demand" is defined to be electricity demand net of production from renewable sources. We consider net demand because production from renewable sources has near-zero marginal costs and is "non-dispatchable": wind and solar sources produce only when the wind is blowing or the sun is out. In order to implement the event-study, we restrict the sample to observations less than 12 months before or after March 15^{th} 2011 and estimate the following regression:

$$G_{i,t} = \sum_b (\alpha_{i,b} \cdot \mathbf{1}\{L_t \in B_b\}) + \sum_b (\beta_{i,b} \cdot \mathbf{1}\{L_t \in B_b\}\mathbf{1}\{t \geq 3/15/2011\}) + \gamma_m + \epsilon_{i,t} \quad (1)$$

where $G_{i,t}$ is the total quantity of electricity produced by fuel type i in hour-of-sample t in Germany. L_t is net demand in hour t, and $\mathbf{1}\{L_t \in B_b\}$ is an indicator that takes on the value one if L_t is in bin B_b and is zero otherwise. Next, the indicator $\mathbf{1}\{t \geq 3/15/2011\}$ takes on the value one if the observation corresponds to an hour-of-sample on or after

March 15^{th} 2011 and is zero otherwise. Finally, we include month-of-year fixed effects (i.e.: γ_m) and cluster standard errors by week-of-sample.

Figure 2 plots the coefficient estimates of interest (i.e.: $\hat{\beta}_{i,b}$) along with their 95% confidence intervals. Panel (a) of this figure shows that average hourly electricity production from nuclear sources dropped by roughly 5 GWh across all levels of net demand. Panels (b)-(d) demonstrate that this lost nuclear production was offset in large part by increases in electricity production from fossil fuel fired sources. Specifically, production from lignite increased by roughly 1 GWh on average at low levels of net demand. Production from hard coal increased by 2-3 GWh on average across all levels of net demand. Finally, gas-fired electricity generation also increased by roughly 2 GWh on average, and by as much as 6 GWh for hours-of-sample with very high net demand.

[Figure 2 about here.]

While these results provide a simple examination of the data, the event study approach has several limitations in our context. First, hourly plant-level data on electricity production are not available prior to 2015. Consequently, the event study framework cannot be used to explore heterogeneity in how different plants respond to the nuclear phase-out beginning in 2011. This heterogeneity is especially important because the amount of local air pollution emitted per MWh of production can vary significantly across plants burning the same type of fuel. In addition, the monetary damage from local air pollution emissions is also tied directly to the number of people exposed to this pollution; the same level of pollution emissions from two different plants can have very different damages based on the number of people living near each of these plants.

Second, the event study framework relies on the assumption that changes in power plant operations around March 15, 2011 are caused by the nuclear reactor closures rather than changes in other factors that determine production behavior. To ensure that this assumption holds, we examine the impact of the phase-out in a fairly narrow window around the initial 2011 shutdowns. Focusing on this narrow window allows us to argue that firms could only respond to the nuclear shutdowns in the very short-run by adjusting output. However, subsequent nuclear plant shutdowns occurred incrementally and were pre-announced. As such, firms may have been able to take actions in anticipation of these later closures.

Finally, as discussed in Section 3, other important economic factors also changed over our 2010-2017 sample period independent from the nuclear phase-out in 2011. For example, coal and natural gas plants had similar marginal costs in 2011. However, coal prices decreased precipitously from 2011-2015 while natural gas prices increased over this period. Coal plants were thus increasingly more likely to produce in place of natural gas plants from 2011-2015 even absent any changes in nuclear power production. In addition, many older coal and gas plants were retired between 2010 and 2017, and a number of new fossil fuel-fired plants came online during this period as well. Summarizing, it is unlikely that market outcomes before versus after March 2011 were driven solely by the phase-out, especially as we look further in time after the 2011 shutdown decision.

5 Machine Learning Approach

5.1 Methodology

We use a machine learning approach to more credibly estimate the market and environmental impacts of the series of nuclear plant closures that occurred between 2011 and 2017. This machine learning approach has two advantages over the event study framework discussed in the previous section. First, hourly plant-level data on electricity production are not available prior to 2015; for this reason, we estimate the event study regressions using data on hourly aggregate electricity production by fuel type. As we noted earlier, plant-level heterogeneity is particularly important for estimating the damages from local air pollution exposure: different plants burning the same type of fuel may have very different emissions factors and number of people living nearby. The machine learning algorithm allows us to use hourly plant-level data from 2015-2017 to estimate plant-level heterogeneity in response to the nuclear phase-out over our entire 2010-2017 sample period.

Second, as discussed earlier, a variety of economic factors relevant for electricity production decisions changed over time independently from the nuclear phase-out. The event study framework affords us only limited ability to control for these factors. In contrast, the machine learning approach allows us to estimate the impact of the nuclear phase-out on plant-level economic and environmental outcomes controlling for a wide range of observed market factors.

Importantly, the goal of our machine learning framework is to best predict market outcomes for different values of the input variables. This differs from traditional econometric methods in two ways. First, we do not seek to identify the causal effect of one variable on another. Second, though we are able to provide bounds on our estimates, it has proven impossible to derive standard errors on the predictions from machine learning models absent randomization of treatment and control groups (Wager and Athey, 2018). Summarizing, our machine learning algorithm gives us substantially more accurate predictions of market outcomes than the event study approach at the cost of being unable to conduct traditional statistical inference on these predictions.

5.2 Data

We train our machine learning algorithm to predict power plant operations using a data set of roughly 4.5 million observations. The outcome of interest is the hourly quantity of electricity produced by each "dispatchable" plant in our sample. We subtract "non-dispatchable" renewable output from electricity demand because renewables have near-zero marginal cost and thus produce whenever nature permits (ex: the sun is out or the wind is blowing). Hourly data on plant-level electricity production are available for all EU member states since 2015 from ENTSOE.[4] We incorporate electricity imports and exports at each border interconnection between Germany and its neighboring countries into our framework by treating each border interconnection point as if it is a power plant. For example, consider the hourly net electricity imports from France to Germany. If France exports 100MWh of electricity to Germany, this border point would be "producing" 100MWh. Conversely, if France imports 100MWh of electricity from Germany, this border point would be "producing" -100MWh.

The dependent variables considered in our machine learning framework are the production levels from each power plant and border points in our sample. In all cases, we normalize the relevant dependent variable by dividing output by the maximum production capacity of each power plant or the maximum transfer capacity of the border point

[4]More specifically, the data are available for plants with capacity greater than 100 MW. This covers 100% of production from nuclear plants, 95% from lignite plants, 85% from hard coal plants, 50% from gas plants and 45% from oil plants. We treat the operating behavior of these plants as being representative of the remaining plants with capacity less than 100MW.

as applicable. Our algorithm focuses on dependent variables that are bounded between 0 and 1; we rescale the flows from border points from their original scale of -1/1 to 0/1 when applying the algorithm. We refer to this rescaled output as the operating rate for each power plant.

The independent variables include electricity demand, local weather, each plant's marginal cost, the availability of other power plants, and a wide range of power plant characteristics such as fuel type, efficiency, technology, and location. We estimate a predictive model that takes these independent variables as inputs and outputs a predicted operating rate for each power plant in each hour. Importantly, we have data on these independent variables from 2010-2017. This allows us to predict hourly, plant-level electricity production from 2010-2017 using our model despite only observing hourly plant-level production from 2015 onward.

We also build a predictive model for wholesale electricity prices. However, there is no cross-sectional variation in these prices; the hourly wholesale electricity price is the same throughout Germany. In this case, the independent variables for the time-series model of electricity prices include electricity demand, national average weather, and the marginal cost associated with the marginal unit (i.e.: the unit with the largest marginal cost that produces a positive quantity in that hour-of-sample).

5.3 Empirical Methods

We predict outcomes using a Random Forest regression algorithm (Breiman, 2001). In particular, we use the Quantile Regression Forest algorithm (Meinshausen, 2006). Random forests are especially well-suited for our empirical context for several reasons. First, each plant's production is based on a potentially complex combination of factors such as the marginal costs and availability of other plants, electricity demand at different locations, and transmission constraints. Consequently, the relationship between plant-level production and the independent variables listed above is likely to be highly non-linear and include multiple interactions. Random forest methods are well-suited to use variation in the data in order to find these interactions rather than pre-specifying how independent and dependent variables relate using polynomials or splines as in a more standard regression framework.[5]

In addition, the Random Forest algorithm ensures that the support of possible outcome predictions is bounded by the support of the outcome values in the training data-set. This prevents nonsensical predictions such as plants producing negative amounts of electricity or producing greater than their capacity. Finally, using the Quantile Regression Forests algorithm allows us to produce predictions for the full conditional distribution of the outcomes rather than just their expected value. This property both allows us to better understand the uncertainty in our analysis and to make corrections that ensure that our predicted outcomes meet certain physical constraints (e.g. that electricity supply equals electricity demand). More details can be found in Appendix B.

We use the Quantile Random Forest model to construct two data series. First, we predict hourly plant-level electricity production at each dispatchable plant (i.e. each fossil plant or border point) using the observed values of the independent variables over 2010-2017. This provides us with electricity production levels at each plant in the "factual" scenario with the nuclear phase-out. We note that the machine learning model is necessary for estimating plant-level production even in the factual scenario because there is no hourly plant-level production data prior to 2015.

Second, we use the model to estimate hourly production for the same set of dispatchable plants in the counterfactual scenario where there was no nuclear phase-out. Put another way, we predict plant-level production assuming that the nuclear reactors that were shut down in 2011, 2015, and 2017 would have remained operational until 2017. To do this, we first calculate the amount of electricity these nuclear plants would have produced in each hour-of-sample if they had remained online.[6] We subtract this counterfactual nuclear output from net electricity demand, thus reducing the production needed from the remaining dispatchable plants. In our primary specifications, we hold all of the other independent variables that do not depend on net demand fixed at their observed

[5]In their application for predicting housing values, Mullainathan and Spiess (2017) report that the Random Forest method results in the most accurate predictions, as measured by out-of-sample R^2, among the various methods evaluated (e.g., OLS, Regression Tree, LASSO, and Ensemble).

[6]We assume that the nuclear plants that were shut down would have operated at 80% of their capacity on average. We choose this relatively conservative 80% operating rate because the nuclear plants that were shut down tended to be older; newer nuclear plants often achieve operating rates of 90-95%. We adjust this counterfactual nuclear output based on observed fluctuations in monthly total nuclear production from 2012 to 2014 because there were no nuclear shutdowns during this period. This adjustment primarily reflects the fact that nuclear plants tend to go on maintenance during the summer months when demand is lowest.

values. A natural concern is that the phase-out led to changes in other independent variables such as the available production capacity from other plants. We discuss the various sensitivity analyses we implemented to address this concern in Section 5.5. Further details on the implementation of our machine learning algorithm can be found in Appendix Section B.

Finally, we calculate different market and environmental outcomes using the predicted hourly electricity production from each plant with versus without the nuclear phase-out. Though our exposition has focused on hourly plant-level production, we utilize a similar approach to assess the impact of the phase-out on wholesale electricity prices.

5.4 Model Validation

This subsection presents figures and tables comparing observed outcomes with the outcomes predicted by our machine learning algorithm.

[Figure 3 about here.]

Figure 3 reports daily average observed versus predicted wholesale prices in 2017 USD per MWh, as well as the difference between the two (i.e., the prediction error). It is evident that the machine learning model delivers very accurate predictions; the difference between observed versus predicted prices is nearly zero throughout the entire period. Nevertheless, the adjusted R^2 from the regression of observed average daily price on the predicted average daily price is 0.98.

Figure 4(a) compares observed hourly plant-level operating rates (i.e., percentage of capacity utilized) with the predictions from the machine learning model. Specifically the predicted electricity production (scaled on the y-axis) is plotted against the observed production (x-axis) so that observations on the 45 degree line indicate perfect prediction accuracy. Each pixel in the figure represents the predicted vs. actual operating rate in increments of 2% and darker areas correspond to a higher number of plant-hour (or plant-year) observations.

We check the out-of-sample cross-validated performance to avoid overfitting and give a fair assessment of how the model may perform when used to make predictions about our counterfactual no-phase-out scenario. The cross-validated out-of-sample R^2 is 0.61 and the mean squared error (MSE) is 0.061.[7]

However, even this small level of prediction error understates the relevant prediction accuracy of the machine learning model. Specifically, we will primarily use the predictions from our model to compare outcomes with versus without the phase-out at the plant-month and plant-year levels. We therefore also evaluate the predictive performance of the model at these levels of aggregation. Specifically, Figure 4(b) plots predicted versus observed annual average operating rates. As the figure shows, the performance is substantially improved, with most of the observations clustered close to the 45 degree line, and the areas of systematic error largely disappear. The cross-validated out-of-sample R^2 rises to 0.93 and the mean-squared error falls to 0.006.[8]

[Figure 4 about here.]

As an alternative metric to the cross-validated out-of-sample R^2 and MSE, we also evaluate accuracy of the machine learning predictions by testing whether variation in predicted hourly plant-level production is correlated with observed variation in ambient air pollution at nearby monitors. To this end, we use data from air pollution monitors in Germany spanning the entire 2010-2017 analysis period; we match each power plant to its three closest air pollution monitors.[9] Specifically, we construct a daily plant-level measures of air pollution concentrations as the inverse distance-weighted average of the readings from these three monitors. We then estimate panel regressions of daily average ambient pollution concentrations on daily total plant-level production. We include plant fixed effects, year fixed effects, and month-of-year fixed effects in order to control for seasonality in air pollution and electricity production, as well as, plant-specific emission intensities.

[Table 2 about here.]

Table 2 reports the results of this analysis. Each row reports the coefficient estimates,

[7] By comparison, a simple OLS regression with the same independent variables only achieves an out-of-sample R^2 of 0.37 and a mean-squared error of 0.091.

[8] A simple OLS regression with linear covariates is still clearly inferior with an out-of-sample R^2 of 0.63 and an MSE of 0.025.

[9] The average distance between power plants and the nearest air pollution monitors is 6.5 km, with a range of 0.25km to 31 km.

along with standard errors clustered by plant, from separate regressions for 5 air pollutants: PM_{10}, $PM_{2.5}$, SO_2, CO, and NO_2. For ease of interpretation, both the dependent variables and the plant-level production variables are standardized to have a mean of 0 and a standard deviation of 1. The columns correspond to different estimation samples. Column (1) is from models where the dependent variable is standardized observed daily plant-level production from 2015-2017. In column (2) the dependent variable is standardized predicted daily production over the same 2015-2017 period, and in column (3), the dependent variable is standardized predicted production over the full 2010-2017 period. The key comparison to assess the validity of the Random Forest prediction algorithm is between columns (1) and (2). The estimates in column (1) confirm that increases in observed daily production correspond to increases in pollution concentration levels for all pollutants except for SO_2. For example, a standard deviation increase in average daily production leads to a 0.13 standard deviation increase in average daily concentration of PM_{10}, or roughly a 1% increase in daily concentrations.

Column (2) replicates the analysis using the daily plant-level production predicted by the Random Forest model as the dependent variable. The resulting coefficient estimates are similar in magnitude and exhibit the same patterns and statistical significance as the specification in column (1) using observed production. Finally, column (3) reports estimates assessing the impact of predicted prediction on pollution levels over the entire 2010-17 sample period. These estimates documented in column (3) are similar to those in columns (1) and (2). Taken together, the analysis in Table 2 provides evidence that additional electricity production leads to higher concentrations of ambient air pollutants. More importantly, this table also provides evidence that our predicted plant-level production estimates are accurate even for the pre-2015 sample period where we do not have data on plant-level production.

5.5 Sensitivity Analyses

This subsection describes and motivates three sensitivity analyses we conduct that pertain to how we construct the counterfactual no-nuclear-phase-out scenario. The full results of these analyzes are described in Section 6.4. In our primary specifications, we assume that the effect of the phase-out flows solely through reductions in electricity production from the nuclear plants that were shut down. Put another way, we assume that the other observed factors in our model do not change as a result of the phase-out. This assumption makes sense for many of our predictors such as plant characteristics, temperature, and seasonality of demand. However, other factors may have changed as a consequence of the phase-out. For example, the phase-out may have led to an increase in retail electricity prices, which in turn might reduce aggregate electricity demand. As another example, over longer timescales, the phase-out may have accelerated investment in new replacement production capacity. We address these concerns by demonstrating how sensitive our results are to varying factors that may have changed as a result of the phase-out.

Our first sensitivity analysis focuses on how the nuclear phase-out impacts investment in fossil fuel-fired capacity. Prior studies have demonstrated that, if the phase-out had not occurred, the amount of fossil fuel-fired capacity necessary to ensure that demand is met even during peak hours in Germany would have been 4 GW lower by 2020 (Traber and Kemfert, 2012) and 8 GW lower by 2030 (Knopf et al., 2014). This reduction in capacity could be due either to fewer new fossil plants being built or older existing plants closing early. To capture this, we calculate how this 4GW (8GW) reduction by 2020 (2030) would impact fossil-fuel-fired capacity during our 2010-2017 sample period.[10] We then re-run the analysis for the counterfactual no-phase-out scenario removing the relevant fossil capacity from the system in each year.

Another sensitivity analysis accounts for the fact that the incentives to invest in renewable production may not have been as strong in the absence of the nuclear phase-out. To do this, we re-run our machine learning prediction model for the no-phase-out scenario assuming that renewable production would have been 30 TWh lower by 2017. We chose 30 TWh based on changes made to Germany's renewable energy targets in response to the phase-out decision. Specifically, in 2010, Germany planned on producing at least 30% of its electricity from renewables by 2020. However, this target was increased to 35% following the 2011 phase-out decision (Jacobs, 2012). The difference between these two targets requires a change in renewable production of roughly 30 TWh between 2010

[10] Getting to 4GW (8GW) less fossil capacity by 2020 (2030) can be achieved by assuming that fossil capacity falls by 0.4 GW per year from 2011 to 2030. For our 2010-2017 analysis period, we achieve this with the following modifications: Irsching opens in 2012 instead of 2011, Weisweiler (Blocks C & D) closes in 2011 instead of 2012, Boxberg opens in 2013 instead of 2012, KW Walsum opens in 2014 instead of 2013, GKM Mannheim (Blocks 3 & 4) closes in 2012 instead of 2015, Westfalen (Block E) opens in 2015 instead of 2014, Westfalen (Block C) closes in 2015 instead of 2016, Moorburg (Blocks A & B) opens in 2018 instead of 2015 and KW Voerde (Blocks A & B) closes in 2016 instead of 2017.

and 2017. Reducing renewable production by 30 TWh amounts to an 8% increase in net electricity demand by 2017 for the counterfactual case where the phase-out had not gone ahead. We argue that this 8% increase in net electricity demand is a relatively large response.[11] Consequently, this sensitivity analysis shows how our results change when considering an upper bound on the extent to which investment in renewables was driven by the phase-out.

Finally, one might be concerned that the phase-out increases wholesale electricity prices which in turn might decrease consumer demand. We argue that our second sensitivity analysis should assuage this concern. Specifically, as discussed above, an 8% increase in net demand due to the phase-out is an extremely large response; it is unlikely that consumer demand shifts by more than 8% due to the phase-out. In fact, it is plausible that changes in wholesale prices do not impact customer demand much at all. This is because the commercial and residential customers that make up around half of Germany's total demand are highly price-inelastic; wholesale electricity prices are only roughly a quarter of their overall retail price, with the remainder being network charges, renewable subsidy fees and taxes (BNetzA, 2018). Though larger industrial customers may be more price-elastic, changes in their electricity demand are extremely unlikely to result in changes in aggregate net demand that exceed 8%. Consequently, our third sensitivity analysis focused on changes in net demand due to changes in renewables also helps to address concerns that the phase-out impacted consumer demand through changes in wholesale prices.

6 Social Costs and Benefits of the Nuclear Phase-Out

This section presents the primary results on the full range of impacts of the nuclear phase-out. Specifically, we compare the market and environmental outcomes with versus without the nuclear phase-out using the predictions from our machine learning model.

[11] For example, previous work on the phase-out assumed that investments in renewables did not accelerate due to the nuclear plant closures (Traber and Kemfert (2012); Knopf et al. (2014)). Furthermore, the increases in wholesale electricity prices resulting from the phase-out were unlikely to impact the profitability of investment in renewable capacity. This is because all renewable capacity in Germany is remunerated through feed-in-tariffs that provide a guaranteed above-market price for the electricity produced.

6.1 Private Costs and Benefits of the Phase-Out

This subsection examines how the nuclear phase-out affected wholesale electricity prices, electricity production, revenues and operating costs. All currency units are converted from nominal Euros to constant 2017 USD.

[Figure 5 about here.]

Figure 5 presents our estimates of the impacts of the nuclear phase-out on electricity production and wholesale prices. First among these is Figure 5(a), which reports the monthly average difference in predicted production and net imports (in TWh) with minus without the phase-out policy. We report monthly average differences in fossil-fired electricity production (grey diamonds), net imports (red circles), and nuclear production (purple squares). The start of the nuclear phase-out in March 2011 is marked by the vertical black dashed line; the "with" minus "without" phase-out differences are zero before this point. By construction, we find a stark reduction in total nuclear production of 3-5 TWh per month. The cyclicality of this impact is due primarily to the fact that nuclear reactors typically schedule their maintenance and refuelling outages in the summer months.

The phase-out also caused a large increase in fossil-fuel-fired electricity production of 2-3 TWh per month and a smaller increase in net imports of electricity. Importantly, these increases are calculated taking into account the rise in renewable production over our sample period. Another notable result in Figure 5(a) is that the stark increase in fossil production starting in March 2011 persists over our entire sample period.

Figure 5(b) is constructed similarly and reports the impact of the nuclear phase-out on wholesale electricity prices in 2017 USD per MWh. The estimates clearly show that the phase-out resulted in an increase in wholesale prices, ranging from roughly from 0.5 to 8 dollars per MWh. Another key result in Figure 5(b) is that the increase in wholesale prices persists through the end of 2017, as was similarly noted for fossil fuel electricity production. Finally, the figure also shows that the phase-out may have exacerbated episodic increases in prices, such as the large price spike in January 2017 due to an unusual cold spell in Europe (European Commission, 2017).

[Table 3 about here.]

Column (1) in Table 3 complements the information in Figure 5 by reporting annual average predicted wholesale electricity price and electricity production in the scenario with the phase-out. Column (2) reports these predicted outcomes for the scenario without the phase-out. Column (3) reports the difference between the first two columns and Column (4) provides this estimated effect as a percentage by dividing column (3) by column (1). The estimates reveal that the phase-out caused inflation-adjusted wholesale electricity prices to increase by \$1.80 per MWh on average, a 3.9% increase relative to the prices that would have prevailed if the phase-out had not occurred. Consistent with Figure 5(a), nuclear production fell by an average of 53.2 TWh per year during the phase-out period, corresponding to a 38% decline. The next rows decompose the previously documented increase in fossil production by source. The largest increases, both in absolute and percentage terms, are from hard coal and gas-fired production. Specifically, annual average production from hard coal increased by 28.5 TWh (32%) while gas-fired production increased by 8.3 TWh (26%). Finally, the phase-out caused net imports to increase by 10.2 TWh (37%) per year on average. In sum, the 2011 phase-out lead to large changes to Germany's electricity generation mix.

[Table 4 about here.]

Table 4 examines the impact of the nuclear phase-out on financial outcomes for power plants, once again organized by plant fuel type. We report predicted annual average revenues, operating costs, and operating profits. Revenues are calculated as the product of plant-level production and wholesale electricity prices; we thus ignore any additional revenues plants may receive, such as capacity payments, ancillary services payments, subsidies etc. Operating costs are the product of each plant's hourly production with its hourly marginal cost. Finally, operating profits are simply operating revenues minus operating costs. For net imports, we quantify revenues and costs as the net import of electricity multiplied by the wholesale price in the relevant neighboring country.[12] All of the entries in Table 4 are in billions of dollars (2017 USD) per year.

[12]Our analysis implicitly assumes that the phase-out caused no change to the electricity prices of neighboring countries. Fully modeling electricity markets for each of these interconnected countries would entail a prohibitive amount of additional data collection. This additional modeling would also be unlikely to dramatically alter the overall findings given the dominant role of domestic production in meeting Germany's electricity demand. Finally, since prices in interconnected electricity markets likely increased due to the phase-out, our net import cost estimates are likely to be a lower bound.

The nuclear phase-out had a large effect on the revenues and operating profits of the firms that owned the nuclear plants that were shut down. Specifically, annual average revenues across all nuclear plants declined by $2.2 billion per year. Annual average operating profits earned by nuclear plants fell by $1.6 billion (a 35% reduction). This decline is striking, especially given that it accounts for the increased revenues earned by the nuclear plants that remained open and were thus able to benefit from the increase in wholesale electricity prices.

The revenues previously earned by the shut-down nuclear plants were primarily redistributed to fossil plants, most notably hard coal and natural gas plants. This shift occurred at a less than one-for-one ratio since nuclear plants have a much lower operating costs per MWh than fossil plants. Despite this, annual average operating profits at fossil plants increased by roughly $0.4 and $0.3 billion due to the phase-out at lignite and coal plants respectively. This corresponds to sizable increases of 17% and 64%.

The redistribution of profits amongst electricity producers has interesting implications for the political economy surrounding the phase-out policy. In particular, the four large firms that owned nuclear plants in Germany clearly opposed the policy both privately and publicly. However, there are two important factors that may have tempered their opposition. First, these firms would have been allowed to operate their nuclear plants into the 2030s only if they paid a nuclear fuel tax. This nuclear fuel tax would have taxed away a large portion of the inframarginal rents that these nuclear plants earn. Second, the four firms that owned nuclear plants also had large fossil plant portfolios both in Germany and across Europe. As we have seen, these fossil plants earned larger profits due to the nuclear phase-out, which likely cushioned the reduction in profits earned by the four firms as a result of the nuclear closures.

6.2 External Costs and Benefits of the Nuclear Phase-Out

This subsection presents two separate analyses of environmental costs associated with the phase-out-induced increase in fossil-fuel-fired production documented in the previous subsection. Specifically, burning fossil fuels emits both global pollutants such as carbon dioxide that contribute to climate change and local pollutants that adversely impact the health of exposed populations.

6.2.1 Estimating External Damages Using Reported Emissions Rates

First, we estimate the change in carbon emissions due to the phase-out. To proceed, we calculate the change in the amount of fuel burned by each plant associated with the phase-out impact on each plant's hourly production and using each plant's thermal efficiency (i.e.: how well the plant translates input heat energy to output electricity). We then use the carbon intensity of different fuels documented in industry reports to convert changes in fuel burned to changes in plant-level CO_2 emissions.[13]

We also estimate the change in local pollution emissions due to phase-out-induced changes in plant production levels. Similar to the approach for CO_2 emissions, we translate changes in fuel use into changes in emissions using plant-level emissions rates for each local pollutant from the EU Large Combustion Plant Directive (LCPD). The LCPD database provides annual plant-level data on fuel inputs and emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter (PM). The LCPD data covers the vast majority of large fossil plants in Germany.[14] We assign the small number of plants not in the LCPD database an emissions factor based on the average emissions factor of plants with the same fuel type.

We next monetize the damages caused by CO_2 and local air pollution emissions. For CO_2, we monetize damages assuming a social cost of carbon of \$50/tCO_2. To assess the health damages from increases in local air pollution, we rely on two studies that estimate the health impacts of local pollution in Europe (EEA, 2014; Jones et al., 2018). In particular, Jones et al. (2018) provide estimates of the annual health damages from the local air pollution emitted by roughly four hundred of the largest coal-fired power plants in Europe. We use these data to convert our predicted increases in plant-level kilotons of SO_2, NO_x and PM emissions into monetized health damages.[15]

[13] The carbon intensities we use are 93.6 tCO2/TJ for hard coal, 55.9 tCO2/TJ for gas and 74.0 tCO2/TJ for oil. We consider three different intensities for lignite depending on the mining region that the plant sources its coal from. These are 113.3 tCO2/TJ (Rhineland), 111.2 tCO2/TJ (Lusatian) and 102.8 tCO2/TJ (Central).

[14] Specifically, the data covers 99% of lignite capacity, 98% of hard coal capacity, 90% of gas capacity and 91% of oil capacity.

[15] Specifically, we assume that increased emissions at a given fossil-fuel-fired plant in Germany would have the same health damages as if they were emitted at the nearest location for which we have health damages estimates. The mean distance between each of the power plants in our data set and closest of the 400 locations with damage estimates is 29km. The median is 14km. Jones et al. (2018) provides estimates for roughly 10% of the plants in our data-set, noting that these plants are among the 400 largest coal plants in Europe.

[Table 5 about here.]

Table 5 presents the results of this analysis. Specifically, this table reports the fuel-specific annual emissions for CO_2 (in Megatonnes, Mt) as well as the emissions of three local pollutants: SO_2, NO_x, and PM (in kilotonnes, kt). Lignite and hard coal are by far the two largest polluters, contributing more than 90% of emissions. Lignite and hard coal also contribute the most in terms of monetary damages from emissions, which are reported in billions of USD per year.

In aggregate, the phase-out led to an increase in CO_2 emissions of 36.3 Mt per year. This corresponds to a 13% increase relative to the scenario without the nuclear phase-out. This increase in CO_2 emissions was primarily attributable to an increase in emissions from hard coal plants of 25.8 Mt, with lignite and gas making up the remainder. Valuing carbon emissions at a social cost of carbon of \$50/tCO2, the phase-out results in estimated climate change damages of \$1.8 billion.

The phase-out also led to a roughly 12% increase in the total emissions of each the three local air pollutants we consider (SO_2, NO_x, and PM). Again, this increase is due primarily to increased emissions from hard coal plants. The bottom panel of Table 5 reports annual average mortality damages summed across all three local air pollutants. From 2010-2017, local pollution emissions from fossil plants were responsible for around \$65 billion in mortality costs each year. \$8.7 billion of this annual mortality cost can be attributed to the nuclear phase-out, representing a 15% increase in damages relative to the scenario without the nuclear phase-out.[16] Put another way, the phase-out resulted in more than 1,100 additional deaths per year from increased concentrations of SO_2, NO_x, and PM. The increase in production from hard coal plants is again the key driver here, making up roughly 80% of the increase in mortality impacts.

6.2.2 Estimating External Damages Using Ambient Air Pollution Monitors

As an alternative to calculating damages using fuel inputs and reported emissions, we also compute damages using the estimated relationship between plant-level production and recorded air pollution at nearby monitoring stations. We have already shown that

[16]We use a Value of Statistical Life of \$7.9 million for Germany taken from Viscusi and Masterman (2017).

increased fossil fuel-fired production results in higher concentrations of PM_{10}, $PM_{2.5}$, CO and NO_2 in Table 2. In this subsubsection, we estimate a daily monitor-level regression of ambient air pollution on daily plant-level predicted production for the sample period 2010-2017:

$$P^{PO}_{i,d,m,y} = \alpha + \beta_s Y^{PO}_{i,s,d,m,y} + \mu_i + \delta_m + \delta_y + u_{i,d,m,y} \tag{2}$$

where $P^{PO}_{i,d,m,y}$ is recorded air pollution concentrations near plant i, on day d, in month m, and year y.[17] The "PO" superscript denotes that pollution is measured in the factual scenario with the nuclear phase-out.

$Y^{PO}_{i,s,d,m,y}$ represents daily electricity production at plant i , powered by fuel s, in the factual phase-out scenario. The coefficient of interest, β, is estimated separately for each fuel type s, to account for the differing pollution intensities of lignite, hard coal, natural gas and oil plants. We include plant fixed effects (μ_i) to control for plant-specific factors that are correlated with local air pollution conditional on production, such as the presence of pollution abatement technologies. We also include month-of-year fixed effects (δ_m) and year-of-sample fixed effects (δ_y) to control for trends and seasonality in air pollution and electricity production.

The regression coefficients β_s capture how a one MWh increase in production from fuel type s impacts local air pollution concentration levels. To estimate the change in local air pollution attributable to the phase-out (through its effect on electricity production at plant i), we multiply each coefficient estimate $\hat{\beta}$ by the phase-out driven change in production at plant i, burning fuel s. Formally, we calculate $\Delta POLL_{i,d,m,y}$ $= \hat{\beta}_s \times (Y^{PO}_{i,s,d,m,y} - Y^{NPO}_{i,s,d,m,y})$ which is the estimated increase in pollution levels due to phase-out-induced increases in fossil-fuel-fired production at plant i (using fuel s).

We calculate the increase in premature mortality due to this increase in air pollution concentrations using dose-response estimates from the ESCAPE project (Lancet 2014).[18] Specifically, the ESCAPE project reports that mortality rate when $PM_{2.5}$ exposure is X + 5 micrograms per cubic meter divided by the mortality rate when $PM_{2.5}$ exposure is X micrograms per cubic meter is 1.07. The corresponding hazard ratio for a 10 micrograms

[17] As before, we calculate pollution at each plant as the inverse distance-weighted average of the measurements at the three pollution monitors closest to this plant.

[18] The European Study of Cohorts for Air Pollution Effects (ESCAPE) is one of the few studies on the health impact of air pollution exposure in Europe. It is based on 22 European cohort studies with a total study population of more than 350,000 participants.

per cubic meter increase in NO_2 is 1.01.[19]

Based on these hazard ratios, we can calculate the increase in mortality caused by the additional air pollution due to the phase-out using the following formula:

$$VSL \times POP \times MR \times \left(1 - \frac{1}{\exp(\rho_j \Delta POLL_j)}\right) \tag{3}$$

for j=$PM_{2.5}$ or NO_2. The value of statistical life (VSL) used to monetize the premature mortality due to phase-out-induced increases in air pollution is \$7.9 million as in the previous subsubsection (Viscusi and Masterman, 2017). POP and MR are the population and mortality rate in the exposure group. The parameter ρ_j corresponds to the hazard ratios described above and $\Delta POLL_j$ is the change in ambient air pollution caused by the phase-out for air pollutant j. Finally, we assume that only the population residing within 20 km of the fossil power plants is exposed to the additional air pollution due to the phase-out (approximately 7.5% of the total population of Germany). This population measure is calculated using satellite-based data from the Socioeconomic Data and Applications Center (SEDAC) at NASA.

[Table 6 about here.]

The estimates of monetized mortality damages are reported in Table 6. Specifically, we present the annual average impact of the phase-out on pollution concentrations, premature mortality and the monetized damages from this premature mortality. A few key results emerge. First, there is again clear evidence that the phase-out resulted in significant increases in local pollution that in turn led to large and costly increases in premature mortality. Second, the changes in $PM_{2.5}$ and PM_{10} concentration levels due to the phase-out were responsible for much larger health impacts than the change in NO_2 air pollution (about 10 times more). Finally, the primary drivers of excess mortality are the hard coal and lignite power plants. The estimates in column (3) suggest that the additional production from burning hard coal due to the phase-out led to \$3 billion in annual mortality damages. Phase-out-induced increases in production from lignite led to \$1.2 billion in annual mortality damages. Overall, this analysis points to the phase-out causing annual premature mortality damages of 4.3 billion USD per year.

[19] In order to calculate the hazard ratio for $PM_{2.5}$, we convert PM_{10} to $PM_{2.5}$ by making the simple assumption that $PM_{10} = 0.5PM_{2.5}$. There are no dose-response functions for CO and SO_2 in the ESCAPE project.

Taken together, the results in Tables 5 and 6 paint a remarkably consistent picture of the monetized mortality damages attributable to the nuclear phase-out. That being said, our preferred estimate is the 8.7 billion USD per year in damages calculated based on reported emissions (Table 5). This is because the analysis using reported emissions considers a more complete set of pollutants and implicitly draws on a more sophisticated analysis of pollution transport and exposure. The results presented in Table 6 based on our estimated relationships between pollution concentrations and electricity production (Table 6) serves as a valuable complementary validation exercise, especially given it was derived using an entirely distinct approach. Lastly, we want to emphasize that the air pollution costs of the phase-out are economically sizable, amounting to a roughly 10-15% increase in damages from premature mortality due to air pollution emissions from Germany's power sector.

6.2.3 Estimating Risks from Nuclear Accidents and Waste Storage

Nuclear power plants emit virtually no global or local air pollution. However, nuclear energy does come with catastrophic accident risk and requires storing the waste that results from nuclear production, which has important costs as well. For instance, JECR (2019) estimates that the cost of the Fukushima accident over the next forty years is between 35-80 trillion yen ($330-750 billion). Most of this cost will not be incurred by the firm that owned the Fukishima nuclear power plant; the costs of the Fukishima accident are largely borne by Japanese society as a whole.

More generally, estimates from the literature suggest that the external costs of nuclear power due to waste storage and accident risk fall between €1-4 per MWh (Dhaeseleer, 2013). This wide range is due to differing estimates of accident probabilities and severity, as well as varying assumptions on discount rates. If we value the external costs of nuclear power at $3 per MWh, the expected benefits from the nuclear phase-out are $0.2 billion per year. Even if we value the external costs of nuclear at $30 per MWh, a value far higher than the magnitudes typically found in the literature, the expected benefits from the nuclear phase-out are still relatively moderate at $2 billion per year. This is markedly smaller than our estimate of the external costs associated with the nuclear phase-out.

6.3 Total Costs and Benefits of the Nuclear Phase-Out

This subsection bring the analysis together by summarizing the full range of private and external costs and benefits of the nuclear phase-out. The private costs of the phase-out consist of changes in the operating costs of the power plants in our sample as well as any net costs from changes to imports and exports. The external costs of the phase-out include the monetized climate change damages from carbon emissions, the damages from mortality, and morbidity caused by the air pollution attributable to the change in electricity production mix. Finally, the benefits of the phase-out consist of reductions in the costs associated with nuclear waste and accident risks.

[Table 7 about here.]

Table 7 reports the aggregate cost and benefits of the phase-out. The phase-out resulted in replacing low cost nuclear production with higher cost sources such as fossil fuels and net imports; this increases average operating costs in Germany by $1.6 billion per year. Whilst not trivial, these private costs are small relative to the external costs associated with the phase-out. Specifically, burning fossil fuels to produce electricity rather than using nuclear plants emits global pollutants such as CO_2 as well as local pollutants such as $PM_{2.5}$, SO_2 and NO_2.

The climate damages from phase-out-induced increases in CO_2 emissions alone amount to $1.8 billion per year. However, the largest impact of the phase-out by far has been the external costs from local air pollution emissions. Specifically, increased exposure to local air pollution results in an additional 1,100 excess deaths due to poorer air quality. We estimate the monetized mortality impacts to be $8.7 billion per year when using reported emissions, with a further $0.2 billion per year in morbidity costs. The average reduction in the external costs from nuclear waste and accident risks are small by comparison at $0.2 billion per year. Overall we estimate the annual ongoing costs of the nuclear phase-out as approximately $12.2 billion per year.

6.4 How does the Phase-Out Impact Investment?

Keppler (2012) argues that extending the lifetime of the nuclear reactors in Germany would have required investments of roughly €500 million per reactor, or €8.5 billion in total (roughly \$10 billion). These investment costs are avoided due to the nuclear phase-out. However, Knopf et al. (2014) argues that the phase-out led to 8GW of additional fossil-fuel-fired capacity being required by 2030. If we assume coal-fired capacity has capital costs of \$3500/kW while gas-fired capacity has capital costs of \$1000/kW, the total additional investment costs in fossil-fuel-fired capacity as a result of the nuclear phase-out range from \$8-\$28 billion. Subtracting the avoided investment costs in nuclear from this range, the net investment costs of the phase-out are between -\$2 billion to \$18 billion. That being said, our central estimate of the *annual* net increase in intensive margin costs as a consequence of the nuclear phase-out is roughly \$12 billion. Therefore, no reasonable comparison of the investment costs with versus without the phase-out can overturn the conclusion that the phase-out fails a simple benefit-cost test by a large margin.

However, one could argue that the nuclear phase-out accelerated investment in renewable sources. Increased investment in renewables drives down the production costs and air pollution damages associated with shifting away from nuclear. To explore this argument, we estimated a scenario where the phase-out incentivized a steady increase in investment in renewables. We set the level of this annual investment in renewables such that Germany produces its target of an additional 30 TWh per year of renewable generation by 2020. In this "renewables" scenario, fossil-fuel-fired power plants are tasked with producing roughly 5 TWh less electricity each year. Consequently, the increase in annual average private operating costs due to the phase-out is \$1.4 billion instead of \$1.6 billion in the baseline analysis. The phase-out-induced increase in climate damages costs is \$1.3 billion (versus \$1.8 billion in the baseline analysis) while the phase-out-induced increase in air pollution damages is \$7.6 billion (versus \$8.7 billion in the baseline analysis). Combined, allowing for a sizable increase in renewable production as a consequence of the phase-out decreases the total net costs of the phase-out by only \$1.8 billion per year (from \$12.2 billion in our baseline to \$10.4 billion with increased renewables).

6.5 Robustness Checks

Two externally estimated parameters play a key role in our estimates: (a) the Value of Statistical Life (VSL) used to monetize the additional morality due to phase-out-induced local air pollution, and (b) the external costs of nuclear waste and accident risks. Our central estimate of the cost of the nuclear phase-out is based on a VSL of $7.9 million from Viscusi and Masterman (2017). We believe this Germany-specific VSL to be most reliable/up-to-date. Nevertheless, the Organization for Economic Cooperation and Development (OECD) estimates that the Germany-specific VSL is approximately $3 million, which is one of the lowest VSL estimates for Germany we've seen in the literature.[20] Even using this extremely low VSL of $3 million, we find that the air pollution costs of the phase-out are $3.3 billion (versus $8.7 billion in the baseline analysis). This significantly more conservative assumption on VSL reduces the total cost of the phase-out to $6.4 billion per year (versus $12.2 billion in the baseline analysis).

Similarly, we can value the external costs associated with nuclear waste and nuclear accident risk at $30 per MWh. This is roughly 10 times larger than the external costs of nuclear power estimated in previous studies (Dhaeseleer, 2013). This extremely conservative (i.e.: high) estimate increases the benefits of the phase-out from $0.2 billion per year to $2 billion per year. However, replacing both the VSL and external costs of nuclear power with extremely conservative estimates is still not sufficient to overturn the conclusion that the nuclear phase-out resoundingly fails a simple benefit-cost test.

7 Conclusions and Policy Discussion

Following the Fukashima disaster in 2011, German authorities made the unprecedented decision to: (1) immediately shut down almost half of the country's nuclear power plants and (2) shut down all of the remaining nuclear power plants by 2022. We quantify the full extent of the economic and environmental costs of this decision. Our analysis indicates that the phase-out of nuclear power comes with an annual cost to Germany of roughly $12 billion per year. Over 70% of this cost is due to the 1,100 excess deaths per year resulting from the local air pollution emitted by the coal-fired power plants operating in place of the shutdown nuclear plants. Our estimated costs of the nuclear phase-out far exceed the right-tail estimates of the benefits from the phase-out due to reductions in nuclear accident risk and waste disposal costs.

Moreover, we find that the phase-out resulted in substantial increases in the electricity prices paid by consumers. One might thus expect German citizens to strongly oppose the

[20]Viscusi and Masterman (2017) discusses the shortcomings of the OECD estimates of VSL.

phase-out policy both because of the air pollution costs and increases in electricity prices imposed upon them as a result of the policy. On the contrary, the nuclear phase-out still has widespread support, with more than 81% in favor of it in a 2015 survey (Goebel et al., 2015). This support cannot be chalked up to a lack of concern regarding climate change. Indeed, German citizens widely support the transition to renewables as part of the Energiewende program even though the costs of this transition were €26 billion in 2017 alone. German citizens are also highly aware of the costs associated with the transition to renewables, with charges for renewable subsidies now making up about a quarter of the electricity price paid by residential households.

This raises the question: what drives the global shift away from nuclear power despite the substantial economic and environmental costs associated with this policy? We discuss two potential mechanisms. First, the nuclear phase-out may be the result of rational decision-making by risk averse agents. Specifically, we compare the social costs of the phase-out against the *expected* benefits of this policy. However, nuclear accident risk imposes uncertainty on citizens and the costs associated with nuclear waste disposal are also arguably relatively uncertain. It is thus possible that a sufficiently risk-averse policymaker could phase-out nuclear to avoid the tail risks associated with nuclear accidents and waste disposal, even though the air pollution costs associated with the phase-out are higher in expectation.

To get a sense of the level of risk aversion required to justify the phase-out, we calculate the probability of a major nuclear accident that would result in the expected benefits from the phase-out being equal to the costs. For this back-of-the-envelope calculate, assume that, absent the phase-out, nuclear plants would have been shut down in the same order but by 2032 instead of 2022. This gives 2032-2011 = 21 years over which the phase-out would reduce nuclear production. Our estimated cost of the phase-out is $12 billion per year; this implies a cumulative cost of the phase-out of $250 billion over 2011-2032. The upper bound estimates of the cost of the Fukushima accident are roughly $750 billion (JECR, 2019). Assume for simplicity that there can either be no accidents or there can be one Fukushima magnitude accident during this 21 year window. The probability of this Fukushima-scale accident occurring would have to be $0.33 \approx \frac{\$250 \text{ billion}}{\$750 \text{ billion}}$ in order for the expected benefits of the phase-out to be equal to the costs of the phase-out. This is far greater than even the most conservative estimates of the probability of an accident of this magnitude occurring in Germany.[21] This in turn suggests that policymakers would have to exhibit an extremely high level of risk aversion in order to rationalize the phase-out based on risk aversion alone.

That being said, citizens may also be anti-nuclear because the risks associated with nuclear power are more salient than the air pollution costs associated with fossil-fuel-fired production. Specifically, the literature on the harmful effects of air pollution is becoming more definitive by the day. However, there is still relatively limited public understanding of the scale of the adverse health consequences of local air pollution exposure. This might be because it is difficult to attribute any single death entirely to pollution exposure from a single power plant. Instead, pollution concentration levels are the result of a wide range of different emitters and air pollution slightly but persistently increases the mortality risk of large exposed populations. Similarly, the costs of climate change will primarily be born by future generations, and linking a future climate event to the carbon emissions from a power plant smokestack is even less straightforward. In contrast, a nuclear accident is a highly visible, yet low probability, event that can be clearly linked back to the offending nuclear reactor. This may lead both policymakers and the public to over-estimate the ex-ante probability that nuclear accidents will occur as well as costs of these accidents (Slovic, Fischhoff and Lichtenstein (1979); Slovic (2010)).

Regardless of the underlying causes, it is clear that the German citizenry cares deeply about climate change yet is distinctly anti-nuclear. Policymakers around the world thus face a difficult trade-off. On the one hand, many climate change experts have argued that nuclear power is a necessary part of the shift away from carbon-intensive fossil fuels. Moreover, many voters are willing to incur substantial costs to reduce the risk of climate change. However, many of these same voters are also unwilling to support nuclear power due to fears surrounding nuclear accidents and nuclear waste disposal. Facing this political pressure, countries around the world are shifting away from nuclear production despite the substantial increases in operating costs and air pollution costs associated with this policy. This highlights that it is essential for policymakers and academics to convey the relative costs of climate change and air pollution versus nuclear accident risk and waste disposal to the voting public.

[21] For instance, Wheatley, Sovacool and Sornette (2017) estimates that there is a 50% chance that a Fukushima event (or larger) occurs every 60-150 years across the entire global fleet of nuclear reactors. Germany had less than 4% of the world's nuclear reactors in 2011. Moreover, nuclear reactors in Germany almost certainly come with less accident risk than other parts of the world.

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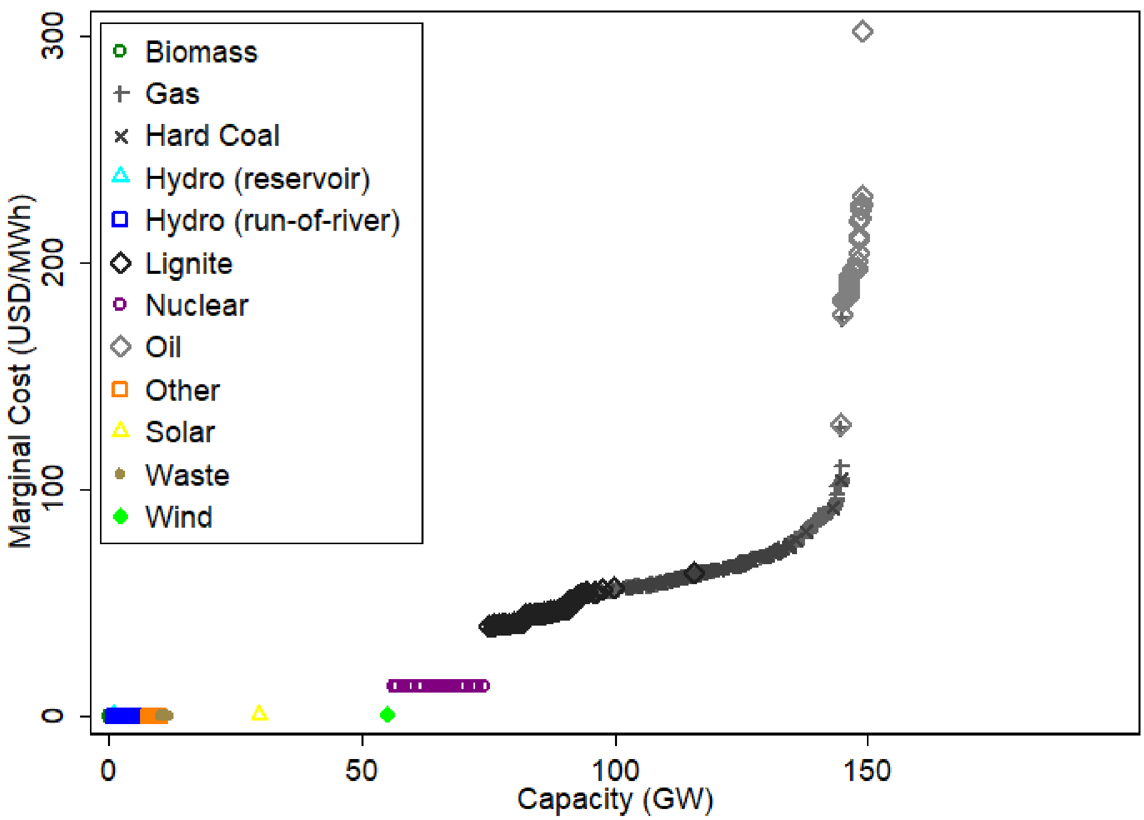
Figure 1: Marginal Cost Curve in 2011

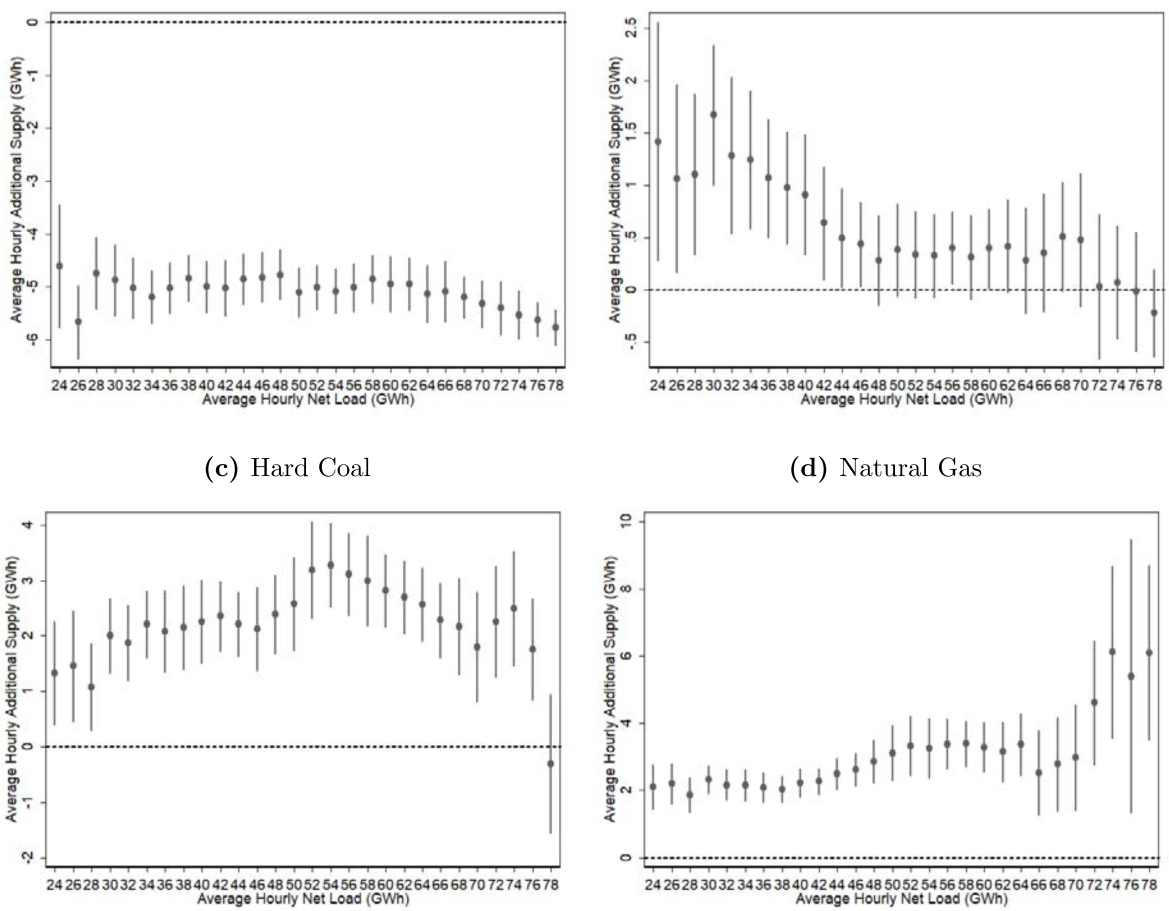


Notes: This figure plots estimated marginal costs for power plants in Germany in 2011. Specifically, plants are ordered in terms of marginal cost to create an aggregate supply curve. For a given marginal cost c (plotted on the y-axis), the x-axis provides the sum of the production capacity (in GW) over all plants with marginal cost less than or equal to c. Marginal costs are in 2017 U.S. dollars. For coal, gas and oil plants, marginal costs are calculated as the sum of fuel costs and an assumed variable operating and maintenance cost that differs by fuel type. Fuel costs are converted to dollars per MWh using the plant's thermal efficiency: how well the plant converts units of input heat to units of electricity output. For this figure, we consider the fuel costs on February 1st, 2011. Nuclear plants are assigned a marginal cost of \$10 per MWh as in Egerer (2016). Hydro, wind and solar have zero marginal costs. For simplicity, the small amount of remaining sources are also assigned a marginal cost of zero (i.e. biomass, waste and other). For ease of presentation, this figure does not show how electricity imports and exports factor into the aggregate supply curve; importantly, we account for imports and exports in our analysis.

Figure 2: Event-Study Estimates: Effect of the 2011 Nuclear Closures on Production

(a) Nuclear

(b) Lignite

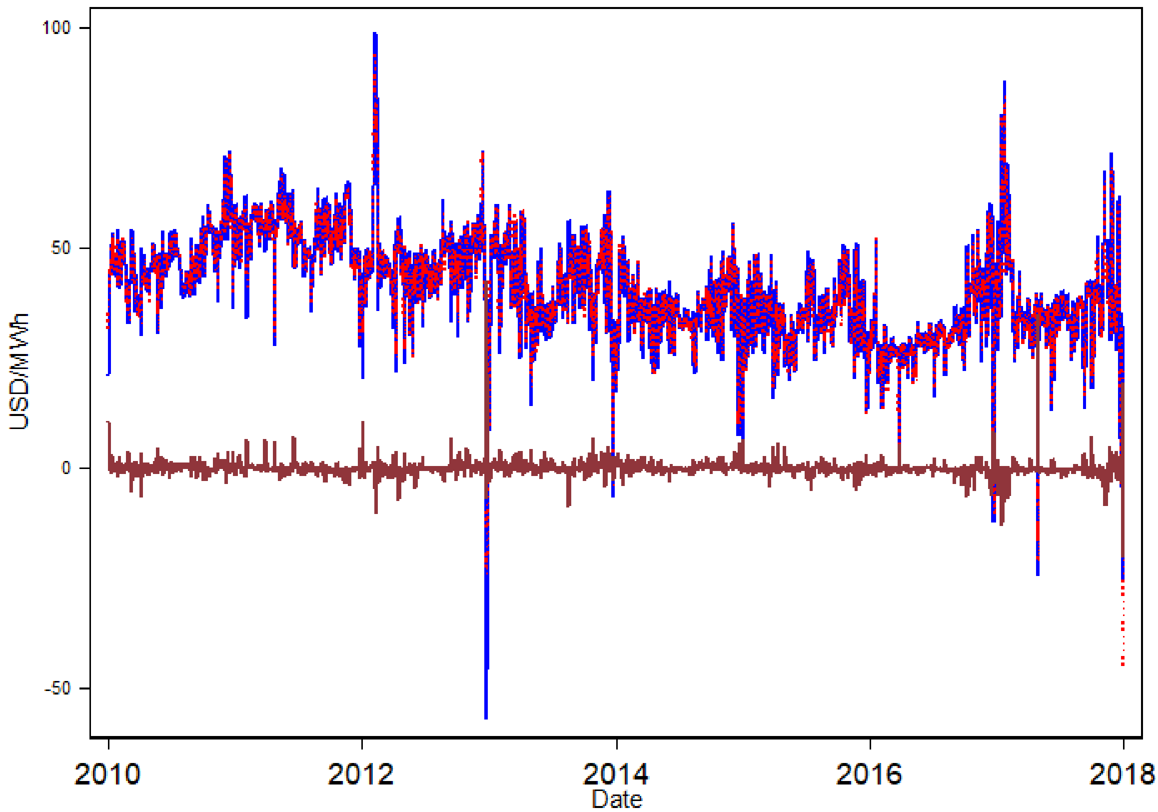


(c) Hard Coal

(d) Natural Gas

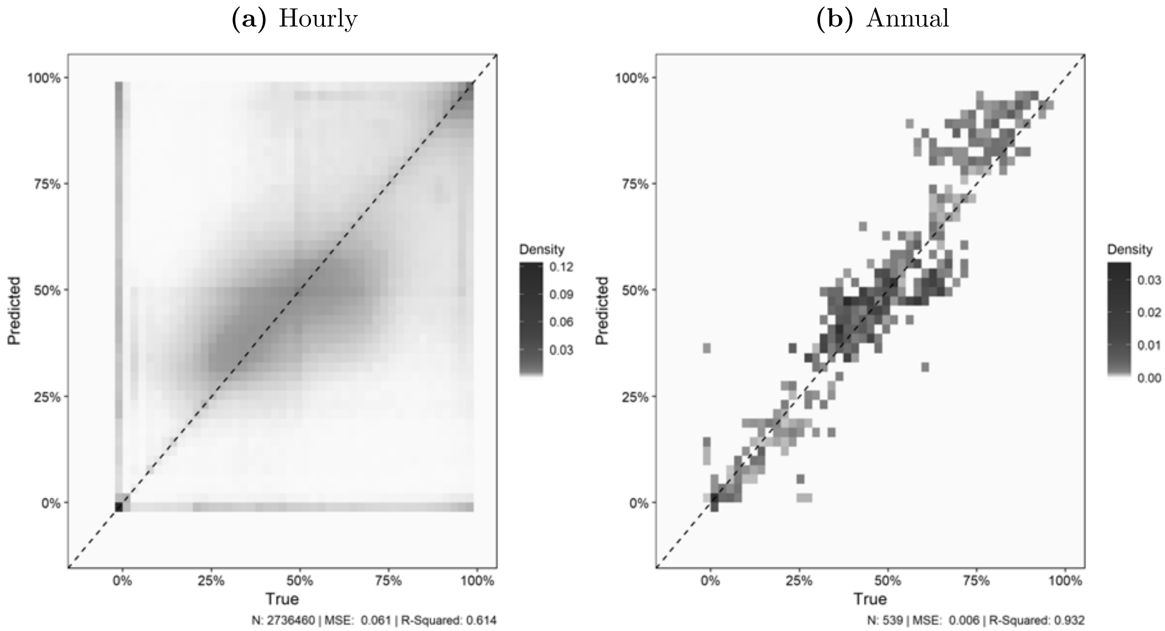
Notes: This figure plots the results from an event study analysis of the effects of the nuclear phase-out in Germany in 2011. The estimates correspond to changes in electricity production by source after relative to before March 15, 2011. Panel (a) presents the estimates for nuclear production, separately for each of 28 equally sized bins of net demand (i.e.: electricity demand minus production from renewables). Panels (b)-(d) present the corresponding estimates for production from lignite, hard coal, and natural gas respectively. The panels also include the point-wise 95% confidence interval around each of the estimated effects; the standard errors used to construct these confidence intervals are clustered by week-of-sample.

Figure 3: Machine Learning Model Performance: Wholesale Electricity Prices



Notes: This figure illustrates the accuracy of the aggregate predictions from the machine learning model presented in Section 5. The model predicts the wholesale electricity price in each hour-of-sample from 2010-2017. The figure depicts the observed wholesale electricity price (solid blue line), our model prediction (dotted red line) and the difference between these two (solid maroon line along the x-axis). Whilst the model predicts prices at the hourly level, the data in this figure have been averaged to a daily resolution for ease of presentation.

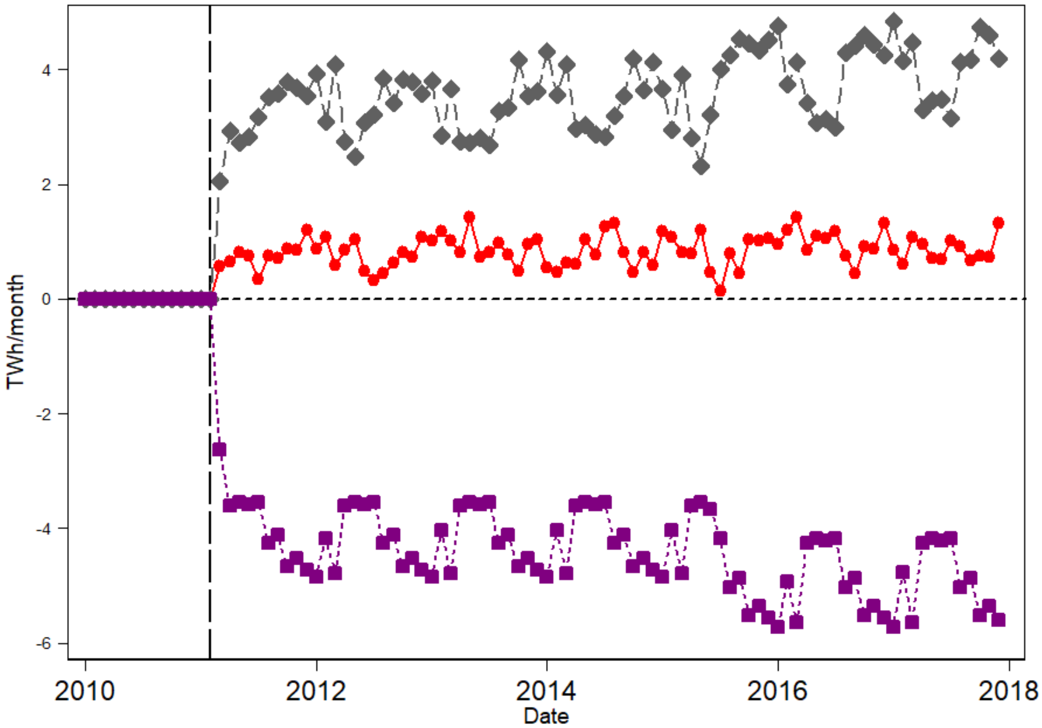
Figure 4: Machine Learning Model Performance: Plant-Level Electricity Production



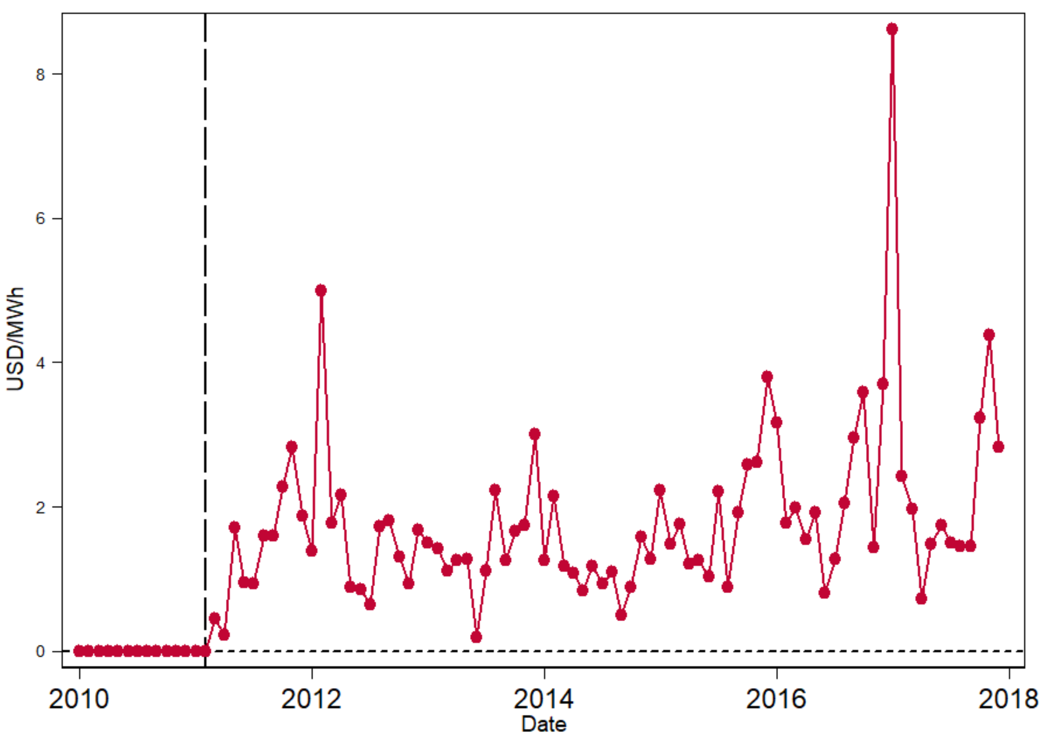
Notes: This figure illustrates the accuracy of the plant-level predictions from the machine learning model presented in Section 5. The model predicts the operating rate of each power plant in each hour, where a value of 0% means that a plant is offline and a value of 100% means that the plant is running at maximum capacity. Values on the 45 degree line indicate perfect accuracy, and we summarize this both visually and by computing measures of Mean Squared Error and R-Squared. We compute these metrics using out-of-sample cross-validation to avoid overfitting and give a fair assessment of how the model may perform when used to make predictions about our counterfactual scenario. We use five-fold cross-validation: we divide the 2015-2017 training dataset into five randomly generated subsets, or"folds". We then estimate our predictive model using four fifths of the data and check how this model performs in predicting outcomes for the remaining one fifth of the data. We repeat this for each of the five folds and then average the resulting measures of performance. Panel (a) shows prediction accuracy at an hourly timescale. Panel (b) shows prediction accuracy after taking annual averages of our hourly predictions. Darker areas indicate higher numbers of plant-hour (or plant-year) observations. Each pixel represents the predicted vs. actual operating rate in increments of 2%.

Figure 5: Impact of the Phase-Out on Electricity Production and Prices

(a) Electricity Production



(b) Wholesale Electricity Prices



Notes: This figure plots the monthly difference between the predictions from our machine learning algorithm with the phase-out minus without the phase-out. The start of the phase-out in March 2011 is marked by the vertical black dashed line. Panel (a) reports the estimates for all fossil-fuel-fired electricity production (grey diamonds), net imports (red circles), and nuclear production (purple squares). Panel (b) presents the change in wholesale electricity prices.

Table 1 Summary Statistics

	2010	2017
All Electricity Sector		
Total Capacity (GW)	172.4	217.6
Electricity Production (TWh)	551.4	591.2
Wholesale Electricity Price (USD/MWh)	70.68	41.81
Net Electricity Imports (TWh/Year)	-3.5	-33.5
By Source		
Nuclear Plants		
Number of Plants	16	7
Average Capacity (MW/Plant)	1,196.9	1,359.4
Annual Electricity Production (TWh)	134.7	70.5
Hard Coal Plants		
Number of Plants	109	87
Average Capacity (MW/Plant)	236.5	288.0
Annual Electricity Production (TWh)	93.9	83.5
Marginal Costs (USD/MWh)	64.9	41.8
Lignite Plants		
Number of Plants	74	61
Average Capacity (MW/Plant)	274.0	344.1
Annual Electricity Production (TWh)	130.9	137.9
Marginal Costs (USD/MWh)	54.2	28.9
Gas Plants		
Number of Plants	242	268
Average Capacity (MW/Plant)	96.9	98.6
Annual Electricity Production (TWh)	53.6	72.3
Marginal Costs (USD/MWh)	77.6	41.8
Oil Plants		
Number of Plants	53	50
Average Capacity (MW/Plant)	79.0	80.6
Annual Electricity Production (TWh)	1.9	3.8
Marginal Costs (USD/MWh)	197.5	125.8
Renewables (Hydro, Solar, and Wind)		
Total Capacity (GW)	52.1	112.5
Annual Electricity Production (TWh)	60.6	157.1

Notes: This table reports summary statistics for Germany's electricity generation sector in 2010 versus 2017. Electricity prices and marginal costs are in constant 2017 USD. While not reported in Table 1, we nuclear plants have a marginal operating cost of approximately $10/MWh (in 2017 USD) based on prior research on Germany's power sector (Egerer, 2016).

Table 2 Estimated Relationship Between Ambient Air Pollution and Electricity Production

	(1) Actual, 2015-17	(2) Predicted, 2015-17	(3) Predicted, 2010-17
PM_{10}	0.132***	0.140***	0.186***
	(0.013)	(0.009)	(0.014)
$PM_{2.5}$	0.152***	0.138***	0.169***
	(0.009)	(0.008)	(0.015)
SO_2	-0.005	-0.008	0.021
	(0.013)	(0.013)	(0.012)
CO	0.172***	0.152***	0.197***
	(0.019)	(0.019)	(0.024)
NO_2	0.167***	0.184***	0.251***
	(0.014)	(0.010)	(0.017)
Year and Month FEs	X	X	X
Plant FEs	X	X	X

Notes: This table reports coefficient estimates from a panel regression of daily air pollution concentrations on daily plant-level electricity production. Both the dependent variable and the independent variable are standardized to have a mean of 0 and a standard deviation of 1. The regressions include plant fixed effects, month-of-year fixed effects, and year-of-sample fixed effects and the standard errors are clustered at the plant level. ***,**, and * denote statistical significance at the 0.1%, 1%, and 5% levels respectively.

Table 3 Estimated Impact of the Nuclear Phase-Out on Wholesale Electricity Prices, Electricity Production by Source, and Net Imports

	Average with Phase-Out (1)	**Average w/out Phase-Out (2)**	**Change (3)**	**Change (%) (4)**
Production ($^{\text{TWh}}/_{\text{Year}}$)	574.4	574.2	0.2	0.0%
Nuclear	86.2	139.4	-53.2	-38.2%
Lignite	160.4	154.3	6.1	3.9%
Hard Coal	118.3	89.8	28.5	31.7%
Gas	39.8	31.6	8.3	26.2%
Oil	11.1	10.7	0.4	3.7%
Net Electricity Imports	-17.2	-27.4	10.2	37.1%
Renewables and Others	175.8	175.8	0.0	0.0%
Wholesale Prices ($^{\$}/_{\text{MWh}}$)	47.3	45.5	1.8	3.9%

Notes: This table reports annual average electricity production by type and wholesale electricity prices with versus without the nuclear phase-out, as estimated using our machine learning algorithm. These annual averages are calculated using data spanning from immediately after the phase-out in March 2011 to the end of 2017. In our baseline specification, the "renewables and others" production category experiences no change by construction. This is relaxed in one of our sensitivity analyses (see Section 6.4).

Table 4 Estimated Impact of the Nuclear Phase-Out on Revenues, Operating Costs, and Operating Profits

	Average with Phase-Out (1)	**Average w/out Phase-Out (2)**	**Change (3)**	**Change (%) (4)**
Revenues (Billion $/Year)	19.3	18.6	0.7	3.9%
Nuclear	4.1	6.4	-2.2	-35.0%
Lignite	7.6	7.1	0.6	8.0%
Hard Coal	5.8	4.3	1.5	34.4%
Gas	2.0	1.5	0.5	30.9%
Oil	0.5	0.5	0.0	7.0%
Net Electricity Imports	-0.7	-1.1	0.4	36.6%
Renewables and Others	–	–	0.0	0.0%
Costs (Billion $/Year)	14.2	12.6	1.6	12.7%
Nuclear	1.0	1.7	-0.6	-37.9%
Lignite	5.1	4.9	0.2	4.0%
Hard Coal	4.9	3.7	1.1	30.1%
Gas	2.3	1.9	0.4	23.2%
Oil	1.9	1.8	0.0	2.5%
Net Electricity Imports	-0.9	-1.4	0.4	31.4%
Renewables and Others	–	–	0.0	0.0%
Profits (Billion $/Year)	5.2	6.0	-0.9	-14.4%
Nuclear	3.1	4.7	-1.6	-33.9%
Lignite	2.6	2.2	0.4	17.0%
Hard Coal	0.9	0.5	0.3	63.6%
Gas	-0.3	-0.4	0.0	8.1%
Oil	-1.3	-1.3	0.0	-0.8%
Net Electricity Imports	0.2	0.2	0.0	-5.9%
Renewables and Others	–	–	0.0	0.0%

Notes: This table reports average annual operating revenues, costs and profits with versus without the nuclear phase-out, as estimated using our machine learning algorithm. All values are annualized averages based on predictions from after the nuclear shutdowns in March 2011 to the end of 2017. Operating revenues are the product of each plant's hourly production with the hourly wholesale electricity price. We ignore any additional revenues plants may receive, such as capacity payments, ancillary services payments, subsidies etc. Operating costs are the product of each plant's hourly production with its hourly marginal cost. Operating profits are operating revenues minus operating costs. Other sources such as renewables are excluded from this table as we avoid making explicit assumptions about their marginal costs or their revenues (e.g., additional non-market subsidies).

Table 5 Estimated Impact of the Nuclear Phase-Out on CO_2 Emissions and Local Air Pollution Mortality Damages

	Average with Phase-Out (1)	**Average w/out Phase-Out (2)**	**Change (3)**	**Change (%) (4)**
CO_2 Emissions (Mt/Year)	316.6	280.3	36.3	13.0%
Lignite	182.8	175.9	6.9	3.9%
Hard Coal	108.0	82.2	25.8	31.4%
Gas	17.0	13.6	3.3	24.5%
Oil	8.9	8.6	0.3	3.6%
SO_2 Emissions (Kt/Year)	151.7	135.8	15.9	11.7%
Lignite	94.7	91.4	3.2	3.5%
Hard Coal	49.5	37.2	12.3	33.0%
Gas	1.2	1.0	0.2	18.4%
Oil	6.3	6.2	0.2	2.5%
NO_x Emissions (Kt/Year)	213.4	189.7	23.7	12.5%
Lignite	121.5	116.8	4.7	4.0%
Hard Coal	69.0	52.5	16.5	31.5%
Gas	12.1	10.0	2.2	21.8%
Oil	10.7	10.4	0.3	2.9%
PM Emissions (Kt/Year)	5.5	4.9	0.6	12.2%
Lignite	3.3	3.2	0.1	3.9%
Hard Coal	2.0	1.5	0.5	30.3%
Gas	0.1	0.1	0.0	24.6%
Oil	0.2	0.1	0.0	3.3%
Mortality (Excess Deaths/Year)	8,549.7	7,407.2	1,142.4	15.4%
Lignite	4,142.9	3,988.1	154.9	3.9%
Hard Coal	3,776.2	2,870.9	905.3	31.5%
Gas	366.1	293.0	73.1	25.0%
Oil	264.4	255.3	9.2	3.6%
Pollution Damages ($bn/Year)	65.3	56.6	8.7	15.4%
Lignite	31.6	30.5	1.2	3.9%
Hard Coal	28.8	21.9	6.9	31.5%
Gas	2.8	2.2	0.6	25.0%
Oil	2.0	1.9	0.1	3.6%

Notes: This table reports estimates for emissions of CO_2 as well as three local pollutants: SO_2, NO_x, and PM. The final row presents estimates of the mortality damages from all three of these local air pollutants. All values are annualized averages based on predictions from immediately after the March 2011 to the end of 2017. Emissions are the product of each plant's hourly generation with our estimate of their emissions rate. Emissions rates are the product of (a) the amount of fuel required to produce one unit of electricity, and (b) the emissions intensity of the fuel. Emissions estimates are limited to fossil-fuel-fired plants in Germany. We ignore other potential sources of emissions in the electricity sector, such as emissions from smaller biomass, landfill gas or waste plants. We also focus on emissions and damages in Germany and so do not estimate changes in emissions in neighboring countries due to changes in net imports. For the pollution damages reported in the last row of the table, we present only the monetary costs associated with premature mortality due to air pollution exposure in order to ensure consistency with the complementary analysis using pollution monitor data.

Table 6 Impact of the Phase-Out on Local Air Pollution Mortality Damages

	Average with Phase-Out (1)	**Average w/out Phase-Out (2)**	**Change (3)**	**Change (%) (4)**
NO_2 Emissions ($^{ug}/_{m^3}$)	28.3	27.7	0.6	2.2%
Lignite	24.9	24.4	0.5	2.1%
Hard Coal	29.6	27.9	1.6	5.9%
Gas	29.3	29.2	0.1	0.3%
Oil	29.5	29.3	0.2	0.6%
PM_{10} Emissions ($^{ug}/_{m^3}$)	21.0	20.6	0.4	1.9%
Lignite	21.7	21.3	0.4	1.7%
Hard Coal	21.3	20.2	1.0	5.2%
Gas	20.7	20.6	0.1	0.3%
Oil	20.4	20.3	0.1	0.5%
$PM_{2.5}$ Emissions ($^{ug}/_{m^3}$)	14.1	13.8	0.3	2.2%
Lignite	15.1	14.8	0.3	2.3%
Hard Coal	13.6	12.8	0.8	5.9%
Gas	13.8	13.8	0.1	0.4%
Oil	13.9	13.8	0.1	0.6%
Mortality ($^{\text{Excess Deaths}}/_{\text{Year}}$)	–	–	493.0	–
Lignite	–	–	124.9	–
Hard Coal	–	–	315.7	–
Gas	–	–	20.2	–
Oil	–	–	32.3	–
Pollution Damages ($^{\$bn}/_{\text{Year}}$)	–	–	4.7	–
Lignite	–	–	1.2	–
Hard Coal	–	–	3.0	–
Gas	–	–	0.2	–
Oil	–	–	0.3	–

Notes: This table reports estimates of the monetary damages associated with the premature mortality resulting from the additional air pollution exposure as a consequence of the nuclear phase-out. The changes in daily concentrations of $PM_{2.5}$, PM_{10}, and NO_2 are obtained by panel regressions of air pollution at the monitor-level on daily, plant-level electricity production; these regressions include plant fixed effects, month-of-year fixed effects and year-of-sample fixed effects. The coefficients from these regressions give us an estimated relationship between electricity production and pollution concentration levels for each pollutant and each fuel type. We multiply the relevant estimated relationship by our predicted changes in production by each plant due to the phase-out. The resulting changes in air pollution concentrations are converted to a change in premature mortality using dose-response estimates from the ESCAPE project (Lancet 2014). We monetize this additional premature mortality using a value of statistical life of $7.9 million for Germany taken from Viscusi and Masterman (2017). We assume that only the population residing within 20 km of Germany's fossil power plants is exposed to the air pollution from these plants (approximately 7.5% of the total population). We do not report the absolute levels of mortality or damages, only the change due to the phase-out, because the baseline levels of pollution recorded at monitors are not attributable entirely to power plant activity; for example, industrial facilities, cars, and trucks also emit these pollutants.

Table 7 Overall Estimated Impact of the Nuclear Phase-Out on Total Costs

	Average with Phase-Out (1)	Average w/out Phase-Out (2)	Change (3)	Change (%) (4)
Total Costs ($^{\$bn}/_{\text{Year}}$)	97.4	85.2	12.2	14.3%
		Private Costs		
Operating Costs	14.2	12.6	1.6	12.7%
		External Costs		
CO_2 Climate Damages	15.8	14.0	1.8	13.0%
Mortality from Local Pollution				
Method 1: Reported Emissions	65.3	56.6	8.7	15.4%
Method 2: Pollution Monitors	–	–	4.7	–
Local Pollution Morbidity	1.9	1.6	0.2	14.1%
Nuclear Waste and Accidents	0.3	0.4	-0.2	-38.2%

Notes: This table reports the estimates of the different intensive margin costs incurred with versus without the phase-out. Private costs are the operating costs of the power plants in our analysis plus any changes in net imports (valued at the electricity price). We assume that the production costs of renewable and other sources are equal to zero when calculating these operating costs. External costs consist of climate damages from carbon emissions, mortality and morbidity costs from air pollution emissions, as well as the costs associated with nuclear accident risk and nuclear waste disposal. For the total costs row in bold, we use the estimates from the reported emissions method when adding in the external costs of local pollution on mortality.

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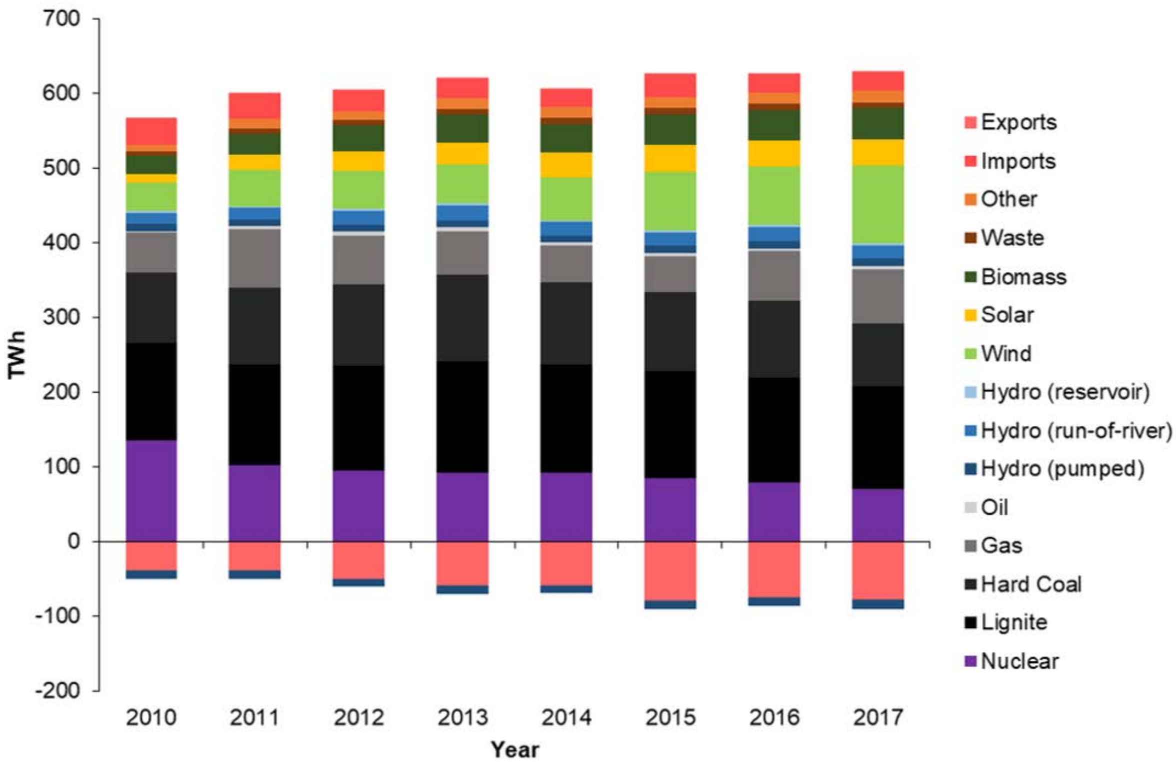
Appendices

A Appendix Tables and Figures

Appendix Figure A.1 presents annual total electricity production in Germany by source as well as total imports and exports. This figure documents the precipitous drop in nuclear production following the 2011 closure of nine reactors as well as the rapid growth in production from wind and solar resources over our 2010-2017 sample period.

[Figure A.1 about here.]

Figure A.1: Electricity Production by Source: 2010-2017



Notes: This figure plots the annual total quantity of electricity produced by different types of sources in Germany from 2010-2017. We also plot the annual total quantity of electricity imports and exports for this same sample period. The data underlying this figure are from BNetzA Monitoring Reports.

B Further Detail on the Predictive Dispatch Model

Studies of the electricity sector traditionally utilize some form of electricity dispatch model that combines engineering and economic modeling tools to simulate the operation of the power grid. These models must explicitly specify firm incentives (ex: whether/how firms exercise market power) as well as operational constraints such as transmission congestion and plants' start-up/ramping costs.

We opt to employ an empirical approach instead. Specifically, our approach seeks to recover how plants are dispatched based on a host of different variables pertaining to plant operations, demand, and electricity transmission. The primary benefit of this empirical approach is that it requires fewer assumptions regarding firm incentives or operational constraints. We allow the data to tell us how these factors impact plant operations.

That being said, this empirical approach has limitations as well. First, we can only examine scenarios that are sufficiently similar to observed outcomes. This is why other empirical models of wholesale electricity markets tend to focus either on ex-post policy assessments or identifying how marginal changes in electricity demand impact plant operations. Indeed, our paper focuses on an ex-post evaluation of the nuclear phase-out in Germany on aggregate market outcomes.

We want to highlight that empirical approaches such as our typically do not offer robust insights for a given plant in a given hour. As such, our empirical modeling should be seen as a complement rather than a substitute for more explicit simulation modeling of electricity markets. This is particularly true when the behavior of individuals plants or short-term physical constraints are of interest rather than aggregate market outcomes.

Our paper utilizes a Random Forest algorithm. This algorithm has a number of useful properties. First, the relationships between our predictors and aggregate market outcomes are likely to be highly non-linear, including many complex interactions. Random Forests are well-suited to letting the data inform where these complex interactions lie rather than having to make strong ex-ante assumptions (e.g. no need to pre-specify polynomials, splines and interactions within a linear regression framework). Second, the structure of the Random Forest regression algorithm means that the support of possible outcome predictions is bounded by the support of the outcome values in the training data-set. This means that the predictions from our model will have a natural bounding of 0-1, thus avoiding the risk of making erroneous predictions (e.g. operating rates above 100% or below 0%).

Third, using Quantile Regression Forests allows us to make predictions regarding the full conditional distribution of our outcomes rather than just the conditional expectation of these outcomes. This is important because there is clearly uncertainty about whether a given plant will operate in a given hour conditional on the covariates for that plant-hour. However, being able to characterize the distribution of potential outcomes means we can (a) examine the uncertainty in our results, and (b) adjust our final estimation to calculate the most likely changes to in plant-level production that still meet physical requirements (i.e. that demand equals supply). For example, though our primary specifications report the conditional averages of predicted outcomes, we find that both the mean and median of the potential predictions produced by our model perform reasonably well (see Figure 4).

Our Random Forest model is estimated using a training dataset of roughly 4.5 million observations. The most important independent variables for our analysis are:

- **Net Load**. Net load is defined as total electricity demand minus production from low marginal cost or non-dispatchable sources. Specifically, we subtract production from renewables (wind, solar, hydro, biomass, waste) and nuclear. This net load variable thus measures the amount of production required by "flexible" (typically fossil-fuel fired) sources.[22]

- **Marginal Cost**. A plant decides whether to produce primarily based on whether its marginal cost is less than the electricity price it will be paid for its output. In electricity markets such as Germany's, the electricity price is typically set by the highest marginal cost plant necessary to meet demand (i.e. the clearing plant that is on the margin). Consequently, we first construct estimates of each plant's marginal cost over time. We then estimate the marginal cost of the clearing plant: the last fossil plant (or border point) necessary to meet net load in a given hour. Finally, we construct a "standardized" marginal cost for each plant as the plant's marginal cost minus the marginal cost of the clearing plant for that hour. Plants

[22]We also include lags and leads of net load to capture the fact that many power plants have dynamic production constraints (e.g. the speed at which they can "ramp up" their output, or the minimum amount of time they have to be offline before they can restart).

typically produce (don't produce) if this standardized marginal cost is negative (positive).

- **Available Capacity**. Where the "marginal cost" variable captures the position of a plant in the supply curve in terms of price, the "available capacity" variable captures the position of a plant in the supply curve in terms of quantity. For each plant, we calculate the total amount of capacity from other fossil plants (or border points) with a lower marginal cost. Our "available capacity" variable is then calculated as the total amount of capacity with a lower marginal cost than the plant minus net load for that hour. Once again, plants with negative available capacity are likely to produce, while plants with positive available capacity are unlikely to produce.

Figure B.1a illustrates the relative importance of each of our covariates. As expected, net demand, marginal cost and available capacity are all particularly important covariates. However, it is noteworthy that the two most important covariates are the type of source (i.e. lignite, hard coal, gas, oil or border point) and whether a fossil-fuel-fired plant is combined-heat-and-power. This reflects the fact that different types of electricity generators face different operational constraints. For example, many natural gas plants in Germany are combined-heat-and-power. As such, whilst they may have higher marginal costs than coal plants, they receive revenues both for their electricity output and from providing heating services. Consequently, combined-heat-and-power plants operate more frequently than would be suggested by simply comparing their marginal cost to electricity prices.

[Figure B.1 about here.]

The machine learning application we use is designed to predict how dispatchable flexible sources such as fossil-fuel plants and border flows increase or decrease their output in order to meet the residual demand left after accounting for output from renewables and nuclear sources. Net load, the relative marginal cost of each plant, and the amount of alternative available capacity are key predictors in the analysis not only because they play a significant role in explaining plant operating decisions, but also because they are the variables we modify in order to construct the counterfactual scenario. For the scenario with the phase-out, the net load variable is the observed net load given the phase-out decision as shown in Figure B.2a. For the counterfactual scenario without the phase-out, nuclear production would have been higher and so net load would have been lower, as shown in Figure B.2b. This reduction in net load also changes the marginal cost and available capacity variables. Specifically, if net load is lower, the marginal cost of the clearing plant would also be lower. Moreover, the amount of capacity below net load is also lower for lower values of net load. This is illustrated in Figures B.2c and B.2d.

[Figure B.2 about here.]

When making out-of-sample predictions using a predictive model such as this, it is important to ensure that the training data-set provides sufficient support across the predictor variables. This is because our algorithm is ill-suited to extrapolate beyond the economic conditions seen in the training data. We are confident that assessing the impacts of nuclear phase-out is an interpolation exercise rather than extrapolation exercise in part because the portfolio of fossil-fuel power plants and the underlying transmission grid does not change very much over our 2010-2017 sample period.

Rescaling certain variables can also help to ensure that our out-of-sample prediction is not extrapolating too far outside the support of the training data.[23] The three main variables we use to approximate the interaction between supply and demand are net load, plant marginal costs, and the amount of available capacity. Almost by definition, the counterfactual no-phase-out scenario will contain some periods where these variables fall outside the range in the training dataset. Even so, there is such wide variation in electricity demand, production from renewables and marginal costs that the overlap in support between these variables in the factual versus counterfactual scenarios is very good. This can be seen in Figures B.1b, B.1c and B.1d.

Figure B.3 shows the median model predictions for how the nuclear phase-out impacted aggregate plant-level electricity production in Germany. As expected, points on this figure tend to lie above the horizontal axis; the nuclear phase-out reduced nuclear generation, with fossil-fuel-fired production filling the gap. The largest response to the phase-out comes from the hard coal plants.

[23]For example, we rescale the marginal costs of each plant by the marginal cost of the last plant needed to clear the market. Even if fuel costs doubled from 2010-20177, for example, the rescaling would ensure that the rescaled marginal costs fed into our algorithm stay within a reasonable range over our sample period.

[Figure B.3 about here.]

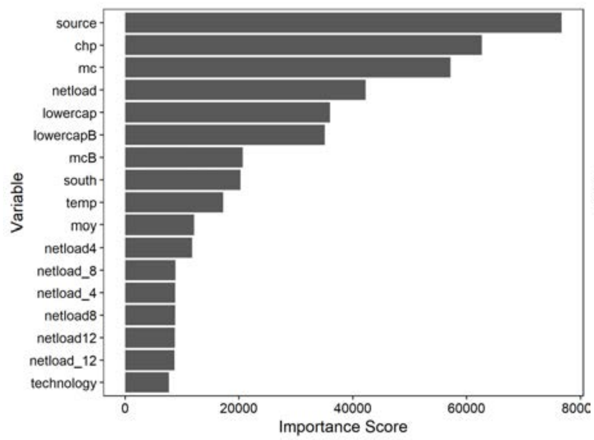
Using the median predictions displayed in Figure B.3 we find around 40 TWh per year of additional supply from higher fossil-fuel plants and net imports. However, it is important to note that there is no constraint in our estimation process that the total amount of estimated replacement production should match the lost nuclear output. In fact, the amount of lost nuclear production is around 50 TWh per year and so using the median predictions actually leads us to under-estimate the level of replacement generation. To remedy this, we utilize the information our quantile regression model provides us on the full conditional distribution of potential changes to output. Specifically, we generate predictions for the 10th, 25th, 50th, 75th and 90th percentiles of each of our outcomes. We then find the combination of these percentiles that fully replaces the lost nuclear generation with the most likely set of plant-level changes (i.e. closest to the median). Put another way, we find the percentiles closest to the median that produce a change in annual total generation equal to the annual lost nuclear output. Ensuring that additional supply exactly meets lost nuclear output only requires moving a few percentiles from the median.

Finally, Figure B.4 illustrates which plants and border points increased production to meet the reductions in nuclear output due to the phase-out. Most of the fossil-fuel generation comes from the industrial regions in the west and south of the country. Changes to net imports come primarily at the borders with Denmark, France and the Czech Republic.

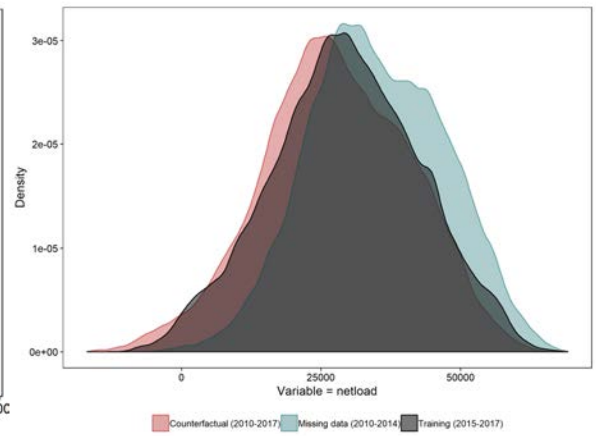
[Figure B.4 about here.]

Figure B.1: Machine Learning Model Diagnostics

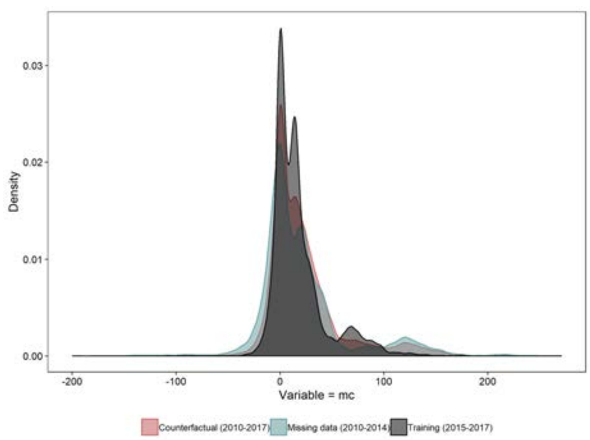
(a) Variable importance scores



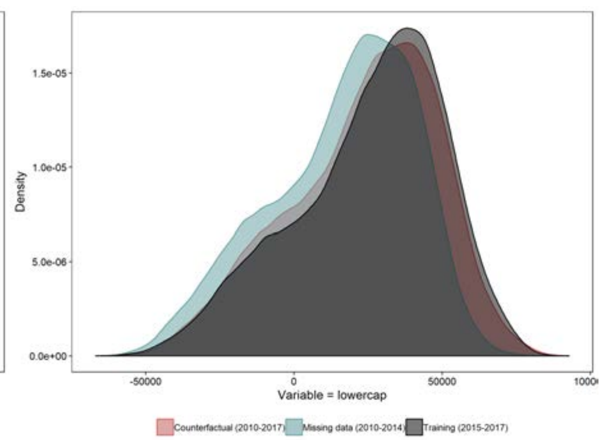
(b) Support of Net Demand



(c) Support of Marginal Cost



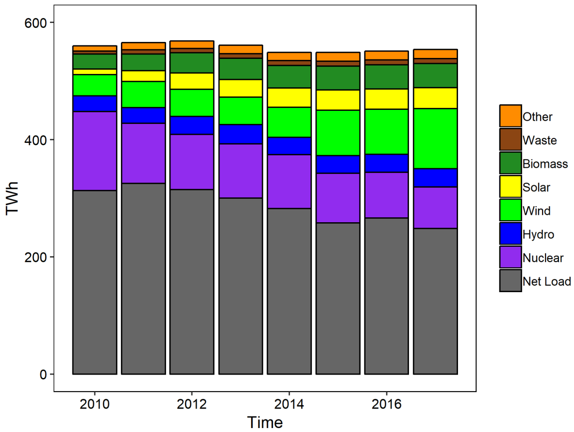
(d) Support of Available Capacity



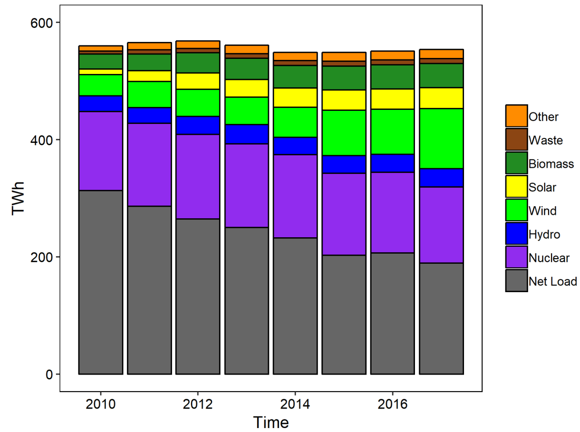
Notes: This figure illustrates a range of key model diagnostics related to the machine learning estimation. Panel (a) shows the importance scores for each of the variables included in the estimation. Importance scores indicate the relative importance of each variable in predicting the outcome of interest. The abbreviated names in the figure are as follows: source = source type (e.g. lignite, hard coal, gas, oil or border); mc = marginal cost relative to the clearing unit; mcB = marginal cost relative to the clearing unit including border capacity; lowercap = amount of capacity with a lower marginal cost; lowercapB = amount of capacity with a lower marginal cost including border capacity; chp = presence and scale of combined-heat-and-power capability; technology = technology type (e.g. steam turbine, combined cycle turbine or transfer); temp = local temperature; south = indicator for whether the plant or border point is located in the south of the country; moy = month-of-year; dow = day-of-week; hod = hour-of-day; netload = electricity load minus production from wind, solar, hydro and nuclear sources; netloadX = difference between current net load and net load X hours ago; netload_X = difference between current net load and net load X hours ahead. Panels (b-d) show the support of three key variables: net demand, standardized marginal cost and available capacity. The grey area shows the distribution of observations in the 2015-2017 training data-set (i.e.: where we have hourly, plant-level production data). The blue area shows the distribution of observations in the missing 2010-2015 data (i.e.: where we only have hourly data on production by fuel type). The red area shows the distribution of observations in the counterfactual scenario (i.e.: without the nuclear phase-out) across the full 2010-2017 analysis period.

Figure B.2: Net Demand and Scenario Implementation

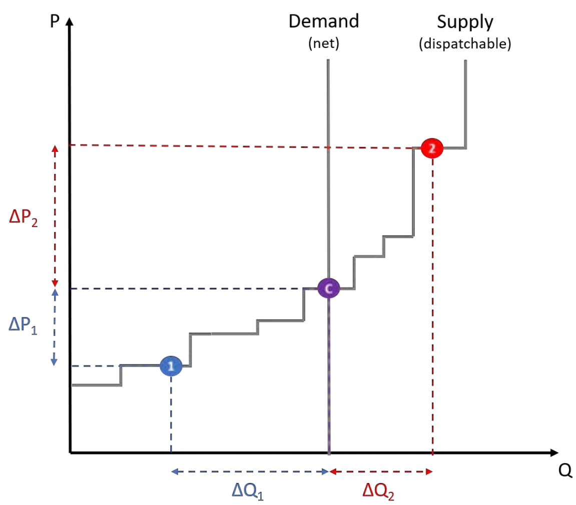
(a) Estimated Net Demand (With Phase-Out)



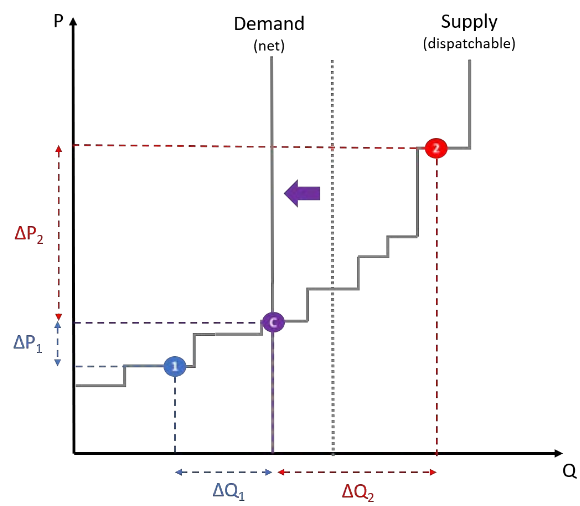
(b) Estimated Net Demand (Without Phase-Out)



(c) Net Demand Illustration (With Phase-Out)

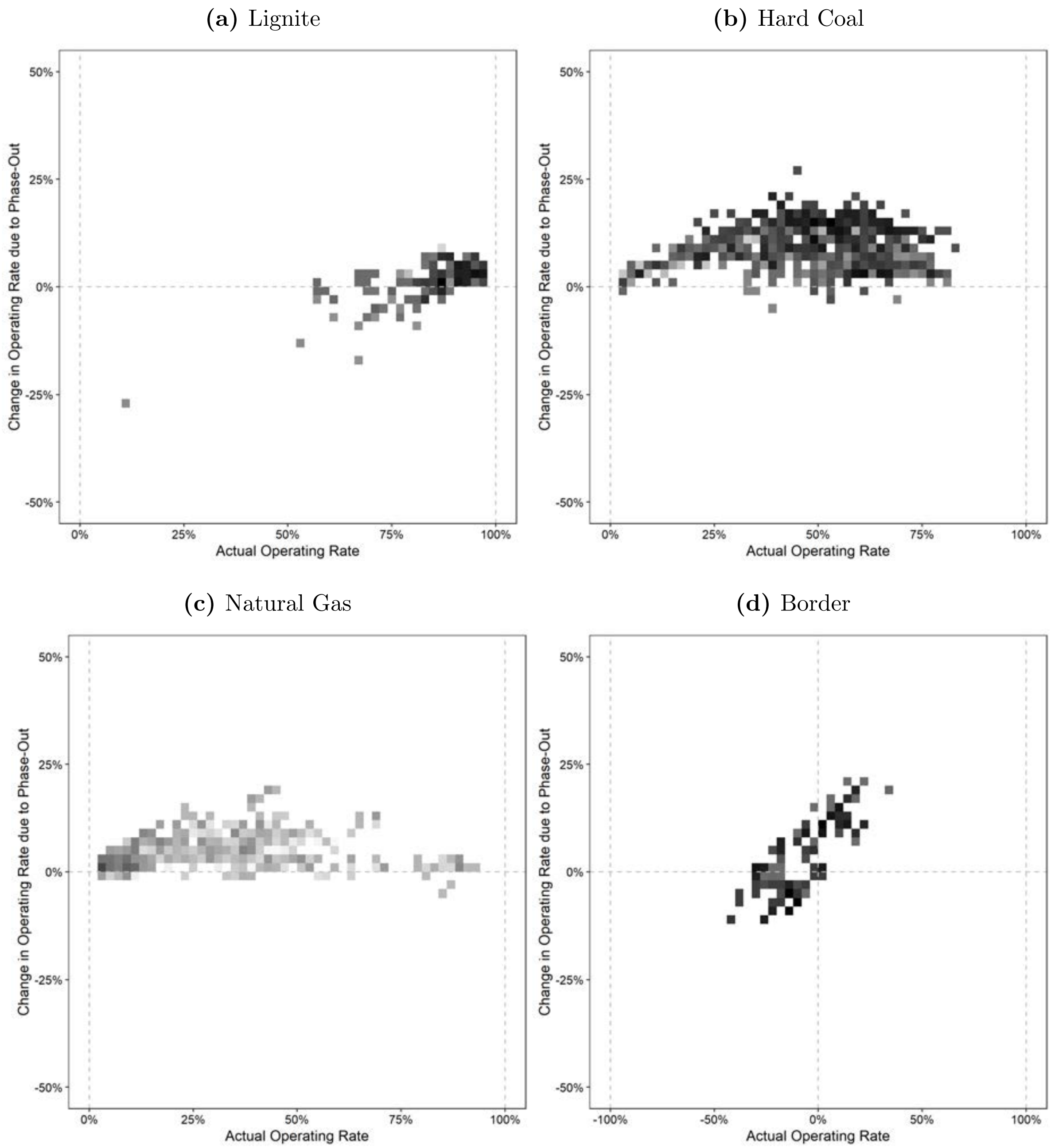


(d) Net Demand Illustration (Without Phase-Out)



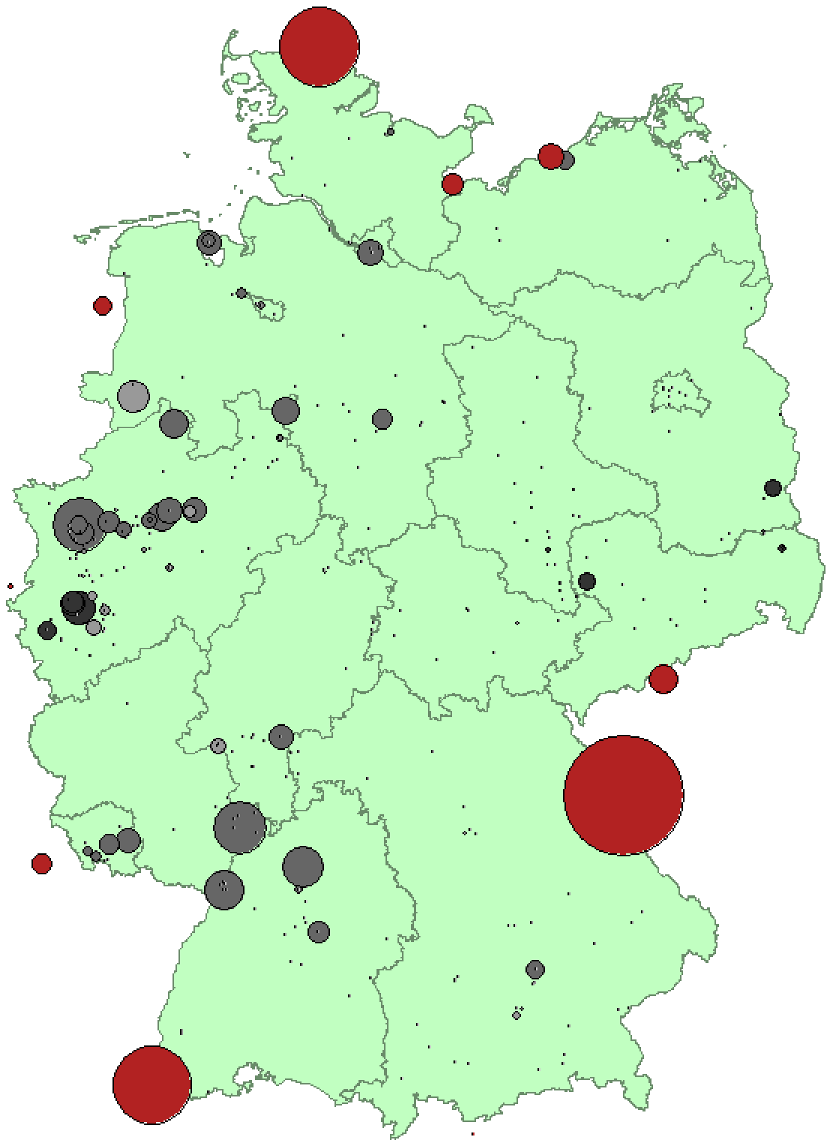
Notes: This figure illustrates the role of the net electricity demand variable in the analysis. Net demand is defined as total electricity demand minus production from low marginal cost or non-dispatchable sources. Specifically, we subtract production from renewables (wind, solar, hydro, biomass, waste) and nuclear. Panels (a) and (b) show the level of net demand both with and without the phase-out respectively. Note that production from renewables is growing over time, which results in less net demand to be satisfied by flexible sources such as fossil-fuel fired plants. Comparing panel (a) to panel (b) shows that more nuclear production without the nuclear phase-out leads to less net demand to be satisfied in this scenario. Panels (c) and (d) provide an illustration of how changing net demand impacts the estimation process. This happens because altering net demand alters the position where net demand intersects with the supply curve of dispatchable capacity. This intersection point is indicated by the clearing fossil-fuel plant (or border point) that is "on-the-margin" (purple). Altering the clearing fossil plant (or border point) affects the relative marginal cost (ΔP) and available capacity (ΔQ) values for all dispatchable supply. These two variables are illustrated for a high marginal cost plant (red) and a low marginal cost plant (blue).

Figure B.3: Plant-level Changes in Production due to the Phase-Out



Notes: This figure illustrates the plant-level disaggregation of the machine learning prediction model results. The model predicts the operating rate of each power plant in each hour, where a value of 0% means the plant is offline and a value of 100% means it is running at maximum capacity. These figures plot plant-level annual average operating rates. The x-axis corresponds to each plant's operating rate in the baseline scenario with the phase-out. The y-axis corresponds to the impact of the phase-out on plant-level operations. This is determined by the difference between the predictions in the scenario with the phase-out versus the scenario without the phase-out. Darker areas indicate higher numbers of plant-year observations. Each panel refers to a different type of dispatchable electricity source. Panel (a) covers lignite plants, panel (b) covers hard coal plants, panel (c) covers gas plants and panel (d) covers border points. Oil plants are not shown because they are a very small portion of total capacity and are largely invariant to the phase-out.

Figure B.4: Map of Plant-Level Changes in Production due to the Phase-Out



Notes: This map illustrates the location of the fossil-fuel-fired plants or border points that increased their electricity production as a result of the nuclear phase-out policy. The size of the circle reflects the amount of additional production provided by the fossil-fuel plant or border point. Points in red are border points and points in grey are fossil-fuel plants. Lignite plants are depicted in the darkest grey, followed by hard coal, then natural gas, and finally oil plants are depicted in the lightest grey.

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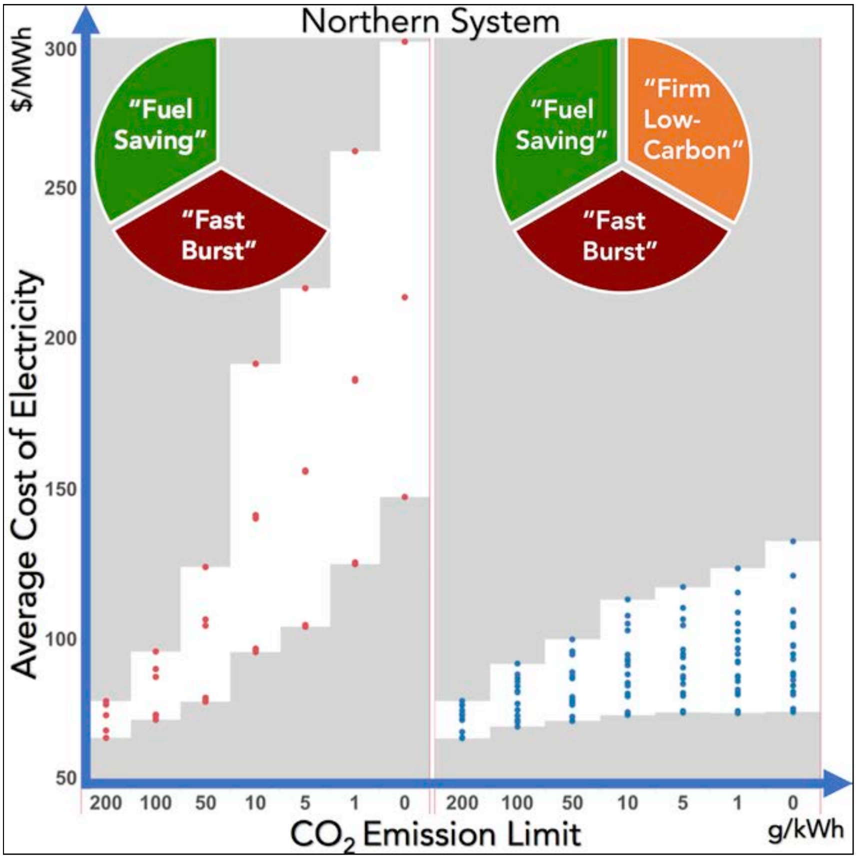
The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation



Full decarbonization of the electricity sector is critical to global climate mitigation. Across a wide range of sensitivities, firm low-carbon resources—including nuclear power, bioenergy, and natural gas plants that capture CO_2—consistently lower the cost of decarbonizing electricity generation. Without these resources, costs rise rapidly as CO_2 limits approach zero. Batteries and demand flexibility do not obviate the value of firm resources. Improving the capabilities and spurring adoption of firm low-carbon technologies are key research and policy goals.

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HIGHLIGHTS

Firm low-carbon resources consistently lower decarbonized electricity system costs

Availability of firm low-carbon resources reduces costs 10%–62% in zero-CO_2 cases

Without these resources, electricity costs rise rapidly as CO_2 limits near zero

Batteries and demand flexibility do not substitute for firm low-carbon resources

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The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation

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SUMMARY

We investigate the role of firm low-carbon resources in decarbonizing power generation in combination with variable renewable resources, battery energy storage, demand flexibility, and long-distance transmission. We evaluate nearly 1,000 cases covering varying CO_2 limits, technological uncertainties, and geographic differences in demand and renewable resource potential. Availability of firm low-carbon technologies, including nuclear, natural gas with carbon capture and sequestration, and bioenergy, reduces electricity costs by 10%–62% across fully decarbonized cases. Below 50 gCO_2/kWh, these resources lower costs in the vast majority of cases. Additionally, as emissions limits decrease, installed capacity of several resources changes non-monotonically. This underscores the need to evaluate near-term policy and investment decisions based on contributions to long-term decarbonization rather than interim goals. Installed capacity for all resources is also strongly affected by uncertain technology parameters. This emphasizes the importance of a broad research portfolio and flexible policy support that expands rather than constrains future options.

Context & Scale

Mitigating climate change while fueling economic growth requires decarbonizing the electricity sector at reasonable cost. Some strategies focus on wind and solar energy, supported by energy storage and demand flexibility. Others also harness "firm" low-carbon resources such as nuclear, reservoir hydro, geothermal, bioenergy, and fossil plants capturing CO_2. This paper presents a comprehensive techno-economic evaluation of two pathways: one reliant on wind, solar, and batteries, and another also including firm low-carbon options (nuclear, bioenergy, and natural gas with carbon capture and sequestration). Across all cases, the least-cost strategy to decarbonize electricity includes one or more firm low-carbon resources. Without these resources, electricity costs rise rapidly as CO_2 limits approach zero. Batteries and demand flexibility do not substitute for firm resources. Improving the capabilities and spurring adoption of firm low-carbon technologies are key research and policy goals.

INTRODUCTION

Full decarbonization of the electric power sector will be pivotal to global climate mitigation efforts. The Paris Climate Agreement of 2015—ratified by 176 countries to date—declares the need to hold increases in global average temperatures to "well below" 2°C and to achieve a net balance of anthropogenic sources and sinks of greenhouse gases by the second half of this century.[1,2] To reach these goals, recent studies have concluded that CO_2 emissions from electricity generation must fall nearly to zero[3–5] or even below zero[6–8] by mid-century, even as electricity generation expands to supply a greater share of transportation, heating, and industrial energy use.[3,9–11]

Despite general agreement on the need for deep decarbonization of the electric power sector, views differ as to the relative importance of various low-carbon electricity resources in near-zero-emissions power systems.

Technological developments have enlarged the array of low-carbon electricity generation resources to include solar, wind, hydro, biomass, nuclear, geothermal, and fossil energy with carbon capture and sequestration (CCS). Technologies for energy storage and for managing electricity demand are also available. The economic and operational characteristics of these resources vary, as does their ability to contribute to meeting electricity demand reliably. As a result of this diversity, power systems are likely to benefit from harnessing a blend of resources, with the various resource types playing complementary roles and adding distinct value to the overall mix of energy services.

Electricity generation technologies have traditionally been classified based on their relative variable costs and the resulting frequency with which they are called upon to meet electricity demand or "load"; e.g., "baseload," "load-following," and "peaking" resources. This classification is no longer meaningful in power systems with substantial penetration of wind and solar energy, since dispatch of each technology is also driven by the irregular variability of these renewable resources. Moreover, most available low-carbon technologies are capital intensive and have very low variable costs. In this context, the distinguishing attributes of electricity technologies relate more to their resource availability and ability to adapt production output in order to meet instantaneous demand. We therefore propose a new taxonomy that divides low-carbon electricity technologies into three different sub-categories (see Figure S1):

1. "Fuel-saving" variable renewable energy (VRE) resources. These include wind power, solar photovoltaics (PV), concentrating solar power, and run-of-river hydropower. They harness renewable energy inputs (wind, solar insolation, water) that vary on timescales ranging from seconds to hours to seasons, have zero (or near-zero) variable costs, and have no fuel costs. At lower penetration levels, they may displace the need for firm capacity, but, at higher shares, capacity needs are driven by periods with low VRE availability. At high energy shares, these technologies therefore contribute value primarily by displacing other higher variable cost generating technologies whenever available and reducing the total fuel consumption and variable costs of the system.
2. "Fast-burst" balancing resources. These include short-duration energy storage (e.g., Li-ion batteries), flexible demand (or schedulable loads), and demand response (or price-responsive demand curtailment). They are either energy constrained (storage, demand flexibility) or have very high variable cost (demand curtailment). These technologies are therefore poorly suited to operating continuously over long periods of time and are better used during high-value periods when relatively fast bursts of power or quick demand adjustments are needed to balance supply and demand.
3. "Firm" low-carbon resources. These are technologies that can be counted on to meet demand when needed in all seasons and over long durations (e.g., weeks or longer) and include nuclear power plants capable of flexible operations,[12–15] hydro plants with high-capacity reservoirs, coal and natural gas plants with CCS and capable of flexible operations,[16,17] geothermal power, and biomass- and biogas-fueled power plants.[7]

In light of recent cost improvements and the rapid expansion of wind power and solar photovoltaics, many recent papers have explored opportunities and challenges associated with achieving very high shares of these VRE resources in power systems.[18–33] Much of this work has focused on how to provide the enhanced operational flexibility on various time scales (from seconds to seasons) needed to balance variable output from high shares of wind and solar energy,[21–23,28] including the potential role of energy storage,[24,29,34,35] demand-side flexibility,[20] and long-distance transmission expansion to smooth variability of renewable output across wider geographic areas.[20,27,31]

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Some of this work has excluded firm low-carbon resources *ex ante*, in part because of the societal challenges or current costs associated with some of these resources. Other research[17,23,34–36] has found that harnessing firm low-carbon resources capable of responding to variations in both demand and renewable energy output can lower the cost of low-carbon power systems by reducing the amount of needed generating and storage capacity, improving asset utilization, and avoiding substantial curtailment of renewable energy output. These studies have typically focused on the role of a specific resource (e.g., energy storage[34,35] or CCS[17]) and have explored a relatively narrow range of possible uncertainties.[23]

Global deployment of nuclear and CCS is lagging well behind the pace envisioned by scenarios to limit global warming to 2°C in the 2014 Intergovernmental Panel on Climate Change assessment report.[37] Both technologies face a range of challenges to greater adoption, including high construction costs and financial risks, technology immaturity (in the case of CCS and next-generation nuclear designs), and risk (both real and perceived). Use of biomass for energy is currently on pace with global 2°C scenarios,[37] but large-scale reliance on bioenergy for power generation competes with other land uses, including food and environmental conservation, as well as other uses for bioenergy in transportation, heat, and industrial sectors. Other firm low-carbon resources are constrained to specific favorable geographies (conventional geothermal, reservoir hydropower), entail significant environmental impacts (reservoir hydro), or remain pre-commercial (enhanced geothermal energy systems). Overcoming challenges to large-scale use of these firm low-carbon resources may prove difficult. Whether it makes sense to take on this task depends partly on the benefits associated with having one or more viable firm low-carbon resources available to contribute to power sector decarbonization.

In this paper we provide a more comprehensive evaluation of the economic and operational benefits of firm low-carbon technologies in achieving deep decarbonization targets, with a focus on nuclear, natural gas with CCS, biogas, and biomass. The analysis examines the interactions between these firm low-carbon resources; fuel-saving variable renewable resources; and fast-burst resources, including short-duration battery energy storage and demand-side flexibility. It also investigates the impact of long-distance transmission interconnections.

We use an advanced electric power system investment and operations model[38] to compare, under several increasingly ambitious decarbonization targets, the economic performance of two kinds of power systems: those that include firm low-carbon technologies among the available resources, and those that exclude these firm resources *ex ante*. Operational details captured by the model include a full year of hourly chronological variability in both renewable energy output and electricity demand and detailed power system operating constraints such as integer power plant start-up and shut-down costs, minimum stable output limits for thermal power plants, and limits on hourly changes in power plant output. Commonly used but simpler models can result in significant errors due to abstraction of relevant power system details and the failure to account for the full variability of renewable resources and inter-temporal constraints on energy storage and thermal power plants.[26,39–42]

A large number of scenarios are analyzed. First, we account for geographic differences in renewable resource potential and patterns of demand using data from two dissimilar US regions: a "northern" system with the demand profile and relatively modest renewable resource potential typical of New England (peak demand of

Table 1. Technological Assumptions

Technology	Conservative	Mid-range	Very Low
Solar ($/kW-AC)	1,800[a]	900[b]	670[c]
Wind ($/kW)	1,455[d]	1,091[e]	927[f]
4-hr Li-ion battery ($/kWh)	440[g]	220[h]	110[i]
6-hr Li-ion battery ($/kWh)	420[j]	210[j]	105[i]
Natural gas CCGT with CCS ($/kW) ($CO_2$ capture rate)	NA	1,720 (90%)[k]	1,050 (100%)[l]
Nuclear ($/kW) (size)	7,000 (1,000 MW)[m]	4,700 (1,000 MW)[n]	4,200 (300 MW)[o]
Biomass ($/kW) (maximum energy share) ($/MMBTU)	3,800 (5%) (3)[p]	3,800 (5%) (3)[p]	3,400 (35%) (7)[q]
Biogas ($/kW) (maximum energy share) ($/MMBTU)	NA	890 (2%) (7.5)[r]	790 (10%) (15)[r]

CCGT, combined-cycle gas turbine; NA, not available.
[a]From NREL[43] 2017 "Utility PV - Low."
[b]50% cost reduction from conservative.
[c]From NREL[43] 2047 "Utility PV - Low."
[d]From NREL[43] 2017 "Land Base Wind, TRG 1 - Low."
[e]25% cost reduction from conservative.
[f]From NREL[43] 2047 "Land Base Wind, TRG 1 - Low."
[g]From Lazard[44] "Li-ion Peaker Replacement."
[h]50% cost reduction from conservative.
[i]75% cost reduction from conservative.
[j]From Lazard[44] "Distribution Substation."
[k]From NREL[43] 2047 "Gas-CC-CCS - Mid."
[l]Net power Nth of a kind plant, May 2015 briefing.
[m]Based on Georgia Public Service Commission.[45]
[n]From NREL[43] 2047 "Nuclear."
[o]From IEA and NEA[46] assuming modular reactor.
[p]From NREL[43] 2017 "Biopower Dedicated - Mid."
[q]From NREL[43] 2047 "Biopower Dedicated - Mid."
[r]From NREL[43] same as gas CT.

34 GW at 4:00 pm on a July weekday), and a "southern" system with the demand profile and higher renewable resource availability characteristic of the Electricity Reliability Corporation of Texas region (peak demand of 94 GW at 4:00 pm on an August weekday).

Second, we account for uncertainties surrounding future technology costs and availabilities by introducing discrete cost assumptions ("conservative," "mid-range," and "very low"; see Table 1) for each of three groupings of technologies: (1) VRE resources (onshore wind and solar PV) and Li-ion battery energy storage (with 4 or 6 hr of output at maximum discharge rate; see footnotes in Table 2). (2) Light-water nuclear reactors and natural gas plants with CCS. (3) Biogas- and solid biomass-fueled plants (see footnotes in Table 2). Using these cost assumptions, we construct and analyze 19 technology cost and availability scenarios (see Table 2). Additionally, we analyze the impact of increasing flexibility in demand scheduling and price-responsive demand curtailment, as well as the effect of increasing long-distance transmission interconnection capacity between the northern and southern systems.

Third, we analyze the economic impact of different emissions reduction targets by modeling each technology and regional scenario subject to seven progressively more stringent CO_2 emissions limits, from 200 gCO_2/kWh down to zero emissions. For context, the direct emissions rate of CO_2 from power generation in the United

Table 2. Technological Scenarios

Scenario	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
VRE and storage[a,b]	C	M	M	M	L	L	L	M	M	M	L	L	L	M	M	M	L	L	L
Nuclear and CCS[b]	C	C	C	C	C	C	C	M	M	M	M	M	M	L	L	L	L	L	L
Biomass and biogas[b]	C	C	M	L	C	M	L	C	M	L	C	M	L	C	M	L	C	M	L

C, conservative; M, mid-range; L, very low technology cost assumptions (Table 1).

[a]This analysis is limited to lithium-ion battery energy storage systems, which are currently widely scalable, face no geographic constraints, and are expected to benefit from further cost reductions due to economies of scale, learning-by-doing, and spillovers from battery production for electric vehicles. Longer-duration pumped-hydro storage resources are difficult to expand due to siting challenges, and medium- and long-duration energy storage options that may provide longer-duration storage capacity (e.g., days rather than hours) are currently too costly or face scalability challenges. However, if a storage technology capable of supplying several days or more of sustained power output becomes economically and technically viable, this technology could serve as a firm low-carbon resource (unlike shorter-duration battery storage). It would be productive for future research to explore the impact of long-duration energy storage options on deep decarbonization and the cost and performance parameters necessary for very-long-duration storage to cost-effectively contribute to decarbonization.

[b]These resources are grouped in order to keep the number of scenarios manageable. Solar, wind, and battery storage are grouped to reflect the more rapid pace of likely cost declines for these technologies. Nuclear and gas with CCS are likewise grouped based on their relatively high costs and slower rate of likely cost declines. Finally, biomass and biogas resources are grouped to reflect their common feedstocks, with the three technology cases reflecting increasing levels of feedstock supply.

States in 2017 was 436.6 g/kWh. Emissions reductions pledged by the United States under the Paris Agreement use 2005 as a baseline year, in which the CO_2 emissions rate from power generation was 595.8 g/kWh.[47,48]

Altogether we evaluate 912 distinct scenarios. A "core" set of 532 scenarios comprises the 19 technology availability and cost scenarios in each of the two power systems, subject to seven different decarbonization targets with and without firm low-carbon resources. We also consider 380 "sensitivity" scenarios that explore the effects of five different levels of demand-side resource availability and two levels of long-distance transmission capacity linking the two power systems.

To our knowledge, this is the first work to systematically explore the feasibility and cost of achieving deep decarbonization goals (up to 100% reductions in power sector CO_2 emissions) across such a wide range of conditions and technology cost projections. This comprehensive analysis increases the robustness of our findings.

The next two sections of the paper present the results of our analysis, focusing first on our core scenarios and subsequently on the impact of demand-side flexibility and increased regional interconnections. This is followed by a discussion of the policy implications and recommendations, and a description of the experimental procedure and assumptions used in our work.

RESULTS

Core Cases

Across the wide range of technology assumptions and power system characteristics considered in our core scenarios, we find that the availability of firm low-carbon resources consistently reduces the system cost of decarbonizing power generation relative to scenarios in which these resources are excluded from the eligible resource mix. As Figures 1 and S2 illustrate, in the absence of firm low-carbon resources, the cost of decarbonizing power generation rises very rapidly as the emissions limit approaches zero. The cost of full decarbonization (zero CO_2 emissions) without firm resources is from 42% to 163% higher in the northern system, and from 11% to 105% higher in the southern system, relative to cases in which firm low-carbon resources are available. The precise difference in cost depends on specific technology cost

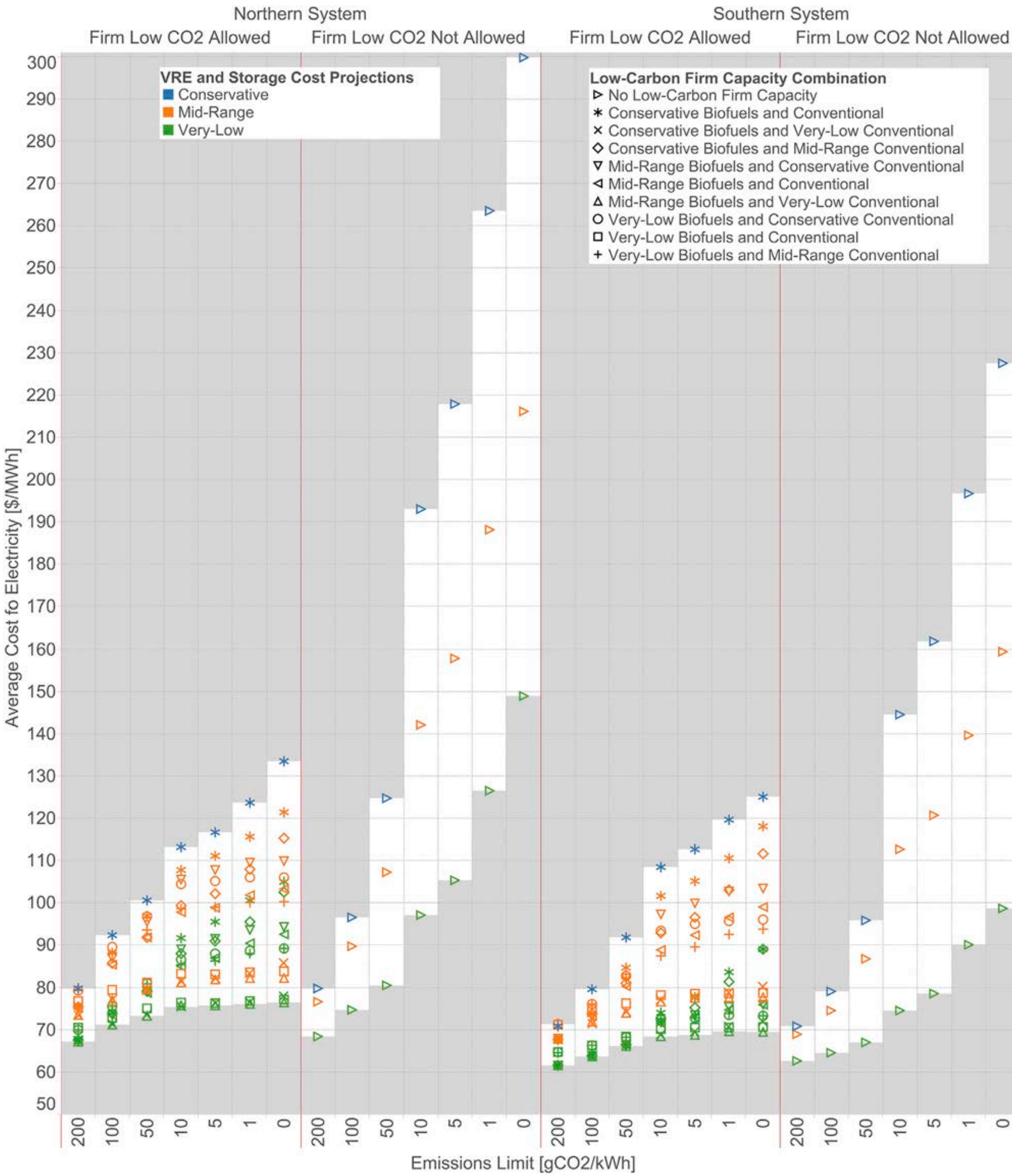

Figure 1. Average Cost of Electricity under Different Technology Assumptions and CO_2 Emission Limits for the Northern and Southern Systems

For cost comparisons, compare visually each of the green (or orange or blue, depending on the VRE and storage cost assumptions) cases in the first panel (where firm resources are included) with the green case in the second panel (where firm resources are excluded). In the "very low" cost projection (green), wind and solar fall by roughly one-third and two-thirds relative to 2017 costs, respectively, and battery costs decline by roughly three-quarters (see Table 1).

and availability assumptions. Even with very-low-cost projections for wind, solar, and energy storage and conservative assumptions for firm low-carbon resources (i.e., the costs of nuclear, natural gas with CCS, biomass, and biogas resources remain unchanged relative to their current levels), the cost of achieving zero carbon emissions in each region is lower when firm resources are available than when they are not (see Figure 1 legend).

These results suggest that firm low-carbon resources are particularly valuable in regions with more modest renewable energy potential (e.g., the northern system) and that these technologies provide an effective hedge against the risk that additional steep reductions in the cost of variable renewables may not be achieved. More generally, the results indicate that including firm resources in the portfolio of available low-carbon technologies is a more robust strategy for achieving affordable deep decarbonization of power generation.

The rapid increase in system cost as the emission limit approaches zero when firm low-carbon resources are excluded contrasts with the much more gradual increase when firm resources are available (Figure 1). The former behavior is explained by the sharp decline in the marginal energy and marginal capacity substitution value of VRE[49,50] and battery storage[35,36] technologies at high penetration levels. As Figure 2 demonstrates, VRE and batteries are only weak-capacity substitutes for firm low-carbon resources, and significantly more than one megawatt of combined VRE and storage capacity is required to replace one megawatt of firm low-carbon capacity in equally reliable systems achieving the same CO_2 emission reductions. To meet demand reliably during periods of low wind and solar availability, large amounts of VRE capacity must be deployed, along with energy storage to shift available supply from high to low VRE output periods. For zero emissions cases without firm resources, the total required installed generation and storage power capacity in each system would be five to eight times the peak system demand, compared with 1.3–2.6 times peak demand when firm resources are available (see Figure 2 legend). For example, in the northern system assuming mid-range costs for all technologies, the total installed power capacity with firm resources available is 48 GW, including 16 GW of VRE and 4 GW of storage capacity. In the absence of firm resources, the installed capacity of VRE and storage would increase to 130 GW and 47 GW respectively. Additionally, fully decarbonized cases without firm resources feature 320–1,160 GWh of installed energy storage capacity, versus 29–380 GWh when firm resources are available (Figure S15). We also demonstrate the robustness of our findings to the availability of longer-duration storage technologies (see Figures S16–S18).

As VRE penetration increases, a growing share of annual VRE generation occurs during periods when a zero marginal cost resource (e.g., wind, solar) is the marginal generator, reducing the energy substitution or fuel-saving value of VRE. In addition, during periods of abundant wind and solar insolation, large installed VRE capacities produce significant excess supply, and it is not cost-effective to build enough energy storage capacity to accommodate all of this surplus. For example, in a fully decarbonized power system, the amount of available wind and solar output that would be wasted due to curtailment in VRE-dominated scenarios would be sufficient to supply 60%–130% of total annual electricity demand (Figure S3). In contrast, when firm low-carbon capacity can be deployed, wind and solar curtailment is reduced to 0%–14% of total annual demand.

As the CO_2 emissions limit grows more stringent, the energy share of high-carbon resources in the least-cost resource portfolio declines monotonically, as expected.

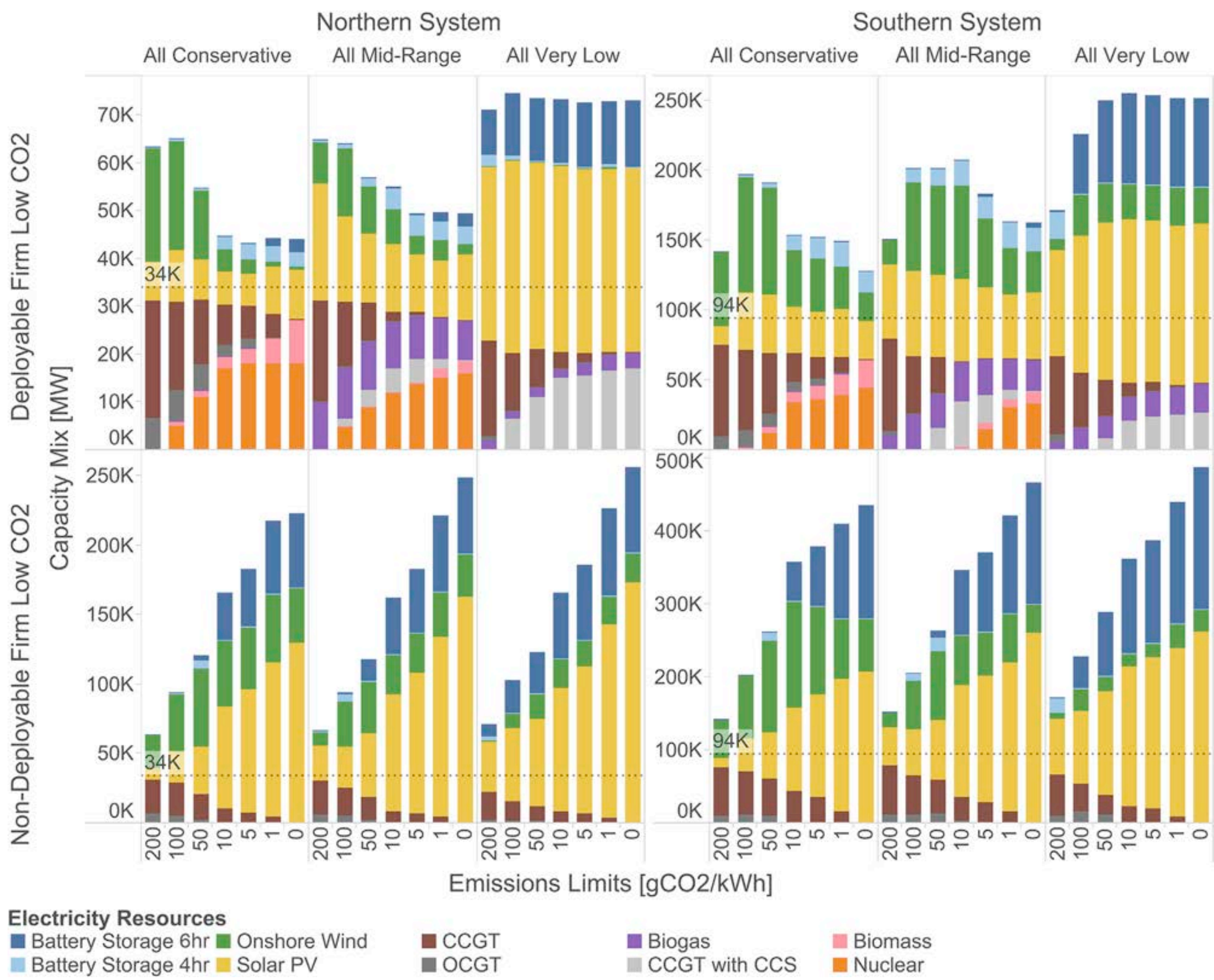

Figure 2. Least-Cost Capacity Mix in the Northern and Southern Systems for Different Carbon Emission Limits

For each system, the plot shows the least-cost capacity mix for the technology scenario combinations of all conservative, all mid-range, and all very low costs for all three groupings of resources, with the northern system on the left and southern system on the right. The top portion of the plot shows the resulting mix when firm low-carbon capacity can be deployed, while the bottom portion shows the resulting mix when these resources are excluded. Note that the y axis has been re-scaled on each sub-plot and a dotted line representing the peak demand of each system has been added as a visual reference. Battery storage capacity has been plotted in instant capacity (MW) instead of energy capacity (MWh) for consistency with generation resources. See Figures S4 and S5 for the capacity mix under the full range of different scenario combinations. CCGT, combined-cycle gas turbine; OCGT, open-cycle gas turbine.

For the cases without low-carbon firm capacity, the outsized installed capacity is driven both by the oversizing of wind and solar capacity and the large volume of energy storage capacity needed to provide sustained energy output during periods of low VRE availability. Commercially available energy storage options such as Li-ion batteries are ill suited to these long-duration storage needs. If firm low-carbon resources are to be eschewed, energy storage resources capable of both sustained output over dozens of hours or longer and very low costs of energy storage capacity suited to low annual utilization rates would be needed.

However, in many scenarios, the energy share of wind and solar in the least-cost portfolio *also declines* as the emission limit continues to tighten (Figure 3). As the penetration of VRE resources increases, the marginal value of additional VRE capacity is linked to its fuel-saving role; that is, to its ability to displace fuel-based generation and thereby to reduce system variable costs. Accordingly, if fossil-fueled generation is replaced by low-carbon firm resources with zero or near-zero marginal costs (i.e., nuclear, hydro, geothermal) as the emission limit tightens, the energy substitution value of wind and solar declines as well (Figure S9). As a result, the energy shares from wind or solar in the least-cost portfolio may fall as the emissions limit

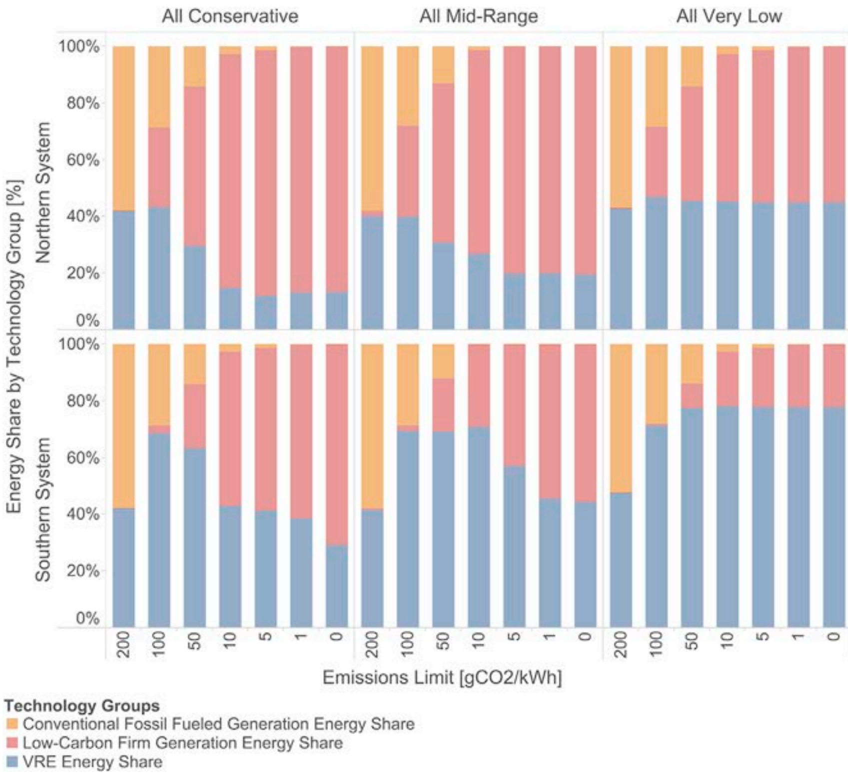

Figure 3. Energy Shares of Least-Cost Portfolio in the Northern and Southern Systems by Technology Group under Different Carbon Emissions Limits

For each system, the plot shows the energy shares of the least-cost mix for the technological scenario combinations of all conservative, all mid-range, and all very low, with the northern system on the left and southern system on the right. The energy shares are calculated as the quotient of the total energy injected into the system by each technology over the total demand of the system plus energy storage losses. See Figure S8 for energy shares under different scenario combinations.

approaches zero. In contrast, if fossil-fueled generation is replaced by firm low-carbon resources with higher fuel costs (e.g., biomass, biogas, natural gas with CCS), the fuel-saving value of wind and solar is preserved and the least-cost energy shares of VRE increase asymptotically as the emissions target goes to zero.

Similar non-monotonic behavior in the energy shares of natural gas with CCS can be observed for the mid-range technology case in which the CO_2 capture rate is assumed to be 90% (Figure S9). Without complete CO_2 capture, the energy share from natural gas plants with CCS shrinks as the emission limit approaches zero. In contrast, natural gas with CCS increases its energy share monotonically when a 100% capture rate is assumed.

The non-monotonic changes in the least-cost share of both VREs and natural gas power plants with 90% CO_2 capture rate indicate that assets that may be optimal under more modest emissions limits may become stranded in a deeply decarbonized power system. Both low-carbon technology investments and near-term policies should therefore be evaluated in light of their potential contributions to eventual deep decarbonization goals and not solely on their more immediate impacts.

Finally, we find that firm low-carbon resources operate in two different modes, depending on technology type and the specific case.

First, firm resources may operate in a ''flexible base'' mode, in which they provide a reliable base of power throughout the year, infrequently cycle off entirely, and are flexible enough to modulate output between their minimum stable output and maximum rated capacity to integrate variable renewable resources when economically advantageous for the system. We define here the ''annual commitment factor'' (ACF) for a given resource i as

$$ACF_i = \sum_{h=1}^{H} C_{i,h} / (g_i \cdot H)$$

where $c_{i,h}$ is the number of generating units of resource type i committed in each hour h, g_i is the total number of generating units of resource i installed, and H is the total number of hours in the year. We consider a technology with an ACF >50%—meaning that the technology is online and generating more often than not—as operating in a flexible base manner in that case. Nuclear power plants most consistently operate in flexible base mode in our results, as do natural gas plants with 100% CO_2 capture rate (see Figures S6 and S14). Gas plants with a lower capture rate and biomass power plants occasionally operate in a flexible base mode but cycle more frequently in other cases.

Notably, in more than three-quarters of cases (122 of 152) with emissions limits less than 10 gCO_2/kWh, the least-cost resource mix includes at least one technology that operates in a flexible base mode. In higher carbon cases, combined-cycle natural gas plants operate as flexible base but emit too much CO_2 to continue in this role at low emissions limits. The availability of a cost-effective low-carbon alternative to combined-cycle natural gas plants substantially reduces average electricity costs as the emissions limit approaches zero (Figure S2). Even a relatively modest amount of low-carbon firm capacity operating in flexible base mode can have a substantial effect on total power system costs (Figures S4 and S5).

In a smaller number of cases, firm low-carbon resources are too costly relative to variable renewables to warrant operation as flexible base resources, and wind and solar (complemented by battery energy storage) dominate the energy supply (Figures 3 and S8; this includes all cases under 10 gCO_2/kWh with very low VRE and storage cost assumptions and, in the northern system, conservative costs for nuclear and natural gas with CCS, or, in the southern system, conservative or mid-range costs for these firm resources). Any firm resources deployed in these cases (e.g., biomass and biogas, or natural gas plants with a 90% CO_2 capture rate) operate as ''firm cyclers.'' This operating mode is characterized by prolonged periods in which all generating units of this type are cycled off entirely and where these units primarily contribute valuable power output during prolonged periods of low solar and wind availability in which energy storage becomes insufficient to meet demand reliably. Firm cyclers are indicated by low values (generally less than 35%) for both commitment factor and capacity factor (Figures S6 and S7). Firm cyclers also reduce total system costs in these cases relative to cases that entirely exclude firm resources (Figure S2).

Demand-Side Resource and Transmission Interconnection Cases

We next consider the role of demand-side flexibility, in the form of reschedulable loads and price-responsive or curtailable loads. Table 3 summarizes five scenarios with progressively increasing demand-side flexibility of each type.

As Figure 4 indicates, firm low-carbon resources (the cases labeled in the figure as ''firm allowed'') continue to play an important role in containing the cost of deep

Table 3. Demand-Side Resource Scenarios

	1	2	3	4	5
Percentage of hourly demand that can be re-scheduled	5	10	15	20	20
Maximum time to serve re-scheduled demand (hr)	6	6	6	6	6
Number of price-responsive demand segments	1	2	3	4	5
Marginal cost of demand curtailment in each demand segment as a percentage of the value of lost load ($15,000/MWh)	70	70–50	70–50–20	70–50–20–10	70–50–20–10–5
Size of each demand segment as a percentage of hourly demand	5	5	5	5	5
Total price-responsive demand as a percentage of hourly demand	5	10	15	20	25

decarbonization even with significant demand flexibility (i.e., when up to 20% of demand is reschedulable at no cost for up to 6 hours and up to 25% of demand is price responsive). Across the range of demand-side flexibility cases, it is 30%–83% more expensive to fully decarbonize electricity generation without low-carbon firm resources in the southern system and 74%–130% more expensive in the northern system.

In cases that exclude firm low-carbon resources, demand-side flexibility plays an important role in reducing the costs of deep decarbonization (Figure 4). However, the marginal value of each increment of demand flexibility declines as VRE and energy storage costs fall (indicated by the tighter spread of system-wide costs in the very low VRE and storage cases). Figure 5 shows how increased demand-side flexibility affects the capacity mix and energy shares in the least-cost power systems. When firm low-carbon resources are excluded, greater demand flexibility lowers average costs by substantially reducing required energy storage and VRE capacity. In effect, greater demand flexibility reduces (but does not eliminate) the need for excess installed VRE and storage capacity to reliably meet demand.

With firm low-carbon resources, however, increased demand flexibility has a more modest effect on total cost and total installed capacity in decarbonized power systems. In these cases, demand flexibility acts most directly as a substitute for energy storage, an indication of their competing roles in the fast-burst balancing resources category (see Figure 5). Increased demand flexibility also has secondary and more ambiguous effects on capacity and energy shares of VRE and firm resources, generally reducing the capacity of the most expensive resources and increasing utilization of lower-cost resources in each case.

We also find that reschedulable or "shiftable" demand is utilized more significantly in cases when firm low-carbon capacity is allowed in the system (see Figure S10). In these cases, demand is regularly shifted in order to optimize the utilization of the firm resource with the highest variable cost (e.g., biomass or natural gas with CCS; Figures S11 and S12). Rather than act as a strong substitute for firm low-carbon resources, demand flexibility instead optimizes their utilization and increases their marginal value.

We also analyzed the potential gains from adding long-distance transmission capacity between the northern and southern systems. Fixed line capacities

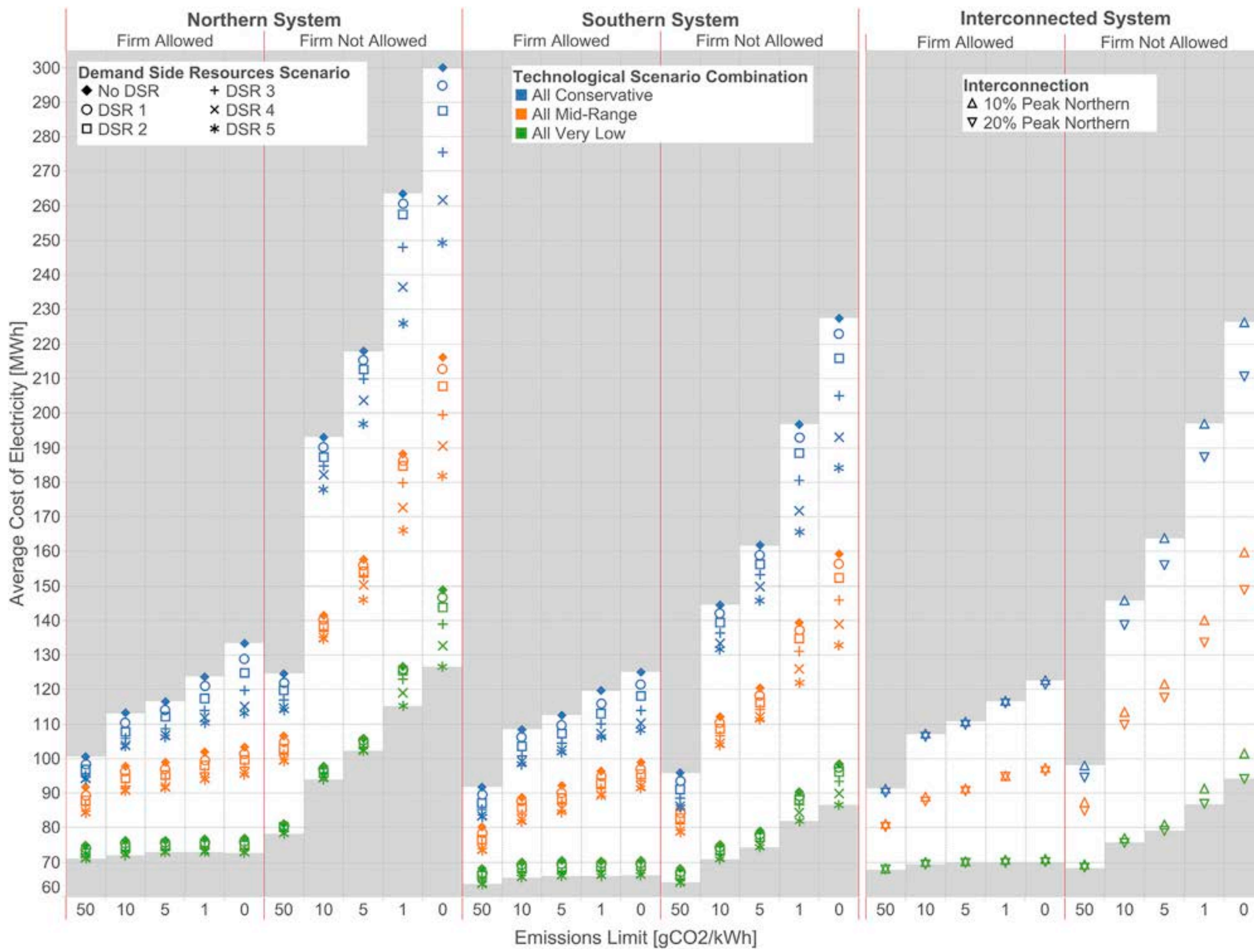

Figure 4. Average Cost of Electricity under Different Technological Assumption Scenarios, and CO_2 Emissions Limits for the Northern and Southern Systems with Different Demand-Side Resources Scenarios and the Interconnected System

The plots show the average cost of electricity for the northern and southern systems under different demand-side resource (DSR) scenarios and the interconnected system under different interconnection capacity scenarios. For each system, results are shown when low-carbon firm capacity is allowed and when it is not. Different colors distinguish scenarios with conservative, mid-range, and very-low-cost projections for all technologies.

equivalent to 10% and 20% of the northern system's peak demand were each considered (see Table 4).

When firm resources are available, connecting the two regions with transmission capacity equal to 10% of the northern system's peak demand has a modest effect on the cost of full decarbonization in each region. In the northern system, the average electricity cost is reduced by between 8.5% (in the conservative case) and 9% (in the very low case) relative to the cost without interconnection, while in the southern system the average electricity cost is reduced by between 2% (in the conservative case) and 0.5% (in the very low case). The marginal benefit of additional interconnection capacity is effectively zero (Figure 4). The first increment of capacity allows for optimal placement of VRE (solar capacity shifts to the southern system; see Figure S14) and better usage of VRE generation due to reduced output variability (with some solar capacity being replaced by wind generation; see Figure S9). These effects enable VRE to substitute to some degree for more expensive technologies, such as energy storage or firm low-carbon resources, in certain scenarios (see Figure 5).

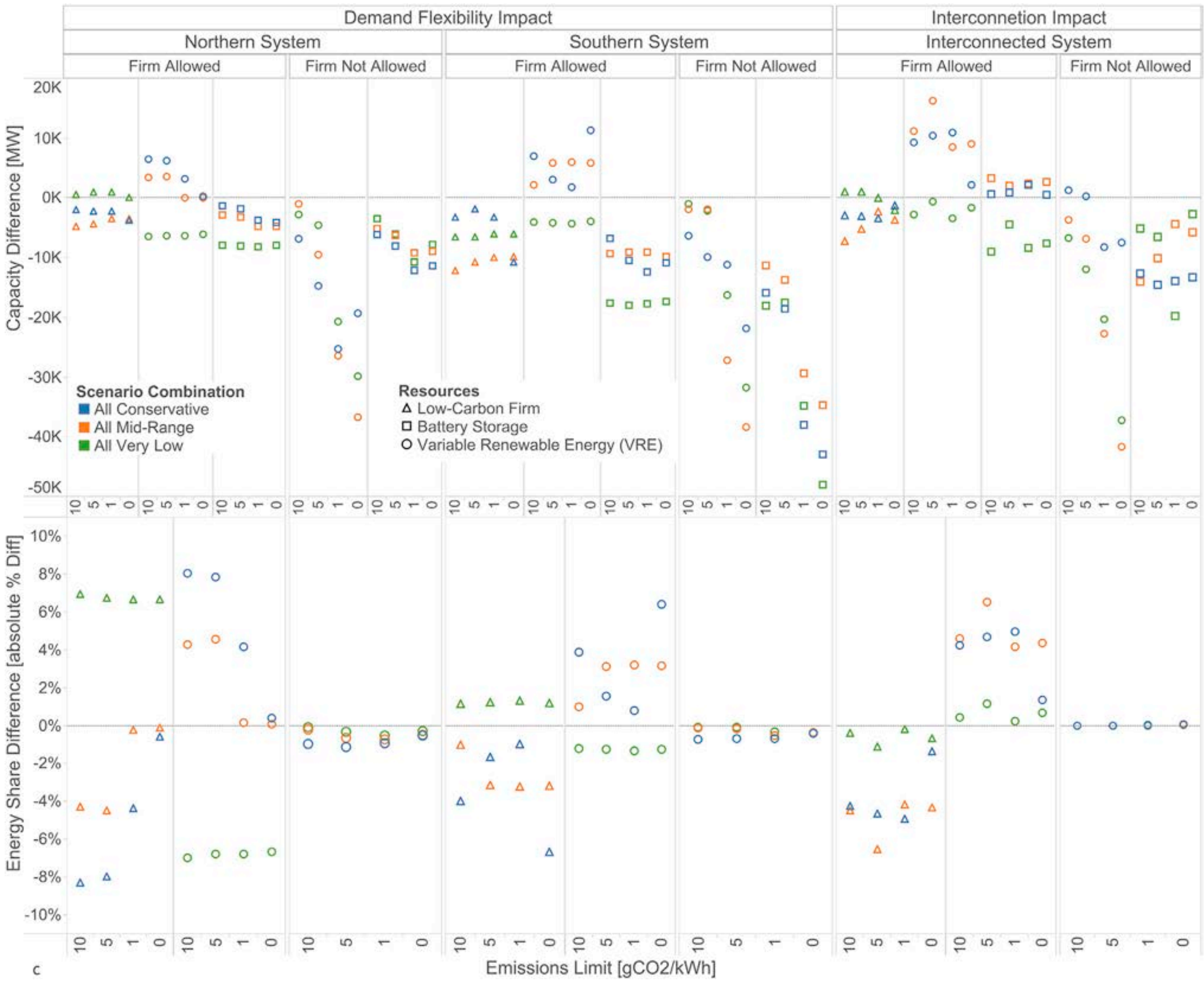

Figure 5. Effect on Capacities and Energy Shares of DSRs (DSR 5 versus DSR 1) and Interconnection (20% versus 10%) as a Function of Emissions Limit
Effect of flexible demand and transmission interconnection on the capacities (top) and energy shares (bottom) of different resources. The effects are shown as the difference between scenarios DSR 5 versus DSR 1 for the impact of demand flexibility (left) and the difference between the 20% and 10% interconnect scenarios for the impact of transmission interconnection (right). Different technologies are shown with different data markers and different technological scenario combinations are shown in different colors. Battery storage capacity differences have been plotted in power capacity (MW) instead of energy capacity (MWh) for consistency; this is done by dividing the total energy capacity by the storage time constant (4 and 6 hr).

If firm resources are not available, transmission interconnection has a greater economic benefit. As Figure 4 illustrates, the first increment of transmission capacity (10% of the northern system peak) reduces the average cost of the combined system to 68%–75% of the cost of the northern system in isolation (and to roughly the level of the average cost of the southern system in isolation). The benefit of the next increment of transmission capacity (increasing to 20% of the northern system peak) is also noticeable, with average electricity costs in the combined system falling below those of either individual system in isolation in all cases.

Finally, Figure 4 shows that, even when zero-cost, zero-loss transmission capacity is available to connect the two regions, the cost of achieving deep decarbonization

Table 4. Interconnection Scenario Assumptions

	10% Case	20% Case
Line capacity (MW)[a]	3,400	6,800

[a]The two systems are assumed to be interconnected at zero cost, with no transmission losses, i.e., transmission costs and losses are not included in the capacity expansion optimization. Instead, transmission interconnection capacity between the two regions is exogenously increased and the effects on other decision variables and costs are analyzed. Figure S13 shows the interconnection usage as function of emissions limit for the different scenarios.

is at least 35% higher in the absence of firm low-carbon resources, providing further evidence of the broad value of these firm resources for cost-effective decarbonization.

DISCUSSION

The availability of firm low-carbon resources is an important factor in containing the cost of power sector decarbonization and thus the overall cost of climate mitigation efforts. This finding appears robust in the face of uncertainties in future technology costs, in the scale of adoption of demand-side flexibility services, and in the availability of long-distance transmission interconnections. The cost-containing role of firm resources is particularly important where solar or wind resources are of lower quality, and will also be especially valuable if solar, wind, and storage costs do not continue to fall rapidly. However, even in regions with abundant renewable resources, firm low-carbon resources can lower the cost of deep decarbonization significantly, even if the firm resources have much higher levelized costs than do variable renewables, and even if very-low-cost battery energy storage technologies are available. In the majority of scenarios analyzed here, firm low-carbon resources operate as a flexible base in decarbonized power systems, providing a steady supply of reliable and adjustable power output throughout the year.

We find that in the absence of firm low-carbon resources, affordable decarbonization of the power sector would simultaneously require further steep reductions in the cost of VRE and battery energy storage technologies, significantly oversizing installed capacity relative to peak demand, significantly greater demand flexibility, and expansion of long-distance transmission capacity connecting wide geographic regions. Development of energy storage resources capable of sustained output over days or longer with very low energy capacity costs suited to low utilization rates could also lower the costs of high VRE pathways, but this potential was not modeled in this study. Given large current uncertainties in all of these outcomes, our results suggest that the availability of firm low-carbon resources—even if much costlier than VRE resources in terms of overnight capital cost or levelized cost of energy—will improve the robustness of decarbonization efforts.

The analysis shows that in decarbonized power systems, short-duration battery energy storage, and demand-side resources play a role (as fast-burst balancing resources) that is distinct from firm low-carbon resources. We also show that firm resources play a key role even with enhanced long-distance transmission interconnections. If fast-burst balancing resources or transmission interconnections are available and cost-effective, these options can help to optimize asset utilization and reduce electricity costs for systems without firm resources and for more balanced systems alike.

Power system assets are long-lived investments, and capacity installed during the next decade is likely to remain in operation until 2050. Recognizing the importance of firm low-carbon resources to the cost of deep decarbonization thus has immediate implications for climate change mitigation and electric power system planning, energy technology and climate policy, and energy research prioritization.

First, although a wide range of public policies currently support the growth of variable renewable resources, policy support for firm low-carbon resources such as nuclear power, geothermal energy, biofuels, and CCS is modest in most jurisdictions. Our results indicate that having one or more firm low-carbon resources available for widespread deployment at reasonable cost will greatly improve the odds that zero or near-zero power sector emissions can be achieved cost-effectively. At present, available firm low-carbon resources face a variety of challenges that impede their widespread adoption, from cost to technology immaturity to risk. If these resources are to be viable options when needed, greater policy support for demonstration, deployment, and improvement of the existing portfolio of firm low-carbon resources is needed today.

Second, further development and improvement of firm low-carbon technologies, particularly those capable of operating as flexible base resources, should be a research and innovation priority. An improved and expanded set of firm low-carbon resources could have a substantial and positive impact on the eventual cost of deep decarbonization of power generation.

Third, given the sensitivity of the least-cost mix of low-carbon electricity resources to uncertain technology cost and performance trajectories, as well as large and potentially non-monotonic changes in the composition of the least-cost resource portfolio as the emission limit is tightened, policies should internalize long-term decarbonization goals and should allow the flexibility to implement the most cost-effective combination of fuel-saving, fast-burst, and firm low-carbon resources to meet those goals. Such policies could include a long-term emissions limit trajectory, a steadily increasing carbon price, or a technology-neutral low-carbon resource procurement requirement. Alternatively, an expanded mix of technology-specific policies that includes significant support for investment in research, demonstration, and deployment of low-carbon firm resources could ensure that these resources would remain a viable part of the climate mitigation portfolio.

EXPERIMENTAL PROCEDURES

Modeling Technique

This research uses the GenX model, an electric power system investment and operations model described in detail in.[38] In its application in this paper, the model considers detailed operating characteristics such as thermal power plant cycling costs (unit commitment), limits on hourly changes in power output (ramp limits), and minimum stable output levels. The model also captures a full year of hourly chronological variability of electricity demand and renewable resource availability (see Figures S19 and S20). The mixed integer linear programming model selects the cost-minimizing set of electricity generation and storage investments and operating decisions to meet forecasted electricity demand reliably over the course of a future year, subject to a specified CO_2 emissions limit.

The GenX model can be configured to co-optimize several interlinked power systems decision layers. Computational limitations entail tradeoffs along each dimension or decision layer, so more detail in one dimension (e.g., time, operational constraints, networks) typically means greater abstraction in other areas. For this study, we configure GenX to deliver high accuracy in hourly operational and unit commitment decisions. This temporal resolution and operational detail is important to capture the effects of chronological variability in renewable energy availability and demand patterns on investment and operating decisions, particularly under scenarios with very high wind and solar energy penetrations. Computational complexity is also increased by the inclusion of stringent annual limits on total CO_2 emissions. However, this level of detail comes at the expense of other limitations that are important to note when interpreting the results of this work. See the Supplemental Experimental Procedures section for full discussion of the limitations of this modeling approach.

Cost and Availability Assumptions

Cost and availability assumptions describing the different analyses are shown in Tables 1, 2, 3, and 4. Economic and technical assumptions can be found in Tables S1–S3.

SUPPLEMENTAL INFORMATION

Supplemental Information includes Supplemental Experimental Procedures, 20 figures, and 4 tables and can be found with this article online at https://doi.org/10.1016/j.joule.2018.08.006.

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AUTHOR CONTRIBUTIONS

N.A.S. performed the modeling, developed the initial experimental design, contributed to and coordinated the manuscript production, and produced the figures. J.D.J. was lead editor of the manuscript. N.A.S. and J.D.J. jointly developed the capacity expansion model, refined the initial experimental design, and performed analysis of results. R.K.L. and F.J.d.S. advised on experimental design and analysis and reviewed and revised the manuscript.

DECLARATION OF INTERESTS

J.D.J. provides consulting and advisory services for the Clean Air Task Force, a nonprofit environmental advocacy organization, and the Clean Energy Program at Third Way, a nonprofit think tank. R.K.L. serves on the Scientific Advisory Council of Engie.

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