Comparing costs of renewable technologies

Independent study by Aurora Energy Research

25 February 2016

Background

In a major energy policy speech on November 18, 2015, UK Secretary of State for Energy and Climate Change Amber Rudd said: "*In the same way generators should pay the cost of pollution, we also want intermittent generators to be responsible for the pressures they add to the system when the wind does not blow or the sun does not shine*."

The U.S. Industrial Pellet Association and Enviva – which as participants in the UK biomass sector have an interest in enhancing their understanding of the issue highlighted by the Secretary of State – asked Aurora Energy Research to undertake an independent analysis of the electricity system costs imposed by intermittent wind and solar generators compared with baseload nuclear and dispatchable biomass generators in the UK.

The system costs imposed by intermittent wind and solar generators are not accounted for in the method of comparing energy technology costs that currently dominates policy debates in the UK and other countries – the so-called "Levelized Cost of Energy" (LCOE) measure.

Methodology

Aurora has used, wherever possible, most recent public data from the UK Department of Energy and Climate Change, Ofgem and the UK System Operator (within National Grid Plc) to underpin our analysis.

In addition to this official data, Aurora has used projections and scenarios for the evolution of the UK energy mix and pricing over time from our proprietary energy market, capacity market and balancing market models.

Summary of findings

- The Levelized Cost of Energy (LCOE) measure ignores important system costs, in particular:
  - Intermittency value adjustment
  - Security of supply value adjustment
  - Balancing costs
  - Transmission costs

- Adding these four system costs to LCOE leads to a new measure for assessing the relative costs of different technologies – Total Cost of Energy or "TCOE"

- Aurora's analysis shows that adjusting for system costs, the TCOE for onshore and offshore wind is **£14.1 - £26.5 / MWh** more expensive than baseload nuclear generation, whilst a more limited system costs adjustment is needed to calculate the TCOE for solar and a very limited adjustment is required for biomass

- UK contract-for-difference (CFD) strike prices are currently not directly comparable across technologies because they ignore both the intermittency value adjustment and security of supply value adjustment – combining these two measures means CFD strike prices need to be handicapped by **£5.8 / MWh** for offshore wind and **£8.6 / MWh** for onshore wind, whilst solar, nuclear and biomass need relatively little adjustment

We adjust Levelized Cost of Energy (LCOE) to reflect difference in net system costs compared to baseload generation

All figures £/MWh generated	Offshore wind (R2)	Onshore wind	Solar (large scale PV)	Nuclear	Biomass conversion
LCOE (latest DECC)*	122	101	158	90	108

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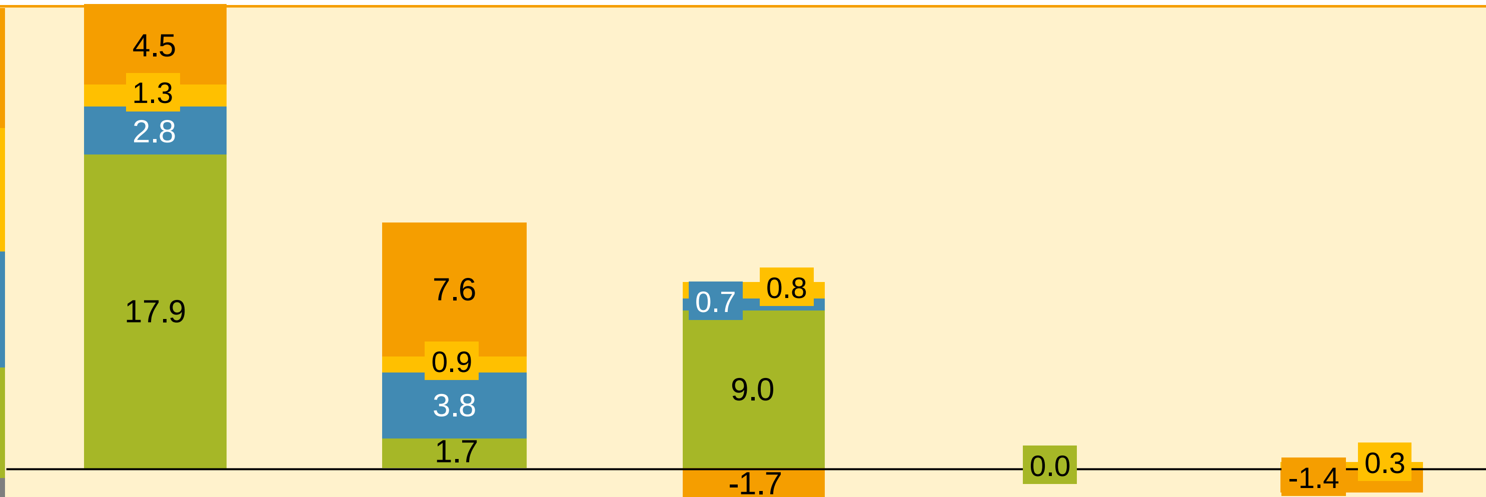
1 Intermittency value adjustment

2 Security of supply value adjustment

3 Balancing costs

4 Transmission costs



	Offshore wind (R2)	Onshore wind	Solar (large scale PV)	Nuclear	Biomass conversion
NET SYSTEM COST DELTA**	26.5	14.1	8.9	0	-1.1

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	Offshore wind (R2)	Onshore wind	Solar (large scale PV)	Nuclear	Biomass conversion
TCOE (Total cost of energy)	149	115	167	90	107

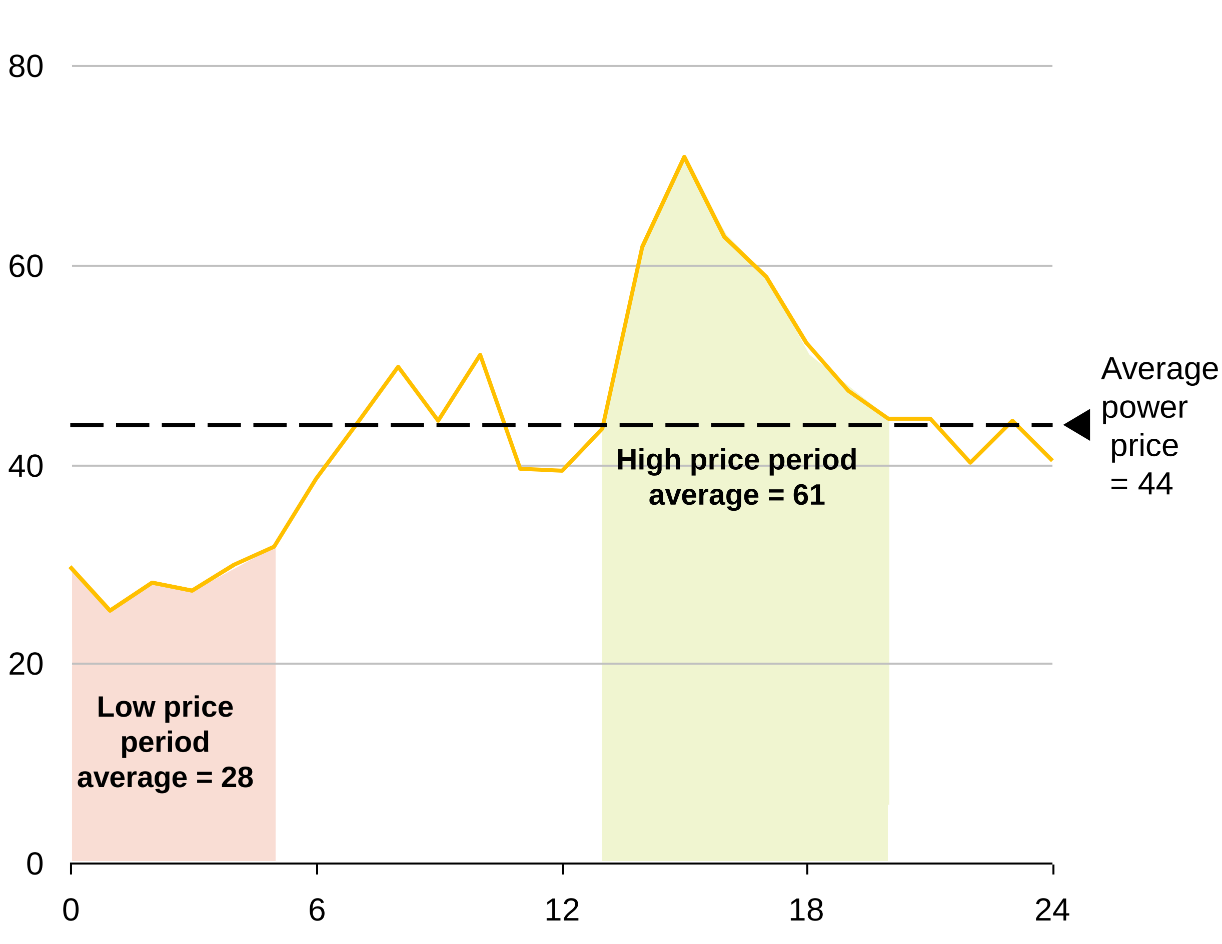
*LCOE figures taken from DECC's 2013 "Electricity generation costs" document, Table 8: central levelised cost estimates for projects starting in 2013, 10% discount rate. LCOE figures vary substantially and the included figures should be considered illustrative. Technology type, location, regulatory restrictions and energy market conditions will all affect the final valuation.

**Evaluation of the impact of lower system inertia caused by asynchronous generation suggests this is unlikely to contribute to the difference in net system value of renewable technologies, and as such we have not included it here.

Source: AER modelling, DECC

The value of intermittent generation can be represented by the power price at the moment it is generating

Wholesale electricity price over 24 hours, £/MWh

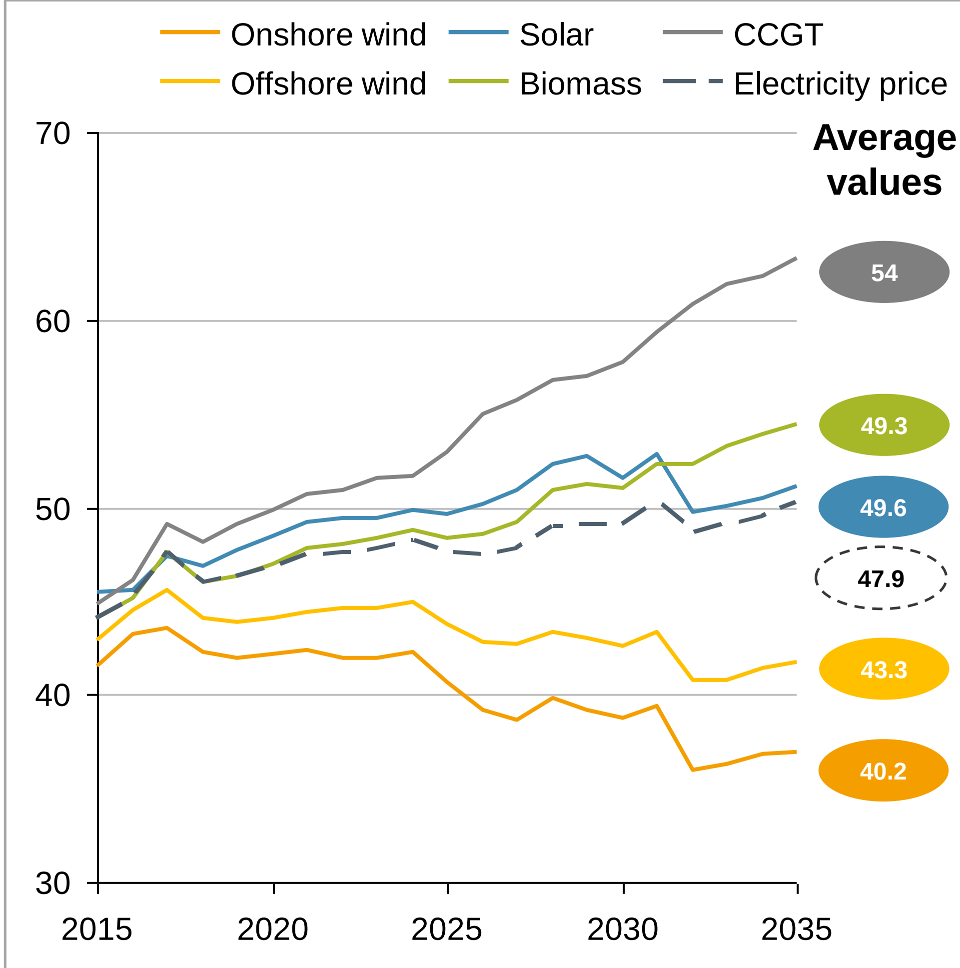


- The value of power generated is well represented by the power price
  - If the price is high, system is tight and power generated at this time is highly valuable form a system operator perspective
  - If the price is low there is abundant generation available relative to demand and so the value of an additional MWh at these times is low
- The ‘capture price’ of a given technology relative to the average power price therefore represents the ‘intermittency adjustment’ of a particular technology
  - Technologies with a capture price less than the average have a positive intermittency adjustment
  - Technologies with a capture price above the average (e.g. dispatchable technologies with high marginal cost) may have a negative intermittency adjustment, i.e. be beneficial from a timing of delivery perspective

Source: AER modelling

Average capture prices can be mapped over time illustrating the impact of changing market conditions and capacity mix

Average capture price, £/MWh

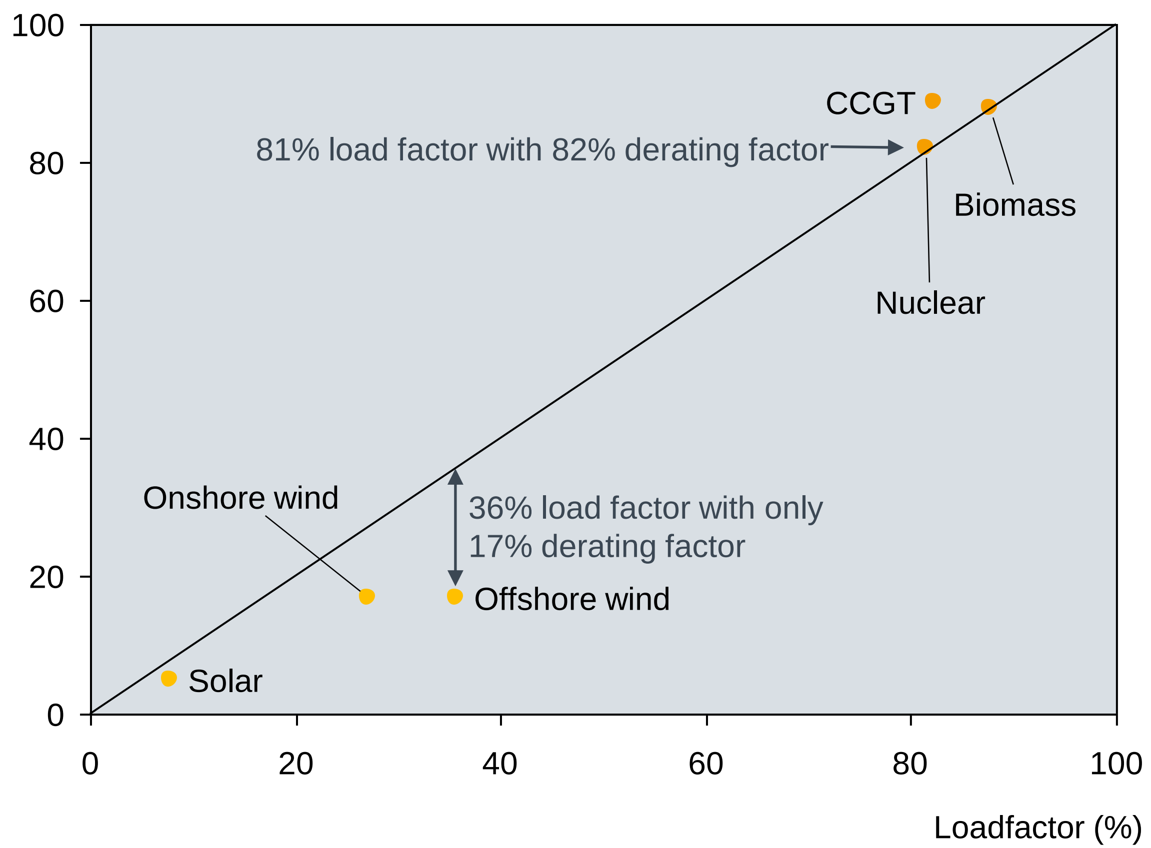


- Aurora have estimated expected capture prices by technology to 2035. This is driven by their underlying expectation of generator mix, policy, fuel prices and other assumptions (see appendix for more details)
- Wind capture price is less than average. The primary reason for this is that with large amounts of highly correlated wind on the system, when the wind is blowing the price tends to be low as expensive technologies are not required
- Solar capture price is slightly above average. This occurs because solar produces most of its energy at times of high demand during the day. The small amount of solar on the system means it doesn't cannibalise its prices, though this could occur with a large increase in solar capacity
- Biomass has a capture price slightly above average. This is driven by its ability to dispatch and thus switch off during times of very low demand when the power price does not adequately cover the costs of generation.
- CCGT has a high capture price because it is able to turn off during periods of low prices when price is below cost of generation
- It is important to note that with a different generator mix, capture prices would vary. The more wind (and nuclear) on the system, the lower the average capture price (due to the saturation effect). We examine alternative scenarios to understand sensitivities

Source: AER modelling

We use average load factors and DECC's capacity market derating factors to estimate each technology's contribution to security of supply on a 'per MWh generated' basis

Capacity market derating factor* against load factor by technology (%)



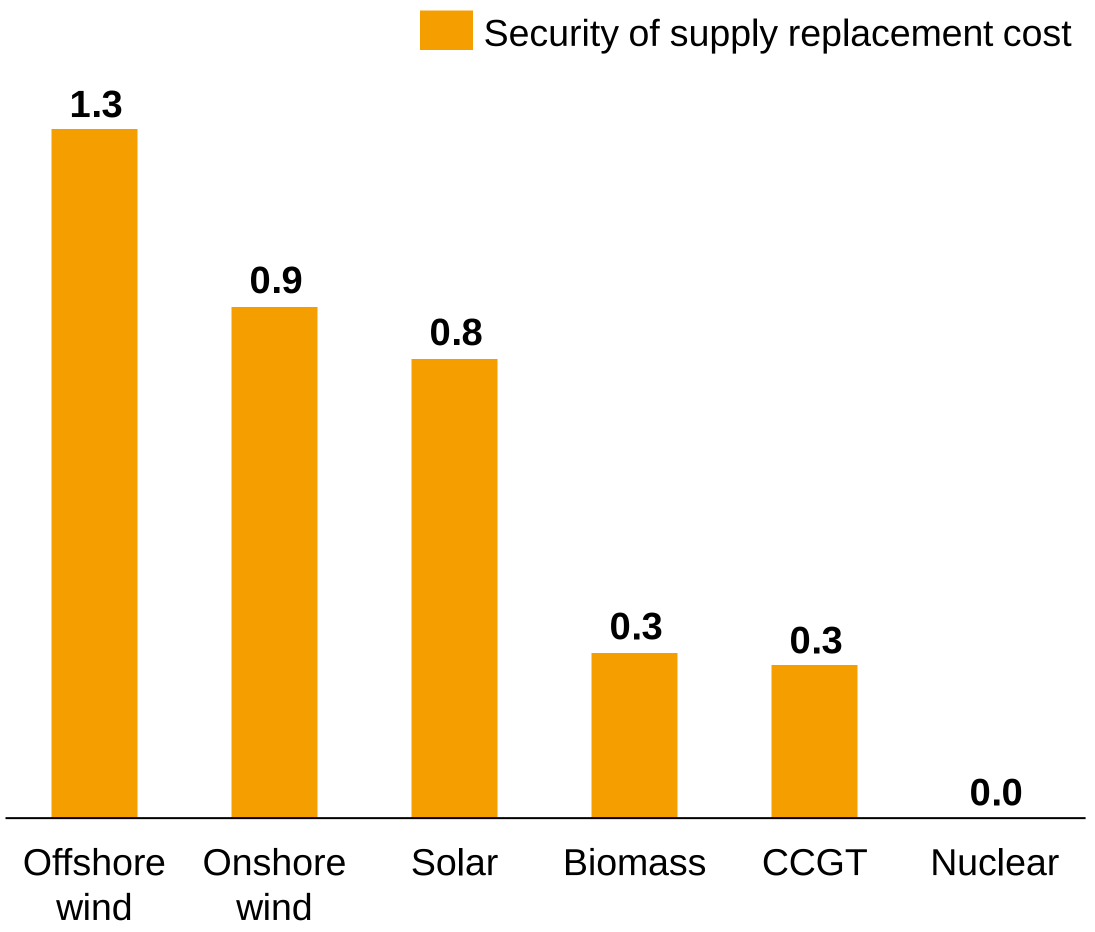
- Technology with low derating factors** relative to actual load factors are less valuable per MWh from a security of supply perspective than those with a smaller difference
- Dispatchable plant has higher capacity derating factors because it is typically only unavailable during maintenance or infrequent faults
- Intermittent technologies are derated more heavily because even when operational, they may not be able to produce energy during a high demand period
- With capacity valued at £18/MW on a derated basis, security of supply cost can then be calculated for each technology

*Capacity market derating factors are taken from DECC; ** The proportion of nameplate capacity credited within the capacity market

Source: AER modelling, DECC

This approach suggests wind generation is less valuable than nuclear by £1 per MWh generated

Capacity value foregone due to lower reliability, £/MWh



- On a per MWh basis, security of supply from intermittent generators is poor value for money
- These plants face a penalty based on the likelihood of them being available to provide power at times of peak demand
- These figures represent the cost of additional capacity procurement to provide the same security of supply per MWh as a baseload plant

Source: AER modelling

Balancing costs also need to be added to the LCOE

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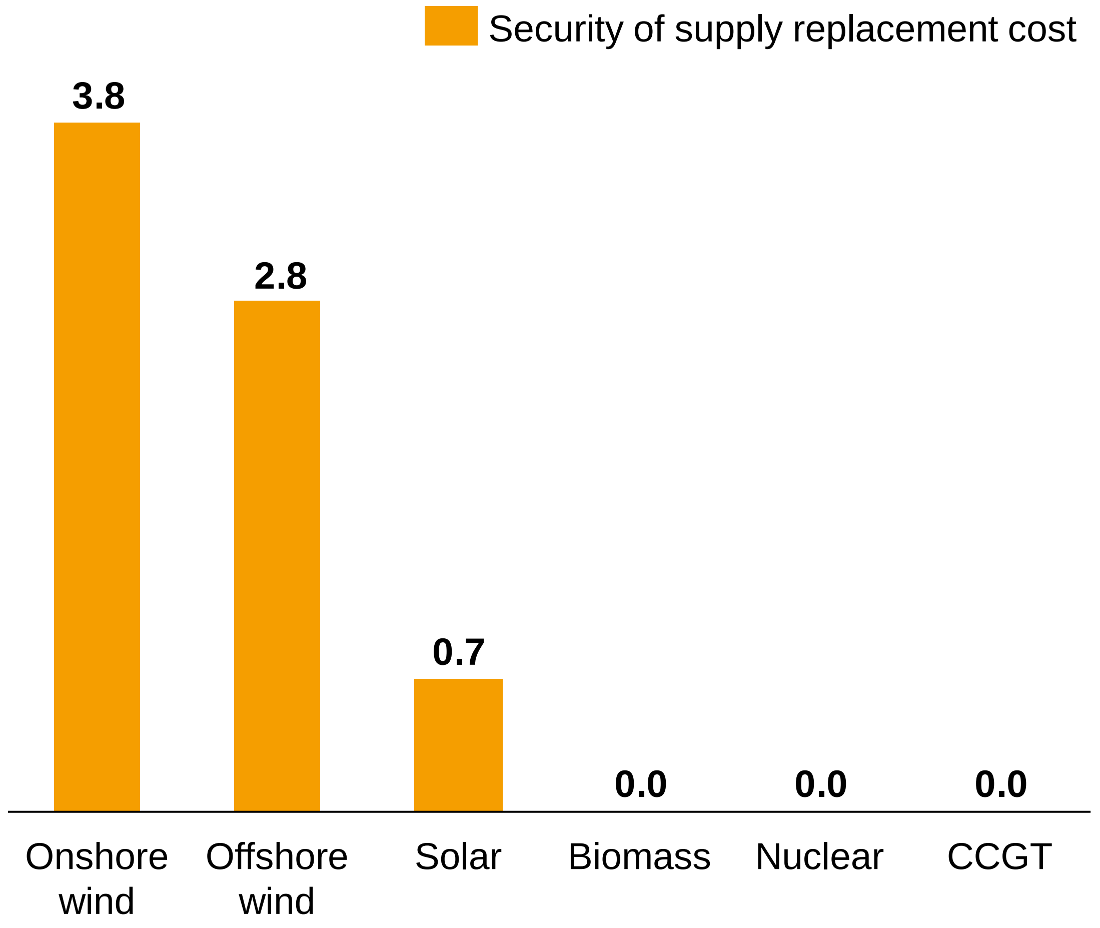
Average balancing cost, £/MWh, 2015-2035

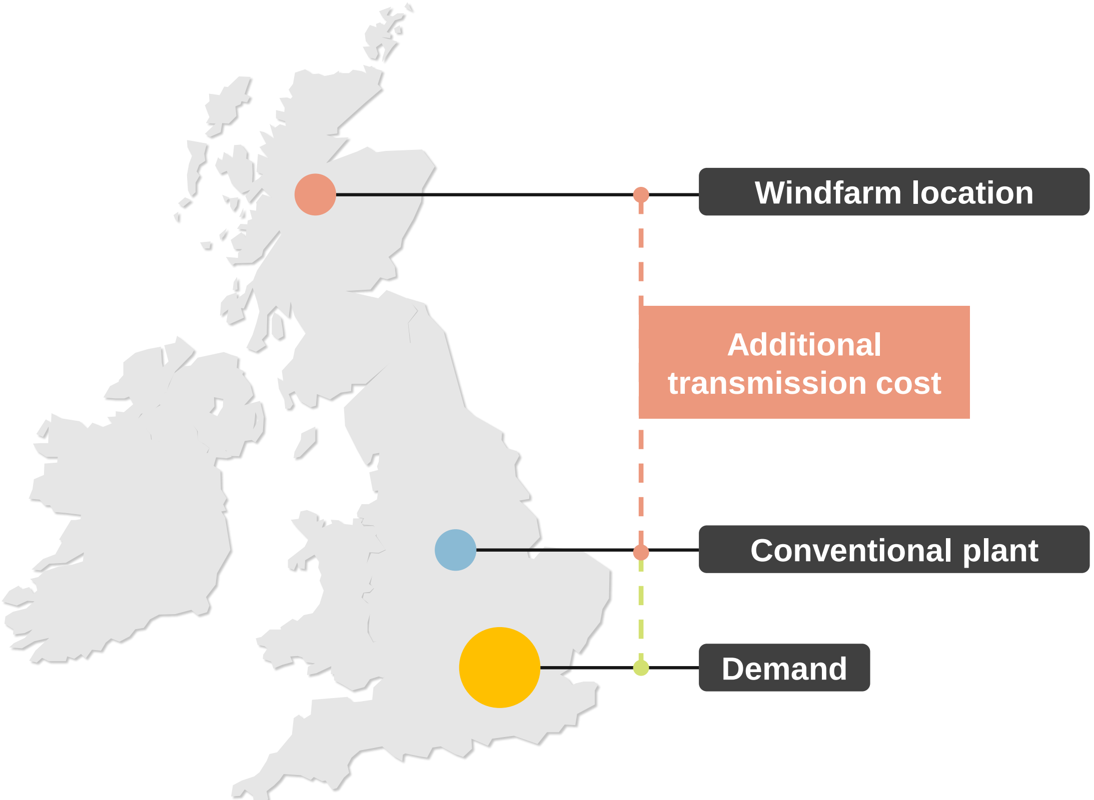


- Balancing costs are incurred when a technology fails to deliver the output it commits one hour in advance
- Aurora has a detailed model of balancing market and can project how balancing costs are likely to increase over time given generation mix and changes to cash-out rules
- Our analysis suggests wind pays highest balancing costs, whereas dispatchable technologies usually meet their commitments and can even make money in the balancing market by over delivering when required

Source: AER modelling

Generators pay for transmission based on their location, but only pay a quarter of total transmission costs

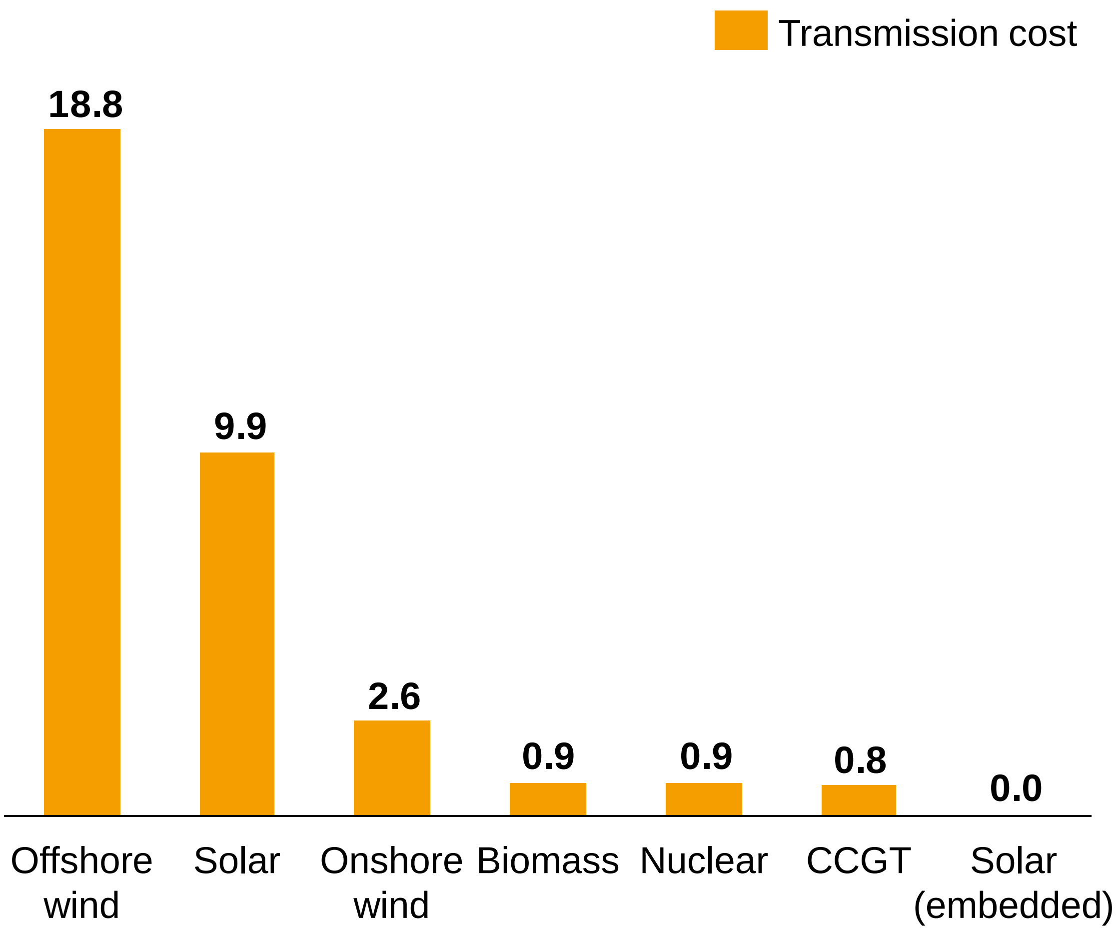
Additional transmission costs are created by remote locations required for some technologies



- National grid charges transmission costs (TNUoS) on the basis of generator location, with generators located a long way form demand charged more
- However, only a part of this transmission cost is paid by the generator: TNUoS is split 27:73 between generators and consumers
- This creates a transmission cost component that needs to be added to the LCOE for costs to be comparable
- Furthermore, technologies with low loadfactors rarely make full use of installed transmission capacity, and so incur a higher cost per MWh generated than high loadfactor plants

Transmission costs are driven by distance from demand centre and load factor

TNUoS and local transmission charging, £/MWh

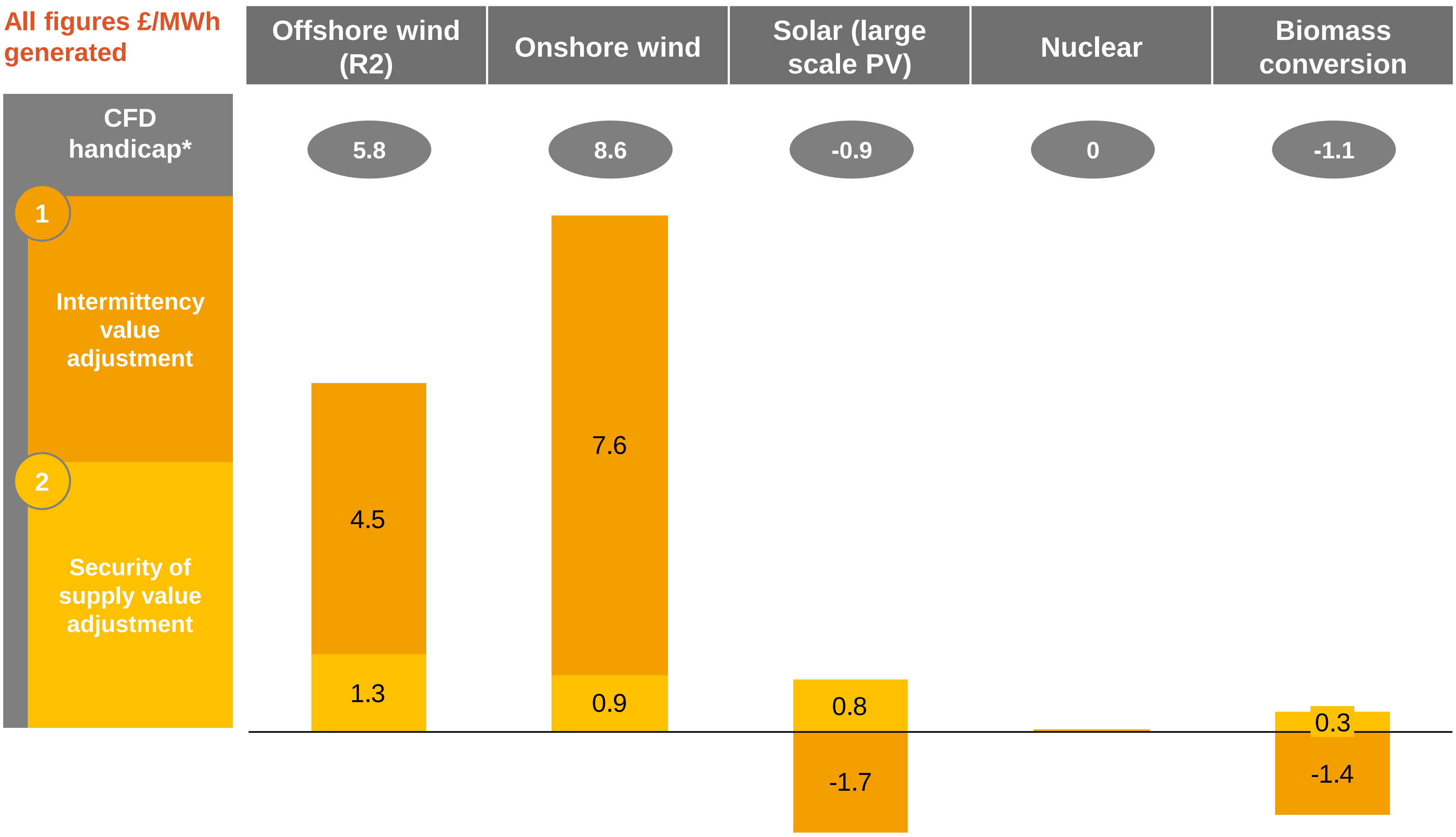


- These figures are derived from well published* TNUoS forecasts of offshore wind and biomass transmission costs
- Transmission costs on a per MWh basis are highest for offshore wind due to the costs of offshore connection and a relatively low load factor
- Low loadfactors mean the cost of a transmission connection is spread over fewer units of energy increasing the per unit cost
- Despite any particular locational constraints, non-embedded solar also suffers from high per unit transmission costs due to a sub 10% loadfactor

*These numbers are based on transmission costs for biomass and offshore wind in the Frontier Economics report, "*The relative system cost of biomass and offshore wind*", Frontier Economics, November 2014. For offshore wind this is £14.11/kW onshore transmission and £45.177 as an average offshore local transmission cost (time weighted average) and for biomass £6.07/kW.

Source: AER modelling

Whilst CFDs reflect the cost of generation, an additional handicap should be applied to determine which technologies are most valuable to the system



*We consider impacts on balancing to be internalised by the technology and factored into the CFD bid. Although BSUoS is paid upfront by all generators, balancing costs are subsequently recovered from out-of-balance plants in a 'cash out' process that exposes other generators to, at most, administrative costs which are unlikely to vary significantly with renewable penetration.

Source: AER modelling, DECC

CFD adjustment factors vary depending on assumptions made

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All figures £/MWh generated

Intermittency value adjustment | Security of supply value adjustment

Scenario*	Onshore wind: Intermittency	Onshore wind: Security of supply	Onshore wind: Total	Offshore wind: Intermittency	Offshore wind: Security of supply	Offshore wind: Total	Solar: Intermittency	Solar: Security of supply	Solar: Total	Biomass: Intermittency	Biomass: Security of supply	Biomass: Total
Aurora base case forecast	7.6	0.8	8.5	4.5	1.3	5.8	-1.7	0.8	-0.9	-1.4	0.8	-0.6
Low nuclear	6.2	0.9	7.2	3.8	1.3	5.0	-1.2	0.9	-0.3	-0.6	0.0	-0.5
On time nuclear	8.6	0.8	9.4	5.3	1.4	6.7	-1.9	0.8	-1.1	-3.2	-0.1	-3.3
Low renewables	5.1	0.8	5.9	2.9	1.4	4.3	-1.7	0.8	-0.8	-0.6	0.0	-0.6
High renewables	10.9	0.8	11.7	7.1	1.4	8.6	-1.8	0.8	-0.9	-5.8	-0.2	-6.0
Low fuel prices	6.1	0.8	6.9	3.9	1.4	5.4	-1.5	0.8	-0.7	-1.8	-0.1	-1.9
High fuel prices	10.1	0.8	10.9	5.8	1.4	7.2	-1.5	0.8	-0.7	-2.1	-0.1	-2.1
High discount rates	7.9	1.0	8.9	4.8	1.7	6.5	-1.6	1.0	-0.6	-2.0	-0.1	-2.1
Low discount rates	7.9	0.7	8.6	4.8	1.2	6.0	-1.6	0.7	-0.9	-1.9	-0.1	-2.0

* See appendix for description of scenarios

Source: AER modelling

Appendix

Scenario descriptions

Scenario	Description
Aurora base case forecast	Identical to Aurora's October 2015 quarterly report forecast report. This scenario reflects our view of the most likely assumption values over the forecast period.
Low nuclear	EPR nuclear new build is cancelled. This includes Hinkley Point C and Sizewell C. Nuclear capacity is ~7GW lower by 2035 compared to base case.
On time nuclear	Adjusts the base case to bring nuclear capacity online on schedule. New nuclear entry begins with Hinkley Point C in 2023 (assumed to enter 2025 in the base case).
Low renewables	Capacity of solar, onshore wind and offshore wind capacity is 20% below base case capacity, phased in from 2015 to 2025.
High renewables	Capacity of solar, onshore wind and offshore wind capacity is 20% above base case capacity, phased in from 2015 to 2025.
Low fuel prices	Gas prices are 50% lower than base case forecast. Coal prices are 10% lower than base case forecast.
High fuel prices	Gas prices are 50% higher than base case forecast. Coal prices are 10% higher than base case forecast.

The ‘cost of backup’ concept for wind typically overestimates the costs of integrating wind

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Energy generation and capacity provision – wind and peaker pairing

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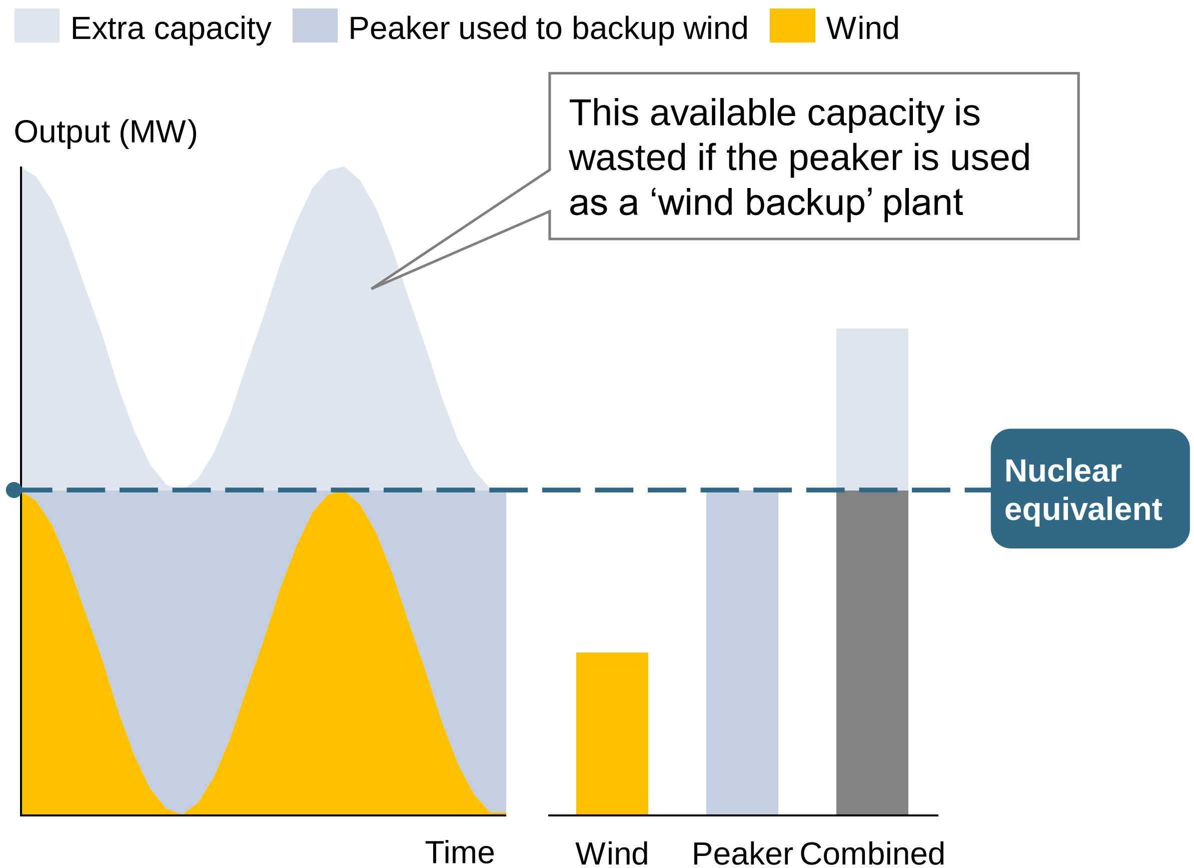

Generation in wholesale market

Capacity contribution to security of supply

- Peaking plant fills in the gaps when wind isn’t generating
- But this isn’t an efficient response to wind. When wind is blowing, the extra peaker capacity is also available to dispatch
- These combined plants provide more security of supply than a nuclear plant.
- This means that these two combined are more valuable than baseload – so this can’t be the ‘cost of backing up wind’
- Compensating for volatile output can be done with a variety of plants on the system, with cheap CCGT filling part of the gap
- Making up security of supply also requires only a small top-up

Statement on assessment of additional issues

Issue	Aurora's assessment
System inertia and frequency response	We believe high asynchronous generation is unlikely to increase frequency response costs. Whilst frequency response is currently provided by conventional plant, which means the price of frequency response is set by the required ramping speed, flywheels and batteries with instantaneous response can competitively provide this service, and price will be set by the size of the infrequent in-feed loss (typically a nuclear or CCGT plant).
Transmission constraints	Aurora has not assessed the impact of technology types on transmission constraints
Grid quality – voltage control, reactive power	Aurora has not assessed the impact of technology types on grid quality
Carbon accounting of supply chain (incl. fuels)	Aurora has not assessed carbon intensity in the supply chains of any technologies
Lost value from converting existing plant	Aurora has not assessed opportunity costs arising from converting existing plant