The Brattle Group

A Learning Investment-based Analysis of the Economic Potential for Offshore Wind:
The case of the United States

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This report was prepared for the Center for American Progress, the US Offshore Wind Collaborative, The Clean Energy States Alliance and the Sierra Club.

The authors are Principals of *The Brattle Group*. All results and any errors are the responsibility of the authors and do not represent the opinion of *The Brattle Group*.

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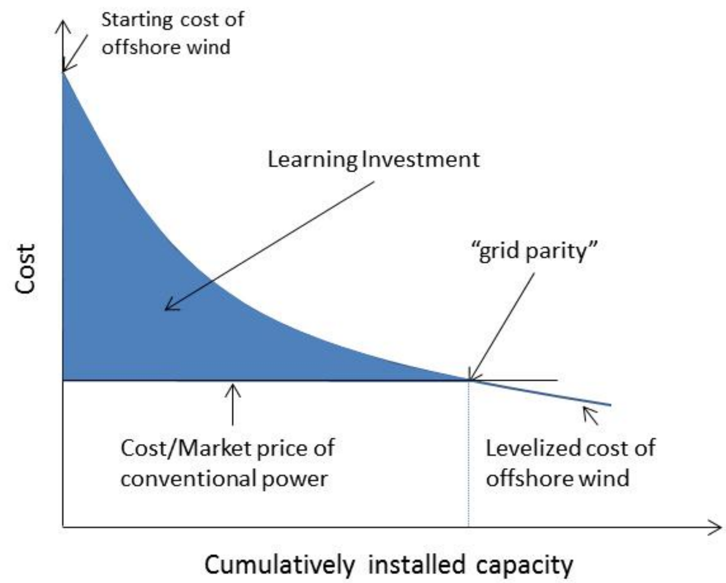
I. EXECUTIVE SUMMARY

The Center for American Progress ("CAP"), the US Offshore Wind Collaborative, the Clean Energy States Alliance and the Sierra Club asked the Brattle Group to conduct a study examining the short- and long-term economics of offshore wind in the United States. In particular, we were asked to analyze the "learning investment", i.e. the total amount of funding required to bring offshore wind to a scale where it can compete with fossil generation on a cost basis, as illustrated below in figure ES-1. We were also asked to examine how, if funded by ratepayers, average rates for electricity might be impacted by such a scaling-up program.

Figure ES-1: The Concept of Learning Investment



Based on: Ferioli, F., K. Schoots and B.C.C. van der Zwaan, "Use and Limitations of Learning Curves for Energy Technology Policy: a Component- Learning Hypothesis", Energy Policy, 37, 2009, 2525-2535.

This report provides a straight-forward analysis of the potential cost of bringing U.S. offshore wind to a scale where it could compete with both conventional (i.e. fossil-fired) and alternative renewable energy sources. It examines whether there is an economically sound rationale for supporting the development of offshore wind in the U.S., even if, at present, the expected cost of energy produced from offshore wind exceeds the cost of generating electricity from fossil-fuel based generation technologies such as natural gas, and the cost of some other renewable energy sources such as onshore wind. The analysis finds that, indeed, based on reasonable assumptions of learning rates, the investment needed to scale-up offshore wind to reach grid parity with fossil fuel generation by 2030 would have only a minor impact on electricity rates and is comparable with the magnitude of support provided to other energy sources in the past.

Rather than claiming that any one technology is "cheaper" or "better" than any other technology, the analysis in this paper is based on three well-established factors:

- First, as technologies mature and scale up, their costs tend to decline. This means that today's relatively high cost of less mature technologies, such as offshore wind in the United States, does not reflect the ultimate cost of the same technologies deployed at a scale and maturity similar to established technologies. The rate at which costs decline for each doubling of the installed capacity is called the "learning rate".

- Second, due to policy, technology development, and supply chain factors, the evolution of the future costs of various renewable technologies is highly uncertain. Similarly, the future path of the cost of fossil-fired and nuclear generation is highly uncertain and depends substantially on the degree with which social costs such as environmental externalities will be reflected in power prices. As a result, it is impossible to predict with any confidence that any one renewable technology will emerge as the least-cost power generation technology over the next 20 years or so. Even if such a technology could be identified, it is doubtful that it could be deployed at sufficient scale to meet total energy demand.

- Therefore, scaling up less mature (and therefore relatively more costly) technologies such as offshore wind is equivalent to buying insurance against the risk that the current incumbent and cheaper technologies will be more expensive than offshore wind at scale in the future, or that market imperfections and practical hurdles will limit the widespread deployment of tomorrow's technologies between now and then. There are several obvious risks mitigated by offshore wind technology. One such risk is an increase in natural gas prices. Because renewable technologies such as offshore wind have no fuel costs, they serve as an effective hedge against future increases in fossil fuel prices and corresponding fuel cost adjustments associated with ratepayer electric bills. A second risk is the potential need to reduce greenhouse gases faster than currently anticipated, leading to a stronger value of reduced greenhouse gas emissions.

- Finally, there are compelling theoretical reasons and evidence that in the presence of un-priced externalities[1] new technologies cannot compete effectively with existing, more mature technologies, especially in commodity markets such as electricity.

Put simply, the rationale for investing into the scaling-up of offshore wind is based on the well-established economic principle of diversification, or colloquially "not putting all your eggs in one basket."

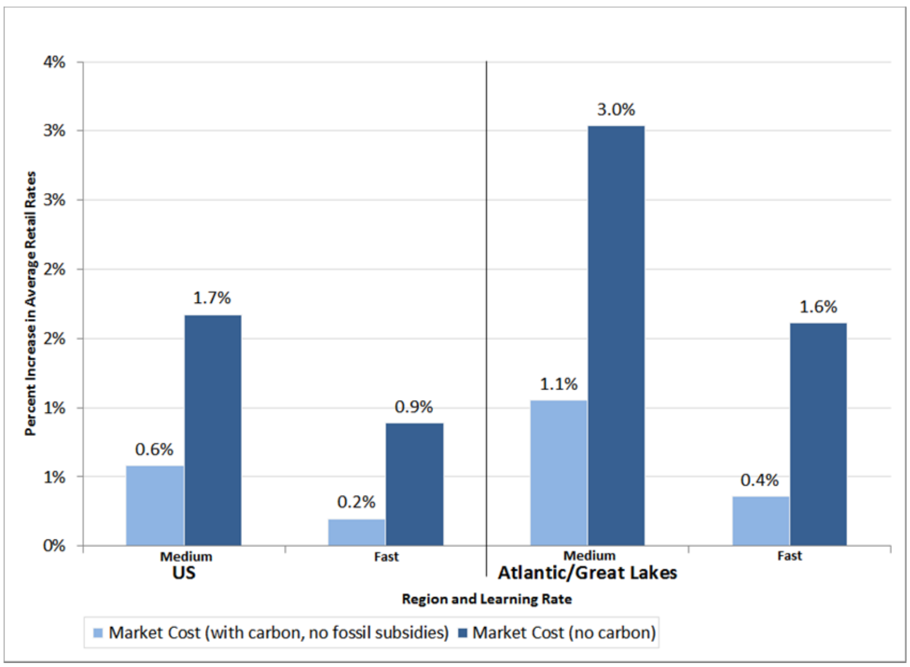
This study estimates the price to society of following this "portfolio diversification" strategy with respect to offshore wind. It estimates the total support needed to bring down the otherwise unsubsidized cost of offshore wind to grid-parity, *i.e.*, assuming that none of the current subsidies for offshore wind (Investment Tax Credit or Production Tax Credit, accelerated depreciation) are taken into account. For the study, we use two alternative definitions of "grid parity": (a) the

[1] The most obvious examples are environmental and health related externalities associated with existing fossil fuel-fired power generation. However, there are also market failures related to the creation of knowledge by early investments in a new technology. For an explanation, see for example Jurgen Weiss and Pedro Marin, "Reforming Renewable Support in the United States: Lessons from National and International Experience"; *The Brattle Group*; prepared for the Bipartisan Policy Center, November 2012.

market cost of the generation most likely displaced by offshore wind, and (b) the market cost of the same generation, but excluding any existing subsidies for such generation and assuming that at least some of the environmental externalities associated with it will be reflected in market prices. Because the total required funding between now and 2030 is difficult to interpret in isolation, the report translates this amount into the range of increases in rates and monthly bills a typical electricity consumer might experience from scaling-up offshore wind.

As shown in Figure ES-2, we find that funding the scale-up of offshore wind technology will likely have only a small impact on average rate payers relative to the impacts of other factors on electricity rates, such as fuel price variation.

Figure ES-2: Impact of offshore wind scaling on average retail rates between 2014 and 2030



Underlying these results are three assumed development paths of the estimated levelized cost of energy ("LCOE") from offshore wind, each using differing assumptions about the initial cost of offshore wind projects in the United States and the learning rates that can be expected, derived from the most recent research and international experience:

- A slow learning path, which assumes a relatively high initial project cost and a subsequent learning rate of 3%, i.e. a reduction of the levelized cost by 3% for each doubling of the cumulatively installed capacity.[2]
- A medium learning path, which assumes an initial cost similar to the cost of currently proposed projects in the United States and corresponding to the most recent estimates, but

[2] For estimating the rate and bill impacts of scaling offshore wind to grid parity, we assume that this slowest learning and highest cost path for offshore wind deployment would not be pursued through 2030 since costs by then would still be $186/MWh and significantly above the expected cost of conventional fossil generation and likely significantly above the cost of alternative renewable technologies.

still above the current cost of European offshore wind projects. The medium learning path assumes a learning rate of 5%.

- A fast learning path, which assumes that initial projects in the United States will cost approximately the same as current projects in Europe and that costs will decline at a rate of 10% for each doubling of cumulatively installed capacity.

All three paths assume that 54GW[3] of offshore wind would be installed by 2030. Based on the medium and fast learning paths, we estimate that the total learning investment between 2014 and 2030 needed to support the scaling up of offshore wind to reach grid parity ranges from a low of $18.5 billion to $52 billion (assuming some greenhouse gas externalities are included in the market price). [4]This is comparable in size to subsidies provided to other fossil fuel energy sources over the past half century and represents only a small portion of the expected total investment in the electricity sector that will likely be needed under any circumstances[5].

The consequence is that, even absent federal subsidies to the wind energy industry such as the Production or Investment Tax Credit, the average increase in electricity rates needed to finance such an investment would be rather modest, As shown in Figure ES-3, if the cost is spread across all electricity sales in the United States, the range of increases of electricity costs would be 0.03-0.22 cents/kWh or 0.2-1.7% of average U.S. retail electric rates, or an additional $0.25 - $2.08 per month for the average customer. If the cost were spread only across the electricity sales in the region, where offshore wind might be located – broadly the NERC sub-regions adjacent to the mid-Atlantic and Northeast and the Great Lakes – the increase in electricity rates would equal 0.06-0.50 cents/kWh, or 0.4-3.0%, or an additional $0.51 to $4.29 per month for the average customer. Given the fact that at present the portion of household consumption spent on electricity and gas is at a 50 year low, we believe such costs are an acceptable price to pay in exchange for creation the option of another cost-competitive power generation technology.

In essence the cost of scaling-up offshore wind looks like a reasonable insurance premium against unexpectedly higher costs under a "one technology" strategy. At a minimum, some initial support for scaling up offshore wind energy makes sense. If it becomes obvious that the cost of this technology does not decline significantly through cumulative deployment over the next decade or so, public resources should be diverted to alternative uses.

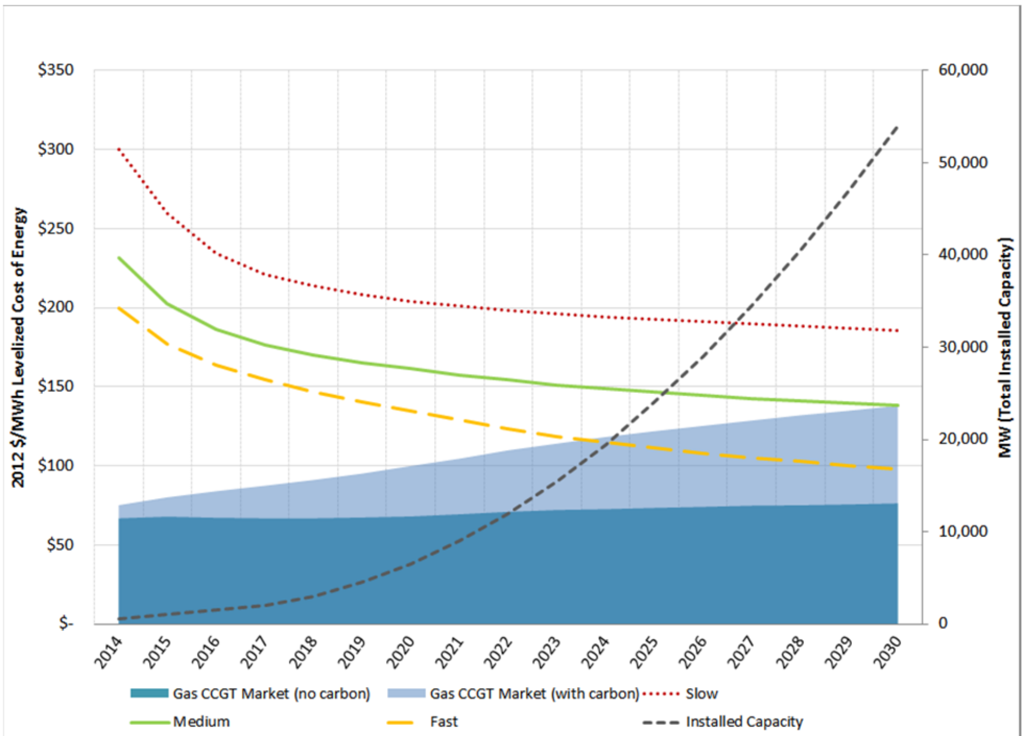
[3] The 54GW assumption corresponds to an assumption made in a recent report by the Department of Energy. As indicated above, we do not suggest that 54 GW would actually be installed. We therefore graph the slow learning scenario as a dotted line – we would assume that if offshore wind costs progress slowly while the costs of other technologies decline more rapidly, further support for scaling-up of offshore wind would be slowed, paused or abandoned.

[4] If no carbon externalities are considered in the grid parity benchmark and assuming fast and medium learning rates, the total learning investment needed for offshore wind to reach "market grid parity" ranges from $79 to $150 billion, respectively. This investment also is comparable with the subsidies provided to fossil fuels in the past fifty years.

[5] As explained above, we exclude the slow learning path from this analysis. However, even if such a path were pursued until 2030 and no carbon were included in market prices by then, the learning investment through 2030 would be approximately $243 billion, which is still less than the cumulative support given to several other energy technologies over the past half century.

As illustrated in more detail in Figure ES-3, these results are driven by the fact that our analysis indicates that offshore wind can reach grid parity by or before 2030 under reasonable expectations about future market conditions and the speed of learning for offshore wind. It is important to re-emphasize that these cost-trajectories assume no subsidies for offshore wind, i.e. they do not include the effect of an investment tax credit, production tax credit, accelerated depreciation or any other tax benefit or subsidy. The shaded areas represent our two alternative "grid-parity" benchmarks. As can be seen, grid parity is reached in the mid-2020s under the fast learning scenario, and by 2030 under the medium learning scenario (both scenarios assume some reflection of the greenhouse gas externality in market prices).

Figure ES-3: Cost of offshore wind under various market and learning assumptions

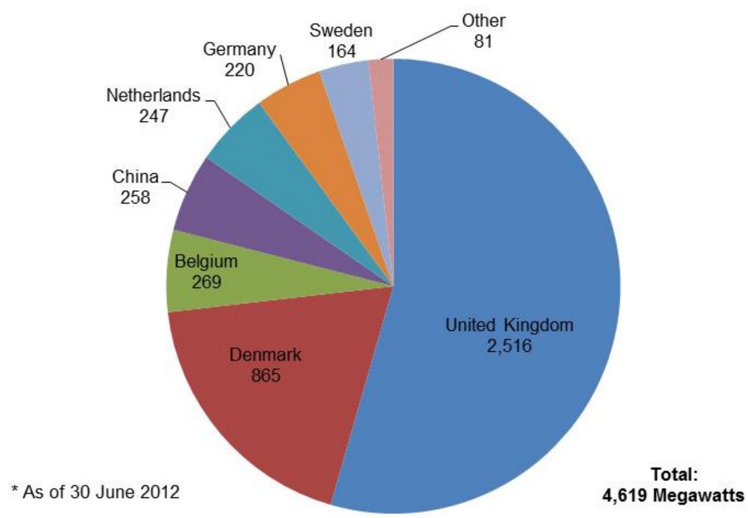


As the economic costs of just a single bad weather event such as hurricane Sandy in late 2012 and which have been estimated to be approximately $50 billion have shown, the cost of creating an option to produce electricity without greenhouse gas emissions may well be worth it given the potential societal cost of further substantial greenhouse gas emissions.

II. INTRODUCTION

Offshore wind is quickly becoming a major component of the renewable energy supply mix in Europe, primarily as a result of aggressive build-out plans in the United Kingdom and Germany and, to a lesser degree, other European countries.[6] In the U.S., attempts to jump-start an offshore wind industry have, so far, been slow to progress. As of the writing of this report, nine planned projects have reached an advanced stage of development (representing over 3000 MW), but there is no project yet constructed and operating.[7] Progress has been slow in the U.S. due to many obstacles facing any new technology, including uncertain, lengthy regulatory processes, lack of state and federal policies to stimulate demand, and lack of a domestic supply chain. However, opportunities to develop U.S. offshore wind abound, with over 4,000 GW of potential at wind speeds of 7 m/s or higher, of which more than 1,000 GW, or approximately the equivalent of the current total installed electric generating capacity in the U.S., are in shallow waters of 30 meters depth or less, and relatively close to major load centers.[8]

Figure 1: Global Installed Offshore Wind Capacity (2012)



Source: Reproduced from Earth Policy Institute, Plan B Updates, based on Global Wind Energy Council, 4C Offshore, EWEA

One critical factor hindering U.S. offshore wind project deployment progress is the perceived high cost of electricity generated by offshore wind facilities relative to alternative renewable energy sources, in particular on-shore wind, and to existing or newly constructed fossil-fired electricity generation. The U.S. Department of Energy's Offshore Wind Strategy and Offshore Wind

6 Section III(A)(1) below discusses the international experience to date.

7 Navigant Consulting, Inc., "Offshore Wind Market and Economic Analysis: Annual Market Assessment", Prepared for the U.S. Department of Energy, November 28, 2012, page XV.

8 United States Department of Energy, "A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States", February 2011, p. 5.

Innovation and Demonstration Initiative have laid out targets of deploying 54GW of offshore wind at a cost of $70/MWh[9] by 2030, with an interim goal of deploying 10GW at $100/MWh by 2020.[10]

This report provides a straight-forward analysis of the potential cost (which we call "learning investment") of bringing U.S. offshore wind to a scale where it can compete with both conventional (i.e. fossil-fired) and alternative renewable energy sources. Most approaches to comparing the cost of various technologies use current cost differences per MWh of electricity produced by various technologies. For this study we derive a range of future costs (and resulting differences between offshore wind and alternatives) and calculate the amount by which a typical electricity bill would have to increase to support the gradual scaling up of offshore wind and the corresponding decline in its relative cost.

We do so in four discrete steps:

- First, we review the literature and evidence on the potential for reducing the cost of offshore wind energy to derive a likely path of costs over time as scale increases. In this step, we review both: (1) bottom-up estimates of costs, mainly reports on the cost of offshore wind component-by-component, and (2) top-down estimates, mostly related to estimates of learning curves. We use both sources of information to develop a range of likely cost declines for offshore wind over time.
- Second, we derive similar cost curves, although in less detail, for alternative renewable energy sources as well as for conventional fossil-fired technologies, most importantly natural gas-fired generation. An important distinction between various renewable energy technologies and fossil-fuel fired power generation is the existence of various externalities, in particular related to emissions of CO_2 and other air pollutants. In addition, conventional technologies benefit from ongoing subsidies. Therefore, we derive cost estimates for the generation most likely displaced by offshore wind under two sets of assumptions: (1) current fossil fuel subsidy levels are maintained and no further attempts are made to price their environmental externalities; and (2) no subsidies and environmental externalities, such as greenhouse gas emissions, are reflected in market prices. We consider the former a lower bound of the cost of fossil-fired generation against which offshore wind is competing. Since our cost estimates of offshore wind do not assume any subsidies, they should be compared to the latter cost, which reflects the full social cost of the fossil-fired generation most likely replaced by offshore wind energy[11].

9 Since the purpose of this report is to estimate the potential cost decline due to learning by 2030, we do not adopt the levelized cost estimates in the DOE report, but rather estimate a range of potential costs based on the deployment assumption of 54 GW in the DOE report.

10 United States Department of Energy, "A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States", February 2011, p. 2.

11 In reality, offshore wind would displace a mix of generation from various sources, the exact composition of which is highly region-specific and will likely change over time. So while the avoided new generation capacity is likely natural-gas fired, offshore wind's impact on various externalities will depend on exactly what generation is displaced by offshore wind energy. Given the generation profile of offshore wind energy, it is likely that in many parts of the U.S. it would displace at least some generation from coal plants, especially in the near future. As we describe in more detail below, we have therefore assumed that the CO2 emissions reductions associated with offshore wind represent a displacement of a mix of coal and natural gas, with the share of coal declining to close to zero by 2030.

- Third, we compare the cost of offshore wind to the costs of renewable and conventional alternatives over time. Based on the identified cost trends, we first evaluate whether among various potential substitutes for fossil fuel, any single renewable technology dominates based on estimated cost (and other) trends. Since we find no technology dominates, we use the cost trends of offshore wind and gas-fired generation to determine when offshore wind, built to sufficient scale, will reach grid parity, and to estimate the total amount of "extra payments", or the learning investment, required to get to that point.
- Fourth, we translate this learning investment into estimates of the impact on average ratepayer bills over time. We distinguish between policies that would have all electricity ratepayers in the U.S. fund the resulting learning investment through increased electricity rates (or corresponding taxes), and policies that would have ratepayers only in those states off the coast of which offshore wind is deployed pay for the learning investment. This analysis offers a simple comparison of the rate impact of scaling up offshore wind to other factors that affect electricity rates, since this average rate impact is more easily understood than comparing costs per MWh at particular points in time.

The remainder of this report covers each of these four steps in detail, followed by some conclusions.

III. THE POTENTIAL FOR COST REDUCTIONS OF OFFSHORE WIND IN THE UNITED STATES

In this section, we examine the potential for cost reduction in the parts of the U.S. with the most offshore wind potential. We rely on two types of existing analyses: "bottom up, engineering-based" and "top down, experience-based". With increasing deployment of offshore wind in Europe, a number of recent studies have examined the potential for cost reductions from a technical/engineering perspective. These "bottom up" studies provide a basis for estimating technological advances likely to reduce the cost of offshore wind over time as the number of offshore wind turbines installed increases. We also rely on "top-down" estimated learning- and experience-related cost reductions for offshore wind.

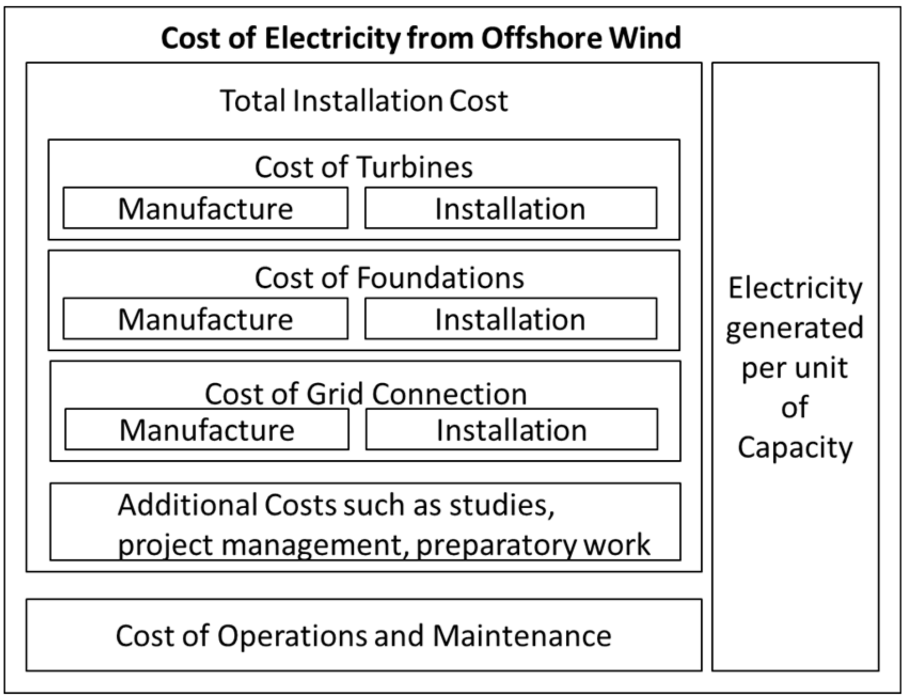
Both approaches are related. Learning and experience curves, as most top-down analyses, ultimately reflect underlying technical advances identified in bottom-up analyses. The main distinction is that the bottom-up analyses derive detailed costs while the top-down approach aggregates component-level effects, learning, and scaling into a single learning rate parameter. Below we compare some of the top-down and bottom-up approaches by calculating the learning rates implied by the most relevant studies.

Many studies focus on total installation cost (per MW of installed capacity), which in turn is a function of the manufacture and installation costs of turbines, foundations and grid connections, plus a number of other "soft" costs such as project management, studies and surveys, *etc*. However, as shown in Figure 1 below, the levelized cost of energy ("LCOE") from offshore wind not only depends on the installed cost, but also on operations and maintenance ("O&M") costs and the amount of electricity that can be generated from a unit of installed capacity. O&M cost for offshore wind can be significant, since the marine environment is harsh and relatively difficult to access. At the same time, O&M may be where most progress in cost reduction is possible, since current O&M costs (outside of the U.S.) still reflect a nascent industry with insufficient dedicated resources and a relatively short learning experience.

The total energy produced from a unit of offshore wind capacity also is an area of potential improvement. Wind turbines are still improving significantly, due to both an evolution towards larger capacity (the industry has been evolving from 2.2MW turbines to 3.6MW and 5MW turbines currently being installed, and larger ones are under development) and more efficient systems (such as an evolution from geared to gearless systems), yielding more output at any given wind speed. As deployment scales up, innovation specific to offshore wind, such as turbine size, also may further increase the production efficiency.

In addition, there is some uncertainty over the ultimate economic lifespan of an offshore wind installation. Given the large share of capital cost to total cost, longer life spans mean lower LCOE.

Figure 1: Factors Driving the Cost of Energy from Offshore Wind Facilities



Source: Isles (2006), TBG

Comparing the cost estimates from different studies and using the actual costs of offshore wind in Europe to estimate future offshore wind costs in the United States is difficult for many reasons. This is because many factors impact the cost of offshore wind and these factors often differ significantly across time and location. For example, estimates of costs or actual costs may or may not include the same assets (in Europe the grid connection is often not counted as part of the cost of the offshore wind project since it is the responsibility of another party). Projects may be built at different distances from shore and in different water depths. The timing of project development will affect such factors as exchange rates, supply bottlenecks, etc. Therefore, understanding the experience gathered elsewhere and the results of other studies serves primarily to develop broad ranges of expected current and future costs for offshore wind generically deployed in the United States. Study comparisons therefore should not be used to try to predict with any precision the costs of any specific offshore wind project.

A. HISTORIC EVIDENCE REGARDING OFFSHORE WIND COST

Until recently, experience with the actual costs of offshore wind farms was limited as the total amount of installed offshore wind capacity was relatively small. Also, it has become clear that learning and scaling effects are far from the only factors determining the cost of offshore wind projects.

1. International Evidence

The first offshore wind projects were installed in the 1990s, essentially in response to the oil crisis of 1973, first in countries such as the Netherlands and Denmark, where space for onshore wind development was limited. Early offshore wind projects were small pilot projects with capacities below 20MW, estimated capital costs of between approximately $1.2-2.4 million/MW[12] and estimated levelized energy costs between $85-145/MWh.[13]

In the early 2000s, the U.K. began its offshore wind development with a 4MW pilot project and the launch of the bidding for Round 1 by the Crown Estate. At the same time, Denmark embarked on an effort to scale up offshore wind production with the construction of several larger scale offshore wind farms, such as Horns Rev (2002) and Nysted (2003), each with approximately 160MW of capacity. Both projects had estimated capital costs of approximately $2 million/kW. Relative to these early projects, as well as the first two U.K. projects (North Hoyle and Scroby Sands, each with 60 MW capacity), the next generation of offshore wind projects were bigger and indeed benefited from learning and scaling effects, which indicated the potential for future offshore wind farms to continue offering lower cost energy.[14] Figure 2 shows the early cost trends in more detail.

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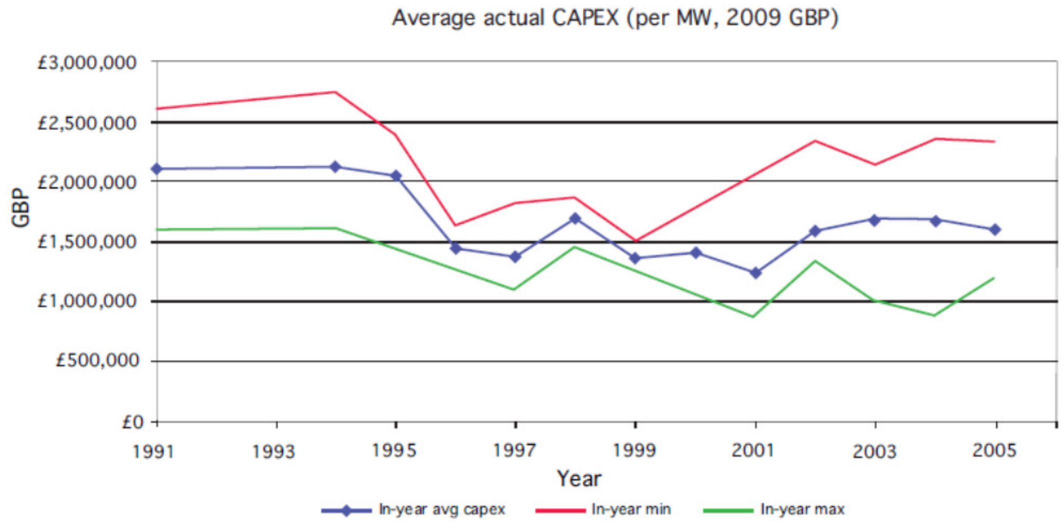
12 Throughout this report we often express values in U.S. dollars even though costs and revenues were originally reported in other currencies. We use today's approximate exchange rates of $1.5/£ and $1.3/€ to convert into dollars.

13 See, *e.g.,* UKERC, "Great Expectations: The cost of offshore wind in U.K. waters – understanding the past and projecting the future," September 2010, for a detailed discussion of the evolution of historic costs for offshore wind.

14 *Ibid,* pp. 9-13.

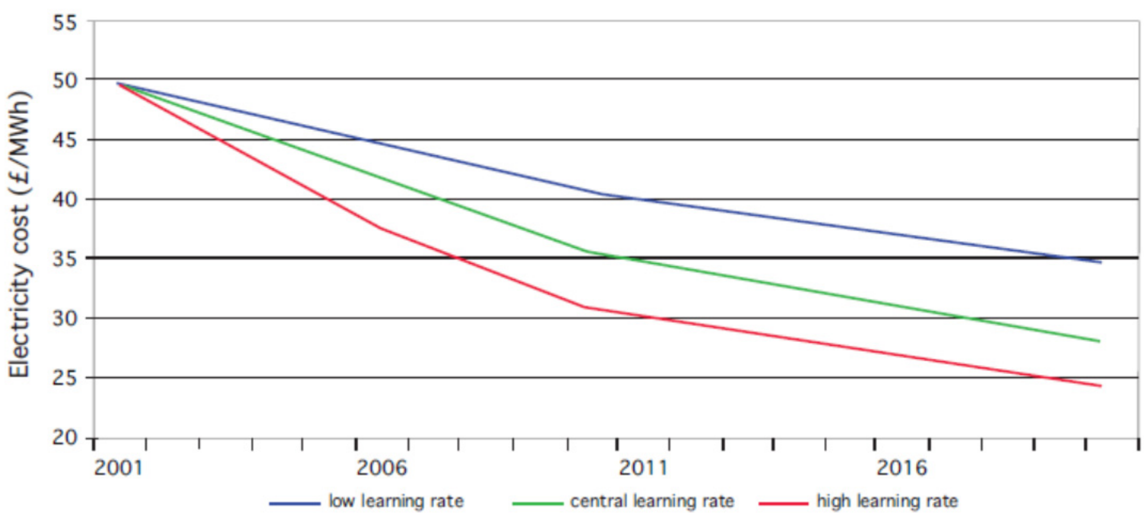
Figure 2: Capital Cost of Early Offshore Wind Projects



Source: Reproduced from Figure 2.2, UKERC (2010)

Based on these early observations, and on observations from the onshore wind industry, learning rates of approximately 15-20% were estimated for wind overall. This range of rates was used to predict the future cost of offshore wind, despite the limited experience with offshore wind at the time, and differences in cost-drivers of onshore and offshore wind.[15] Figure 3, for example, shows a 2002 projection of continually lower costs for offshore wind based on estimated learning rates.

Figure 3: 2002 Projections of Potential Future Costs of Offshore Wind

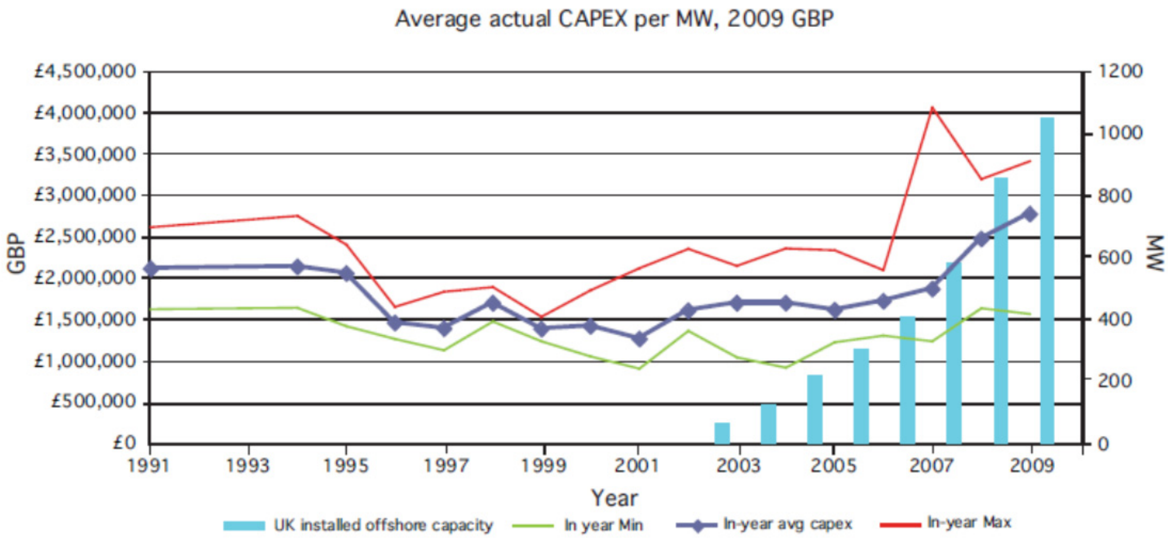


Source: Reproduced from Figure 2.5, U.K. DTI, Future Offshore: A Strategic Framework for the Offshore Wind Industry, 2002

15 *Ibid., p.*pp. 15-16.

However, the anticipated further declines in cost between 2002 and 2009 did not materialize. Rather, as the U.K. installed offshore wind capacity ramped up, so too did the average capital cost, as shown in Figure 4.

Figure 4: Average Capital Cost per MW of Offshore Wind Capacity in the U.K.



Source: Reproduced from Figure 4.1, UKERC (2010), page 43.

Several factors account for the less-than-expected cost decline in the U.K. offshore wind sector from 2005-2009. The recent increase in capital costs of offshore wind projects has been the subject of significant analysis. Broadly speaking, that analysis indicates that the current and future cost of offshore wind is driven not only by learning and scaling effects, but also by a number of additional factors. The most notable factors include the shifting location of offshore wind farms to sites farther away from shore in deeper water; the intensity of competition; potential bottlenecks in the supply chain; increased knowledge about actual project cost relative to expected cost; and fluctuating raw material prices and exchange rates.[16]

Distance from shore and water depth are likely more significant for capital and O&M expenses than for the levelized cost of energy production.[17] Since both factors tend to coincide with locations of better wind resource quality, increases in capital and O&M costs are at least partially (if not more than) offset by increases in capacity factors, so the LCOE produced from wind farms still declines over time, all else equal, as learning and scale increase. However, the other factors identified above must be considered in any estimate of the future cost of offshore wind as they will impact how the total cost and offshore wind's LCOE evolves over time. The estimates of future offshore wind cost in the next two sections investigate these costs explicitly.

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16 See, *e.g.,* NREL, "Large-scale offshore wind power in the United States: Assessment of opportunities and barriers," September 2010, p. 110.

17 The direct relationship between the capital cost of offshore wind and the distance from shore and water depth is well-documented. See, *e.g.,* Bob Van der Zwaan et al., "Cost reductions for offshore wind power: Exploring the balance between scaling, learning and R&D," Renewable Energy (41), 2012, p. 390. The same holds true for O&M costs.

2. Domestic Evidence

The experience with the cost of offshore wind in the U.S. is, of course, even more limited since no offshore wind turbine has been installed in the U.S. as of the writing of this report. It is nonetheless possible to derive estimates of the likely cost of offshore wind based on information available on proposed projects.

NREL has estimated the current (2010) capital cost of offshore wind in the U.S. at about $4.25 million/MW.[18] Levitt, et al. (2011) estimates the current cost for a first of a kind ("FOAK") offshore wind project (i.e. one in an undeveloped market such as the U.S.) at $268/MWh without subsidies, such as the Production Tax Credit ("PTC") or Investment Tax Credit ("ITC"), and financed as a single project (as opposed to on balance sheet), with a global average of $192/MWh and a lowest observed cost of $90/MWh.[19]

There are now several U.S. offshore projects at various stages of development. Their likely cost can be estimated from the available information on these projects, especially proposed or approved off-take contracts. However, there are some important caveats. Contracts are highly project-and product-specific. They differ in length and, at least in some cases, do not cover the entire expected lifespan of the offshore wind project, which means the expected revenue from post-contract market sales also must be estimated to estimate the LCOE over a project's entire life. Since most project-specific economic information is proprietary, many other parameters also must be estimated.[20]

The Cape Wind project off the coast of Massachusetts is the furthest developed U.S. offshore wind project to date. Cape Wind has in place a 15-year power purchasing agreement ("PPA") with National Grid at a base price of $187/MWh, escalating at an annual rate of 3.5%. This base price could be higher or lower than $187/MWh, depending on a number of factors, such as the ultimate size of the project, the existence (or lack) of the ITC or PTC, and other factors.[21] The levelized cost of the Cape Wind PPA, depending on which base price ultimately applies, is estimated at $213-270/MWh. However, the actual levelized cost of the project itself will be different for several reasons. The contract only covers 15 years, so the project will earn market revenue for the remaining 5-10 years of its expected operational life. Since the estimated LCOE over the life of the project is higher than the projected average market prices for energy and capacity (and potentially renewable attributes), revenues under the PPA must be higher for the project to earn sufficient revenues over the course of its life to cover total costs. Also, under several of the base rate scenarios, the project receives either the ITC or PTC, so the base price understates its unsubsidized cost.

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[18] United States Department of Energy, A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States, February 2011, p. 8.

[19] Andrew Levitt *et al.*, "Pricing offshore wind power," *Energy Policy*, Vol. 39, 2011, p. 6418.

[20] The difficulties of drawing conclusions from project-specific PPAs are well understood. See, e.g., NREL (2010), *op. cit.,* p. 119.

[21] See Massachusetts Department of Public Utilities, D.P.U. 10-54, Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the Department of Public Utilities of two long-term contracts to purchase wind power and renewable energy certificates, pursuant to St. 2008, c. 169, § 83 and 220 C.M.R. § 17.00 et seq., November 22, 2010.

Similar issues arise when analyzing the PPA prices of other past and present U.S. offshore wind projects. For example, the PPA for the Delaware project originally proposed by NRG Bluewater Wind was for a term of 25 years, covering essentially the entire expected life of the project and making the PPA a good benchmark for the project's cost. The PPA base price for that project was $99.90/MWh, escalating at 2.5% per year over the contract term. However, the Bluewater PPA has specific provisions related to renewable energy certificates ("RECs"), some of which are retained by the developer. Adjusting for project-specific PPA clauses such as these is difficult, but they have been estimated to result in a levelized cost of the PPA of $230.6/MWh were it translated into a 15-year PPA. This puts its cost roughly at the same level as Cape Wind's cost, which, translated into a 25-year PPA is approximately $214/MWh.[22]

A report on the cost of offshore wind in Virginia estimated lower levelized cost.[23] It estimated the LCOE for a hypothetical (588 MW) project at $105-130/MWh (constant 2008 dollars), which would correspond to approximately $111-137/MWh in $2012,[24] with installed capital costs of $2,780/kW if turbines are manufactured locally, and $3,260/kW if turbines are imported. The report estimated the cost of transmission (both submarine cable and on-shore upgrades and connection) at $153 million.[25]

A more recent study estimated the cost of connecting to the grid 648MW of offshore wind located 28 miles off the Virginia coast (and up to 9 miles onshore) at $652 million,[26] or approximately $1 million/MW. This is substantially higher than the assumed $5.54/kW per km,[27] or roughly $300,000/MW for the same project, and much higher than the estimated cost of the hypothetical 588MW project, for which installed capital costs were estimated.

A very recent report by NREL[28] uses the information described above from international and U.S. projects to determine a range of assumed costs for offshore wind projects. It derives a baseline estimate of $225/MWh ($2010), with sensitivities between $118/MWh and $292/MWh (also $2010).[29] Because this recent NREL report incorporates the findings from much of the experience over the past few years, we rely on this report in particular for the starting cost under our base case, which assumes medium learning rates going forward.

[22] The Bluewater project associated with the PPA described here is no longer active in its original form.

[23] VCERC, *Virginia Offshore Wind Studies*, July 2007 to March 2010, Final Report, April 2010.

[24] *Ibid,* p. 15.

[25] *Ibid,* p. 17.

[26] ABB Power Systems Consulting, Dominion Virginia Power: Offshore Wind Interconnection Study, February 29, 2012.

[27] VCERC, *op. cit.,* p. 10.

[28] S. Tegen, M. Hand, B. Maples, E. Lantz P. Schwabe, and A. Smith, *2010 Cost of Wind Energy Review*, NREL, April 2012

[29] *Ibid*, p. 61.

B. BOTTOM-UP ESTIMATES OF COST REDUCTIONS

Until recently, evidence on the actual costs of offshore wind projects was scarce. However, the rapidly increasing installed capacity base in the U.K. provides increasing information about project costs. The U.K. plans to install up to 18 GW of offshore wind capacity by 2020. A total leased offshore wind capacity through Round 3 of 54 GW[30] has resulted in a number of recent studies examining the potential for cost reductions as the scale of U.K. deployment grows. These studies indicate both current costs for offshore wind projects and bottom-up estimates for how cost is projected to change over time.

Offshore wind tends to be more expensive to build and maintain than onshore wind for several reasons. Offshore wind farms require stronger foundations. Installing them also is more complicated and more dependent on weather conditions than installing onshore wind. Performing O&M offshore also is riskier and can be more costly. Moreover, the sea is a harsh environment for wind turbines, which leads to higher installation cost and maintenance cost.

However, offshore wind offers some distinct advantages over onshore wind technology, such as access to the highest quality wind sites. As a result, offshore wind can have substantially higher capacity factors than onshore wind and this can partially or entirely offset its capital and O&M cost disadvantage. Also, assuming the existence of dedicated (or specialized) port facilities and vessels, offshore wind deployment can take place in a less restricted space, i.e., unencumbered by the limits imposed by onshore infrastructure (e.g., road width, bridge height, etc.). This allows for the development of significantly larger turbines, wind farms, and related economies of scale at both the turbine and farm levels. This has been the observed trend in U.K. projects between Rounds 1, 2 and 3. Round 1 projects ranged in total size from 10-250 MW.[31] Round 2 projects currently under development or construction range in size from 64-1200 MW.[32] Round 3 projects are planned in the range of 600-9000 MW.[33]

As discussed previously, the cost of an offshore wind project at any given time and location is driven by a number of factors complicating a comparison across time and projects. These factors include not only turbine and wind farm size, distance from shore and water depth, and capacity factor (a function of location), but also factors such as the intensity of competition and/or bottlenecks in various steps of the supply chain, planning and permitting complexities, the availability of dedicated/specialized vessels, ports and labor pools to support construction as well as O&M, commodity prices, exchange rates, and financing costs. As a result, there is no single cost for offshore wind projects, per se. The various studies we analyze often use "typical" offshore wind projects as a basis for making cost projections. While such estimates may be inaccurate for any specific project, they will likely be more reliable for the average of multiple offshore wind projects and for assessing the potential for relative cost declines over time.

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30 See DB Climate Change Advisors, "U.K. Offshore Wind: Opportunity, Costs & Financing," November 2011, p. 8f.

31 Including the Beatrice pilot project (10MW). Without Beatrice, the smallest round 1 project is Scroby Sands with 60MW capacity. See UKERC, *Great Expectations: The cost of offshore wind in U.K. waters - understanding the past and projecting the future*, September 2010, Table 3.1, p. 28.

32 *Ibid.,* Table 3.3, p. 32.

33 *Ibid.,* Ibid.,Table 3.4, p. 34.

Learning effects at the global and local level

Understanding how learning and scaling might affect the cost of offshore wind in the United States requires analyzing separately those cost reductions that might occur due to global increases in offshore wind capacity and those that occur locally, since the cost of offshore wind is driven by both local and non-local supply chains.

The cost and performance characteristics of offshore wind turbines are likely driven by a global supply chain. Historically, this supply chain is not specific to offshore wind, but serves both the onshore and offshore wind sectors combined. At the other end of the spectrum, the cost of installation is largely driven by local supply issues, such as the quality and distance of port facilities, the availability of specific vessels to install or maintain offshore wind installations, and the cost and qualifications of the labor pool. Other locally-determined costs include "soft" costs, such as permitting, environmental impact studies, and financing costs.

It is difficult to accurately separate the offshore wind supply chain into local and non-local components. While offshore wind turbine costs are likely driven by the scale of installations globally, enough local (i.e., U.S.) deployment could result in global turbine manufacturers building local manufacturing plants with corresponding lower costs due to shorter transportation routes, more favorable exchange rates (or at least elimination of exchange rate risks), and perhaps lower wage rates. Similarly, though installation costs tend to be determined more by local factors, a global scaling up of offshore wind installations will lead to faster advances in the development of dedicated vessels and lower local installation costs.

1. Crown Estate Pathway Study

The most recent comprehensive study of potential offshore wind cost reductions is the Cost Reduction Pathways Study.[34] The study's goal is to understand whether a levelized cost goal of £100/MWh or less is achievable by 2020. It assumes that projects having reached financial closure by year-end 2011 have capital costs between £2,600/kW and £2,900/kW ($3,900-$4350/kW[35]) and operating expenses (including transmission costs) between £164-167/kW ($246 - $251/kW) per year, with approximately 1.5GW of offshore wind deployed.[36] Assuming a 10% after-tax cost of capital, the study estimates the current LCOE for U.K. offshore wind is £140/MWh ($210/MWh).

The study develops four different scenarios under which progress toward a goal of 40GW installed by 2020 might be accomplished: Slow Progress, Technology Acceleration, Supply Chain Efficiency and Rapid Growth. Each scenario makes different assumptions about the speed of offshore wind deployment, the intensity of competition, the rate of technological progress, the development of associated supply chains, and the depth of financial markets for financing of offshore wind. For each scenario, a cost trajectory through 2020 (Financial Closure by 2020) is

[34] The Crown Estate, "Offshore Wind Cost Reduction Pathway Study," (May 2012).

[35] Throughout this report we use an exchange rate of $1.50/£, which is very close to the average exchange rate over the past five years, which have been fluctuation between approximately $1.40/£ and $1.60/£.

[36] *Ibid.,* pp. vii, 15.

estimated. The average projected levelized costs are £115/MWh, £100/MWh, £96/MWh and £89/MWh ($173/MWh, $150/MWh, $144/MWh and $134/MWh), respectively.

The study identifies three principal sources of cost reductions: technology, the supply chain and, to a limited degree, financing.

Technology is expected to generate cost reductions primarily from new offshore wind turbines. Of the expected 39% reduction in LCOE between 2011 and 2020 due to technology and supply chain improvements, 17% are attributed to new turbines, 3% each to technological advances in installation and support structures.[37] Expected reductions in wind turbine cost, in turn, stem from increases in rated power, which is responsible for approximately 50% of the turbine cost savings, improved blade design and manufacturing (16.7%), changes to the drive train (11%), larger rotors (5.6%), and other improvements (16.7%).[38]

The major change to turbines is expected to be a gradual move from 3-5MW turbines to the 5-7MW class and the introduction of 8MW turbines. This increase in rated power decreases the capital cost on a per MW basis, contributing significantly to overall cost savings. It is also expected to reduce operating costs by approximately 12% on a per MW basis, since maintenance has to be performed at fewer sites for the same total capacity. As of April 2012, 12 manufacturers offered offshore wind turbines with capacity of 5MW or greater, 7 of which have already installed prototypes.[39]

Supply Chain Improvements are expected to lead to cost reductions due to increased competition, scale-related learning, increased productivity, and changes to front-end activities such as permitting, planning, etc. Historically, the turbine market has been dominated by a relatively small number (two to four) of market participants. Going forward, the supply of support vessels and specialized installation contractors is expected to be tight. Tight supply relative to demand increases costs to buyers. In fact, tight supply is one reason that the installed cost of offshore wind has increased over the past few years. As the number and scale of installations increases, more competitors will enter the market, which will relieve some of the tightness along the supply chain and will lower both installed cost and LCOE.

Other improvements expected to contribute to cost reductions include: better offshore wind array optimization, more thorough ex-ante characterization of seabed and other conditions, greater use of surveys, earlier involvement of the supply chain (e.g., developers partnering with suppliers during rather than after development), optimized installation methods (e.g., using specialized installation vessels), and standardization.[40]

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37 *Ibid,* p. 16.

38 The percentage decreases in the Crown Estate study are multiplicative rather than additive. For example, the various cost improvements for turbines are 9%, 3%, 2%, 1% and 3% respectively. So the total forecast potential cost decline due to new turbines is calculates as (1-0.09)*(1-0.03)*(1-0.02)*(1-0.01)*(1-0.03) = (1-0.17), *i.e.* a cost decline of 17%. See Note to Exhibit 3.6, *ibid,* p. 16.

39 *Ibid,* p. 19.

40 For a detailed description of the supply chain related cost improvements, see The Crown Estate (2012), pp. 20-28.

Financing costs are projected to be slightly lower by 2020.[41] Given the relative large contribution of upfront capital cost to the LCOE of offshore wind, a 1% decrease in capital cost is estimated to result in a 6% decrease in LCOE. In the U.K., essentially all construction work for offshore wind farms is equity financed, with over 90% of equity funds coming from integrated U.K. or European utilities, IPPs or oil and gas companies. By 2020, up to 40% of construction finance is expected to be provided by a mix of public lenders (such as the European Investment Bank, or the U.K.'s newly-created Green Investment Bank) and bank and mezzanine debt.[42] Post-construction debt levels are expected to remain relatively low, at 30-40% through 2020 after dipping to 20-25% in the near term, due to better managing and mitigating project risk, as well as policy changes.[43] The former will occur somewhat automatically as scaling up offshore wind creates opportunities for learning and for gaining information about risk factors such as construction cost, post-warranty maintenance expenses and capacity factors and profiles. While financing for U.S. offshore wind initially differs somewhat from financing in the U.K., scaling up U.S. offshore wind should lead to similar scope for risk reductions and lower financing costs.

Another major driver of lower financing costs by 2020 is the planned introduction of feed-in tariffs for offshore wind, which are expected to lower the cost of equity by an estimated 0.5%.[44] The U.S. is not yet moving from a certificates approach to a feed-in tariff, and the current U.K. approach is not too different from an RPS. However, the form of policy support and, in particular, the approach for collecting revenues from the sale of output from an offshore wind project can have a significant impact on an offshore wind project's LCOE.

To compare the results of the Crown Estate study with the other studies we reviewed, we translate the range of estimated cost reductions reported in the Crown Estate study into implied learning rates. The learning rate is defined as the percentage decline in cost resulting from a doubling of cumulative installed capacity. Translating bottom-up cost estimates into implied learning rates allows us to compare the results to the top-down estimates of learning rates for offshore wind discussed in the next subsection.

Table 1 shows the implied learning rates of the estimated cost changes between now and 2020 from the Crown Estate study.

41 It is worth noting that assumed reductions in financing costs are based on factors other than changes in the general interest rate environment. Higher or lower general interest rates would have an important impact on the costs of offshore wind, given the high fraction of capital investment in total costs.

42 *Ibid,* p. 29.

43 *Ibid,* p. 29.

44 *Ibid,* p. 32.

Table 1: Learning Rates implied by Crown Estate Scenarios

Scenario	Description	Implied Learning Rate*
Slow Progression	• 31GW in Europe by 2020 (12GW in UK) • Incremental technology evolution, progress limited by market size • Limited completion /economies of scale • Modest developments in financing solutions, reduced in risk/cost of capital	4.4%
Technology Acceleration	• 36GW in Europe by 2020 (17GW in UK) • High levels of technology evolution across all wind farm • elements (e.g. turbines progress rapidly to 5-7MW+) • Fragmented supply chain with some improvement in collaboration • Limited improvement in cost of capital due to ongoing changes in technology	7.1%
Supply Chain Efficiency	• 36GW in Europe by 2020 (17GW in UK) • Incremental technology evolution (e.g. steady progress to 5-7MW turbines) • Greater competition, investment, project collaboration and better risk management • Deeper financial markets, lower risk/lower cost of capital	7.9%
Rapid Growth	• 43GW in Europe by 2020 (23GW in UK) • High levels of technology evolution across all wind • farm elements (e.g. turbines progress rapidly to 5-7MW+) • Greater competition, investment, project collaboration and better risk management • Challenging volume of finance required	8.9%

Source: The Crown Estate (2012), p.38; TBG analysis.

* To calculate the implied learning rate, we first calculated the number of doublings of total capacity under each scenario. We then used the estimated change in cost from £140/MWh today to the cost in each scenario by 2020 to derive the implicit percent change in cost for each doubling of installed capacity to achieve a particular scale.

2. UKERC Great Expectations Study

A second study from the U.K. also provides a recent and comprehensive bottom-up estimate of the cost trajectory of offshore wind.[45] The study provides a detailed assessment of potential future cost reductions by component. For example, it estimates capital costs by forecast year out to 2050, ranging as low as £2,400/kW.[46] It also reports annual O&M expenses of £50,000/MW, or far lower than the number reported in the Crown Estate study. It ultimately reports the cost of offshore wind in the U.K. at £145/MWh in 2009,[47] or close to the estimated £140/MWh for year-end 2011 in the Crown Estate study. At an exchange rate of 1.5, this implies a cost today of $210-$218/MWh. By 2020, the study estimates cost could be as low as £95/MWh ($143/MWh), but is expected to be £116/MWh ($174/MWh).

[45] UKERC, "Great Expectations: The cost of offshore wind in U.K. waters – understanding the past and projecting the future", September 2010.

[46] *Ibid.,* pp. 93, 109.

[47] *Ibid.,* p. 93.

3. U.S.-Based Cost Estimates

In addition to the two U.K. studies, there are two notable studies of U.S. offshore wind costs.

A 2010 study by NREL projected a 12.5% decrease in capital costs by 2030, from $2,400/kW.[48] The same study projected a 15% increase in the performance of both onshore and offshore wind over the same period.[49] However, the recent increase in offshore wind costs observed since the study was published, and discussed above, puts in doubt its near-term cost assumptions.

A more recent study by the Department of Energy also projects a decrease in capital costs to $2.6 million/MW by 2030, and in LCOE from $270/MWh in 2010 to $70/MWh by 2030.[50] However, this cost development path is more aspirational than actual, as it is not estimated from observed cost decreases.

C. Estimated Cost Reductions based on Learning Curves

In addition to bottom-up estimates of potential cost declines for offshore wind energy, there also are several top-down estimates of learning rates derived, not from engineering assessments, but rather from historical evidence on cost changes for offshore wind or similar industries. In this section, we summarize the top-down estimates and compare them to the bottom-up numbers already discussed to develop a range of assumptions about both starting costs and learning rates going forward for U.S. offshore wind, as a basis for the analysis presented in the next section of this report.

1. Prior Studies

Top-down studies typically estimate progress ratios ("PR") for all, or portions of, offshore wind costs. Progress ratios and learning rates ("LR") are directly related. The LR is simply the percentage cost reduction (per unit of capacity or per unit of energy generated) expected from a doubling of cumulative installed capacity, or $LR = 1 - PR$.

At least five studies specifically estimate learning rates for offshore wind.

First, a 2002 study from Denmark analyzed the potential for cost reductions for offshore wind, onshore wind, and solar PV.[51] For all three technologies deployed to 2030, the study estimated component-specific PRs and a range of capital costs. As we noted previously, however, the absolute capital cost estimates likely are not reliable going forward, since the study does not account for the drivers of the recent cost increases of offshore and onshore wind. In relative terms, the study estimated learning rates for offshore wind components of 5% to 7.5% for the

48 NREL, "Large-Scale Offshore Wind Power in the United States: Assessment of Opportunities and Barriers," September 2010, p. 121. Stated in $2006.

49 *Ibid.*

50 U.S. Department of Energy, "A National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States," February 2011, p. 15.Ibid., p.

51 Lako, P., "Learning and Diffusion for Wind and Solar Power Technologies - Monograph in the framework of the VLEEM project," Petten, the Netherlands, ECN, 2002.

capital cost of turbines and foundations, and from 2.5% to 5% for cabling infrastructure.[52]. The study found learning rates for offshore wind were less certain than for onshore wind. However, given a higher average expected capacity factor of offshore wind (36% compared to 24% in the study), it projected that offshore wind costs could match the lower cost of onshore wind by 2030.[53]

Second, a 2004 study took a similar approach, separately estimating learning rates for offshore wind turbines, foundations, grid connections, and installation.[54] The study noted the difficulty of estimating learning curves for offshore wind due to limited actual experience to date. However, it applied the experience in related industries, in particular onshore wind, to offshore wind and supplemented the empirical data with information from interviews.[55] Table 2 identifies the sources of potential cost savings the study identified in each area.

Table 2: Potential Improvement Opportunities for Offshore Wind Cost

Cost Area	Improvement Opportunities
Wind Turbines	Larger Scale, Improved Design, Standardization and Economies of Scale
Foundations	Standardization, Economies of Scale, Design Regarding Dynamic Loads
Grid Connection	Standardized Design for HVDC cables, Applying XLPE insulation to HVDC cables; Advances in valve technology and power electronics
Installation	Standardization of hammer equipment, development of purpose-built ships, learning-by-doing

Source: Junginger, M., et al. (2004).

According to this study, learning rates for onshore wind turbines are 18-19% assuming global effects, and about 8% looking only at national deployment with an assumed turbine-related learning rate of between 15-19%.[56] Learning rates for grid connection are assumed to be relatively large, on the order of 30% (based on cumulative MW miles installed). The large cost reductions are based on both the relatively low current experience with HVDC links to offshore wind farms, giving rise to large potential cost reductions, and also the possibility that as HVDC connections get deployed, technology could shift to even lower cost alternative approaches.[57] The study points to substantial existing experience in installing foundations, based on the offshore oil and gas industries. However, the study's estimated cost reductions for foundations are not based on experience curves. Like the 2002 study, the study focuses on capital costs (components and

52 *Ibid., p.*p. 29.

53 *Ibid., p.* 30.

54 Junginger, M., *et al*., "Cost Reduction Prospects for Offshore Wind Farms," *Wind Engineering*, Vol. 28, No. 1, 2004, pp. 97–118.

55 *Ibid.,* pp. 3-4.

56 *Ibid.,* p. 5. The evidence on learning for onshore wind is used as an input into the analysis of learning rates for offshore wind.

57 *Ibid.,* p. 5.

installation). It estimates changes to the installed cost of offshore wind turbines over time, ignoring potential increases in capacity factors due to improving turbine design (or better placement of turbines) or potential O&M cost reductions.

Third, a 2006 study from Sweden provides more recent estimates of learning rates for onshore and offshore wind.[58] The study highlights the distinction between estimates related to capital costs alone, and estimates that impact the LCOE. It points to a range of studies examining the capital cost of onshore wind Denmark, with learning rates between 9-10%, compared with learning rates of 17% for the LCOE over the same time period (1981-2000).[59] The study also points out that learning rates for onshore wind based on cumulative installations across countries may be quite similar even though the actual costs of deployment differ substantially.[60] This highlights the importance of local factors not easily captured in global assessments. Thus, while it may be possible to generalize learning rates across countries, the absolute cost levels may differ by country, even assuming similar cumulative installed capacity.

The study updates the prior estimates of learning rates, finding a learning rate of only 3% and a poor statistical fit with the data, indicating that onshore learning curves may not be indicative of learning rates for offshore wind.[61] The study finds initial cost declines with an implicit learning rate of approximately 10% followed by more recent cost increases, attributable in part to the difference between the observed prices and the underlying but unobserved costs. That difference is consistent with the absence of competition and the existence of supply bottlenecks, as described above.[62]

Fourth, a 2011 report summarizes prior estimated learning rates.[63] The estimates range from roughly 10% considering only learning, to less than zero, after accounting for other factors that influence cost over time, such as raw material prices and industry competitiveness.

Finally, a 2012 study accounts for changes in relevant commodity prices.[64] The real cost of offshore wind has stayed flat since 1991. However, as Figure 6 shows, the study estimates a learning rate of approximately 3% from 1991 to 2008, after accounting for changes in commodity prices. Estimated learning rates averaged nearly 5% per year between 1991 and 2005, but later declined with increases in offshore wind costs.

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58 Lisa Isles, "Offshore wind farm development: Cost reduction potential", Lund, Sweden, Lund University, 2006.

59 *Ibid,* pp. 16-25.

60 *Ibid,* p. 28.

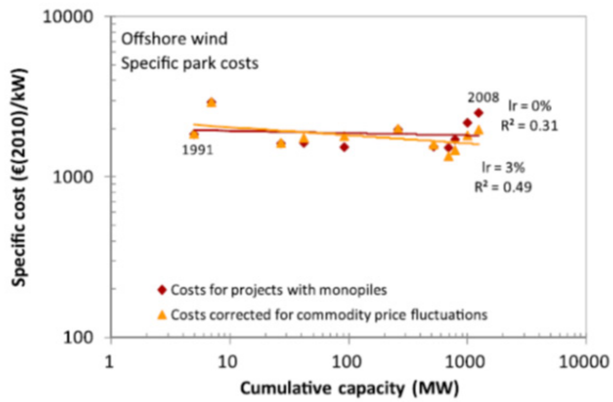
61 *Ibid,* p. 41f.

62 *Ibid,* p. 49.

63 Hoefnagels, Ric, *et al.,* "Long Term Potentials and Costs of RES, Part I: Potentials, Diffusion and Technological Learning," Report compiled within the European research project RE-Shaping (work package 5), May 2011.

64 Van der Zwaan, *et al.,* "Cost reductions for offshore wind power: Exploring the balance between scaling, learning and R&D," *Renewable Energy* 41 (2012), pp. 389-393.

Figure 6: Learning Rates Accounting for Commodity Prices



Source: van der Zwaan et al. (2012), Figure 3.

2. Conclusions

Projecting the trajectory of the future cost of offshore wind is complex. Nonetheless, there are some consistencies in general cost trends between the various bottom-up/engineering studies and the more general top-down/statistical analyses described in this section.

The prior studies indicate a range of LCOE cost reductions consistent with learning rates between 3% and 10% per doubling of capacity, assuming that some of the factors that have been driving up costs over the past few years are temporary. For example, the future cost of offshore wind likely depends significantly on the evolution of raw material prices (such as steel). The range of potential cost reductions assumes that raw material prices in the future return to their historic trends (on a real basis). The range of learning rates also is consistent with the learning rates historically observed for onshore wind on a LCOE basis, but for somewhat different reasons. Since a larger share of total capital expense for offshore wind is related to foundations (and grid connection), cost reductions for capital expenses going forward may be somewhat less than the corresponding cost reductions for onshore wind at comparable cumulative capacity. However, there seem to be more opportunities for lowering the significant O&M expenses through the development of more specialized supply chains as well as more opportunities for increasing the output from offshore wind farms, due to the relative lack of physical constraints on the size of offshore wind turbines and wind farms, and the ability to reach better wind resource sites as technology progresses.

This being said, the range of potential cost reductions going forward could underestimate actual cost reductions to the extent that structural technology changes are more likely for offshore wind than they are for onshore wind at this point. For example, one of the potential reasons why learning rates for offshore wind might be lower than they have been for onshore wind is the assumption that foundations, which represent a much higher portion of offshore wind than onshore wind costs, are relatively mature. It is, however, possible that innovation – for example towards floating foundations – provides entirely new opportunities for cost reduction not captured by typical learning rate estimates.

For our analysis, we therefore apply learning rates in the range of 3-10%[65], recognizing that there is some possibility that offshore wind technology might go through more fundamental technology shifts as just described, which in turn could lead to greater cost reductions than those reflected in this range. On the other hand, the experience of the last several years has shown that the overall evolution of offshore wind costs depends critically on factors such as raw material prices, which in turn could potentially grow at rates higher than average inflation, making progress of offshore wind costs slower than predicted by this range[66].

IV. THE POTENTIAL FOR OFFSHORE WIND TO BE COST-COMPETITIVE WITH ALTERNATIVES

In this section we provide an analysis of the potential for offshore wind to be cost-competitive with alternative sources of energy in the U.S. at various scales and over various time frames.

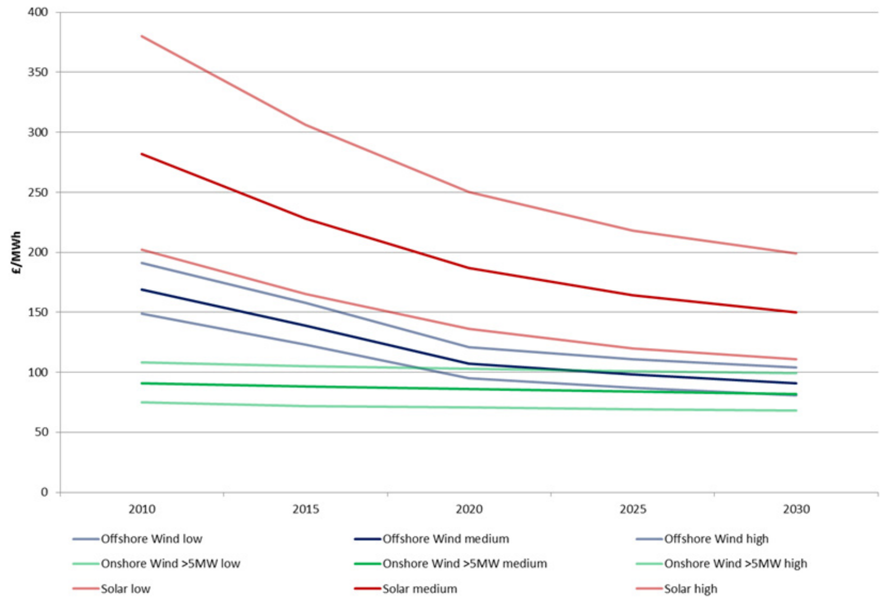
A. THE COST OF ALTERNATIVE RENEWABLE ENERGY SOURCES

The cost of alternatives to offshore wind, such as onshore wind and solar PV, is highly dependent on a number of factors, including: the current level of deployment (and embedded learning effects), the anticipated future deployment levels and related additional learning-related cost declines, the basic costs of the technology, and the resource quality of the location where the technology is assumed to be installed. Figure 8 provides one estimate of the trajectories of the LCOE for solar PV, offshore wind and large-scale onshore wind in the U.K. between 2010 and 2030.

65 The reports we cite provide many potential sources of lower LCOE, which include both lower costs and higher capacity factors. Our own calculations are largely insensitive to which particular factors drive decreasing LCOE. For the purpose of calculating the amount of new CCGT capacity required in the absence of offshore wind, we assume that the capacity factor for new offshore wind projects increases at a steady rate of 0.5% per year, from 37.5% in 2014 to 40.7% by 2030. For our macroeconomic impact analysis, we assume that, given the change in capacity factors, installation and operating expenses decline proportionally and enough to result in an LCOE equivalent to what is implied by our assumed learning rates. To calculate the LCOE, we use a publically available LCOE model developed available at www.energy.ca.gov/reti/.../2011-04-11_RETI_COG_Updated.xls

66 It is worth noting that some of the factors that might slow cost declines for offshore wind might also affect other renewable or conventional technologies.

Figure 8: Estimated LCOE for Renewable Technologies in the U.K.



Source: DB Climate Change Advisors, "U.K. Offshore Wind: Opportunity, Cost & Financing," Exhibit 14.

As Figure 8 shows, the cost of PV in the U.K. is currently above the cost of offshore wind, which in turn is above the cost of large-scale onshore wind. The same is likely true in the United States as well. While this relationship is expected to hold through 2020, the cost paths of each technology are uncertain – as indicated by the lighter colored bands around the costs of each technology, as well as the overlap over time in the cost trajectories. This means it is unclear whether any one technology will dominate the others in terms of LCOE, even assuming all technologies can be built out to projected levels. Below, we discuss in more detail what this implies for the potential learning investment support for offshore wind (and other renewable technologies) as part of a renewable resource portfolio.

Globally, learning rates for both onshore wind and solar PV have been higher than those for offshore wind. Long-term estimates of learning rates for wind (mostly onshore) range from 9% to 19%,[67] with a recent source showing an average LCOE learning rate of 14% between 1984 and 2011.[68] This range of estimated rates reflects the importance of the underlying assumptions, including: the time period over which learning rates are estimated, whether they are estimated based on a single country or at a global level, exchange rates, etc. Given the fact that onshore wind has become a globally integrated industry, we think it is appropriate to use a global approach to forecasting future costs for onshore wind.

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67 Erik Lantz *et al., IEA Wind Task 26: The Past And Future Cost Of Wind Energy, Work Package 2*; NREL, May 2012, p. 18.

68 Powerpoint presentation, Bloomberg New Energy Finance Summit, Day-2 Keynote, Michael Liebreich, March 20, 2012, p. 16.

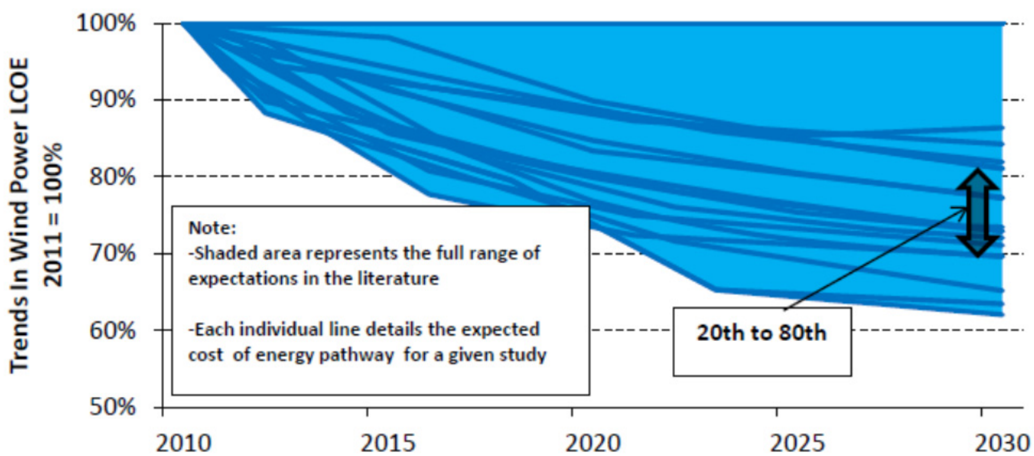
1. Onshore Wind

Based on the range of estimated learning rates from recent studies, we assume the LCOE of onshore wind will decline by between 20% and 50% in real terms relative to current costs by 2030. There is also a relatively wide range of estimates of the current LCOE of onshore wind. As with offshore wind, the LCOE of onshore wind depends on several factors, most notably wind speed and wind profile at the facility location. Differences in capital costs (due both to differences in transportation costs and labor costs) and exchange rates also have a material impact.

For example, as Figure 8 above illustrates, the LCOE of onshore wind in the U.K. as of 2010 was estimated at £91/MWh. At an exchange rate of $1.5/£, this translates into an LCOE of $136.5/MWh. Recent U.S. estimates of the LCOE of onshore wind put the cost closer to $70/MWh,[69] a difference of almost 50%. Part of this difference is driven by different assumptions about capacity factors, which in turn are a function of local wind quality. For example, the £91/MWh is based on an assumed annual capacity factor of 29% in the UK.[70] However, recent U.S. projects have average capacity factors exceeding 30%, with significant improvements expected going forward.[71] Also, the more recent U.S. data reflects declining installation costs.

Lantz et al. (2012) present a graph combining the results from 13 recent studies examining the likely evolution of onshore wind costs through 2030. Figure 9 shows the estimated range of further cost reductions of between 20% and 30% by 2030 relative to 2010, with extreme cases of cost reductions at zero or nearly 40%.

Figure 9: Summary of potential evolution of LCOE for onshore wind



[69] Erik Lantz et al., *IEA Wind Task 26: The Past And Future Cost Of Wind Energy, Work Package 2*; NREL, May 2012, p. 16, which addresses the cost decline between 2009-2010 and 2012.

[70] Department of Energy and Climate Change, Review of the generation costs and deployment potential of renewable electricity technologies in the UK, Study Report, Updated October 2011, p. 23.

[71] Erik Lantz et al., IEA Wind Task 26: The Past And Future Cost Of Wind Energy, Work Package 2; NREL, May 2012, p. 11f, which suggests that due to recent technological progress the land area where onshore wind can achieve a capacity factor of 35% or more has increased by 270% when compared to turbines installed in 2002-2003.

Source: Reproduced from Erik Lantz et al., IEA Wind Task 26: The Past And Future Cost Of Wind Energy, Work Package 2; NREL, May 2012, Figure 11, page 26.

It is important to note that while the cost of onshore wind has declined substantially and is forecast to decline further, the ultimate cost of onshore wind will also depend significantly on the location of the on-shore wind capacity relative to the demand it is serving. The largest centers for electric demand are located at or near the coasts, i.e., close to where offshore wind might be deployed, but potentially far from the best wind resources in the United States, which are located in the center of the country. Therefore, significant additional infrastructure costs would need to be incurred to assure that onshore wind power can actually be delivered to those load centers. The cost of the additional investment in transmission needed to bring substantial wind resources from the Center of the U.S. to the East have been estimated by the National Renewable Energy Laboratory in its Eastern Wind Integration and Transmission Study. For a reference case and four scenarios with assumed wind penetration rates of 20% to 30%, those costs were estimated to range from $32-93 billion ($2024)[72]. As we will show below, this cost range is similar to the total learning investments needed for offshore wind to reach grid parity under a number of our scenarios.

2. Solar PV

The cost of solar PV has been falling rapidly over the past decade. Early estimates assumed a 20.2% learning rate for panels, based on module prices and cumulative deployment between 1968 and 1998.[73] Estimated learning rates for the Balance of System ("BOS") and installation were 13% and 6%, respectively.[74]

As with wind, understanding the evolution of solar PV costs over time requires learning and scale effects to be disaggregated from shorter-term cost drivers, such as changing degrees of competition, supply-demand balances, and fluctuations in raw materials prices and exchange rates. It also requires an understanding of how the LCOE of solar PV in the U.S. may be driven by learning that takes place locally, regionally and globally. Some parts of the solar PV supply chain are clearly global, while others, such as installation, are inherently local.

In addition to understanding how the cost of PV might evolve as a result of learning and scaling, deriving cost estimates for solar PV between now and 2030 also requires an estimate of the evolution of the installed capacity over time. Jäger-Waldau (2012) compares estimates of PV deployment on a global scale between today and 2030 (and beyond). Across six scenarios from two studies (Greenpeace and IEA), estimated PV installations increase from 70 GW at the end of 2011 to between 234GW and 1,764GW by 2030.[75] This implies approximately two doublings of the installed capacity at the low end (e.g., 2 x 2 x 70 = 280GW) and more than four doublings at the high end (e.g., 2 x 2 x 2 x 2 x 70GW = 1120GW).

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[72] EnerNex Corporation, "Eastern Wind Integration and Transmission Study"; prepared for The National Renewable Energy Laboratory; revised February 2011, p. 39.

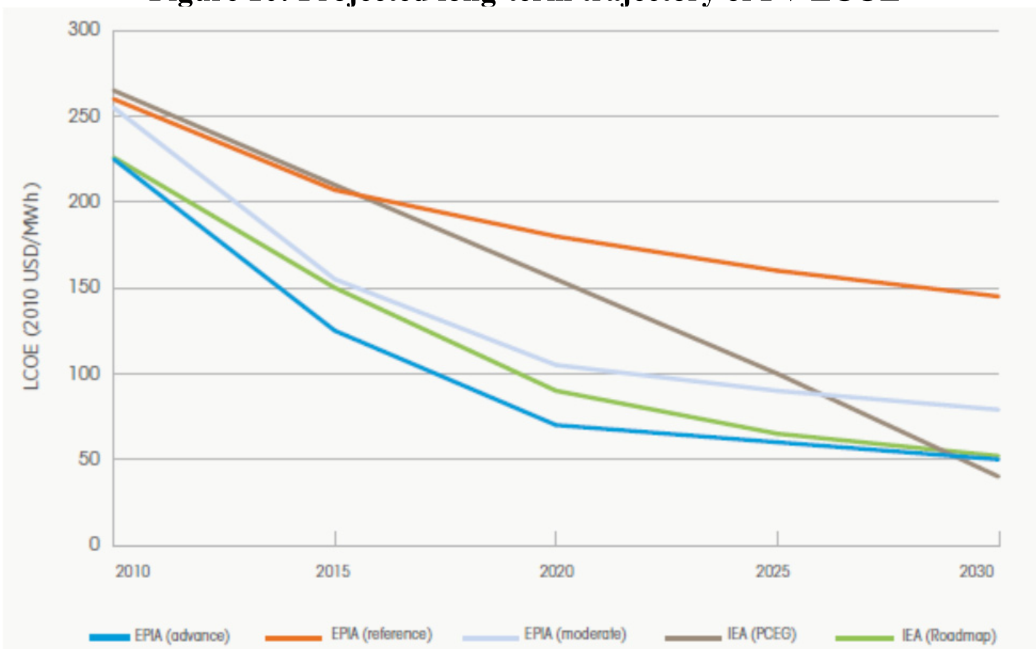
[73] Lako (2002), *op. cit.,* p. 43.

[74] Ibid, p. 44.

[75] Arnulf Jäger-Waldau, *PV Status Report 2012, Part 1, EUR 25749 – 2012*, 2012, p. 38.

Solar PV learning rates, expressed on a \$/We[76] installed basis rather than on an LCOE basis, have been estimated at between 15% and 24%.[77] The LCOE of solar PV has likely seen even steeper declines, as decreases in installed costs have coincided with increases in solar cell efficiency and hence has resulted in higher power generation per installed Watt of capacity.

Figure 10: Projected long-term trajectory of PV LCOE



Source: Reproduced from Figure 6.1, Irena, Renewable Energy Technologies: Cost Analysis Series, Solar Photovoltaics, Volume 1: Power Sector, Issue 4/5, June 2012, page 39

3. Conclusions about the cost of onshore wind and PV relative to offshore wind

In summary, research and empirical evidence on the current and estimated future cost of various renewable alternatives to offshore wind suggest a wide range of estimates. There is no clear evidence that any one renewable technology will dominate the alternatives in terms of cost. Even though at present the cost of onshore wind is likely lower in most locations than the cost of offshore wind, this does not by itself justify putting all resources into the further scaling of onshore wind. Even though the one technology focus would, all else equal, result in faster cost declines for the chosen technology, the evidence on learning rates especially over long periods of time is quite imprecise.[78] Hence, the chance of "betting" on the wrong technology in such a case would be very high. Part of the problem is that a simple application of learning rates tends to miss the potential impact of technology structural changes inside a given technology, giving rise to

[76] Solar capacity is often reported on a "watt equivalent" or We basis.

[77] Morgan Baziliana, *et al., Re-considering the Economics of Photovoltaic Power*, 2012, p. 4.

[78] For a discussion of this topic, see OECD/International Energy Agency, "Experience Curves for Energy Technology Policy", 2000, p. 92.

"knees" in the learning curves for a particular technology[79]. That is, there are situations where, due to some discrete technological change, the learning rates for a particular technology - such as the potential move to floating platforms for offshore wind described above – might accelerate for some time and then slow down again thereafter.

Even assuming one technology were cheaper than others based on a sophisticated forecast of learning rates, it is not clear whether any single technology can be ramped up to sufficient scale to meet all energy needs by 2030 and beyond.

Given the uncertainties about both cost and scalability across various renewable energy technologies, a strategy of investing in the scaling up (and associated learning) of only one technology (or a select few) is both risky and likely inefficient. Instead, offshore wind likely will be one technology among several that can be used to develop a diversified electricity portfolio. Therefore, we focus on the learning investment that may be needed to bring offshore wind to grid parity relative to fossil-fired generation, acknowledging that a similar innovation premium also may be required (and may be desirable) for alternative renewable technologies. The magnitude of such a premium depends on the current state and future potential of each technology. However, a detailed analysis of alternatives to offshore wind, paralleling the analysis in this paper, is beyond our current scope.

B. CONVENTIONAL POWER ALTERNATIVES

To calculate the learning investment needed to bring offshore wind power to grid parity, we need to compare the cost of offshore wind to the cost of electricity generation in the absence of offshore wind, *i.e.*, the cost of electricity that would be replaced by offshore wind. This determination is somewhat dependent on the geographic focus of the comparison.

The two potential sources of energy that set the market price for electricity and which would likely generate electricity in the absence of powder generation from offshore wind are natural gas-fired and coal-fired power generation. With the increasing availability of low-cost natural gas (from shale gas) in many parts of the U.S., gas-fired generation is the technology offshore wind power typically would displace. In the Southeast U.S., however, coal-fired power generation remains the dominant form of electric power generation and could, therefore, be a valid comparison technology for determining the cost of offshore wind power that would result in grid parity. However, for purposes of simplicity, we focus here primarily on the cost of natural gas-fired power generation from today through 2030 as the measure of "grid parity"[80].

Even though natural gas-fired capacity is likely a good benchmark against which the cost of offshore wind can be compared, in reality, the generation from offshore wind likely would displace a mix of electricity from coal and natural gas. While the costs of both types of energy are likely to be close at the margin, coal and gas-fired generation differ significantly with respect to various emissions including CO_2. The precise pattern of avoided generation due to installing offshore wind depends on many factors, including the location of offshore wind in relation to the existing generation and grid infrastructure, the evolution of coal and gas prices, etc. However, we

79 *Ibid*, p. 34.

80 We include some additional costs related to carbon emissions from a mix of both gas and coal-fired power generation in our measure of CO_2-grid parity as defined and described below.

use a straightforward approach to obtain a reasonable (although not precise) estimate the impact of actual generation displaced by offshore wind as a mix of coal and natural gas rather than only natural gas. Specifically, we assume that the CO_2 intensity of the displaced energy in 2014 is 0.7 tons/MWh, declining linearly to 0.55 tons/MWh by 2030. The carbon intensity of natural gas fired generation is approximately 0.5 tons/MWh, while the carbon intensity of coal-fired generation is approximately 1 ton/MWh. Our approach therefore assumes that initially 60% of the displaced electricity is gas- and 40% coal-fired, declining to 90% gas-fired generation by 2030. This assumption reflects the likely fact that current low natural gas prices will lead to a gradual shift to a larger share of U.S. power generation coming from natural gas over time.

While there are still cost reductions due to technological improvement for gas-fired generation, its primary cost drivers will be fuel costs and the extent to which environmental externalities associated with burning fossil fuels are reflected in power prices. Thus, we project the costs of fossil fuel-fired generation most likely displaced by offshore wind under two scenarios: (1) with current policies remaining in place and assuming no carbon-pricing through 2030, and (2) with market prices which include the social cost of carbon but without existing subsidies for gas-fired generation by 2030 to provide a fair comparison to unsubsidized offshore wind[81].

In particular, the first case assumes that any existing subsidies for fossil fuels remain in place over the forecast horizon. The first case also assumes that no additional environmental costs will be imposed on fossil technologies, including any costs related to greenhouse gas emissions. The latter assumption is likely conservative, estimating the lowest possible grid costs between now and 2030. The second case assumes existing subsidies for fossil fuel and fossil fuel-fired power generation are removed and some modest environmental externalities are priced-in. This second estimate comes closer to reflecting the social cost of fossil fuel-based power generation even though it still underestimates the full social cost by excluding non-carbon externalities (such as criteria air pollutants) from the calculation.

1. No Consideration of Subsidies or Externalities

To estimate the future cost of power generation from natural gas without considering changes to subsidies or externalities (the first case), we rely on publicly-available information on their projected, future capital costs, as well as other inputs to the calculation of their LCOE, most notably the future price of fuel.

For natural gas-fired generation, the generation technology could be a single cycle combustion turbine ("CT") or a combined cycle gas turbine ("CCGT"). Since offshore wind, though not dispatchable, will function like a baseload or intermediary power plant, we limit our analysis to forecasting the cost of a CCGT as a basis of comparison to the future cost of offshore wind.

We use the DOE's most recent estimate for the overnight capital cost of \$977/kW (\$2010) for conventional CCGTs as our estimate of capital cost (\$1,087/kW in \$2012).[82] We assume that

[81] Relative to the impact of assuming greenhouse gas externalities being reflected in market prices, removing remaining natural gas subsidies only has a minor impact on the results of the analysis since, as explained below, remaining natural gas subsidies, on a per MWh basis, are relatively small.

[82] EIA AEO 2012, "Assumptions to AEO 2012, Electricity Market Module", Table 8.2 (overnight cost of conventional gas/oil combined cycle plant).

through 2030 this capital cost will essentially stay constant, by 2030 at $1,003/kW ($2010) estimated by the DOE as the capital cost of an advanced CCGT ($1,116/kW in $2012).[83] While the cost of offshore wind is largely driven by its capital cost, the cost of a CCGT also is driven significantly by capacity factor, fuel cost, and power plant efficiency. Compared to offshore wind, gas turbine technology is more mature, so that future increases in power plant efficiency will be relatively small. Nonetheless, turbine manufacturers continue to make progress. Current new CCGTs are expected to ultimately reach heat rates of approximately 6,800 BTU/kWh (GE F-Series),[84] but future CCGTs may have significantly lower heat rates of as little as 5,800 BTU/kWh.[85] Recognizing that further progress is likely, but also taking into account the fact that the latest technology takes some time to fully penetrate the market, our projections assume heat rates for new CCGTs will drop linearly from an assumed 7,050BTU/kWh in 2014 to 6,333 BTU/kWh by 2030.[86]

For our fuel price forecast, we rely on the DOE 2012 Energy Outlook. Figure 11 shows DOE's projected natural gas price trajectory through 2030. We use the EIA's estimated gas price for the power sector and recognize that the actual cost of natural gas delivered will depend somewhat on the location of the plant.

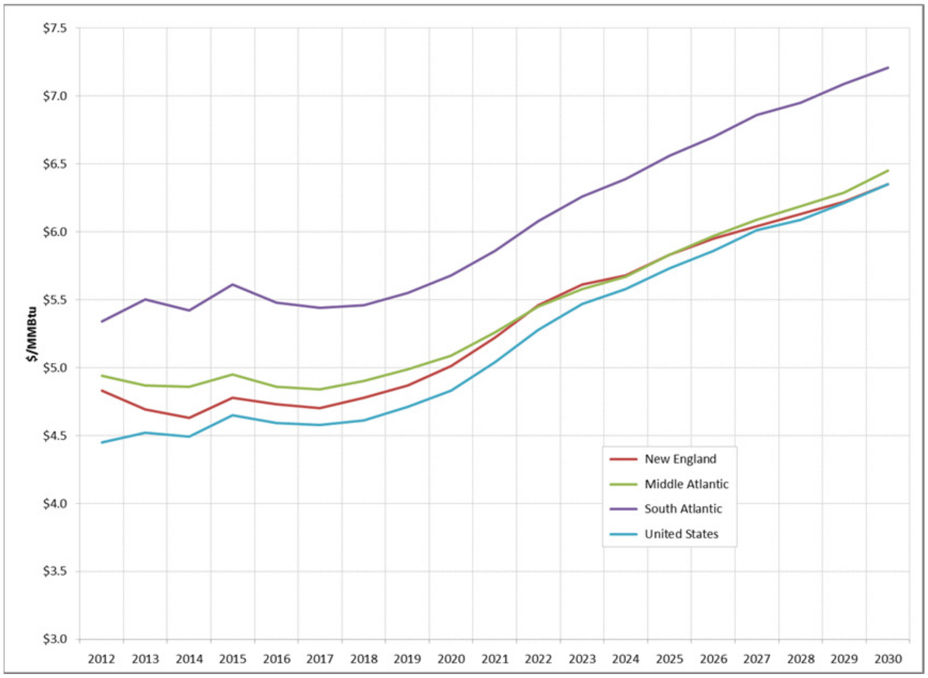
83 *Ibid*, Table 8.2 (overnight cost of advanced gas/oil combined cycle plant).

84 *Ibid*, Table 8.2 (heat rate of the nth conventional gas/oil combined cycle plant).

85 See Hudson Clean Energy Partners, Is Grid Parity Always Down the Road?, November 2011, p. 4.

86 Based on EIA, Updated Capital Cost Estimates for Electricity Generation Plants, November 2010. The assumed 2014 heat rate is equal to the assumed 2011 heat rate for conventional CCGTs. The 2030 heat rate is the EIA's assumed heat rate for an nth of a kind plant for an advanced CCGT.

Figure 11: Forecast Natural Gas Prices through 2030 ($2010)



Source: EIA, Annual Energy Outlook 2012, Early Release

As Figure 11 shows, the current low delivered prices for natural gas are expected to persist through the decade in real terms, but eventually increase to reach levels of approximately $7/MMBtu by 2030. Major drivers of uncertainty over future natural gas prices are the continued availability of relative cheap shale gas as well as to what extent the large imbalance between domestic natural gas prices and international price levels will lead to significant enough export activity to drive up domestic gas prices over time.

These projections are within the range of other forecasts of the LCOE from CCGTs going forward. For example, the DOE's Open Energy Project cost projections for CCGTs' LCOE range from $40-70/MWh with a median of $50/MWh for 2012, changing to a range of $40-110/MWh by 2030, also with a median value of $50/MWh.[87]

2. Considering Subsidies and Externalities

The above calculations of the LCOE for gas-fired combined-cycle plants, however, do not provide the appropriate benchmark for assessing whether offshore wind has reached grid parity from the perspective of public decision makers. Instead, they only represent a benchmark for "market gird-parity" under the narrow assumption that existing fossil subsidies stay in place and that no negative externalities will be reflected in market prices by 2030, including, in particular, any reflection of the cost of greenhouse gas emissions. Even if this were the case, the social cost of the electricity most likely displaced (or avoided) by offshore wind is higher since it should be

87 See http://en.openei.org/apps/TCDB/. The LCOE calculation assumes a 7% discount rate and a 39.2% tax rate. [we should see how this would affect our results]

calculated without subsidies and including any negative externalities caused by gas-fired power generation.

Therefore, in the second case, we construct an estimate of the LCOE of CCGTs that excludes existing subsidies and adds the cost of carbon. This is an economically more appropriate benchmark for assessing the cost at which offshore wind reaches grid-parity from society's perspective. Prior research has considered the level of existing subsidies and the social cost of any externalities associated with natural gas-fired power generation. Based on this research, we derive a reasonable range of adjustments to the LCOE of CCGTs to derive social grid parity measures.

a. Existing Subsidies for Natural Gas

Fossil fuel subsidies in the U.S. were an estimated $5.5-7.5 billion in 2007 and $2.4-3.2 billion in 2010.[88] Much of the decline between 2007 and 2010 was due to decreases in support for coal. Historically, of the $300 billion of tax support received by oil and gas between 1950 and 2010, oil received approximately 2/3 and natural gas 1/3.[89] This suggests that in 2010, tax subsidies for natural gas were approximately $1 billion. Natural gas production in the U.S. in 2010 was 22.1 quadrillion BTU (i.e., 22.1 billion MMBTU),[90] which corresponds to a tax subsidy of approximately $0.045/MMBtu, or 1% of the current (and projected future) price of natural gas. Other studies also estimate the impact of tax subsidies on the price of natural gas in the range of 1% or less, citing estimates of the impact of removing tax preferences in the range of $0.023-0.027/million BTU.[91] Assuming an average heat rate of 8,000 BTU/kWh on average for power generators using natural gas,[92] a subsidy of $0.045/million BTU translates into an equivalent subsidy of approximately $0.36/MWh of electricity production.

Separate analyses of subsidies for natural gas related only to electric power production conclude that such subsidies amounted to $654 million in fiscal year 2010, or approximately $0.63/MWh of electricity generated from natural gas.[93] Based on this range of estimates, we assume the price of natural gas excluding subsidies will increase the cost of power generated from natural gas by $0.5/MWh.

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88 US EIA, Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010, July 2011, pp. 9, 18; Molly Sherlock, Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures, Congressional Research Service; May 7, 2010, Table A-3.

89 Management Information Services, Inc., 60 Years of Energy Incentives: Analysis of Federal Expenditures for Energy Development, October 2011, p. 1.

90 US EIA, 2012 Annual Energy Outlook.

91 Maura Allaire and Stephen Brown, Eliminating Subsidies for Fossil Fuel Production: Implications for U.S. Oil and Natural Gas Markets, p. 7.

92 We assume a lower heat rate for new NGCTs, Currently, the heat rate for a CCGT is 7,000 – 8,500 BTU/kWh. The heat rate of a single cycle gas turbine is typically above 10,000/kWh.

93 U.S. EIA, Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010, July 2011, Table ES4, p. xviii.

b. Negative Externalities of Natural Gas

A 2010 report by the National Research Council estimates the value of various externalities associated with the production, transport and use of natural gas.[94] The two primary sources of externalities identified are both related to emissions: criteria air pollutants and greenhouse gas emissions.

The study estimates externalities associated with emissions of criteria air pollutants. On average, these costs are 0.16 cents/kWh ($2007), with a median value of only 0.036 cents/kWh.[95] Expressed in 2012 $/MWh, they average $1.72/MWh with a median cost of $0.39/MWh. The average criteria pollutant-related externality cost from gas-fired power plants is projected to decrease to 0.11 cents/kWh ($2007) by 2030, equivalent to $1.18/MWh in $2012.[96] The externality cost of natural-gas fired power generation related to criteria pollutants differs substantially by plant. The 10% of plants with the highest pollutions per plant were responsible for 24% of total net power generation and 65% of the effects,[97] suggesting that the National Research Council estimates likely overestimate the cost of criteria pollutant-related externalities for new CCGTs, which tend to be more efficient than the average (and CCGTs more efficient than CTs, which are included in the National Research Council sample). Therefore, we assume an average externality cost for new CCGTs equal to the median value in 2012 (i.e., $0.39/MWh), declining to $0.27/MWh by 2030.[98]

The magnitude of greenhouse gas externalities from gas-fired power generation – without consideration of the impact of greenhouse gas emissions from the production and transport of natural gas - depends on: (1) the estimated rate of greenhouse gas emissions from gas-fired power plants, and (2) the estimated externality cost per ton of carbon dioxide equivalent (“CO2e”). On average, greenhouse gas emissions from natural-gas fired power plants are approximately 0.5 tons/MWh. This rate varies, depending on the efficiency of the plant, based on its technology and how often it operates at or near its optimal output level. More efficient, new CCGTs operating closer to their efficient level have lower emissions than older plants operating at lower output levels.

Nonetheless, applying a CO2e emissions rate of 0.5 tons/MWh to the low, medium, and high GHG cases in the National Research Council study (i.e., $10, $30 and $100/ton of CO_2e in $2007), the greenhouse gas-related externality cost of gas-fired generation is 0.5, 1.5 and 5 cents/kWh, respectively.[99] In $2012/MWh, this corresponds to a range of $5.40 to $53.80 per MWh.

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94 National Research Council, Hidden Cost of Energy: Unpriced Consequences of Energy Production and Use, The National Academies Press, 2010

95 National Research Council (2010), Table 2-14, p 118. The median value is much lower than the average because a relatively small number of older plants are responsible for a significant portion of total criteria pollutant emissions.

96 *Ibid,* p. 125.

97 *Ibid,* p. 122.

98 We use the ratio of the estimated mean externality in 2010 and 2030, 0.16 cents/kWh and 0.11 cents/kWh respectively, to derive an equivalent median externality in 2030.

99 *Ibid*, p. 306f.

There is a significant range of uncertainty around estimates of the value of avoided greenhouse gas emissions. While the cost of additional greenhouse gases increases over time as GHG concentrations in the atmosphere increase, its impact on the price of natural gas, were this externality internalized, depends on the regulatory approach taken. For example, a carbon tax might begin relatively low and increase over time. Cap-and-trade programs such as those operating in Europe and California, and previously considered by the U.S. Congress, typically include carbon price floors which increase over time at a rate greater than inflation[100]. The starting value of a typical proposed price floor is in the \$10-15/ton of CO_2 range.

Because of these uncertainties, there is likely no "right" answer to the cost of greenhouse gas emissions, year by year, between now and 2030. Based on the tendency for policy to gradually increase the price of carbon when carbon regulation is implemented, we assume that the cost of greenhouse gases, notably CO_2, emitted from gas-fired power generation, increases linearly (in real terms) from \$5.4/MWh in 2014 to \$53.8/MWh in 2030, representing corresponding CO2-prices rising linearly from \$10/ton in 2014 to \$100/ton by 2030 (\$2010, hence slightly higher in \$2012). These carbon prices are based on the carbon externality prices identified by the National Research Council's 2010 study (high value). While a carbon price of \$100/ton by 2030 is higher than the 2030 floor price for carbon under existing legislation such as California's AB 32 or previously proposed federal legislation such as Waxman-Markey, it is a reasonable estimate of the carbon price required to meet longer term carbon reduction goals[101]. It is also important to note that the resulting assumption about the carbon cost of gas-fired power generation does not reflect greenhouse gas emissions other than CO_2, even though there is some evidence that the extraction and transport of natural gas may result in additional direct methane emissions which, while small relative to total natural gas use, has a global warming forcing potential more than 20 times greater than CO_2.

c. Avoided externalities from offshore wind energy production

While new offshore wind capacity certainly would displace new gas-fired capacity, it is also likely that offshore wind deployed between now and 2030 also would displace energy from a variety of sources, mostly a combination of gas- and coal-fired generation.

The exact mix of electricity sources displaced by offshore wind will depend highly on the generation mix in the relevant region at the relevant times as well as on the actual output profile of offshore wind in place. A precise estimation of the sources of electricity displaced by offshore

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100 For example, the most recent climate change bills proposed in the United States Congress, such as the Waxman-Markey bill, included such a price floor. The cap-and-trade system for greenhouse gases in California under Assembly Bill 32 ("AB32") also include a very similar price floor, which escalates at a real annual rate of 5%.

101 For example, the U.K. Department of Energy and Climate Change ("DECC") has estimated that a global carbon price of £70 (or \$105) per ton of CO2 by 2030 for purposes of creating benchmark prices for meeting long-term reduction targets. (DECC, "Carbon Appraisal in UK Policy Appraisal: A revised Approach", Table 1). This also corresponds to the higher of the expected price of carbon under the European Union Emissions Trading Scheme and the U.K. carbon price floor as used by DECC (DECC, "Carbon values used in DECC's energy modeling", October 2011, page 3.)

wind would therefore require a determination not only of the overall deployed offshore wind capacity, but also its specific location over time. This is beyond the scope of this report.

However, to capture the fact that offshore wind will likely displace at least some coal-fired power generation since it produces power somewhat more evenly across the day and the seasons than other renewable technologies such as solar PV (and to a lesser degree onshore wind), we make relatively simple but reasonable assumptions about the technology mix of the electricity displaced by offshore wind. In particular, we assume that during the first year we study, 2014, approximately 60% of the displaced energy is gas-fired, and 40% is coal-fired. Second, we assume that by 2030 the mix will shift to 90% gas-fired and 10% coal-fired. Our assumptions are based on two factors: the current trend of new generation is almost exclusively gas-fired and a substantial portion of the coal fleet is slated for retirement over the next two decades.

Making these assumptions means that actual avoided externalities are somewhat higher than those based on a direct comparison of offshore wind with natural gas. Incorporating the resulting effect into our calculation of avoided greenhouse gases is relatively straightforward. Rather than assuming a carbon intensity of avoided generation of 0.5 tons/MWh – corresponding to the carbon intensity of natural gas-fired generation – we assume a carbon intensity of 0.7 tons/MWh in 2014, decreasing linearly to 0.55 tons/MWh by 2030.

Capturing the avoided externalities other than CO_2 from displacing some coal-fired generation is substantially more difficult for two reasons. First, the estimates of the size of negative externalities associated with coal-fired power generation cover a very wide range. Recent estimates of the externality cost of coal range from $94/MWh to $269/MWh ($2008).[102] Subtracting the estimated climate externalities and converting to $2012 results in a range of $87/MWh to $170/MWh. At the high end, assuming that initially 40% of the power from offshore wind would displace coal-fired generation, these estimates would bring the social cost of power displaced by offshore wind close to the current cost of offshore wind and imply that offshore wind would be cheaper than the social cost of the power it displaces within a few years of ramping up its deployment.

Second, it is not clear whether or not some or all of the negative externalities associated with coal-fired power generation will be reflected in market prices by 2030, in part because of disagreement about the reliability of the estimated externalities.

To be conservative, we therefore chose to limit our consideration of the impact of coal-fired power being displaced by offshore wind to an inclusion of the associated CO_2 reductions only. This is not to suggest that the non-GHG externalities associated with coal-fired power generation are not real. To the contrary, as stated previously, the decision about making a learning investment in offshore wind should be based on full consideration of all social costs. However, in an effort to provide a conservative estimate of the learning investment that might be needed to bring offshore

[102] See Paul R. Epstein, Jonathan J. Buonocore, Kevin Eckerle, Michael Hendryx, Benjamin M. Stout III, Richard Heinberg, Richard W. Clapp, Beverly May, Nancy L. Reinhart, Melissa M. Ahern, Samir K. Doshi, and Leslie Glustrom. 2011. "Full cost accounting for the life cycle of coal", in Ecological Economics Reviews. Robert Costanza, Karin Limburg & Ida Kubiszewski, Eds., Ann. N.Y. Acad. Sci. 1219: 73–98.

wind to grid parity, we exclude non-GHG externalities of coal-fired generation from our two measures of potential market prices – with and without inclusion of carbon prices.

Table 3 shows our resulting assumptions about the value of subsidies, the cost of externalities associated with criteria pollutants, and the cost of greenhouse gas emissions for purposes of determining "CO_2-grid parity" for offshore wind from 2014 and 2030.

Table 3: Assumptions

Assumption	Unit	2014	2020	2030
Price of CO2	$2012/ton of CO2e	$11	$49	$111
Cost of criteria pollutants from CCGTs	$2012/MWh	$0.39	$0.35	$0.27
Natural gas subsidies	$2012/MWh	$0.50	$0.50	$0.50
Total externality and subsidy value in market price	$2012/MWh	$8.29	$31.86	$61.69

C. THE POTENTIAL FOR GRID PARITY

In this section, we combine the various factors analyzed above to determine the total learning investment necessary to bring offshore wind to grid parity (under the two alternative definitions of grid parity described on page 2 above and further refined on page 41 below). Figure 12 below shows the evolution of offshore wind cost between now and 2030 assuming a total installed offshore wind capacity by 2030 of 54 GW, under three different assumed starting costs and learning rates. In addition, Figure 12 shows how these offshore wind cost scenarios compare to potential trajectories of the cost of a new CCGT with and without inclusion of a market price for CO_2 and with and without existing tax subsidies.

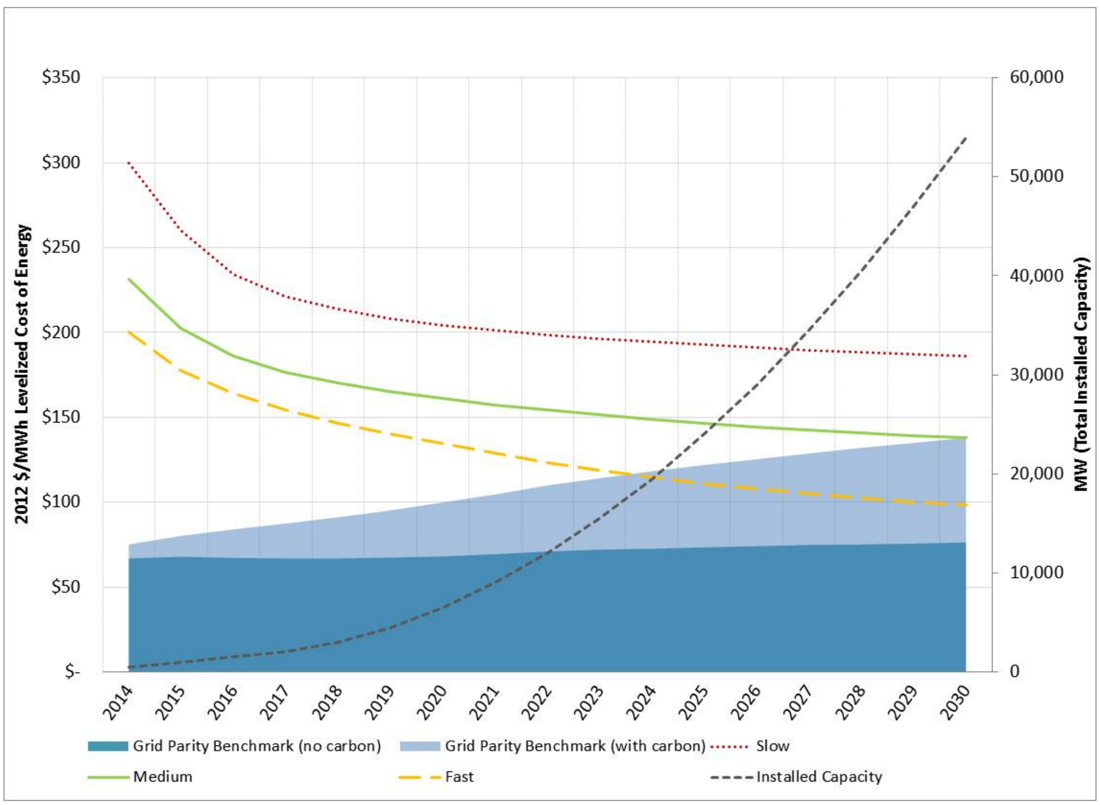
To construct the three price curves for offshore wind in Figure 12, we used the assumed starting prices of $300, $231 and $200/MWh and assumed learning rates of 3%, 5% and 10% respectively for the slow, medium and fast learning scenario. As described above, the $200/MWh starting point in the fast learning scenario reflects the current best estimate of the cost of offshore wind in the U.K. In other words, the fast learning scenario starting point assumes that any learning that has taken place in Europe over the past few years can be replicated instantaneously in the U.S. with the first project. While this is unlikely to be the case – in part because advances in building a domestic supply chain in the U.S. have not been made – it is nonetheless possible that U.S. starting costs may be comparable to current U.K. costs due to other factors such as lower labor costs, better wind resource closer to shore, etc. However, this is an optimistic scenario.

Our most realistic scenario assumes medium learning rates of 5% and a starting point corresponding to NREL's most recent review of all the evidence concerning likely costs of U.S. offshore wind, cited above. The starting cost of $231/MWh under this scenario is significantly higher than the current cost of offshore wind in the U.K. We would therefore assume that the cost-disadvantage relative to the U.K. would be made up relatively quickly. To capture this "catching-up" effect, we essentially assume that the first U.S. wind project in our medium learning rate scenario is smaller than 500 MW; the effect is that, in the first few years, there are more doublings of installed capacity with corresponding declines in levelized costs. The net result of this approach is that current U.K. costs are reached within 2-3 years, but that further cost declines thereafter occur more slowly.

We use the same rationale for the slow learning scenario. The higher starting cost of $300/MWh corresponds approximately to the expected cost of initial small pilot projects. We again assume an even smaller first project with correspondingly more doublings of cumulative installed capacity in early years, after which further cost declines are moderated by the slow learning rate under this scenario.

As can be seen in the graph, assuming the gas price trajectory included in the 2012 Annual Energy Outlook's base case through 2035, offshore wind reaches market grid parity by 2030 under the medium learning rate scenario, using NREL's starting LCOE of $231.MWh if a reasonable carbon price is included in market prices. It is important to note that it is highly likely that, by 2030, market prices in the U.S. will reflect at least some value of the greenhouse gas emissions associated with natural gas-fired power generation. Moreover, offshore wind reaches CO_2-grid parity even sooner – by 2025 – under the fast learning scenario.

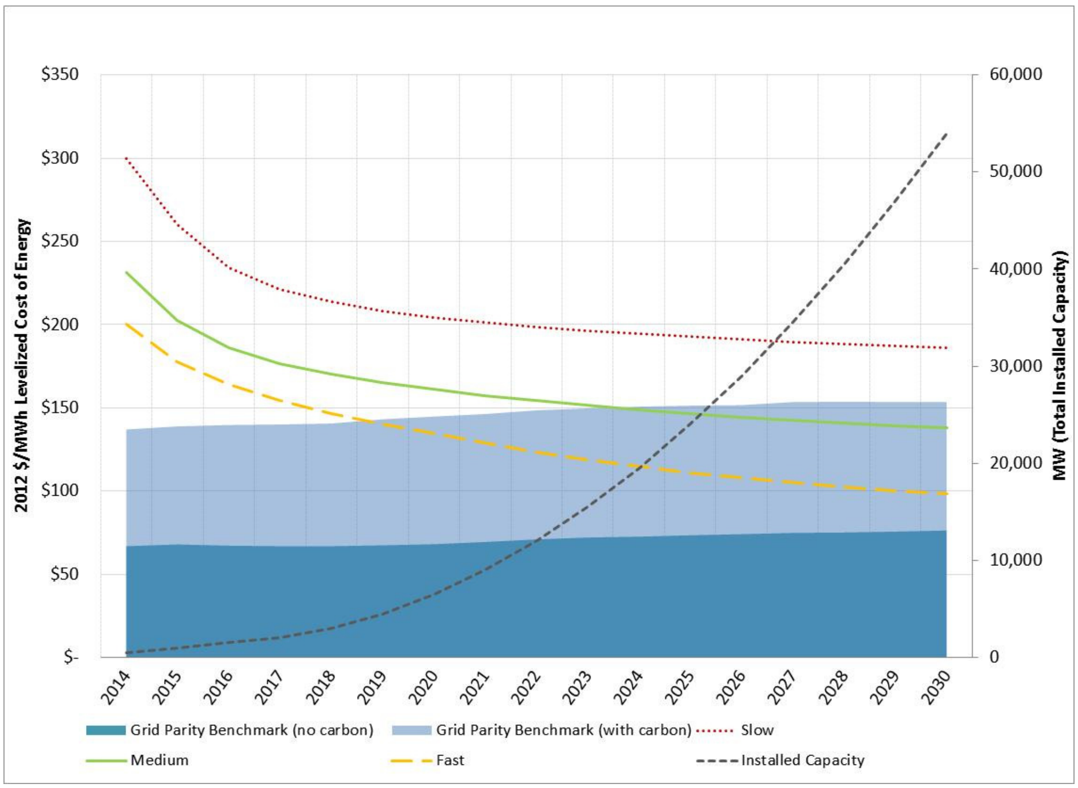
Figure 12: Offshore Wind Path to Potential Grid Parity



It also is important to note that, while Figure 12 captures the impact of including or not including a carbon price in the grid parity benchmark, neither of the two benchmarks reflects the full social cost of the fossil generation that would be displaced by offshore wind.

In particular, to the extent offshore wind electricity displaces coal-fired power generation, which is likely the case, particularly in the near future, any avoided negative externalities associated with the generation of electricity from coal should be included in the assessment of the cost of a learning investment in offshore wind. To illustrate this point, Figure 13 below is identical to Figure 12 above, with the exception that we include the externality cost of coal fired generation in the lighter blue area representing the cost of the electricity that would be the substitute for offshore wind energy in its absence. We use the "best" case assumptions from the earlier cited study on the externality cost of coal-fired power generation, which, excluding the cost of carbon already reflected in our **CO_2**-grid parity benchmark, is estimated at \$146.9/MWh (\$2008), translating into \$154.6/MWh (\$2012).

Figure 13: Offshore Wind Path to Potential Grid Parity with coal externalities



As can be seen in Figure 13, consideration of the negative externalities related to coal-fired generation would reduce the discrepancy between the cost of offshore wind and the social cost of the electricity generation it avoids substantially and would potentially result in "grid parity" between 2019 (fast learning scenario) and 2024 (medium learning scenario). Because of the issues related to the reliability of estimates of the externality costs for coal-based generation discussed above, we will use the results from Figure 12 above in our analysis going forward.

Also, in our analysis, we will not consider the impact of making learning investments in offshore wind through 2030 under the slow growth scenario. The simple reason is this: while we suggest that learning investments in offshore wind may be beneficial to society as a means of creating insurance against higher future gas prices, climate change risks, etc., we do not suggest that such learning investments should or would likely be pursued indefinitely in the absence of evidence that the cost of offshore wind is actually decreasing enough to make grid parity, however defined, a likely outcome in the relatively near future. In our slow learning scenario, by 2030, the levelized cost of offshore wind will be $186/MWh. We estimate the corresponding cost of gas-fired generation (and still including a small share of coal-fired generation for purposes of determining the value of avoided greenhouse gas emissions) between $74/MWh and $136/MWh. Hence, even at 54 GW of installed offshore wind, a substantial cost difference would remain under the slow learning rate scenarios. It is therefore likely (and desirable) that continued learning investments in offshore wind would be terminated prior to a full build-out to 54 GW. This is the logical approach of informed public policy and, therefore, ratepayers and society simply would not be exposed to the full cost of building out offshore wind to 54 GW by 2030 if the slow learning scenario actually occurs in the U.S. While we do not propose a specific mechanism for determining the point in time when observed costs above those that would be considered satisfactory progress would lead to an end of continued public investment, policy-makers have long experience with many approaches to ensuring that there is limited investment in technologies for which not enough cost declines are observed.

V. THE COST AND RATE IMPACT OF BRINGING OFFSHORE WIND TO GRID PARITY

In this section, we derive estimates of the learning investment needed to bring offshore wind to "grid parity". To do so, we define grid parity in two alternative ways.

A. GRID PARITY DEFINED

We define "**market grid parity"** as the point at which offshore wind is expected to be cost competitive with the market price of conventional, i.e. fossil-fired power generation, assuming that current subsidies for fossil fuels and fossil power generation technologies stay in place, and no significant additional externalities, in particular no carbon externalities, are included in the market price. This is the harshest possible test for offshore wind meeting grid parity in that it: (1) compares the unsubsidized cost of offshore wind[103] to a subsidized fossil alternative; and (2) assumes no additional legislative action at the state or national level on climate change will occur between now and 2030.

Since climate change policies are likely to have at least some impact on fossil-fuel costs between now and 2030, we define a second type of grid parity, which we call **CO_2-grid parity**, which removes from the market price of fossil power any embedded subsidies and adds the costs of greenhouse gas emissions assuming such costs will be reflected in market prices of electricity.

B. METHODOLOGY

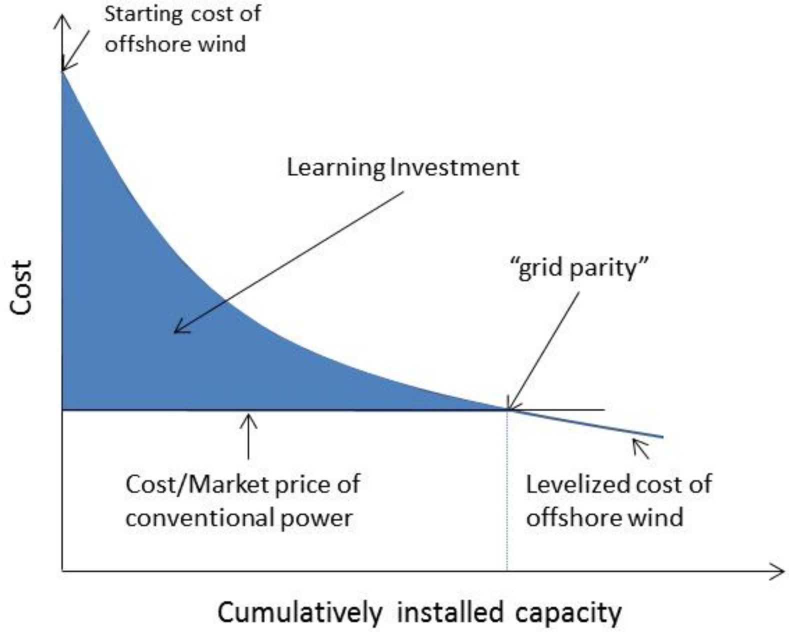
To calculate the total cost of bringing offshore wind to a scale where it can compete with either the market or the social cost of natural gas-fired power generation, we rely on a framework outlined in Figure 13 below, where the total amount is called "learning investment".

[103] Our calculations determine the total cost of the subsidy/learning investment, rather than including it in the LCOE assumptions.

To implement this framework requires making a number of informed assumptions. First and perhaps most importantly, the concept illustrated in Figure 13 below uses cumulative installed capacity as the horizontal axis since it is based on the concept of learning rates, which rely on the same measure.

Since we are comparing the costs of multiple technologies over time, we make an informed assumption about the speed of deployment and associated evolution of cost over time for each of the technologies considered.

Figure 13: The Concept of Learning Investment



Based on: Ferioli, F., K. Schoots and B.C.C. van der Zwaan, "Use and Limitations of Learning Curves for Energy Technology Policy: a Component- Learning Hypothesis", Energy Policy, 37, 2009, pages 2525-2535.

For this reason, we fixed the time horizon of our analysis from 2014 to 2030, and rely on price forecasts for each of the technologies other than offshore wind over that time horizon, rather than explicitly modeling their cost development using the observed or estimated learning rates.

More precisely, in previous sections we examined the potential costs of onshore wind and solar photovoltaic technology in the United States by 2030 and concluded that there was at least some potential overlap between the costs of both technologies and the cost of offshore wind under our three development paths (assuming low, medium and high learning rates and different 2014 cost starting points). Based on this analysis, we concluded that none of the renewable technologies dominates all others on a cost basis under all reasonable scenarios.

In this section, we therefore limit our analysis to calculating the learning investment as defined by the cost of offshore wind as compared to the cost of the incumbent technology, which we assume to be natural-gas fired combined cycle gas turbines ("CCGTs"). The cost of CCGTs in turn is also somewhat determined by learning effects. However, given the relatively mature state of the industry, the price of natural gas is likely the more important determinant of the evolution of the LCOE of CCGTs, as described above.

As indicated, we calculate the learning investment for offshore wind both relative to the projected market cost (market grid parity) and to the projected social cost (CO_2-grid parity) of the mix of power that offshore wind would likely replace between now and 2030, which, as described earlier, we assume to be a mix of coal and natural gas for purposes of capturing the impact of lowering CO_2 emissions[104].

As discussed above, under our low learning rate scenarios grid parity is not reached scenarios by 2030. We nonetheless limit our analysis to the time frame through 2030. It is therefore possible that the total learning investment to reach grid parity (however defined) is greater than our estimates under some conditions. However, this also assumes that offshore wind capacity would continue to be scaled up aggressively even though there is no evidence of learning and cost decreases sufficient to bring offshore wind costs close to grid parity over an acceptable period of time.

C. THE "COST" OF GRID PARITY

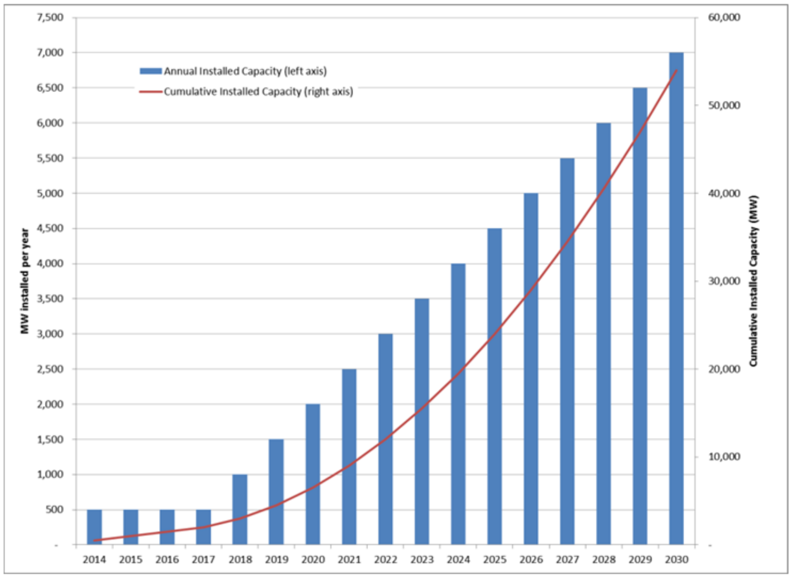
Using the above methodology, we calculate the learning investment to scale up offshore wind from 0 MW today to 54 GW by 2030 under three different assumed cost paths. We assume that the first offshore wind farm built in the United States will have a capacity of approximately 500 MW and that subsequent deployment will occur in increments of 500 MW, with a gradual scaling up of annual installed capacity.

Figure 14 below shows the assumed path of deployment of offshore wind under all three learning scenarios. The assumed path is, of course, somewhat arbitrary since actual deployment could follow many paths. It is, however, likely that deployment will build over time along a path at least somewhat similar to the one we assume. This is because the capacity of the supply chain to deliver projects will be small at first, but increase over time. Also, the confidence in the ability of all aspects of the supply chain to deliver projects will grow with installed capacity. Finally, it is likely optimal to gradually scale up the deployment of offshore wind so as to benefit as much as possible from learning from earlier projects.

It is nonetheless important to note that we have not attempted to derive the cost-minimizing path of deployment. In essence, calculating such a path involves trading off the higher costs of building more projects earlier and the faster cost declines that would be estimated under such a path, and which would allow future projects to be installed at a lower cost.

[104] We assume that in the absence of offshore wind the corresponding capacity would be provided by CCGTs. However, only for the purpose of capturing the cost of carbon emissions, we assume that offshore wind would displace a mix of gas and coal-fired generation.

Figure 14: Assumed U.S. Offshore Wind Development Path



Based on this assumed development path, the learning investment needed for each of our three learning cases, comparing offshore wind to the market and social cost (market w/$\mathbf{CO_2}$) of CCGTs (and the CO_2 cost of a mix of gas and coal-fired generation) respectively is summarized in Table 4 below.

Table 4 Total Learning Investment 2014-2030 ($2012)

Scenario	Offshore Wind Learning Rate	2014 LCOE (OSW)	2014 LCOE (Market without CO_2)	2014 LCOE (Market w/CO_2) *	2030 LCOE (OSW)	2030 LCOE (Market without CO_2)	2030 LCOE (Market w/CO_2) *	Total Learning Investment (Market without CO_2)**	Total Learning Investment (Market w/CO_2)**
	%	*$2012/ MWh*	*$2012/ MWh*	*$2012/ MWh*	*$2012/ MWh*	*$2012/ MWh*	*$2012/ MWh*	*$2012 billion*	*$2012 billion*
Slow	3%	$300	$66.82	$75.11	$186	$76.27	$137.96		
Medium	5%	$231	$66.82	$75.11	$138	$76.27	$137.96	$ 150	$52
Fast	10%	$200	$66.82	$75.11	$98	$76.27	$137.96	$ 79	$18

* As described above, the LCOE of gas includes the impact of including carbon pricing for the mix of coal and gas fired generation assumed to be displaced by offshore wind.
** Since we consider it unlikely that learning investments into offshore wind would continue through 2030 under the slow learning scenario, we do not calculate the total learning investment that would be needed if scaling up under this scenario continued through 2030.

The estimated range of required learning investments over the next 15-20 years – between $18 billion and $150 billion ($2012) is broadly in line with cumulative support for other, now more established, fossil fuel energy technologies. For example, oil subsidies between 1950 and 2010 have been estimated to have equaled $369 billion ($2010). Over the same time period, subsidies from various sources have been estimated to have equaled $73 billion for nuclear power, $104 billion for coal, and $121 billion for natural gas[105]. Globally, fossil fuel subsidies generally fluctuate between $300 billion and $500 billion per year according to the International Energy Agency [106] and reached $523 billion in 2011.[107] Another point of comparison to put the offshore wind learning investment in perspective is provided by a recent report by *the Brattle Group,* which estimates that the incremental costs of retrofitting or replacing existing coal-fired power plants between 2012 and 2016 to comply with various EPA regulations is between $126 billion and $144 billion (these costs would be passed on to ratepayers).[108] Finally, the ranges of learning investments we estimate are a relatively modest portion of the overall investment of $1.5-2 trillion in the national electricity infrastructure likely needed between now and 2030.[109]

However, comparing absolute levels of subsidies across fuels and technologies provides only one way to understand the amount of the learning investment needed to bring offshore wind to grid parity. We therefore also translate the range of potential learning investments required to scale up offshore wind between now and 2030 into average electric rate effects, which provide a better indicator of the impact of the learning investment on individual electricity consumers.

VI. THE ECONOMIC IMPACT OF SUPPORTING OFFSHORE WIND TO REACH GRID PARITY

A. THE "RATE" IMPACT OF BRINGING OFFSHORE WIND TO "GRID PARITY"

In this section, we translate the total learning investment estimated above for various scenarios into the average impact on a typical electric bill. This exercise is simple in concept: we divide the total learning investment between 2012 and 2030 by total relevant estimated electricity sales, *i.e.* the total kWh for which customers receive bills. This analysis ignores the complex process of ratemaking and allocating costs to different rate classes. As a result, our figures do not represent an attempt to predict the actual rate impact of bringing offshore wind to scale for any customer class in any given state. Rather, the calculations are intended to put the magnitude of the required effort into perspective.

Estimating average rate impacts requires an assumption about who will pay the learning investment for offshore wind. In most European countries, where feed-in tariffs or national renewable certificate schemes have been used, the cost of support for offshore wind generally has been borne by ratepayers at the national level through a surcharge on energy bills to all customers.

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105 See Management Information Services, Inc., 60 Years of Energy Incentives: Analysis of Federal Expenditures for Energy Development, October 2011, Exhibit 1, page 1.

106 See International Energy Agency, "IEA analysis of fossil-fuel subsidies", World Energy Outlook 2011, Paris, October 4, 2011

107 See http://peakoil.com/enviroment/iea-world-energy-outlook-fossil-fuel-subsidies-jumped-30-to-523-billion-in-2011/

108 See Metin Celebi, Frank Graves, and Charles Russell, Potential Coal Plant Retirements: 2012 Update, The Brattle Group, October 2012, page 10.

109 See Marc Chupka et al., Transforming America's Power Industry: The Investment Challenge 2010-2030, The Brattle Group, prepared for the Edison Foundation, November 2008, page vi.

Estimating Rate Impact

Translating our calculated learning investment for offshore wind into estimated rate impacts requires a number of assumptions. In reality, rates are determined in complex ways and, given the lack of specificity of how exactly the learning investment would be paid, where projects would be located, what other factors might impact rates, etc., we do not attempt to predict how actual rates might change if offshore wind were brought to scale.

Rather, the goal of the calculation we perform in this section is to put the learning investment for offshore wind into perspective by showing what portion of typical retail rates this premium would represent. To make this assessment, we proceed in the following steps:

1. In each year, we assume that a certain number of offshore wind farms get built (see Figure [X] for the development path we assume to get to 54GW by 2030, which is a scenario used in the DOE's 20% Wind by 2030 study).
2. In each year, we assume these plants get built as a certain levelized cost of energy, with an expected life of 25 years and an expected capacity factor – which we assume will increase slightly every year, due to technological improvements. These improvements are part of the reason why the LCOE also drops year by year due to the learning effects discussed at length throughout the report.
3. We next calculate the net present value of the total cost of energy over the life of these plants constructed in any given year and compare this total amount to the equivalent cost of generating the same number of total kWhs over the life of these plants, built in a given year, by combined cycle gas turbines, the default fossil power generation technology (or, in some instances coal-fired generation).
4. The difference between the two net present values is the total amount of extra payments for electricity that gets locked in (expected costs – in reality costs may turn out to be different) in each year with the construction of the assumed new offshore wind capacity.
5. We then divide this total amount by the total assumed kWh sales, either at the federal or regional level, to estimate the support that is needed to scale up offshore wind in that year, per kWh of electricity sold.
6. This approach essentially assumes that rates in any given year will increase to compensate not just for the difference between offshore wind and gas-fired generation in a single year, but over the life of the offshore wind farm. It does not correspond directly to how rates in any given year would be determined. On the other hand, we limit the calculation in any given year to offshore wind farms built in that year and do not consider support that is needed and stems from offshore wind farms built in previous years.
7. Our approach does not attempt to predict the rate increase in any single year with any accuracy, but instead examines the overall rate increase over the entire period 2014-2030t. And in reality, if ratepayers signed a contract with an offshore wind project rather than with a CCGT, at prices reflecting the LCOE of each technology, the rate impact of any single project would be to increase rates by some amount over the entire duration of the contract/plant life. Hence the rate impact in the first year, say 2014, would likely be small as only one new offshore wind project is assumed to get built and only 1/25th of the premium of that plant over a CCGT would need to be recovered through higher rates in that year. We, on the other hand, assume that 100% of the lifetime cost difference between the two would be recovered. However, as the offshore wind program scales up, in any future year, more new offshore plants get added. Each of them will need to recover 1/25th of their cost difference to CCGTs in any given year. So in any given year, ratepayers will pay premiums for multiple offshore wind projects constructed in the past and still in operation. This is true for offshore wind projects constructed the last year before offshore wind reaches grid parity. In other words, once offshore wind reaches grid parity, rate payers will still be paying a premium for the offshore wind projects built less than 25 years ago and hence 24 more years into the future.

In the U.S., however, the early offshore wind projects have been developed under the assumption that either ratepayers in a given state or utility service territory pay for the cost of a project. In the case of Cape Wind, for example, the customers of the utility with an off-take agreement with Cape Wind will have their bills increase by the amount necessary to pay for the additional cost of the project. In the case of New Jersey's offshore program, on the other hand, all ratepayers in the state will finance any additional cost (but only if the net economic benefits of future projects supported by New Jersey's ratepayers are demonstrated to exceed the costs). U.S. offshore wind projects also benefit from federal subsidies, such as the Investment Tax Credit, Production Tax Credit, and advantaged federal tax depreciation.

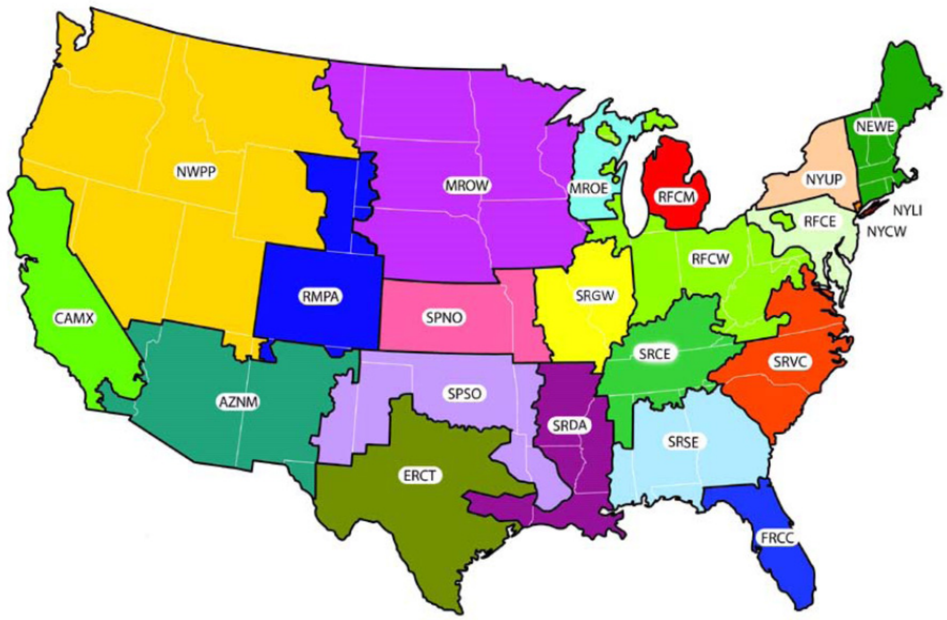
Therefore, in the U.S., a combination of federal taxpayers and the ratepayers of individual states and/or utilities are paying for some portion of the learning investment for these early offshore wind projects. There is not necessarily a right answer as to who should be paying. Benefits from bringing offshore wind cost down to grid parity will be shared by many constituencies at both the state, regional, and national level. For example, additional jobs may be created locally; and the generation mix supplying electricity to any given state may be affected depending on the project's location, with corresponding state and regional air quality benefits.. Overall, the effects in terms of increasing the diversity of choices, reducing $\mathbf{CO_2}$, and creating value chains for associated products will have benefits for society at large.

The cost per ratepayer of funding the learning investment estimated above will be smaller the greater the base. We therefore estimate first the rate impact assuming that costs associated with the learning investment for offshore wind are incurred by all electricity customers in the United States. This is in essence the equivalent of financing the scaling up of offshore wind exclusively at the federal level through tax credits, loan guarantees, a national RPS, and/or a mix of other federal investment mechanisms. This is also the nature of the subsidies provided to the nuclear, natural gas, and coal industries – paid for my all ratepayers through federal level support mechanisms.

Beyond federal financing, there are many options for financing offshore wind at the local, state and regional level. It is beyond the scope of this paper to analyze the myriad of potential rate impacts that would result from the different financing patterns. Instead, we consider a sub-national scenario which assumes that offshore wind will be supported by the regions where offshore wind is installed.

Figure 15 below shows a map of the NERC regions for which the Energy Information Administration estimates region-level developments such as future electricity demand. We use the following regions – New England (NEWE), New York City & Westchester (NYCW), Long Island (NYLI), Upstate New York (NYUP), RFC East (RFCE), RFC West (RFCW), RFC Michigan (RFCM), Midwest Reliability Organization East (MROE), SERC Virginia-Carolina (SRVC) and SERC Southeast (SRSE) – to calculate average rate impacts for this regional financing scenario. In reality, fewer or more states may share in the cost associated with the learning investment.

Figure 15: NERC Regions



Source: Energy Information Administration

1. Federal Level Support needed

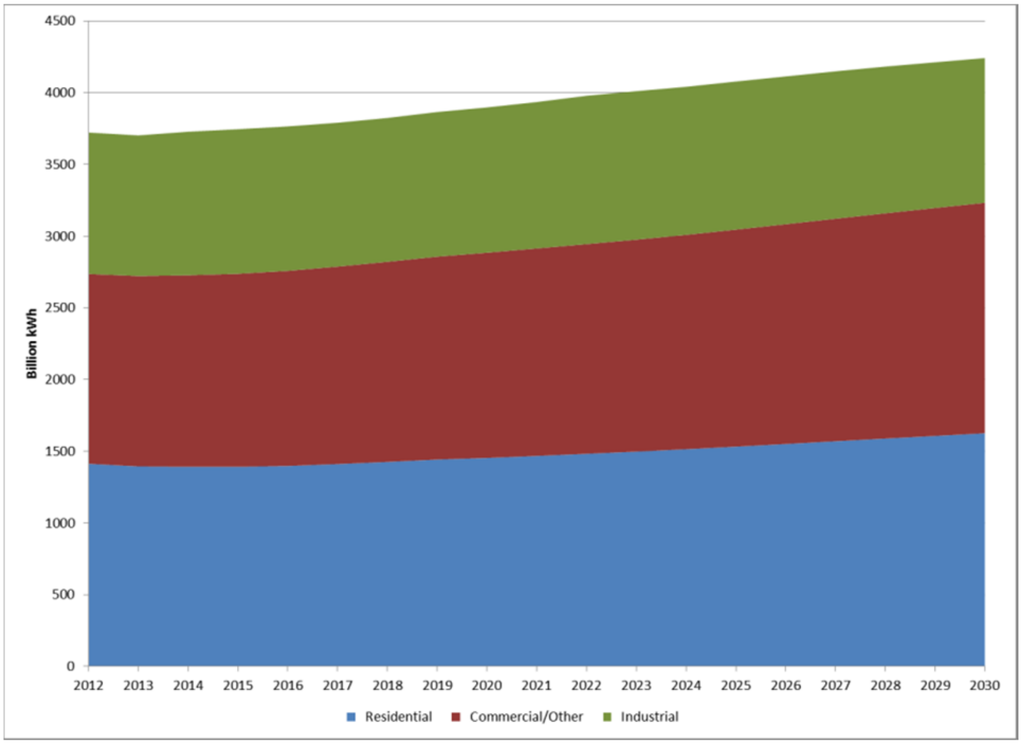
To estimate the average rate impact of the offshore wind learning investment assuming it is financed at the federal level, we simply divide the total learning investment for offshore wind from 2014 - 2030 by the total estimated electricity sales to all customer groups over the same time horizon.

We use the Energy Information Administration's Annual Energy Outlook projections. Figure 16 below shows the expected trajectory of total sales of electricity by customer segment between 2014 and 2030. As the figure shows, annual sales of power to residential, commercial and industrial customers in the AEO's Reference Case are expected to increase from approximately 3.7 billion kWh in 2012 to a bit less than 4.3 billion kWh by 2030. Total sales over the entire period are estimated at 75.2 billion kWh.

Of course, projecting total electricity sales over the next two decades is a difficult task and involves many uncertainties. However, given the objective of this analysis, namely to estimate the approximate rate impact of the total estimated offshore wind learning investment, we believe it is reasonable to use the AEO's Reference Case. Should actual demand grow more slowly for some reason, the rate impact would be somewhat larger. However, it is unlikely that this increase would be material. It is, of course, also possible that actual sales will exceed those in the Reference Case, in which case the rate impact would be smaller.

Using the range of learning investments calculated for various scenarios in the previous section, the resulting average rate impact would be approximately 0.03 cents/kWh to 0.23 cents/kWh. Average retail rates are approximately 10 cents/kWh in 2012 and, according to the EIA's forecast are assumed to stay relatively constant in real terms through 2030. Therefore, financing the learning investment for offshore wind through U.S. wide electricity rates would require an increase in average electric rates of 0.2-1.7% between 2014 and 2030, where 0.2% corresponds to the average rate increase under the fast learning rate scenario and using CO_2-grid parity as the relevant benchmark.

Figure 16: Total U.S. Sales of Electricity



Source: U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2012, Reference Case (excluding transportation sales)

Table 5 summarizes the average rate impacts we estimate for the low, medium and high learning cases against both the market grid and CO2- grid parity benchmarks. As can be seen from Table 5, while the total amount of learning investment necessary to scale up offshore wind is significant, in particular under the low and medium learning scenarios, even in those relatively high investment cost cases, the average rate impact, both in absolute and in percentage terms, is modest. It is important to note that in the cases where grid parity is reached by 2030 or earlier, the calculated rate increase does not reflect the rate savings that would result after grid parity has been reached (since in subsequent years the cost from offshore wind would be equal or lower than the grid parity benchmark).

Table 5: Rate Impact of Learning Investment for Offshore Wind Financed Nationwide

Grid Parity Benchmark	Learning Scenario	Total Learning Investment 2014-2030	Rate Impact	Rate Impact	Avg. Monthly Bill Impact
		(2012$ billion)	*(2012 c/kWh)*	*% Rate Increase*	*$/month*
Market Cost (no carbon)	Medium	$ 149.6	$ 0.22	1.7%	$ 2.08
	Fast	$ 79.4	$ 0.12	0.9%	$ 1.10
Market Cost (with carbon, no gas subsidy)	Medium	$ 51.9	$ 0.08	0.6%	$ 0.72
	Fast	$ 17.7	$ 0.03	0.2%	$ 0.25

It is also worth noting that assuming average monthly consumption of 940 kWh[110], the typical monthly bill would increase by a modest $0.25 - $2.08.

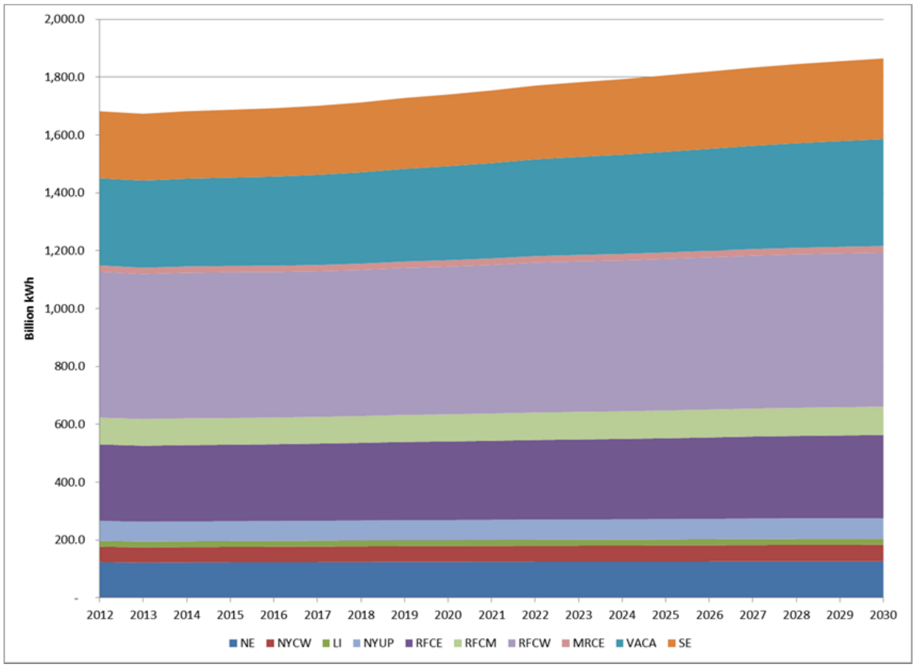
2. Regional Support needed

We also performed the same analysis for those NERC regions in which offshore wind in adjacent Atlantic Ocean and Great Lakes waters could be located. As discussed above, it is possible that offshore wind could be built in other parts of the United States, notably the Gulf Coast and perhaps the Pacific Ocean. If that occurs, and the learning investment is funded in each case by adjacent NERC regions, the actual rate impact of alternative build-out and funding patterns will be different from the one we calculate here. Nonetheless, the analysis is indicative of how average rate impacts change if the learning investment is funded by a smaller set of customers.

Figure 17 shows the EIA's forecast of electricity sales for the Atlantic Coast and Great Lakes NERC sub-regions we considered, which include essentially any NERC sub-region touching the Atlantic or the Great Lakes, with the exception of Florida, where the likelihood of development of offshore wind remains relatively limited.

110 See Energy Information Administration (http://www.eia.gov/tools/faqs/faq.cfm?id=97&t=3), last updated on December 6, 2011

Figure 17: Projected Electricity Sales 2012-2030
for Atlantic Coast and Great Lakes Region



Source: U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2012, Reference Case for EMM regions NEWE, NYCW, NYLI, NYUP, RFCE, RFCW, RFCM, MORE, SERCVC and SERC-SE.

Electricity sales in this collection of NERC sub-regions are expected to increase from 1,682 billion kWh in 2012 to 1,865 billion kWh by 2030, representing total electricity sales of 33.4 billion kWh between 2012 and 2030. Table 6 below shows the corresponding average rate impact if the total learning investment associated with scaling up offshore wind were financed by rate payers in the NERC-regions adjacent to the Atlantic Coast and Great Lakes.

Table 6: Rate Impact of Learning Investment for Offshore Wind Financed Regionally

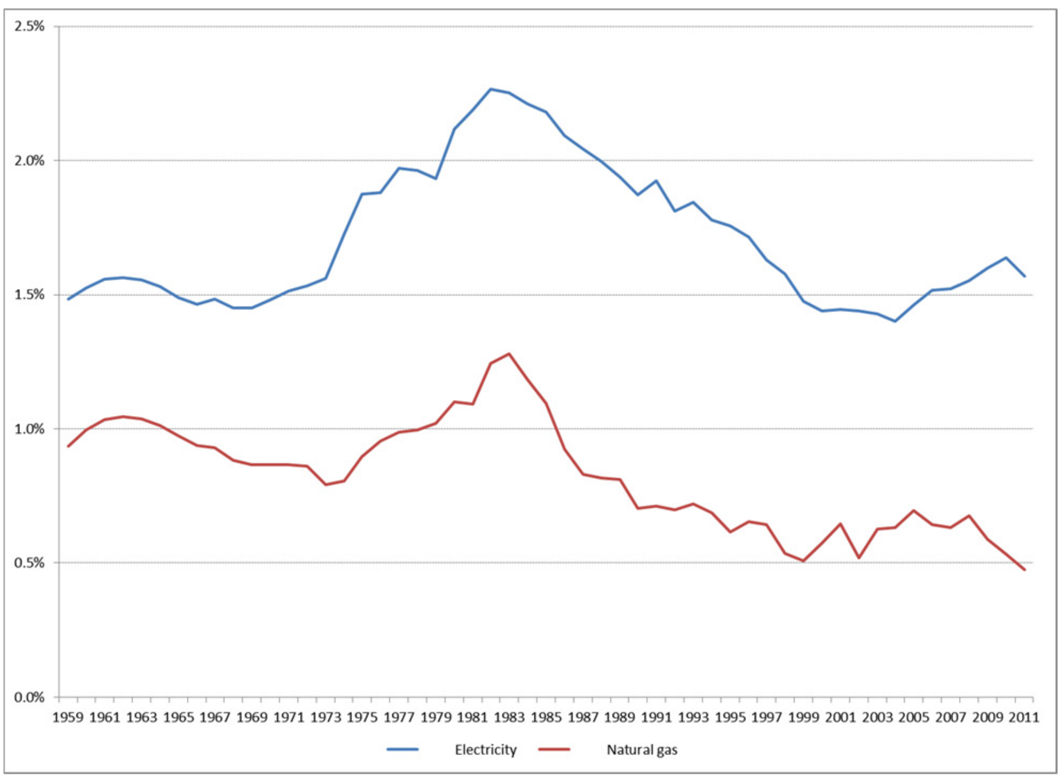
Grid Parity Benchmark	Learning Scenario	Total Learning Investment 2014-2030 *(2012$ billion)*	Rate Impact *(2012 c/kWh)*	Rate Impact *% Rate Increase*	Avg. Monthly Bill Impact *$/month*
Market Cost (no carbon)	Medium	$ 149.6	$ 0.50	3.0%	$ 4.29
	Fast	$ 79.4	$ 0.26	1.6%	$ 2.27
Market Cost (with carbon, no gas subsidy)	Medium	$ 51.9	$ 0.17	1.1%	$ 1.49
	Fast	$ 17.7	$ 0.06	0.4%	$ 0.51

The total learning investment required to reach grid parity in this regional view does not change from the federal support scenario. However the total investment is spread over fewer total kWh in sales, resulting in average rate impacts that are higher than in the case where the learning investment is funded nationally. It is, however, worth noting that even in this regional support case, the average rate increases necessary to scale-up offshore wind remain modest, between 0.06-0.51 cents/kWh, depending on the assumed learning scenario and grid parity benchmark. The corresponding average increase in monthly bills assuming average monthly consumption of 860 kWh[111] would range from $0.51 to $4.29.

3. Putting numbers into perspective

Since this paper addresses the cost of making a learning investment in offshore wind over the next roughly 20 years, it is useful to compare the potential rate increases necessary to finance this learning investment to the evolution of total household spending on electricity (and natural gas). Figure 18 below shows the evolution of the share of electricity in total household consumption expenditure from 1959 to 2011.

Figure 18: Share of electricity/natural gas in total household consumption expenditure



Source: Bureau of Economic Analysis, Table 2.4.5U. Personal Consumption Expenditures by Type of Product

As can be seen from Figure 18, the share of electricity in total household consumption expenditures in 2011 was 1.6%, about equal to the share in 1959 and down from a high of 2.3% in

[111] To calculate 860 kWh per month, we used the same monthly data cited above (EIA), but used only information from those states included in our regional scenario analysis.

1982/1983. The combined share of natural gas and electricity – that is expenditures related to heating and powering the house – were at their lowest in 2011 since 1959. For the share of electricity to equal its maximum over the past 50+ years, the average household consumption expenditure would have to increase by over 40%. If household consumption expenditure on both electricity and natural gas is considered, the increase would have to be almost 75%. The average rate increases we estimate that might be necessary to finance the learning investment into offshore wind therefore generally represent less – and across most of the scenarios significantly less – than 10% of the difference between current household spending on electricity (and natural gas) as a percentage of total household spending and the corresponding expenditure in the early 1980s.

VII. CONCLUSIONS

In this study, we estimate the learning investment, defined as the total amount of support that would be required to scale-up offshore wind energy between 2014 and 2030 to a point where, at least under many scenarios, the technology reaches grid parity (taking into account subsidies and externalities).

We also examine whether other alternatives to gas-fired power generation, in particular onshore wind and solar PV, dominate offshore wind in the sense of producing power at a lower cost than offshore wind under any reasonable set of assumptions. We conclude that this is not the case. Solar PV costs are currently higher or comparable to the cost of offshore wind on a levelized cost basis. And it is not clear whether solar costs will decline so rapidly that its cost will always be below the cost of offshore wind (in addition, solar PV obviously only generates electricity during day light hours, which means that it is not a perfect substitute for offshore wind and vice-versa).

While onshore wind tends to be cheaper on a levelized cost basis than offshore wind today, the incremental potential for further cost declines is substantially greater for offshore than for onshore wind, given the former's relatively low total installed base when compared to onshore wind. Also, there are some questions as to the continued availability of very high quality onshore wind sites and their proximity to load centers along the eastern seaboard, which in turn means that the LCOE of onshore wind by itself may underestimate the cost of delivering such electricity to load centers which will require significant transmission expansion costs.

As a result, we conclude that scaling up offshore wind is a reasonable element of a diversified strategy to develop future electricity technologies, all of which, at scale, have the potential to compete with incumbent power generation technologies, in particular natural gas-fired generation. We estimate the learning investment needed to develop 54 GW of offshore wind by 2030. Depending on the assumed current cost of offshore wind in the United States and the speed of learning – which we assume to be 5% to 10% per doubling of installed capacity – the total required learning investment between 2014 and 2030 ranges from $17.3 billion to $150 billion[112]. **This learning investment is comparable with the mix of subsidies provided to other energy sources over the past half century**.

Furthermore, we find that the average increase in electricity prices needed to finance such an investment would be modest. If the cost is spread across all electricity sales in the United States,

[112] As discussed above, we assume that the slow learning case with 3% cost decrease per doubling of installed capacity would likely not be pursued through 2030 and 54 GW of capacity installed.

the range of increases of electricity costs would be 0.03-0.22 cents/kWh, or 0.2-1.7% of average U.S. retail electric rates. If the cost were spread only across the electricity sales in the region, where offshore wind might be located – broadly the NERC sub-regions adjacent to the mid-Atlantic and Northeast and the Great Lakes – the increase in electricity rates would equal 0.06-0.50 cents/kWh, or 0.4-3.0%. Given the fact that at present the portion of household consumption spent on electricity and gas is at a 50 year low, we believe such costs would likely be an acceptable price to pay in exchange for creating the option of another cost-competitive power generation technology – and a technology that is carbon emissions free and not subject to escalating fuel cost as are fossil fuel technologies.

As the economic costs of just a single bad weather event such as hurricane Sandy in late 2012, which have been estimated at $50 billion or more have shown, the cost of creating an option to produce electricity without greenhouse gas emissions may well be worth the learning investment given the potential cost of not being able to produce power at scale without further substantial greenhouse gas emissions.

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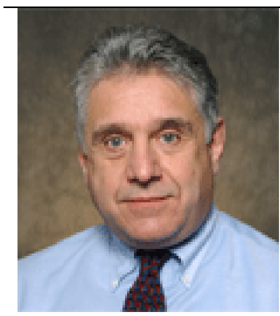

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