

ISSUE BRIEF

MONEY TO BURN II

SOLAR AND WIND CAN RELIABLY SUPPLY THE UNITED KINGDOM'S NEW ELECTRICITY NEEDS MORE COST-EFFECTIVELY THAN BIOMASS

A new study commissioned by the Natural Resources Defense Council and conducted by Vivid Economics indicates that by 2025, electricity from coal-to-biomass conversions will not be one of the three lowest-cost forms of electricity in the United Kingdom, and will not be needed to ensure reliability of electricity supply as the country phases out coal. According to the findings, any new biomass capacity constructed will be outcompeted by lower cost generation—and will thus be an obsolete asset—within the decade. Continuing to support biomass conversion through a Contract-for-Difference could result in the country paying an excess implicit subsidy of over £360 million compared to wind energy.

In 2015, the United Kingdom adopted a program to retire all coal plants by 2025, becoming the first country to commit to a time-bound phase-out of coal.¹ This cornerstone policy is part of the U.K. government's broader commitment to reduce greenhouse gas (GHG) emissions by 80 percent from 1990 levels by 2050. Since then, the costs of clean energy technologies like solar and wind have fallen dramatically—particularly in the offshore wind industry—across European geographies similar to the United Kingdom.² Today, a reliable, coal-free electricity grid dominated by truly clean wind and solar energy is not only possible, but is the smart economic choice.

Unfortunately, the United Kingdom has continued to rely heavily on biomass energy to meet its climate and renewables targets, primarily through the conversion of coal plants to burn biomass. These converted coal plants rely on millions of tonnes of imported wood pellets from the Southeastern United States and elsewhere for fuel, and receive billions in subsidies from the U.K. government.³

A key reason behind this subsidy program is that the U.K. government treats biomass as a zero-carbon source of electricity at the point of combustion, on par with other renewables like solar and wind. However, biomass is

much less energy dense than coal and other fossil fuels and emits more carbon per unit of generated electricity. Overwhelming scientific evidence from multiple peer-reviewed studies conducted around the world has debunked the myth of biomass “carbon neutrality” (See: European Researchers Bust Biomass Carbon Neutrality Myth Once and for All).⁴ A report from the United Kingdom's own previous Department of Energy and Climate Change supports these findings, concluding that burning forest-derived biomass from whole trees and other large-diameter wood increases carbon emissions relative to coal and natural gas for decades.⁵

The government has also signaled its willingness to keep coal plants open if they are “abated,” either via biomass co-firing or conversion, under the same flawed assumption that all biomass is “carbon neutral” at the smokestack.⁶ Thus, continued investment in biomass threatens to erode the climate gains of a coal phase-out and wastes additional resources to extend the life of old coal plants that would otherwise shutter their doors.

In November 2016, the groundbreaking study *Money to Burn* evaluated the most cost-effective path to ensure reliability of electricity supply and decarbonise the U.K. power system through 2025 when all economic costs are taken into account.⁷ Commissioned by NRDC and conducted by Vivid Economics, a London-based consultancy with expertise in U.K. energy systems, the study concluded that in the period 2020–2025, wind and solar are likely to be the least-cost options to achieve these objectives, even after accounting for the costs of integrating solar and wind into the grid.

Replicating the methodology of the original *Money to Burn* study, this 2017 update utilizes a whole-system approach to compare the costs of different scenarios for electricity generation. This approach factors the latest technology costs, the costs of integrating solar and wind power into the electricity grid, and the cost of carbon pollution (See: Methodology).

The study concludes that there is no economic or strategic case for coal-to-biomass conversion in the United Kingdom. The results of the economic modelling indicate that by 2025, even if already installed, biomass would be costlier to operate than building completely new solar and wind capacity, even when the costs of integrating solar and wind into the grid are fully accounted for. In 2025, biomass will be too costly to meet day-to-day electricity demand, and it is also not the least-cost option to meet the reliability requirements of the electricity system (i.e. to accommodate peak demand). If the U.K. government were to support the construction of new biomass capacity, it would likely be too expensive to run—and become a stranded asset—within the decade. These results hold true even for scenarios that do not fully account for biomass carbon emissions and their associated costs.

Thus, not only is biomass a dirty form of energy, but any additional subsidies funneled to biomass would be money sunk into a dying industry, rather than invested in the smart, truly clean, and growing renewable energy sector—akin to investing in steam trains in the jet engine era. Vivid Economics calculates that if the U.K. government supports further biomass conversions in 2025 via a Contract-for-Difference (CfD), it could require an excess implicit subsidy of more than £360 million over five years. By contrast, solar and wind offer a strategic investment opportunity; they are already projected to be a more cost-effective replacement for coal in the near-term, and maintain significant scope for additional cost reductions and deployment. Together, they offer the prospect of a truly clean and lower-cost generation mix for the United Kingdom into the future.

Ahead of its second CfD auction, which began in April 2017 and was ongoing at the time this report went to print, the U.K. government merged the funding allotment for converting coal power stations to burn biomass (known as ‘pot 3’) with the ‘established technologies’ allotment (known as ‘pot 1’) and has to date left this pot unfunded.⁸ The Department for Business, Energy and Industrial Strategy (BEIS), the Ministry charged with regulating bioenergy, has also said it could decide to delete future funding for “coal to biomass conversions.”

However, dedicated biomass plants that co-generate heat, known as combined heat and power plants (CHP), were made eligible in the second CfD auction. While this analysis did not examine the economics of biomass for CHP (as these projects tend to be significantly smaller than electricity-only biomass conversions), it is worth noting that current U.K. policy requires so-called “high quality Combined Heat and Power” facilities to achieve just 35 percent efficiency to qualify for an enhanced subsidy. By comparison, Drax power station, the United Kingdom’s largest coal-fired power plant, which utilizes decades-old technology without any heat capture, achieves 38 percent efficiency, and the European Union’s Renewable Energy Directive requires plants to meet an efficiency threshold of 70 percent in order to qualify for subsidies. Reforming the United Kingdom’s bioenergy

METHODOLOGY

The 2017 update utilizes a whole-system approach to comparing the costs of different scenarios for electricity generation, referred to here and throughout as “total economic costs”. Total economic costs include:

1. The latest technology costs—which include capital costs, operations and maintenance (O&M), and fuel costs—for biomass, onshore wind, offshore wind, and large-scale solar photovoltaic (PV). We include both U.K. estimates and projects in comparable European geographies;
2. The costs of ensuring reliability of supply. This includes system integration costs (SICs), which are the costs associated with backup generation required to “firm up” wind and solar, and the costs associated with increasing the flexibility of the system to adapt to fluctuations in demand;
3. The costs of carbon pollution. This is calculated based on the United Kingdom’s continued legislative commitment to keeping global warming below 2 degrees Celsius—the basis for international commitments on climate change enshrined in the 2015 Paris Climate Agreement. The Technical Appendix contains more information on how the United Kingdom translates its climate commitments into economic decision-making.

policies will thus require not only ending subsidies for the least efficient and most uneconomic uses of biomass—namely, electricity-only biomass conversions, such as those conducted by Drax—but also closing this efficiency loophole for biomass CHP.

UPDATES TO KEY ASSUMPTIONS TO REFLECT FALLING COSTS OF RENEWABLES

As in 2016, the 2017 analysis is based on modelled scenarios that estimate and compare the total economic costs of biomass and other renewable technologies. The analysis varies assumptions about technology costs, including biomass fuel costs, and GHG emissions intensity between scenarios. The 2017 analysis includes the same three biomass emissions scenarios as in 2016 (Table 1). Two of the

scenarios (Scenarios 1 and 2) reflect only partial emissions accounting, including one directly from Drax. Scenario 3 is a conservative low-end scenario that reflects full emissions accounting. The Technical Appendix provides a detailed description of all cost assumptions, biomass emissions scenarios, and Imperial College’s WeSIM model employed in the study.⁹

Vivid Economics reviewed the most recent data on current and projected technology costs and revised the 2016 study levelised cost assumptions for onshore wind, offshore wind, large-scale solar PV, and biomass. Table 2 summarizes the results of this assessment. These updated costs serve as underlying assumptions for the detailed economic modelling of the power system conducted in this study. Vivid and Imperial College then conducted power system modelling to

TABLE 1: BIOMASS EMISSIONS SCENARIOS

| SCENARIO | DESCRIPTION | EMISSIONS ACCOUNTING | KGCO2/KWH |
|----------|--|--|-----------|
| 1 | Estimate of Drax biomass ^A | Partial accounting, including cultivation, processing, transport | 122 |
| 2 | U.K. emissions limits for 2020-2025 ^B | Partial accounting, including cultivation, processing, transport | 200 |
| 3 | SELC low estimate using BEAC calculator ^C | Full emissions accounting | 1,277 |

Source: A. Drax (2015) Biomass Supply; B. Represents the upper limit of allowed emissions from cultivation, processing, transportation. C. Represents the low end of estimates of full emissions accounting from a 2015 analysis commissioned by the Southern Environmental Law Center (SELC). SELC used a scenario including 17 percent Mill residue, 48 percent Fine forest residues, and 35 percent from Additional hardwood harvests. See: Dr. Thomas Buchholz and Dr. John Gunn, “Carbon Emissions Estimates for Drax biomass powerplants in the UK sourcing from Enviva Pellet Mills in the U.S. Southeastern Hardwoods using the BEAC model,” prepared for the Southern Environmental Law Center, May 27, 2015, https://www.southernenvironment.org/uploads/audio/2015-05-27_BEAC_calculations_SE_hardwoods.pdf.

EUROPEAN RESEARCHERS BUST BIOMASS CARBON NEUTRALITY MYTH ONCE AND FOR ALL

In February 2017, the Chatham House issued a seminal report challenging a fundamental assumption underlying European renewable energy policy: that burning forest biomass to produce electricity is “carbon neutral.”¹⁰ Amongst its key findings, the report states that:

“Overall, while some instances of biomass energy use may result in lower life-cycle emissions than fossil fuels, in most circumstances, comparing technologies of similar ages, the use of woody biomass for energy will release higher levels of emissions than coal and considerably higher levels than gas.”

Contrary to industry claims that they only use low carbon sources, Chatham House underscores the conclusions of previous studies, which found that about three-quarters of the pellets from the southern United States came from whole trees and other large diameter wood, while residues accounted for only one-quarter.¹¹

Three months later, the European Academies Science Advisory Council (EASAC)—a body made up of the national science academies of all EU Member States—released a study echoing these conclusions.¹² EASAC concludes that EU policies are currently biased towards the use of forest biomass for energy with potential negative effects on the climate over the short to medium term. The authors express concern that with substantial imports of forest biomass into some EU Member States, allowing biomass energy to be counted as “carbon neutral” or “zero” emissions in the consuming country gives a false impression of that country’s progress towards reducing climate pollution. Instead of Member States counting biomass emissions in the energy sector where biomass is burned, emissions are simply shifted to the lands sector, where the loss of forest carbon is occurring, or to the biomass exporting country.

The EASAC report warns that using forest biomass for energy requires science-based standards to avoid negative impacts on the climate, since the wide range of bioenergy scenarios includes those where burning forest biomass releases significantly more carbon dioxide per unit of electricity than fossil fuels over long timeframes. The authors also state plainly that compared with solar and wind energy, the impacts of biomass on levels of carbon dioxide in the atmosphere is very poor, and renewables subsidies should reflect this.

1) determine the capacity mix required to ensure reliability of supply, allowing them to check if solar and wind build rates are feasible; and 2) project precise system costs in 2020 and 2025, which are a function of the capacity mix in those years. The results of this modelling effort are shown below in Figure 1 and Figure 2.

Technology cost projections for wind, solar, and biomass have fallen rapidly, even in just the year since publication of the original *Money to Burn* study in November 2016, and key analyses have been updated, which have improved understanding of costs for these technologies. For example, solar module costs have fallen around 65 percent over the last two years alone, and appear to be falling at around 20 percent for every doubling of capacity.¹⁴ In particular, price caps in the United Kingdom’s most current round of subsidy auctions for offshore wind, as well as contracted projects in comparable European geographies, indicate significantly lower offshore wind prices than were assumed in 2016.

Vivid Economics indicated that system integration costs remained broadly unchanged year-over-year.¹⁵ The Technical Appendix provides detailed information on updates to all key cost assumptions in the 2017 analysis.

RESULTS

The modelling results depicted in Figure 1 and Figure 2 show 2020 and 2025 projections for the total economic costs of biomass, wind, and solar under the various scenarios. The modelling demonstrates that by 2020, biomass will be higher cost than onshore wind and solar from a total economic cost perspective. In 2025, in all cases, biomass will be higher cost than all forms of wind and solar. According to the results of the analysis, biomass capacity that is already installed will be running at reduced load factors in 2025. This is due to high fuel and carbon costs for these facilities. Instead, it is cheaper to build new solar and wind capacity. If new biomass conversions were to be constructed, they would be stranded assets—meaning uneconomic to run for any purpose—within the decade.

Table 3 summarizes the modelled renewable capacity added between 2020 and 2025.^b This result is shown graphically in the first bar graph of Figure 3. The analysis indicates that under central levelised technology cost assumptions, biomass is not part of the least-cost technology mix to meet the United Kingdom’s affordability, climate change,

TABLE 2: SUMMARY OF 2017 REVISIONS TO LEVELISED COST OF ENERGY PER PER MEGAWATT HOUR (MWh)

| | 2017 REVISION COMPARED TO 2016 STUDY | 2017 LEVELISED COST OF ENERGY PER MWh IN 2020 | 2017 LEVELISED COST OF ENERGY PER MWh IN 2025 |
|----------------------------|---|---|---|
| Onshore wind | ↓ by £20/MWh in 2020; unchanged for 2025* | 65 | 65 |
| Offshore wind ^a | ↓ by £20/MWh in both 2020 and 2025** | 101 | Central: 82 Low: 70 Very low: 60 |
| Solar | ↓ by £25/MWh in 2020 | 69 | 64 |
| | 2025 Ambitious: ↓ by £27/MWh*** | 46 | 37 |
| Biomass conversion | ↓ by £23/MWh in both 2020 and 2025**** | 89 | 89 |

* Based on new evidence from the U.K. Department for Business, Energy & Industrial Strategy (BEIS), although international auctions suggest this could be even lower.

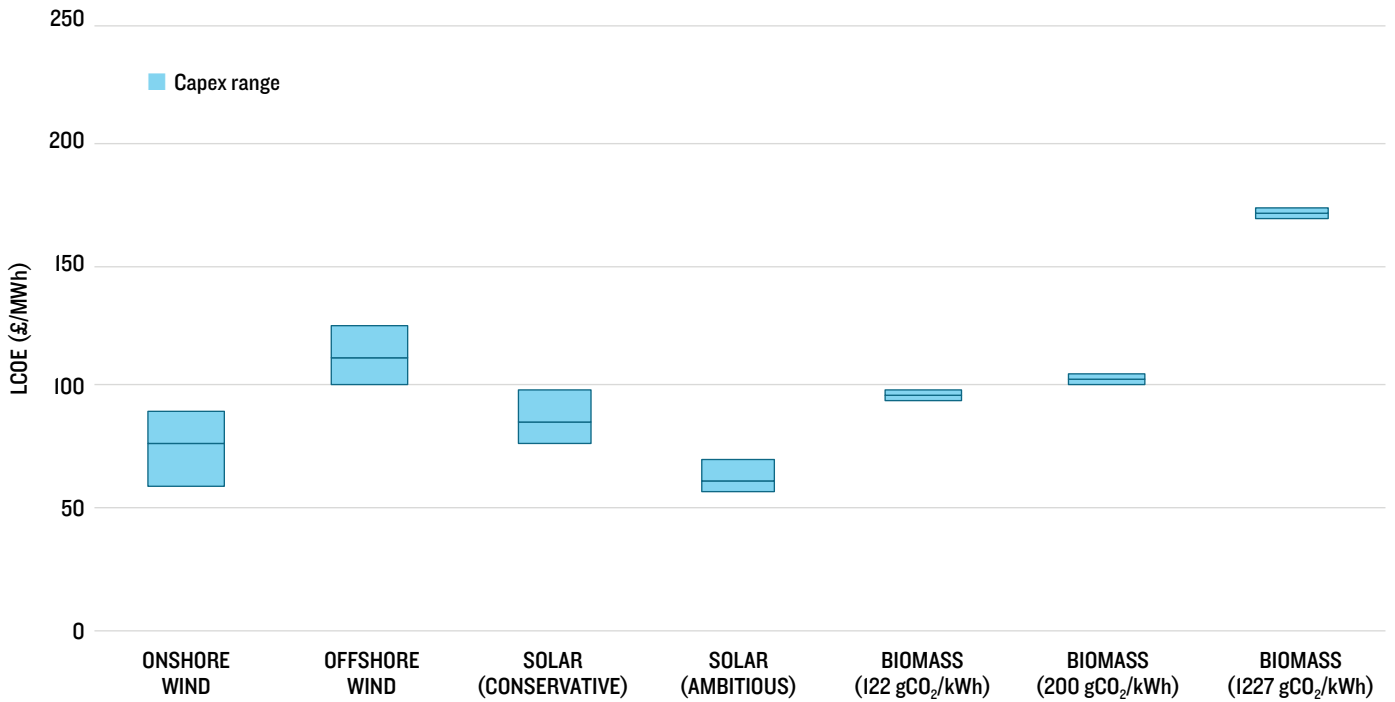
** Based on new evidence from BEIS and is corroborated by international evidence.

*** Based on BEIS projections for 2020. Because it is challenging to project solar PV costs in 2025 given the wide range of available estimates, Vivid modelled two scenarios.

**** Based on new BEIS evidence (ARUP, 2016) from a range of public, internal and stakeholder sources, triangulated between U.K. and international sources and filtered for transferability to potential future U.K. projects. The key drivers of the recent cost reduction are decrease in construction and operating costs, increases in load factor and efficiency. Several large installations of this technology have taken place since the last assessment, providing the conditions for standardisation and learning associated with cost reduction. Further significant falls in cost are unlikely for the few remaining potential biomass conversions in the United Kingdom.¹³ See Technical Appendix for more information.

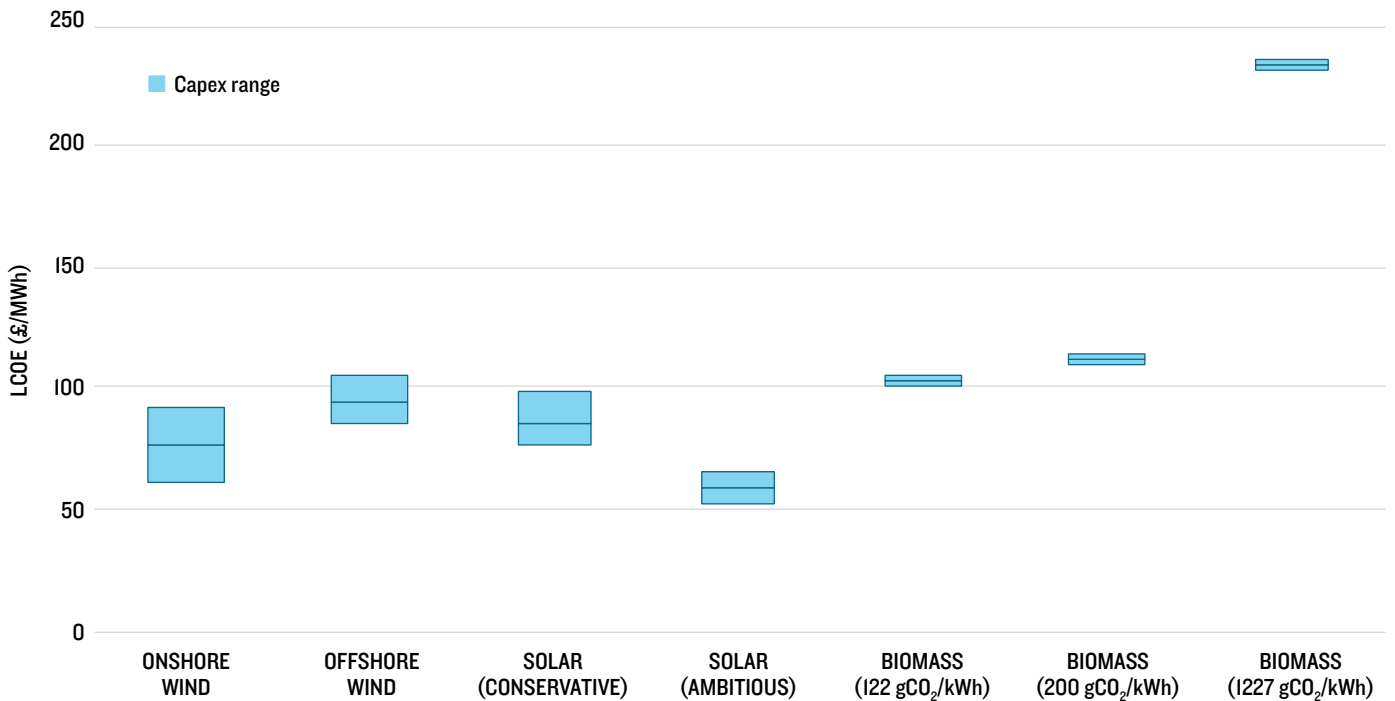
a Because U.K. offshore wind subsidy auctions were ongoing at the time 2017 modelling was conducted, Vivid Economics modelled three offshore wind cost scenarios to capture various price sensitivities. These range from a central projection equal to the government’s published price cap of £86 per MWh in 2025 for this most recent auction round, which equates to a levelised cost of £82 per MWh in 2025 and forms a conservative upper bound in the analysis, to a low cost sensitivity of a £77 per MWh auction strike price, which equates to £70 per MWh in 2025. Vivid also modelled an aggressive lower bound scenario in which auction results come in at £60 per MWh.

FIGURE 1: TOTAL ECONOMIC COSTS FOR WIND, SOLAR, AND BIOMASS ELECTRICITY GENERATION IN 2020*



*Only capital expenditure (capex) uncertainties explored in Figure 1 and Figure 2. Further uncertainty is possible from projected biomass conversion costs, in particular as it relates to future biomass fuel prices.

FIGURE 2: TOTAL ECONOMIC COSTS FOR WIND, SOLAR, AND BIOMASS ELECTRICITY GENERATION IN 2025



or electric reliability objectives in 2025, even under Drax’s own incomplete emissions figures (122 g/kWh), which significantly underestimate emissions and thus carbon costs.

Figure 3 also captures two other modelled scenarios to demonstrate that new biomass conversion is not justified in 2025 under reasonable assumptions. According to the results, new biomass conversion is only economic if biomass electricity is assumed to be zero-carbon, while other low-carbon technologies are allocated their full lifecycle emissions, as shown in the second bar graph. This assumption is not credible and would create a wholly uneven playing field. Even then, biomass conversion is not economic when compared to solar and wind, as long as there is a sufficient pipeline of onshore wind projects that can be developed or levelised costs of offshore wind are £70

or lower per MWh (i.e. the “Low” offshore wind technology cost), as shown in the third bar graph.

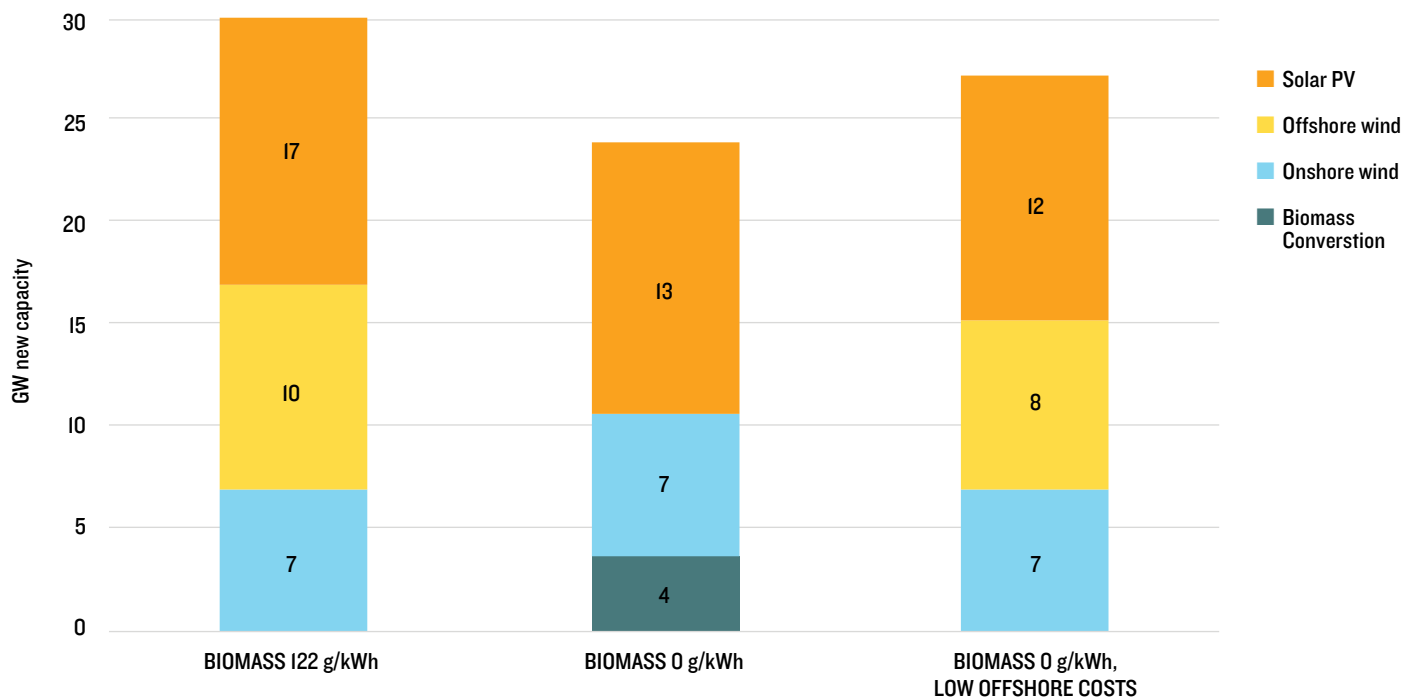
TABLE 3: RENEWABLE CAPACITY ADDITIONS BETWEEN 2020 AND 2025 UNDER ALL MODELLED EMISSIONS SCENARIOS

| | WIND | SOLAR | BIOMASS |
|-----------------------------------|------|-------|---------|
| Capacity additions 2020-2025 (GW) | 17 | 17 | 0 |

Source: National Grid (2017) Future Energy Scenarios

Note: Level of wind build is ambitious but within site constraints and consistent with National Grid’s ‘2 degree’ build rate for the 2020-2025 period. Electricity grid emissions are constrained to 140 g/kWh overall, consistent with Fifth Carbon Budget. See Technical Appendix for more detail.

FIGURE 3: GIGAWATTS (GW) OF NEW INSTALLED CAPACITY IN 2025 UNDER DIFFERENT BIOMASS EMISSIONS SCENARIOS



b Vivid Economics reports results as the capacity added between 2020 and 2025 because capacity in 2020 is already contracted; thus, there is no chance of additional capacity being built before then.

ONE COMPANY STANDS TO BENEFIT MOST FROM CONTINUED BIOMASS SUBSIDIES: DRAX

In 2013, Drax announced that it had moved firmly into executing plans to transform the Drax power station into a predominantly biomass-fueled generator.¹⁶ In 2016, the company announced that it had converted three of its six units to burn biomass in the form of wood pellets, accounting for 65 percent of its total output.¹⁷

In 2015, at an average price of £42.69 per certificate, solid woody biomass received over £800m in subsidies under the United Kingdom's Renewable Obligation Certificates scheme. According to its 2016 Annual Report, Drax alone received £541.43 million in subsidies for its biomass conversions,¹⁸ all under programmes intended to promote clean, renewable energy—equivalent to £1.48 million per day.

While there are other coal plants left around the United Kingdom that could turn to biomass to remain in operation, the most realistic future biomass conversion prospects are likely at Drax power station. Drax has explicitly signaled its interest in converting its remaining coal-fired units to burn biomass and has not been shy in welcoming additional subsidies. In a "Q&A" section of Drax's 2016 Annual Report, company CEO Dorothy Thompson writes,

*"We have now delivered on our original strategy to upgrade three generating units to run on compressed wood pellets. However, we would like to do more, and have consistently said that with the right conditions we stand ready to convert further units."*¹⁹

Vivid Economics conducted additional analysis, based on the economic modelling done for this study, to estimate the impact on U.K. government subsidy expenditures if Drax received support to convert its 4th unit, a 645 MW boiler, to biomass. Vivid found that the total excess implicit subsidy^c to Drax could be more than £360 million over five years if offshore wind prices are £60/MWh or lower. This includes the wholesale revenues and support payments required to build 645 MW of additional biomass capacity via new coal-to-biomass conversions compared to supplying the equivalent amount of electricity with offshore wind over the five-year period 2023-2027,^d if these plants had to pay the full costs of operating (e.g. lifecycle carbon emissions and system integration costs).

c This approach to subsidy calculation reflects the gap between consumer prices and economically efficient prices.

d The current CfD auction round is for projects constructed in 2021/2022 and 2022/2023. Because large projects are typically phased in in ~300 MW blocks, it is unlikely that the full 645 MW of capacity could come online in 2022. Thus, 2023 is the first year that the United Kingdom could practically install 645 MW of offshore wind at very low cost. An end date of 2027 was chosen because biomass conversions under CfD are subject to an expiry date of 31 March 2027 under current U.K. government policy.

DISCUSSION

Coal-to-biomass conversions will not be a low-cost source of electricity in the short-term or long-term future. These conversions are a poor strategic investment for meeting U.K. electricity system needs. The results of this updated economic modelling analysis indicate that biomass will be higher cost than onshore wind and large-scale solar PV in 2020 and 2025, even when biomass carbon emissions are not fully accounted for. By 2025, it will be cheaper to build new renewables than to run existing biomass facilities in all cases.

Biomass proponents argue that biomass can generate low-carbon electricity at times of low wind or solar generation. However, the economic modelling of the power system conducted for this analysis demonstrates that it is more cost-effective to deploy a combination of wind, solar, and natural gas generation to meet this objective than to deploy biomass generation, even in order to meet demand under a tight carbon constraint.

Continued subsidies for biomass conversions could thus represent hundreds of millions of pounds in wasted resources if Drax continues with conversion of its remaining coal-fired units to biomass. This would be money funnelled into a dying sector whose assets could be rendered uneconomic and obsolete within the decade.

There are a number of uncertainties that could impact these results, most notably biomass fuel costs and the rate at which offshore wind costs continue to fall in the United Kingdom. However, while government assumptions about the levelised cost of biomass conversions were revised down this year, the bulk of biomass costs (approximately 85 percent) remains fuel costs, which forms a floor on potential cost reductions. The Technical Appendix provides detailed information on the costs associated with biomass conversion. By contrast, offshore wind costs have no fuel-related expenses. Thus, the falling costs and scope for rollout of offshore wind offer the United Kingdom a substantial strategic investment opportunity that could significantly reduce the overall cost of the U.K. generation mix and help achieve the country's climate change goals.

Biomass conversions will not be a low-cost source of electricity in the short-term or long-term future. These conversions are a poor strategic investment for meeting U.K. electricity system needs.

REFORMING BIOENERGY POLICIES IN THE EU'S 2030 RENEWABLE ENERGY DIRECTIVE

Groups from around the world have sounded the alarm about harvesting biomass for energy production and the impacts this massive new source of demand for wood is having on forests and communities. The sourcing practices of Drax are of particular concern for U.K. policymakers. In its 2016 annual report, Drax reported sourcing 59 percent of its 6.59 million tonnes of wood pellets from the United States, primarily from the Southeast.²⁰ The region leads the world in wood pellet manufacturing and export, with the lion's share bound for the U.K. electricity market.²¹ It is also home to some of the most biologically diverse forest ecosystems in North America, and its coastal plain has been recognised as a global biodiversity hotspot.²²

Since 2013, media and local groups have conducted on-the-ground investigations into the supply chains of Enviva, a principal wood pellet supplier to Drax.²³ These investigations have exposed the unsustainable logging practices being used to source Enviva's wood pellet mills, including the clearcutting of wetland forests. They also spotlight the vast quantities of trees and other biomass entering the wood pellet export market that are known to be carbon-intensive.²⁴

In 2009, the European Commission adopted ambitious targets for cutting GHG emissions and increasing the amount of renewable energy consumed in the European Union through 2020. Unfortunately, these targets also ended up enshrining a critical error in EU policy: all biomass, whether true forestry wastes and residues or whole trees from old growth forests, was deemed "carbon neutral."²⁵ Thus, when power plants in Europe burn biomass, they are not required to account for their smokestack emissions.

As discussed, the science on biomass carbon emissions has advanced significantly since then and has clearly demonstrated that most forms of forest-derived biomass—in particular whole trees and other large-diameter wood—are a high-carbon fuel, even compared to coal.²⁶ Burning this biomass for electricity increases, not decreases, carbon

emissions for many decades—far beyond the timeframes that guide EU climate policy and are relevant for avoiding the worst consequences of climate change.

In response to the developing science and increased controversy about destructive biomass industry practices, the European Commission published an updated draft 2030 EU Renewable Energy Directive (RED) in late 2016, which included proposals on bioenergy sustainability.²⁷ The draft RED contains a provision that would require electricity from biomass installations larger than 20 MW that 'start operations' three or more years after adoption of the RED, or receive support under schemes approved by the same date, to be produced in "high efficiency cogeneration" if they are to count towards the renewable energy target or qualify for public subsidies.²⁸ If strengthened, this provision could significantly limit the least sustainable uses of biomass—namely, biomass burning in large, electricity-only power plants and, in particular, coal-to-biomass conversions, such as those operated by Drax.

Unfortunately, the proposal contains several critical loopholes. First, efficiency targets for co-generation facilities remain ambiguous. Second, the proposal fails to adequately deal with the existing biomass industry. Third, the draft RED allows long grace periods before installations have to meet efficiency standards. Finally, it excludes power plants smaller than 20 MW.²⁹

To avoid subsidising high-carbon bioenergy and high-risk feedstocks under the guise of 'renewable energy,' the revised EU Renewable Energy Directive for 2030 must close these loopholes when the proposal undergoes amendments from the European Parliament and European Council. As long as the United Kingdom remains a member-state of the European Union, it continues to have a critical role to play in this reform effort. The United Kingdom also has the opportunity to follow the science on carbon emissions, incorporate on-the-ground evidence to avoid high carbon feedstocks from destructive forestry operations, and acknowledge the emerging economic realities to immediately ramp down biomass subsidies and shift investments to the truly clean, reliable, and cost-effective energy solutions the country needs.

ENDNOTES

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ECONOMICS OF BIOMASS UPDATE: TECHNICAL APPENDIX

Report prepared for the Natural Resources Defense Council

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1. Introduction

This technical annex supports the Natural Resources Defense Council’s issue brief on UK coal phase-out without biomass. This document contains:

- a briefing on the modelling assumptions, authored by Vivid Economics; and,
- detailed description of the WeSIM model employed by this study, authored by Imperial College.

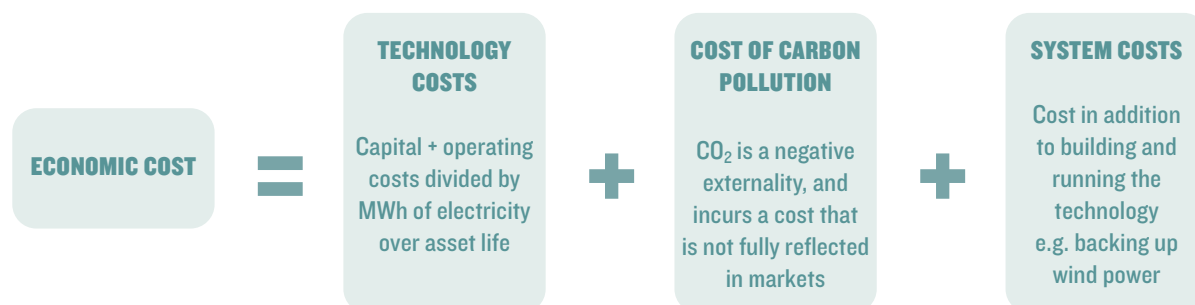
2. Modelling assumptions

2.1 Technology cost assumptions

Levelised cost assumptions

The most common way of comparing the costs of electricity generation technologies is using the levelised cost metric. Levelised costs are calculated over the lifetime of the plant, and are annualised capital and operating costs divided by MWh of electricity that it is expected to generate over its lifetime. However, from the perspective of government interested in making decisions in the best interests of society, it is important to take account of externalities, which are omitted from the levelised cost metric. Two key externalities are important: carbon costs and the system integration costs. From the government’s perspective, it is therefore total economic cost which is important, including levelised costs, carbon costs, and system integration costs (SICs), as set out in Figure 1.

FIGURE 1: THE TOTAL ECONOMIC COST INCLUDES LEVELISED COST, CARBON COST, AND SYSTEM LEVEL COSTS

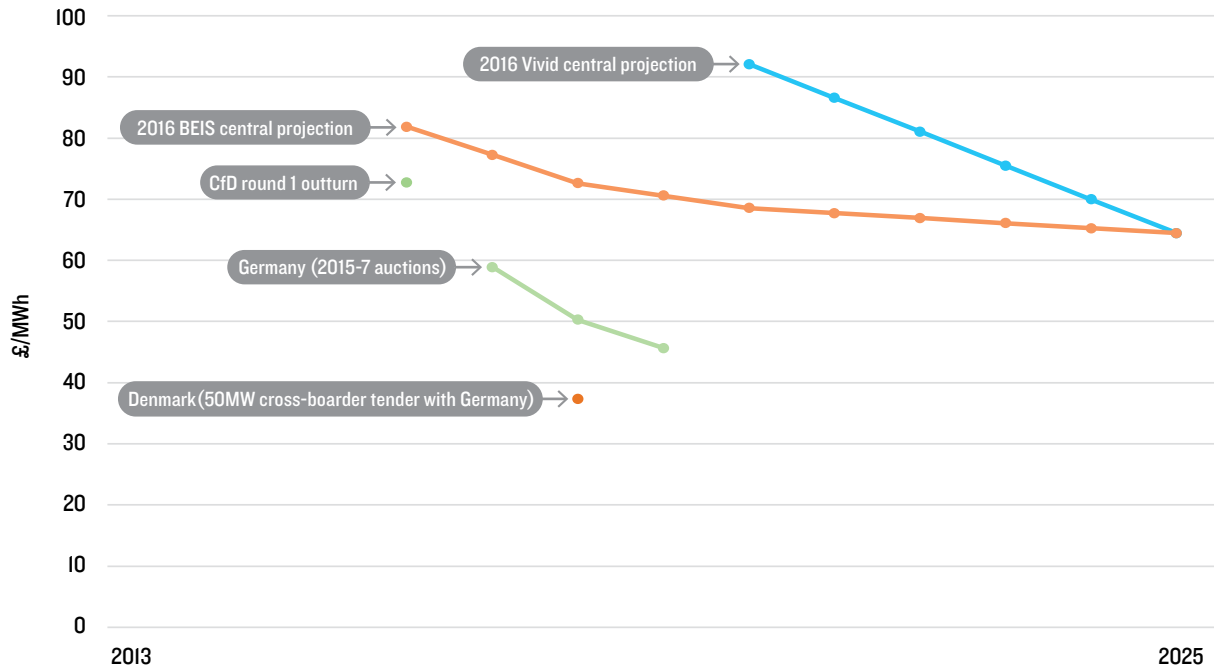


Source: Vivid Economics

Levelised costs of variable renewables – onshore wind, offshore wind and solar – have fallen substantially in recent years, with scope for further reductions in future:

- **Solar:** The costs of solar panels have fallen sharply over the last decade, and it is now one of the most cost effective low-carbon generation technologies. Solar module costs have fallen around 65 percent over the last two years alone, and appear to be falling at around 20 percent for every doubling of capacity (IRENA, 2016a). Recent Northwest European experience suggests dramatic cost reductions beyond what has been experienced in the UK, though it is possible that if new auctions were held, these values would be replicated in the UK context (Figure 2).
- **Onshore wind** is already one of the most cost-competitive low carbon technologies, and costs are falling globally from cheaper turbine prices and higher output (IRENA, 2016b). In the UK, deployment of onshore wind is ultimately limited by site availability. Recent auctions in Germany suggests costs continue to fall, although deployment of this technology option is currently limited in the UK.
- **Offshore wind:** In the UK, costs have been falling in recent years as a result of larger turbines and other improvements (Catapult, 2015). Opportunities exist for further cost reduction in line with achieving £100/MWh or below in the 2020s. Recent European auction prices suggest much lower prices are possible in the UK auctions to be completed in late 2017. However, comparability of results between continental Europe and the UK are constrained because of different auction designs and the fact that UK wind must pay costs of grid connection.

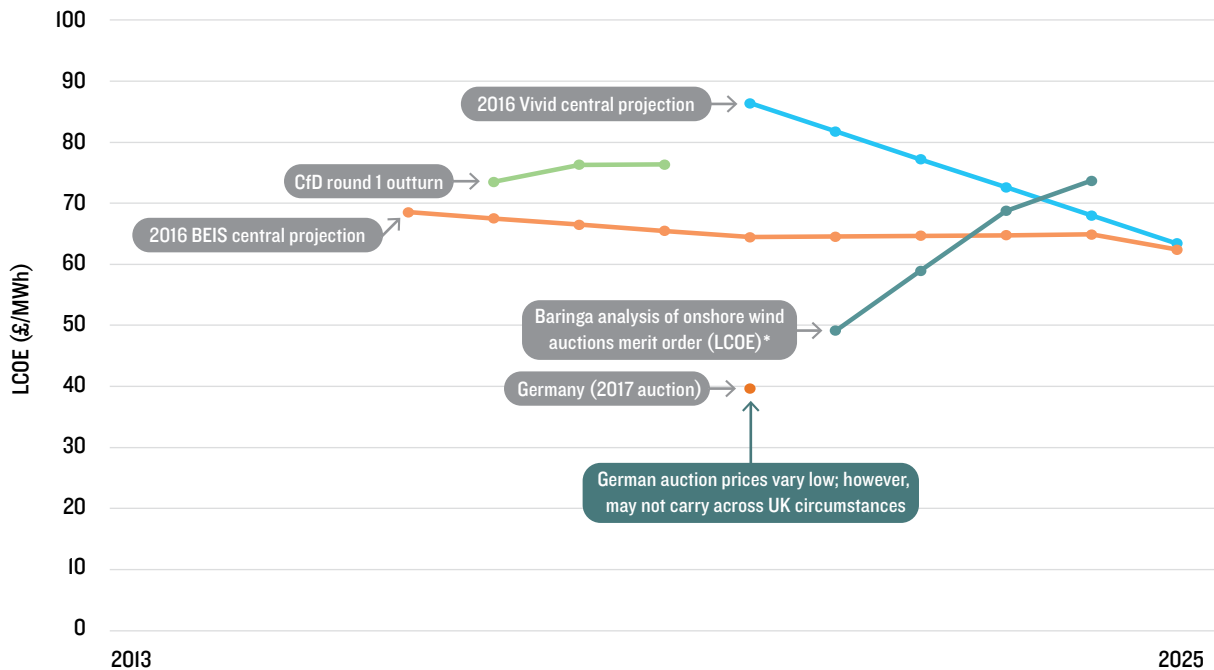
FIGURE 2: RECENT SOLAR AUCTIONS SHOW FALLING COST ACROSS NORTH-WEST EUROPE



Note: Figures are in 2016 real prices.

Source: BEIS (2016); www.pv-magazine.com (2016); Vivid Economics (2016)

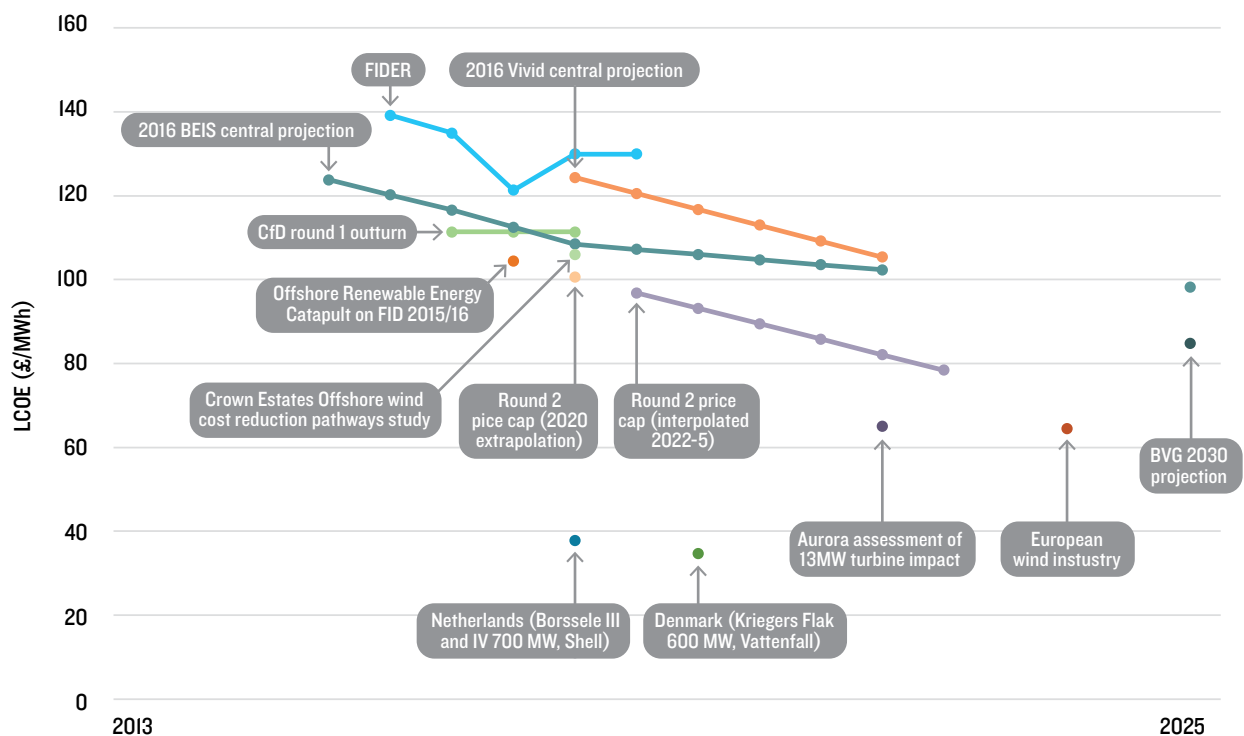
FIGURE 3: RECENT ONSHORE WIND AUCTIONS IN GERMANY SUGGESTS CONTINUED FALLING COSTS



Note: Figures are in 2016 real prices.

Source: BEIS (2016); Baringa (2017); www.bundesnetzagentur.de (2017); Vivid Economics (2016)

FIGURE 4: RECENT OFFSHORE WIND AUCTIONS IN GERMANY SUGGESTS CONTINUED FALLING COSTS



Note: Figures are in 2016 real prices.

Source: BEIS (2016); vattenfall.com (2016); Reuters (2016); Offshore Renewable Energy Catapult (2017); Crown Estate (2012); Vivid Economics (2016)

Biomass conversion, by contrast, is a mature technology and comparatively little cost reduction is expected.

The potential for costs to fall in the future is limited, as biomass in the power sector relies on existing combustion techniques that are already achieving high efficiencies. Notwithstanding this, there is some potential for cost reduction through the improvement in the level of competition – moving from the Renewables Obligation (RO) to the Contracts for Difference (CFD) auction mechanism. The cost structure of biomass conversion is also different to that of wind and solar, comprised of around 85 percent fuel costs. Renewables consume no fuel and as a consequence, have minimal operations and maintenance costs. The majority of the costs associated with building renewable energy projects are capital costs of construction. As a result, even significant reductions in capital cost would have a smaller impact on the overall cost of biomass than capital cost reductions in wind and solar.

Estimates from ARUP (2016) suggest cost of around £89/MWh. This is a 20 percent reduction relative to estimates in 2013. The key drivers of the recent cost reduction are decrease in construction and operating costs, increases in load factor and efficiency. Several large installations of this technology have taken place since the last assessment, providing the conditions for standardisation and learning associated with cost reduction. The ARUP report notes that further significant falls in cost are unlikely for the few remaining potential biomass conversions in the UK:

- Capital costs: the ARUP report notes that costs have fallen due to learning and standardisation but are unlikely to change further, as there is “no additional downward pressure and the majority of industry learning has already taken place.”
- Operational costs: “Stakeholders indicated that cost is expected to remain broadly flat going forward.”
- Efficiency: this increase was relatively modest (36 percent to 40 percent), and now represents a high level of efficiency reflective of a mature technology. Load factors are now assumed to be at 79 percent, with relatively little scope for further upwards revision.
- Corroborating the evidence from the ARUP (2016) report, CCC (2016) estimates biomass costs at £87/MWh, based on the likely costs of plant proceeding under the RO.

TABLE 1: LEVELISED COSTS ASSUMED IN THIS STUDY

| TECHNOLOGY | 2020 | 2025 |
|-------------------|------|------|
| Large scale solar | 69 | 64 |
| Onshore wind | 65 | 62 |
| Offshore wind | 101 | 82 |

Source: Vivid Economics

Note: Costs are in real £2017. Sensitivities on offshore wind costs are also modelled at £70/MWh and £60/MWh to encompass the range of possibilities associated with the 2017 auctions that are expected to deliver low prices.

Carbon emissions costing

The UK is statutorily committed to action to reduce emissions, and this has implications for the costing of options for the power sector. The Climate Change Act commits the UK to reduce emissions by at least 80 percent in 2050 from 1990 levels. The Act requires the Government to set legally binding Carbon Budgets. A Carbon Budget is a cap on the amount of greenhouse gases emitted in the UK over a five-year period. The first five Carbon Budgets have been put into legislation and run through 2032.

The UK's target consistent carbon values serve as a way to translate the UK's commitments into economic decision-making. In order to do so, the UK government has produced a carbon price trajectory for policy appraisal, which reflects a set of target consistent carbon values that reflect the cost of meeting the UK's domestic and international targets in the short- and long-term. These values are based on literature and modelled scenarios, and are peer reviewed by an expert panel. This study adopts this trajectory in estimating carbon values. In a central case the carbon values reach £77/tCO₂ in 2030, growing steadily to around £220/tCO₂ in 2050.

This study assesses three potential biomass emissions scenarios, spanning the results of different accounting methods. Our first two scenarios represent only partial emissions accounting, but are consistent with UK policy. In the UK, an emissions limit on new biomass of 285 kg CO₂e/MWh, falling to 200 kg CO₂e/MWh in 2020 and 185 kg CO₂e/MWh in 2025, is based on the EU Renewable Energy Directive methodology that covers only cultivation, harvesting, processing and transport, as well as direct land use change since 2008 (EC, 2009). The third emissions scenario modeled represents a low-end estimate of full emissions accounting, using the Biomass Emissions and Counterfactual (BEAC) calculator to estimate emissions from cultivation, processing, transport, as well as emissions from changes in forest carbon stocks and estimates of indirect land use change. A higher-end estimate, also based on the BEAC calculator, is presented in Table 4 for the purpose of comparison, but was not modeled. Figure 4 and its underlying text provides a diagram of the components of full biomass emissions accounting and an explanation of what is and is not included in the EU Renewable Energy Directive methodology.

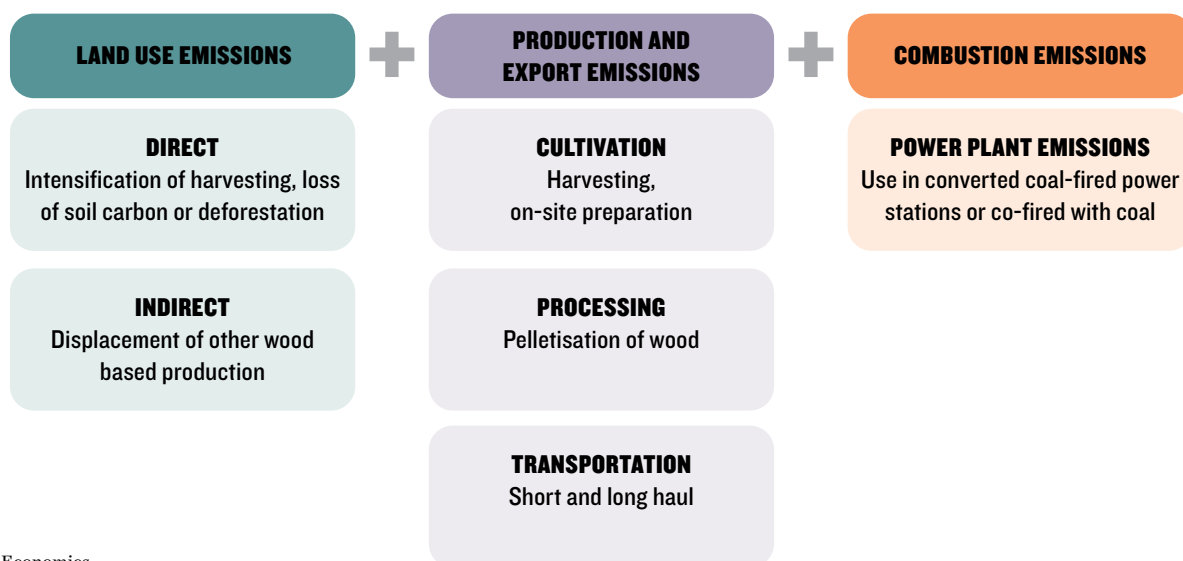
TABLE 2: EMISSIONS LEVELS ASSUMED IN THIS STUDY

| EMISSIONS SCENARIO | GCO ₂ /KWH |
|--|-----------------------|
| Estimate of Drax biomass (partial accounting) | 122 |
| UK emissions limits for 2020-20252 (partial accounting) | 200 |
| SELC low estimate – using BEAC calculator (full emissions accounting, low-end estimate) | 1277 |
| SELC customised mix – using BEAC calculator (full emissions accounting, high-end estimate, not used in cost modelling) | 2677 |

Source: Drax (2015); SELC (2015)

Notes: UK emissions limits represent the upper limit of allowed emissions from cultivation, processing, transportation. SELC low estimate represents the low end of estimates of full emissions account from SELC (2015). SELC used a scenario including 17 percent mill residue, 48 percent fine forest residues, and 35 percent from additional hardwood harvests. SELC customised mix scenario assuming a dominant share (80 percent) of the feedstock is derived from additional biomass harvests in the Southeastern U.S. hardwoods with the remainder coming from sawmill or forest residues.

FIGURE 5: COMPONENTS OF FULL BIOMASS EMISSIONS ACCOUNTING



Source: Vivid Economics

The Renewable Energy Directive lifecycle accounting (LCA) methodology requires only partial emissions accounting for biomass. This includes the emissions from the cultivation, harvesting, processing and transport of the biomass feedstocks. It also includes direct land use change where the land use has changed category since 2008, e.g. from forest to annual crop land, grassland to annual crop land. However, this accounting methodology does not account for changes in the carbon stock of a forest, foregone carbon sequestration of land, or indirect impacts on carbon stocks in other areas of land, which are necessary for full biomass emissions accounting. According to the Department of Energy & Climate Change’s 2014 report, Life Cycle impacts of Biomass Electricity in 2020, these CO₂ fluxes can be significant. The report finds, “Recent reports have shown that the above factors omitted in the Renewable Energy Directive LCA methodology can have significant impacts on the total GHG intensities of some types of bioenergy feedstocks, and therefore need to be considered if we wish to understand the true GHG intensities of different bioenergy feedstocks and technologies”.

System integration costs

The replacement of firm capacity with intermittent technologies creates a negative externality at the system level – System Integration Costs (SICs). SICs are the costs of backup generation to supplement wind and solar generation during periods of lower generation, as well as the costs associated with increasing the flexibility of the system to adapt to fluctuations in supply and demand. Previous studies of SICs in the UK context have shown that these can add around 10 percent to the cost of variable renewables, such as wind and solar (NERA, 2015). Recent evidence from UKERC (2016) summarise the evidence on SICs, confirming that these are likely to be small, around £10/MWh. In this study, we incorporate the full costs of meeting reliability of supply through the inclusion of SICs at this figure of £10/MWh.

These figures are all outputs of the WeSIM model developed by Imperial College to estimate these costs; a summary of their modelling approach can be found later in the Appendix.

System integration costs used in this study arise from:

- **Backup capacity costs:** with any generation technology, there is a risk that a plant will be unable to produce electricity some of the time. For this reason, electricity systems need ‘back-up’ capacity to reduce the risk of a shortage. Intermittent technologies like wind and solar have a much greater risk than conventional technologies of not being available when needed. Consequently, they require more back-up capacity to meet demand.
- **Increased balancing costs:** these arise due to a need for operating reserve driven by the intermittency of renewable generation technologies, or the result of the generation pattern associated with a given technology.
- **Transmission costs:** these are costs associated with reinforcement of transmission and distribution networks. Generators are likely to face higher transmission charges in more remote locations. Distribution and Transmission Network Use of System Charges (DUoS and TNUoS) seek to charge generators in different places and of different technologies a price for network access reflecting the marginal cost these assets impose on the networks.

- **Cost of achieving a level of carbon emissions:** these are the costs associated with additional low-carbon capacity in order to compensate for increased emissions associated with higher system balancing requirements.

System costs are estimated relative to a benchmark technology, assumed here to be nuclear power. Nuclear is used as a benchmark as it has relatively low system integration costs but also has low carbon emissions. Any technology can in principle be used as a benchmark.

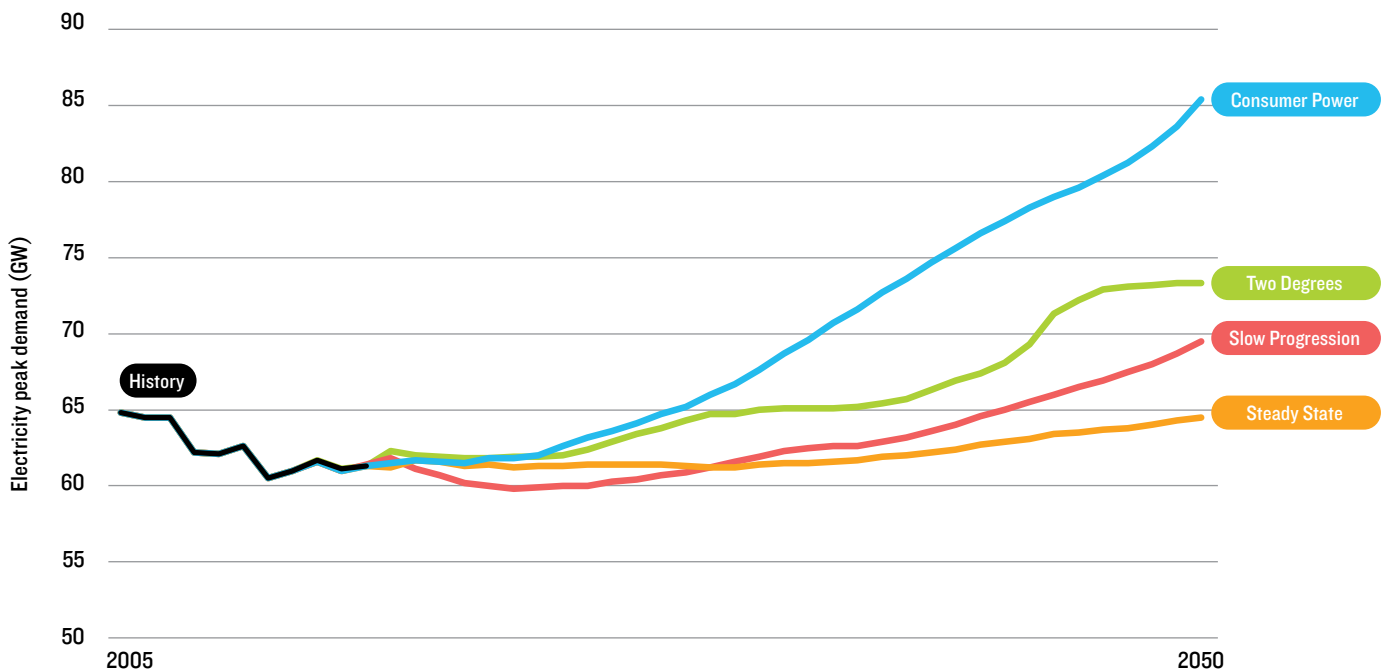
Previous studies of the system integration costs have not included estimates for the full emissions of biomass.

When these emissions are included, a new category of system costs arises. This is because the emissions associated with biomass, similar to the addition of other high-emissions generation sources, force the whole electricity grid to compensate with additional emissions reduction technologies (and associated) costs to ensure total emission coverage towards 100 g/kWh in 2030. We use the trajectory to 2025 suggested by the CCC as consistent with meeting the legislated carbon commitments at the whole-of-economy level. Although these power sector specific reductions are not legislated, if they were to be mandated, and to include lifecycle emissions similar to those in Table 4, then biomass emissions would force the construction of significant additional zero carbon plant by 2025 in order to compensate for the higher emissions from biomass.

2.2 Demand assumptions

For both demand and capacity assumptions we assume development along the lines of the Two Degrees scenario, as developed by National Grid in their analysis of possible futures for the UK electricity system. The Two Degrees scenario represents a future in which the renewable energy target for 2020 and CO₂ reduction targets for 2020, 2030 and 2050 are all met. We have conservatively chosen this scenario as it is the most favourable to biomass due to the higher peak demand and therefore requirement for firm generation. To fully test whether the system can cope without further biomass, the Two Degrees scenario will test the potential to fill the capacity gap with wind and solar.

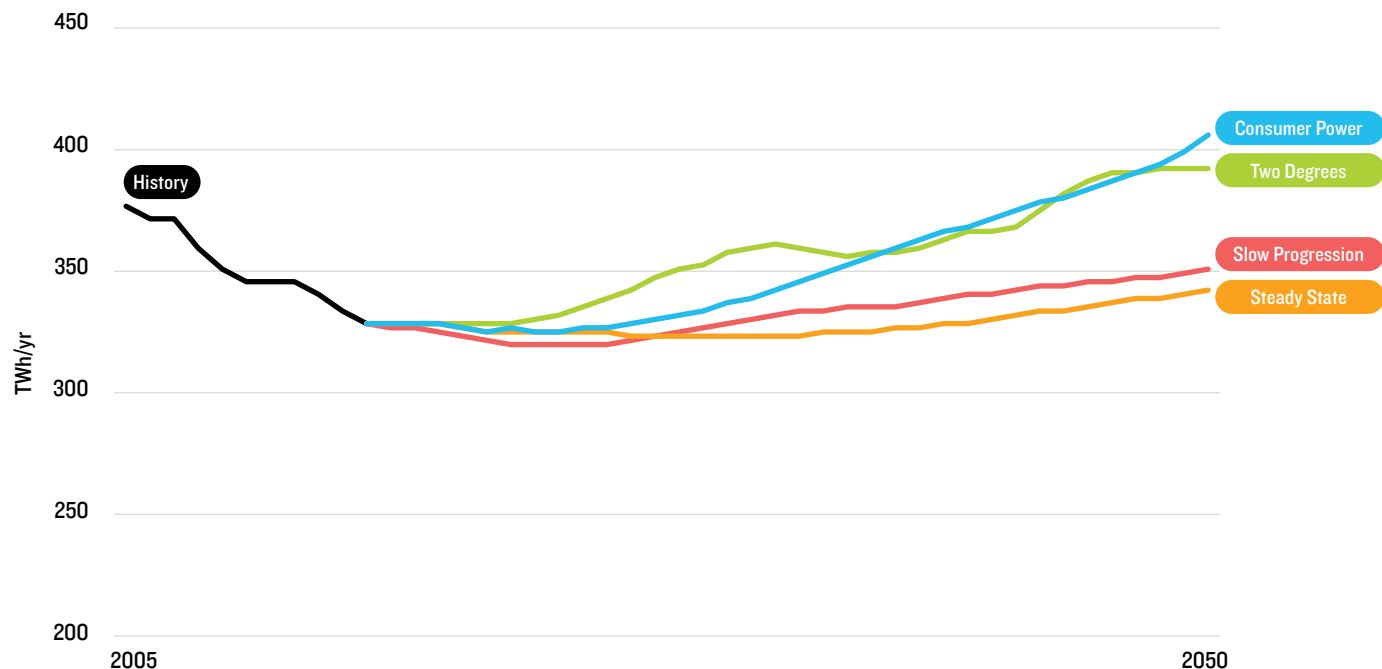
FIGURE 5: PEAK DEMAND ASSUMED IN NATIONAL GRID'S TWO DEGREES SCENARIO VERSUS ALTERNATIVES



Source National Grid (2017)

Demand in the Two Degrees scenario is 328 TWh in 2020, rising to 339 TWh in 2025. Peak demand is 61.8 GW in 2020 rising to 62.4 GW in 2025. This level of demand is relatively similar to other scenarios in 2025, as shown below in Figure 6. The demand trajectory for Two Degrees rises substantially following 2025 due to increasing penetration of electric vehicles and heat pumps.

FIGURE 6: ELECTRICITY DEMAND PROJECTIONS ASSUMED BY NATIONAL GRID, TWO DEGREES SCENARIO VERSUS ALTERNATIVES



Source National Grid (2017)

Note: Shown above is National Grid's view of underlying weather corrected consumer demand, before reduction by on-site and behind the meter generation. Transmission and distribution losses are included.

2.3 Capacity assumptions

In order to assess whether biomass is required to meet reliability of supply in the period 2020 to 2025, we conducted model runs, which begin with a specified capacity mix in 2020 and then solve for the cheapest mix of technologies to meet demand in the period to 2025. Given the requirement to meet a declining emissions trajectory (between 140-150 g/kWh in 2025, on a path to less than 100 g/kWh in 2030), we constrain the ability for high carbon power sources to be constructed to meet the capacity gap (that is, gas, oil, coal). We also fix other low carbon technologies, such as tidal and hydro, at the levels expected under National Grid's Two Degrees scenario for 2025 (Table 6). The model is then allowed to make up any remaining gap in capacity with the cheapest of biomass, wind or solar in the period to 2025.

Due to retirements of coal and nuclear power in the UK, there is a need for a large amount of new capacity to be built in the UK in the 2020s. We used the WeSIM model to optimise the UK power system and fill this capacity gap with the least cost mix of low-carbon power capacity. When left to optimise for the uptake of biomass, solar and wind, the WeSIM model estimated around 17 GW of solar build and 17 GW of new wind (Table 3). This level of uptake in the period 2020-2025 is within the range of what is assumed in other studies, albeit at the upper end of deployment rates that are expected to be possible:

- **Onshore wind:** Site availability, rather than build rate, is the relevant constraint here, although numerous studies suggest available onshore sites of between 20-30 GW (CCC, 2015; National Grid, 2016). Given that 12.3 GW is expected in 2020, this allows room for the remaining 7 GW required in our uptake scenario. It is also consistent with the historical installation rates of onshore wind, for example, 1.4 GW was installed in 2016 (CCC, 2016).
- **Offshore wind:** The constraining factors on wind build include the rate of annual offshore build that can be achieved without the market overheating so that prices remain on a falling cost trajectory. Previous studies by the CCC suggest this rate is around 2 GW per annum or 10 GW over the period 2020-2025 (BVG, 2015). Overall, the uptake of 17 GW of wind is consistent with the upper levels in the national grid Gone Green scenario.
- **Solar:** The UK installed 3.5 GW of solar in 2015 (CCC, 2016), so the rate of solar build in the period 2020 to 2025 is of a similar level.

If these rates of renewables were not to come forward, there are other options which could be increased to rebalance. For example, studies suggest there is potential for Tidal to contribute at least 3.6 GW by 2023, and possibly higher. It is unclear the extent to which these projects would be higher cost, as there are not projects in operation that can be used for cost comparison. Pöyry (2014) suggests that a programme of 3.6 GW of tidal power could be delivered in the UK at an average cost of around £111/MWh, and that tidal would be able to produce power with low system integration costs. This is similar to the central estimate for biomass in the lowest cost of our scenarios. If biomass costs are higher than this, it is possible that the tidal programme would also be lower cost.

TABLE 3: RENEWABLE CAPACITY ADDITIONS

| TECHNOLOGY | WIND | SOLAR | BIOMASS |
|-----------------------------------|------|-------|---------|
| Capacity additions 2020-2025 (GW) | 17 | 17 | 0 |

Source: Output of modelling conducted for this study

ASSUMED CAPACITIES IN 2020 AND 2025 FROM THE TWO DEGREES SCENARIO

| TECHNOLOGY | 2019/20 | 2024/25 |
|----------------------|-------------|------------|
| Storage | 5.3 | 7.7 |
| Biomass | 3.6 | N/A |
| CCS | 0 | 0 |
| CHP | 4.4 | 4.6 |
| Gas | 26.5 | 20.9 |
| Coal | 3.9 | 0 |
| Hydro | 1.8 | 2.0 |
| Interconnectors | 5.0 | 15.6 |
| Marine | 0.1 | 1.3 |
| Nuclear | 9.0 | 4.8 |
| Offshore wind | 9.5 | N/A |
| Onshore wind | 13.1 | N/A |
| Solar | 14.3 | N/A |
| Other thermal | 4.2 | 4.3 |
| Other renewable | 3.3 | 4.0 |

Source: National grid (2016)

Note: Bolded technologies are not assumed—the model optimises for these. Storage and DSR assumptions developed by Vivid Economics and Imperial College.

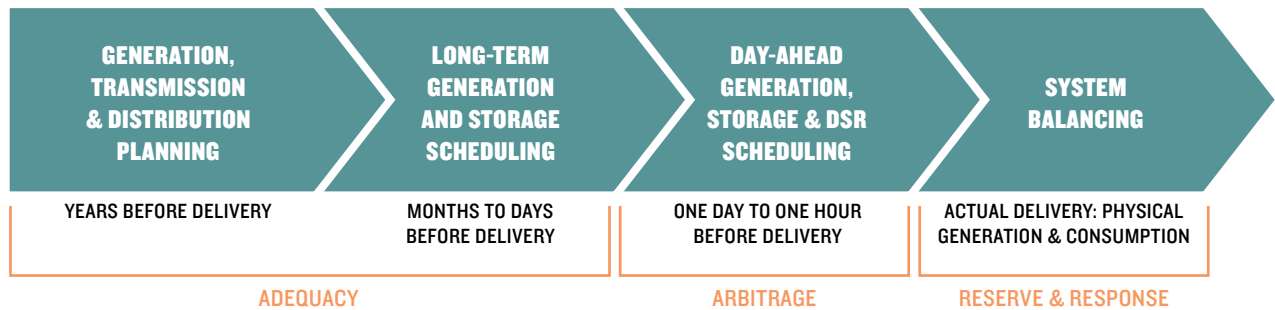
3. Whole Electricity System Investment Model (WeSIM)

3.1 Introduction

WeSIM is a comprehensive electricity system analysis model that simultaneously balances long-term investment decisions against short-term operation decisions, across generation, transmission and distribution systems, in an integrated fashion. When considering development of future low carbon electricity systems, including application of alternative smart flexible technologies such as demand side response (DSR), distributed energy storage, flexible network technologies and emerging designs of flexible generation technologies, it is important to consider two key aspects:

- **Different time horizons:** from long-term investment-related time horizon to real-time demand-supply balancing on a second-by-second scale (Figure 7); this is important as, for example, alternative smart technologies can impact system investment and operation cost (and carbon) performance simultaneously.
- **Different assets in the electricity system:** generation assets (from large-scale to distributed small-scale), transmission network (national and interconnections), and local distribution network operating at various voltage levels. This is important as alternative technologies may be located at different sites in the system and at different scales.

FIGURE 7: BALANCING ELECTRICITY SUPPLY AND DEMAND ACROSS DIFFERENT TIME HORIZONS



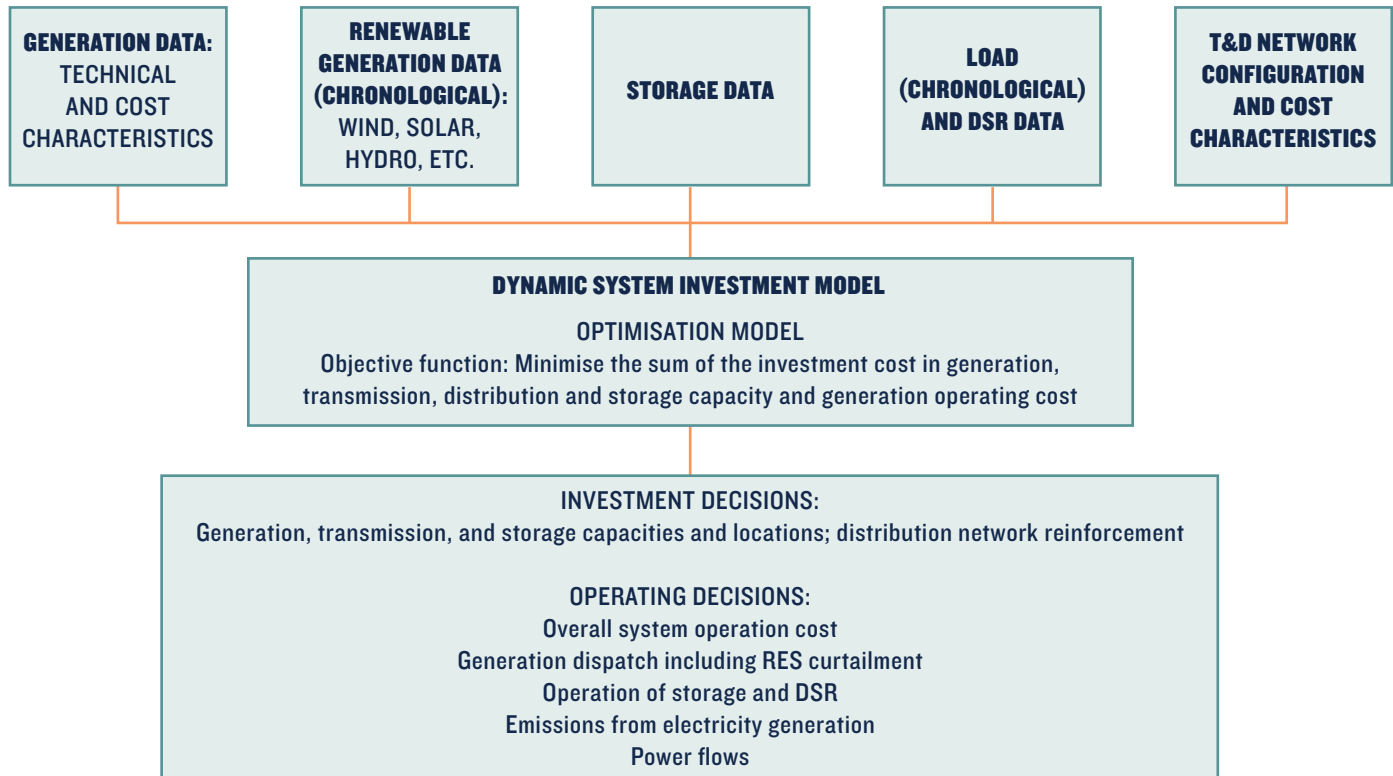
Source: Imperial College

In this context, WeSIM is a holistic model that enables optimal decisions for investing into generation, network and/or storage capacity (both in terms of volume and location), in order to satisfy the real-time supply-demand balance in an economically optimal way, while at the same time ensuring efficient levels of security of supply. A key feature of WeSIM is in its capability to simultaneously consider system operation decisions and infrastructure additions to the system, with the ability to quantify trade-offs using alternative smart mitigation measures, such as DSR, new network technologies and distributed energy storage, for real-time balancing and transmission and distribution network and/or generation reinforcement management. The model also captures potential conflicts and synergies between different applications of distributed resources (for example DSR or distributed energy storage) in supporting intermittency management at the national level and reducing necessary reinforcements in the local distribution networks.

3.2 WeSIM model structure and features

WeSIM carries out an integrated optimisation of electricity system investment and operation and considers (i) short-term operation with a typical resolution of half an hour or one hour (while also taking into account various frequency regulation requirements), which is coupled with (ii) long-term investment, that is planning decisions with the time horizon of typically one year (the time horizons can be adjusted). An overview of the WeSIM model structure is given in Figure 8.

FIGURE 8: STRUCTURE OF *WESIM*



Source: Imperial College

The objective function of *WeSIM* is to minimise the overall system cost, which consists of cost of investment in generation, network and enabling technologies and cost of operating the system:

- The investment cost includes capital cost of various generating technologies, the cost associated with their flexibility characteristics, investment cost of energy storage technologies, capital cost of new interconnection capacity, the reinforcement cost of transmission and distribution networks including cost of emerging flexible network technologies.
- System operating cost consists of the annual generation operating cost and the cost of interruption driven by capacity inadequacies. The model captures part load efficiency losses and generation start up costs, while taking into account dynamic characteristics of generating plant, which is a key aspect to quantifying system integration cost of renewable generation and role and value of alternative emerging enabling technologies, such as storage.

There are a number of constraints that need to be respected by the model while minimising the overall cost. These include:

- *Power balance constraints*, which ensure that supply and demand are balanced at all times.
- *Operating reserve constraints* include all forms of fast frequency regulation and reserve services needed for secure operation of the electricity system on a second by second basis. The amount of operating reserve services is a complex function of system inertia and uncertainty in generation and demand across various time horizons, driven by dynamic characteristics of different generation technologies, storage and flexible demand. *WeSIM* schedules the optimal provision of reserve and response services, taking into account the capabilities and costs of potential providers of these services (response slopes, efficiency losses and so on). This also considers alternative balancing technologies such as storage and DSR, including, for example, voltage control driven demand response, smart refrigeration/HVAC systems, interruptible charging of electric vehicles and so on.
- The share of spinning and standing reserve and response is optimised ex-ante to minimise the expected cost of providing these services, and we use our advanced Stochastic Unit Commitment model (SUC) to calibrate the amount of reserve and response scheduled in *WeSIM*. Stochastic scheduling is particularly important when allocating storage and DSR resources between energy arbitrage and reserve as this may vary dynamically depending on the system conditions.

- *Generation: WeSIM* optimises the investment in generation capacity while considering the generators' operation costs and CO₂ emission constraints, and maintaining the required levels of security of supply. *WeSIM* optimises both the quantity and the location of new generation capacity as a part of the overall cost minimisation. The model can limit the investment in particular generation technologies at given locations.
- *Annual load factor constraints* can be used to limit the utilisation level of thermal generating units, for example to account for the effect of planned annual maintenance on plant utilisation.
- For *wind, solar, marine, and hydro run-of-river* generators, the maximum unit electricity production is limited by the availability of resource that is location specific. The model will maximise the utilisation of these units. In certain conditions when there is oversupply of electricity in the system or reserve/response requirements limit the amount of renewable generation that can be accommodated, it might become necessary to curtail their electricity output in order to balance the system, and the model accounts for this.
- For hydro generators with reservoirs and pumped-storage units, the electricity production is limited not only by their maximum power output, but also by the energy available in the reservoir at a particular time (while optimising the operation of storage). The amount of energy in the reservoir at any given time is limited by the size of the reservoir. Minimum energy constraints and efficiency losses are taken into account.
- *Demand-side response constraints* include constraints for various specific types of loads. *WeSIM* broadly distinguishes between the following electricity demand categories: (i) weather-independent demand (ii) heat-driven electricity demand (space heating/cooling and hot water), (iii) transport demand and (iv) smart appliances' demand. Different demand categories are associated with different levels of flexibility. Losses due to temporal shifting of demand are modelled as appropriate. Flexibility parameters associated with various forms of DSR are obtained by using detailed bottom-up modelling of different types of flexible demand.
- *Power flow constraints* limit the energy flowing through the lines between the areas in the system, respecting the installed capacity of the network as an upper bound (*WeSIM* can handle different flow constraints in each flow direction). The model can also invest in enhancing network capacity if this is cost efficient. Expanding transmission and interconnection capacity is generally found to be important for facilitating efficient integration of large intermittent renewable resources, given their location. Interconnectors provide access to renewable energy and improve the diversity of demand and renewable output on both sides of the interconnector, thus reducing the short-term reserve requirement. Interconnection also allows for sharing of reserves, which reduces the long-term capacity requirements.
- *Local distribution network constraints* are devised to determine the level of distribution network reinforcement cost, as informed by detailed modelling of the representative UK electricity distribution networks. *WeSIM* can model different types of distribution networks, for example urban, rural, and so on with their respective reinforcement cost.
- *Emission constraints* limit the amount of annual carbon emissions. Depending on the severity of these constraints, they will have an effect of reducing the electricity production of plants with high emission factors such as oil or coal-fired power plants. Emission constraints may also result in additional investment into low-carbon technologies such as nuclear, CCS or renewables in order to meet the constraints, depending on the cost.
- *Adequacy constraints* ensure that there is sufficient generating capacity in the system to supply the demand with a given level of security. If there is storage in the system, *WeSIM* may use its capacity for security purposes if it can contribute to reducing peak demand, given the energy constraints.
- *WeSIM* allows for the security-related benefits of interconnection to be adequately quantified. Conversely, it is possible to specify in *WeSIM* that no contribution to security is allowed from other regions, which will clearly increase the system cost, but can be used to quantify the benefits of EU wide market. This market integration choice will also impact the value of alternative technologies.

3.3 System topology

WeSIM is used to assess the electricity infrastructure development and system operation within UK or EU. Different network topologies will generally be used to balance the complexity and accuracy of modelling. The EU interconnected network model is presented in Figure 9.



Source: Imperial College

Different levels of market integration can be modelled in *WeSIM* through distinctive levels of energy exchanges cross-border, sharing of security or various operating reserves, for example country, regional, EU levels. *WeSIM* optimises the generation, storage, and demand side response dispatches by taking into account diversity of load profiles, renewable energy profiles (hydro, wind, PV, CSP) across Europe, in order to minimise the additional system capacity to meet security requirements. Finally, *WeSIM* simultaneously optimises investment profile in generation infrastructure and transmission networks capacity, while meeting security and CO₂ constraints as appropriate.

3.4 Distribution network and demand-side modelling

Regarding the local distribution networks *WeSIM* uses a set of representative networks that follow the key characteristics of different type of real GB (and EU member states) distribution network. These representative networks are calibrated to match the actual electricity distribution systems.

Understanding the characteristics of flexible demand and quantifying the flexibility they can potentially offer to the system is vital for establishing its economic value. In order to offer flexibility, controlled demand technologies must have access to some form of storage when rescheduling their operation (for example thermal, chemical or mechanical energy, or storage of intermediate products). Load reduction periods are followed or preceded by load recovery, which is a function of the type of interrupted process and the type of storage. This in turn requires bottom-up modelling of each individual demand side technology (appliance) understanding how it performs its actual function, while exploiting the flexibility that may exist without compromising the service that it delivers. In our analysis we consider the following types of flexible demand:

- **Electric vehicles.** EV loads are particularly well placed to support system operation and investment, given the relatively modest amount of energy needed daily, generally short driving times, and relatively high power ratings expected for EV batteries. *WeSIM* modelling of EVs is based on statistics for light-vehicle driving patterns calibrated with the GB and EU driving data patterns.
- **Heat pumps and HVAC systems.** *WeSIM* models the patterns of thermal loads (cooling and heating) for a variety of building types and sizes covering both commercial and domestic sector, construction characteristics and insulation/energy efficiency levels, size, occupancy patterns, indoor temperature settings and outdoor temperatures (this is informed by a detailed thermal building simulation models). The heat demand models take into account hourly temperature variations, considering the temperature dependency of heat pump coefficients of performance. The modelling is then used to investigate building thermal response under different control strategies. Smart appliances. The operation of appliances is scheduled to respond to electricity system conditions (while not compromising the service quality delivered), thus potentially providing support to generation/demand balancing including provision of various types of reserve, peak reduction, and network congestion management. This also includes refrigeration appliances that can potentially contribute to providing frequency regulation services. Bottom up models are used to understand the interdependency between the level and duration of service provided and the corresponding energy payback.

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