EXPERT REPORT: DAMAGE CAUSED TO EEMSHAVEN BY THE COAL BAN

RWE AG and RWE Eemshaven Holding II BV vs.

Kingdom of the Netherlands

ICSID Case No. ARB/21/4

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Brattle

NOTICE

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I. Introduction

I.A. Scope of work

1. On 10 December 2019, the Dutch government approved a law to prohibit the use of coal for generating electricity by 2030 at the latest (the "Coal Ban").[1] The law affects RWE AG and RWE Eemshaven Holding II B.V. ("RWE Eemshaven", collectively "Claimant") because Claimant owns a Dutch coal-fired plant, Eemshaven, which will have to close at the end of 2029 as a result of the Coal Ban. RWE Eemshaven is a subsidiary and group company of RWE AG (when referring to the RWE group of companies, "RWE"). Without the Coal Ban, Eemshaven could technically continue operating until the end of 2054. Counsel for the Claimant, Luther Rechtsanwaltsgesellschaft mbH, has asked Brattle to estimate the damages the Claimant has suffered due to the change in the value of the Eemshaven plant as a result of its enforced early closure. Accordingly, Eemshaven is the object of our valuation.

2. In making our damage calculations, Counsel for Claimant have provided us with the following instructions:

   a. To use a valuation date immediately before the impending Coal Ban became known in such a way as to affect the value of Eemshaven. In practice, this instruction implies that the valuation date should be 9 October 2017 because the following day, the Rutte III cabinet published a Coalition Agreement that contained an announcement that coal-fired power plants would be closed by 2030 at the latest. This formulation of the Coal Ban was sufficiently defined and foreseeable to affect the valuation of coal-fired plants.[2] The amount that a third-party buyer would have been willing to pay for Eemshaven would have reduced significantly after 9 October 2017. Hence, based on our instructions, using 9 October 2017 as the Valuation Date is the most reasonable choice. It would only make sense to use a later Valuation Date, if we believed that a prospective buyer for Eemshaven would have paid the same price before the October 2017 announcement as after the announcement. We do not consider this to be a credible assumption.

   b. To quantify the loss in value of Eemshaven taking into account the Coal Ban as approved by the Dutch parliament.

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[1] **Exhibit BR-1**, Minister of Economic Affairs and Climate, Electricity Production Prohibition Act, dated 20 December 2019.

[2] **Exhibit BR-2**, 2017-2021 Coalition Agreement, Confidence in the Future, dated 10 October 2017.

c. To assume that Eemshaven will only burn coal since co-firing biomass is not economically viable without the SDE+ support scheme, which will no longer be available after 2027. According to Claimant's other expert, NERA Economic Consulting GmbH ("NERA"), it would not be viable to operate Eemshaven using only biomass without subsidies.[3] Hence, the Coal Ban will lead to the closure of Eemshaven at the end of 2029.

d. To measure the change in the value of Eemshaven by reference to the change in its "Fair Market Value" or "FMV".

I.B. The Authors of This Report

3. Our names are Dan Harris and Serena Hesmondhalgh. Mr Harris has been a consultant focused on the energy sector for twenty years and Dr Hesmondhalgh for over thirty years. We are both experts in the economic and financial analysis of the energy sector, particularly in the analysis of large capital investments such as natural gas pipelines, power stations, electricity transmission lines, distribution networks, and refineries. We have both provided expert witness testimony on damages in many arbitrations and court cases concerning such energy sector investments. Between us, we have provided expert testimony in ECT, ICC, LCC, SCC, and UNCITRAL arbitrations. Appendix A contains our CVs.

4. We understand that our duty in this case is to inform the Court of our independent professional opinions, based on our experience and understanding of the facts in this case. We do not offer any opinion on the legal merits of the claims. We are committed to expressing our full opinions, even those aspects that might not favour the commercial interests of the Claimant. The Brattle Group has worked for subsidiaries of the RWE group, but not the Claimant specifically, on three occasions in the last ten years, but has no ongoing relationship with RWE, its subsidiaries, or its legal advisors other than the work we are doing for RWE in relation to the Coal Ban. RWE Generation Holding B.V. is compensating The Brattle Group for our analysis and for the work of our supporting team of economists. The compensation is based on The Brattle Group's standard hourly rates applied to the time dedicated to the analysis, and does not depend in any manner on the outcome of the dispute.

I.C. Structure of the report

5. Section I.D summarises our findings and conclusions. The relevant factual background to the case is provided in Section II, whilst we provide an overview of our framework for estimating damages in Section III. The remaining sections, Sections IV to VII, go through each of the

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steps of our damages framework, and present damages calculations inclusive of interest. Finally, in section VIII, we comment briefly on the possibility of Eemshaven's remaining open after 2030 by converting to natural gas or 100% biomass.

6. Dr Hesmondhalgh has been primarily responsible for Sections IV and V and Mr Harris for Sections III.A to III.D, VI and VII. They are jointly responsible for the remaining sections.

I.D. Summary

7. To measure Eemshaven's loss in value as a result of the Coal Ban, we calculate the difference between the Fair Market Value of the plant "but-for" the Coal Ban, and the Fair Market Value with the Coal Ban in place, its "actual" value.

8. With the Coal Ban, Eemshaven can no longer burn coal from 1 January 2030.[4] Hence, the plant will have to close by the end of 2029, since NERA finds that it would not be viable to continue operating using only unsubsidised biomass. Consequently, almost all the loss in value from the Coal Ban results from the Claimant's inability to operate Eemshaven beyond 2030.[5]

9. For both the actual and but-for cases, we determine the Fair Market Value of Eemshaven using the standard discounted cash flow ("DCF") methodology. First, for each relevant year, we calculate free cash flows to the plant by subtracting fixed and variable operating costs, tax and capital expenditures from the plant's revenues.[6] Second, we discount the free cash flows back to the valuation date, October 2017, using a discount rate that reflects the risk of the cash flows. Discounting reflects the fact that a euro today is worth more than a euro that is only available at some future date.[7] The sum of the discounted free cash flows represents the Fair Market Value of the plant: what a willing and informed buyer would have been prepared to pay for Eemshaven as of the valuation date.

10. Eemshaven's free cash flows are, in essence, the difference between its revenues and its costs. In turn, Eemshaven's revenues depend on the level of electricity prices, which are

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4 **Exhibit BR-1**, Minister of Economic Affairs and Climate, Electricity Production Prohibition Act, dated 20 December 2019.

5 There are also some earlier cash flow effects, starting in 2020, which we take into account. These reflect different decisions regarding investments and tax payments between our but-for and actual cases. See Harris-Hesmondhalgh Workpapers, Tables H – Financial Model.

6 Note that under our DCF approach, the cost of building Eemshaven is not relevant, since RWE has already incurred these costs i.e. they are "sunk". The capital costs therefore play no role in deciding whether to generate electricity on a given day or whether to continue operating the plant.

7 For a more detailed explanation of discounting, see Section VI.C.

largely driven by the price of coal, gas and CO_2 (collectively "commodity prices").[8] The prices of coal and CO_2 are also the most significant drivers of Eemshaven's electricity production costs. Hence, with regard to both revenues and costs, commodity prices are the most important determinant of Eemshaven's free cash flows and value. Commodity prices fluctuate from day to day and, given the long time frame over which we have to forecast the free cash flows, we adopt a methodology which captures a full range of possible outcomes for commodity prices for that period so as to arrive at a robust damages estimate.

11. In more detail, we have carried out a probabilistic analysis of the likely development of commodity prices that is based on (a) our best estimate of future developments, (b) the volatility of each commodity price and (c) the historic correlation between movements in prices for the various commodities. Using this framework, we have created 100 different commodity price paths. This kind of exercise, also referred to as a Monte Carlo simulation, is a common way to capture a wide range of possible future outcomes.[9]

12. We have used these 100 commodity price paths to construct 100 'pairs' of free cash flow paths – each 'pair' consisting of one set of cash flows for the actual case (with the Coal Ban) and one for the but-for case (without the Coal Ban), both based on the same commodity price path. We then use a discount rate to calculate the present value of each pair of free cash flows, as of the valuation date. This results in 100 'pairs' of actual and but-for Fair Market Values, one 'pair' for each commodity price path.

13. For each of the 100 commodity price paths, the loss in value of Eemshaven resulting from the Coal Ban is simply the difference between the Fair Market Value in the actual case, and the Fair Market Value of the but-for case. Hence, we calculate 100 estimates of loss in value that Eemshaven has suffered due to the Coal Ban. Note that, in the but-for case, if a commodity price path is unfavourable, it seems reasonable to suppose that the Claimant would curtail its losses by closing the plant. As a result, none of our estimates of the loss in value of Eemshaven is strongly negative.[10] Hence, the value of the plant is not simply the average of a number of positive and negative cases, because the Claimant can largely eliminate negative outcomes by closing the plant. This ability to largely eliminate losses in cases with unfavourable commodity prices means that the loss in value for any commodity price path cannot be strongly negative and is generally either zero or positive.

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8 See Sections IV.B and IV.C.

9 See for example **Exhibit BR-3**, Levy, G., Computational Finance Using C and C#, Quantitative Finance Series, 2008, p. 37. **Exhibit BR-4**, Berk, J.B., DeMarzo, P.M., Corporate Finance, Third Edition, p. 1057.

10 The loss in value can be negative because we assume that a decision to close the plant would only be made after two years of losses.

14. By construction, each of the 100 price paths is equally likely to occur. Hence, we could arrive at a final damages figure by simply taking the average of the plant's loss in value for each of the 100 price paths. However, a few of the price paths lead to a particularly high loss in value (damages). To ensure that the estimate of the loss in value is robust, we prefer to avoid a situation where a few cases have a very large effect on the damages claimed. Conservatively, we exclude from the average the price paths corresponding to the top and bottom 5% of the 100 damages outcomes. After removing these 'outliers', then, we find that:

    a. The actual value of Eemshaven, assuming closure in 2030, is [redacted].

    b. The value of Eemshaven absent, or 'but for', the Coal Ban is [redacted].

    c. Accordingly, the damages resulting from the Coal Ban are [redacted].

15. From an economic perspective, the Claimant's damages claim represents a reasonable cost for reducing carbon emissions. We calculate that, on average, closing Eemshaven at the end of 2029 will result in 210 million tons of avoided carbon emissions. [11] Accordingly, the claim is equivalent to the Netherlands paying around €16 for each tonne of avoided carbon. [12] This price is lower than the CO_2 price has been since mid-2018.[13]

[11] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H7.

[12] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H7.

[13] See Appendix H.

II. Relevant factual background

II.A. The plant

16. Eemshaven is the largest coal-fired plant in the Netherlands,[14] with a nameplate net capacity of 1,560 MW, split between two identical 780 MW units (see Figure 1). The plant has an effective net capacity that varies by month [redacted], depending on the external temperature.[15] In normal operation, the Eemshaven plant requires around [redacted] full-time equivalent staff.[16]

FIGURE 1: EEMSHAVEN POWER PLANT[17]

[14] **Exhibit BR-5**, Report of the Ministry of Economic Affairs, 2016.

[15] Harris-Hesmondhalgh Workpapers, Tables E.1 and E.2 – Dispatch Model, Tables E.1.2 and E.2.2. Note data in Workpapers represents one unit.

[16] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H29.

[17] **Exhibit BR-6**, Velatia Networks, Safe and Reliable, Goodbye to the Coal Power Plants in the Netherlands by 2030, dated 21 January 2019.

17. The maximum annual output of the plant is approximately [redacted],[18] enough to provide the electricity for around [redacted] Dutch households,[19] or roughly [redacted] of the current Dutch population.

18. The plant opened in 2015 after [redacted] years of construction works[20] and, in line with general industry expectations,[21] it was expected that technically it could operate for 40 years – so until 2054. At present, Eemshaven operates using a mixture of hard coal and biomass.[22] However, the plant's use of biomass is constrained by environmental permits which only allow Eemshaven to burn 800,000 tonnes of biomass per year. [23] The plant will only burn biomass when it expects it to be economically viable to do so. This is currently the case primarily because Eemshaven receives subsidies for any electricity it generates using biomass up to a limit of 1,788,889 MWh per year,[24] but these subsidies will cease after 2027.[25]

II.B. The Dutch electricity generating market

19. In 2017, the total installed capacity of generating plants in the Netherlands was approximately 31.7 GW.[26] As shown in Figure 2, the majority of the plants (61%) were gas-fired, with coal-fired plants accounting for only 14.5% or 4.6 GW. Aside from one relatively small nuclear plant, the remaining plants produced electricity from renewable sources of various types.

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[18] [redacted]. This is based on average effective net capacity, [redacted] days of maintenance per year and a forced outage rate of [redacted]. See Harris-Hesmondhalgh Workpapers, Tables E.1 and E.2, Tables E.1.2 and E.2.2.

[19] According to **Exhibit BR-7**, CBS, Trends in the Netherlands 2018, Economy, the average consumption of electricity in Dutch households is over 2,900 kWh.

[20] Harris-Hesmondhalgh Workpapers, Tables G – Investment and Depreciation Model, Tab 'Blad 1'.

[21] See, for example, **Exhibit BR-8**, International Energy Agency and Nuclear Energy Agency, Projected Costs of Generating Electricity, 2015 Edition, dated 30 September 2015, p.30.

[22] **Exhibit BR-9**, RWE, Eemshaven Power Plant

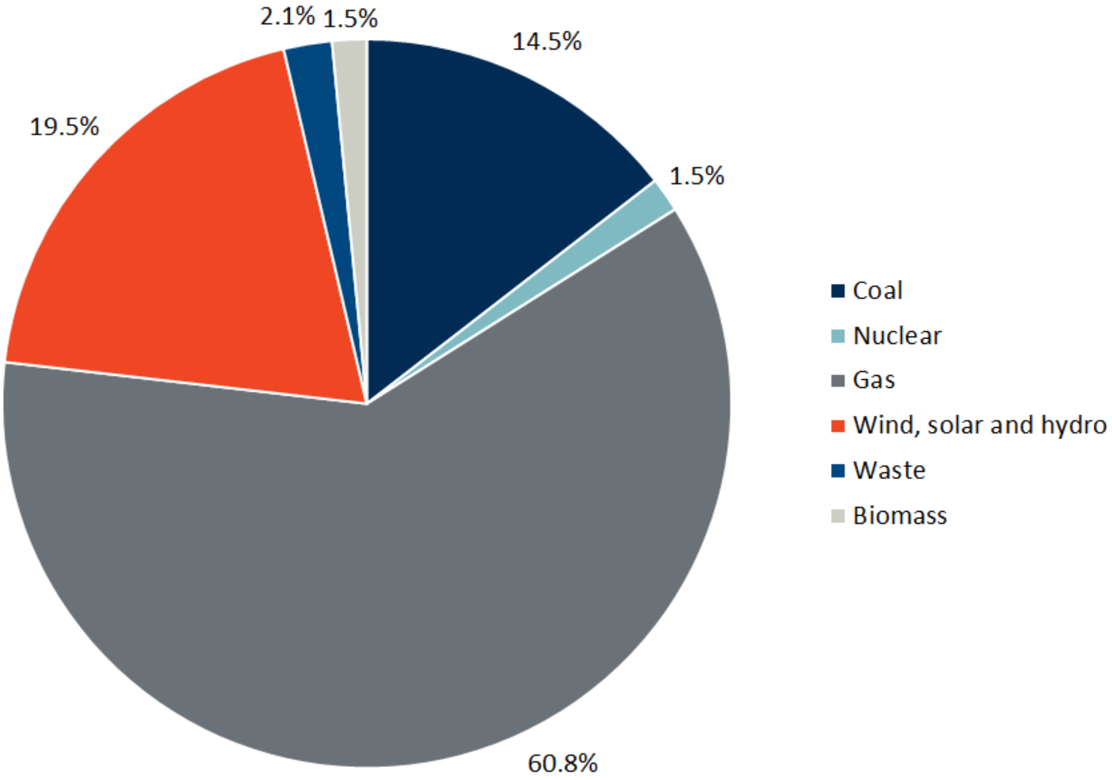
[23] **Exhibit BR-10**, RWE, Environmental Permit Eemshaven, dated 11 December 2007, pp. 90-92 for the granted request and **Exhibit BR-11**, KEMA Consulting, Application for Incorporation Permit, dated 20 December 2006, pp. 48-49 for the request details, see Table 3.1.2.

[24] See Table 1 below.

[25] **Exhibit BR-12**, National Enterprise Agency of The Netherlands, Eemshaven: Decision to Grant a Subsidy, dated 30 November 2016. We understand that, as of the valuation date, RWE expected that the subsidies would not start before May 2019 and that is what we have modelled.

[26] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis, Tab 'Breakdown of the Dutch Generation Capacity'. For more information visit: https://transparency.entsoe.eu.

FIGURE 2: BREAKDOWN OF DUTCH GENERATING CAPACITY IN 2017[27]



20. There were five operational coal-fired plants in the Netherlands in October 2017.[28] In addition to Eemshaven, RWE owned another coal plant, Amer-9. At that time, the other coal plants belonged to Uniper, Vattenfall, and ENGIE:

    a. Uniper owned the MPP3 plant near Maasvlakte, which is a large (1,070 MW) modern coal plant that only began operating in 2016.[29]

    b. Nuon, and then Vattenfall, owned Hemweg 8, a 630 MW combined heat and power plant that was commissioned in 1994.[30] As discussed in the next section, Hemweg 8 closed at the start of 2020, and received some compensation for its closure, and

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27 Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis. For more information visit: https://transparency.entsoe.eu, last accessed on 8 January 2021.

28 **Exhibit BR-13**, Government of The Netherlands, The Future of Fossil Fuels. Prior to October 2017, additional coal-fired energy units operated in in the Netherlands. However, between 2016 and 2017, five units closed as a result of the Dutch Energy Agreement (Energieakkoord, 2013): Amer 8, Gelderland, Borssele, and Maasvlakte unit 1 and 2. See **Exhibit BR-14**, Final Report 2014-2019, Dutch Coal Covenant, pp. 10-13.

29 **Exhibit BR-15**, Our power plants in the Netherlands - Uniper, last accessed on the 23 December 2020.

30 **Exhibit BR-16**, Vattenfall, Vattenfall's Last Coal Power Plant in The Netherlands is Closing, dated 20 December 2019.

c. ENGIE owned 730 MW plant also located near Maasvlakte, which began operating in 2015.[31]

II.C. The Coal Ban

21. The possibility of a phase out of coal-fired plants was first raised in November 2015, when the Dutch parliament adopted a resolution calling on the cabinet to investigate such a phase out taking into consideration all the relevant advantages and disadvantages.[32] However, the coal plant closure was opposed by the Dutch prime minister, who considered that it would result in electricity imports from brown coal plants, which would be more environmentally harmful than generating electricity from the modern Dutch hard coal plants, including Eemshaven.[33] As a follow up to the 2015 resolution, the Rutte II cabinet conducted an inquiry into the future of the Dutch coal plants, which considered several different possibilities. In January 2017, the cabinet concluded that closing the coal plants had many disadvantages and was not required to meet the CO_2-reduction aims set for 2020. It was only after the 2017 election and the formation of the Rutte III cabinet in October 2017 that a Coal Ban became sufficiently defined and probable that it would have affected the value of coal-fired plants in the Netherlands.[34]

22. The political parties in the coalition released the Coalition Agreement on 10 October 2017, a document that reflects their policy priorities for the period 2017-2021. The Coalition Agreement includes a dedicated chapter on climate and energy that includes a commitment to close coal-fired power plants "by the end of 2030 at the latest".[35]

23. On 20 December 2019, the prohibition on the use of coal for electricity generation came into force.[36] The law granted transitional periods for coal-fired plants during which they could continue to operate, with different transitional periods being specified according to the efficiency of the plant. For plants with an electrical efficiency above 44% - Eemshaven and

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[31] **Exhibit BR-17**, de Volkskrant, One of The Last Four Coal-Fired Power Stations in The Netherlands Wants to Close, dated 21 October 2020.

[32] **Exhibit BR-18**, Phys.Org, Dutch Lawmakers Approve Plan to Close Coal Power Plants, dated 26 November 2015.

[33] **Exhibit BR-18**, Phys.Org, Dutch Lawmakers Approve Plan to Close Coal Power Plants, dated 26 November 2015.

[34] **Exhibit BR-2**, 2017-2021 Coalition Agreement, Confidence in the Future, dated 10 October 2017pp. 42-43.

[35] **Exhibit BR-2**, 2017-2021 Coalition Agreement, Confidence in the Future, dated 10 October 2017pp. 42-43.

[36] **Exhibit BR-1**, Minister of Economic Affairs and Climate, Electricity Production Prohibition Act, dated 20 December 2019.

the two Maasvlakte plants – the transitional period extends until 31 December 2029.[37] For less efficient plants, such as Amer 9, the transitional period ends on 31 December 2024. Hemweg 8 closed on 1 January 2020 because, unlike Amer 9, it does not burn biomass and so does not produce renewable heat or electricity. In return for this early closure, Hemweg 8 received compensation of €52.5 million.[38]

24. We understand that the Dutch State has not provided Claimant with any financial compensation for the loss in Eemshaven's value resulting from the Coal Ban.

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[37] Article 3 of the Coal Ban Law, **Exhibit BR-1**, Minister of Economic Affairs and Climate, Electricity Production Prohibition Act, dated 20 December 2019.

[38] Based on its efficiency, the date by which Hemweg 8 could have originally expected to stop burning coal would have been the same as that for Amer-9, the end of 2024. However, the government brought forward its closure to 1 January 2020 and provided compensation to its owner, Vattenfall. **Exhibit BR-19**, European Commission Press Release, State Aid: Commission Approves Compensation for Early Closure of Coal Fired Power Plant in the Netherlands, Brussels, dated 12 May 2020.

III. Valuation framework

25. As outlined above, we have been instructed to measure the change in the Fair Market Value of Eemshaven as a result of the Coal Ban. In this section, we:

    a. Briefly discuss the concept of Fair Market Value from an economic perspective;

    b. Describe conceptually how we measure damages as the difference between cases with and without the Coal Ban;

    c. Explain why we have chosen to use a Discounted Cash Flow (DCF) methodology to determine the Fair Market Value of the plant; and

    d. Explain why the DCF method is the valuation method best suited to measure FMV in this case.

26. We also outline the specific approach that we have taken to determining the cash flows used in the DCF model, including how we have accounted for risks and alternative future commodity price developments.

III.A. What is a "Fair Market Value"?

27. According to the International Valuation Standards, the Organisation for Economic Co-operation and Development ("OECD") defines the "Fair Market Value" of an asset as "*the price a willing buyer would pay a willing seller in a transaction on the open market*."[39] The International Valuation Standards also quote the definition of the United States Internal Revenue Service, which defines "Fair Market Value" as:

> *"the price at which the property would change hands between a willing buyer and a willing seller, neither being under any compulsion to buy or to sell and both having reasonable knowledge of relevant facts."*[40]

28. Both definitions are substantively the same, and we adopt them in this report.

29. Alternatives to the FMV perspective include:[41]

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[39] **Exhibit BR-20**, International Valuation Standard Council, International Valuation Standards, dated 31 January 2020, p. 23.

[40] **Exhibit BR-20**, International Valuation Standard Council, International Valuation Standards, dated 31 January 2020, p. 23.

[41] **Exhibit BR-20**, International Valuation Standard Council, International Valuation Standards, dated 31 January 2020, pp. 21-22.

a. the equitable value of an asset – the value that it would have if it was transferred between two specific parties, and

b. the investment value of an asset – the value of an asset to a specific owner.

30. Hence, the relevant feature of adopting a FMV approach in this case is that we do not take into account any value associated with Eemshaven that is specific to it being owned by RWE, and would not accrue to a third-party buyer. Since operating a large coal-fired power plant like Eemshaven is a complex undertaking, we assume that a "willing buyer" in the case of Eemshaven would be a large sophisticated corporation, which also operates a number of other power plants. In our view, this is the most likely buyer profile. It would be very unlikely for a company that owns no other power plants to bid successfully for Eemshaven. We highlight where this criterion becomes relevant throughout the report.

III.B. Measurement of damages – actual and but-for cases

31. As noted above, Counsel for Claimant have asked us to calculate the loss in value of Eemshaven resulting from the Coal Ban, on a FMV basis. We make this assessment using 9 October 2017 as the Valuation Date and adopting the following standard approach:

a. We calculate the FMV of Eemshaven 'but-for' the Coal Ban as of the valuation date. That is, Eemshaven would be legally permitted to continue generating electricity from coal until 2054. We refer to this as the but-for case.

b. We also calculate the FMV of Eemshaven as of the valuation date with the Coal Ban in place. This means that Eemshaven is not allowed to generate electricity from coal from January 2030 onwards. We refer to this as the actual case.

c. The difference between the FMV in the but-for case and the FMV in the actual case measures the loss in value of the plant. This is the damage suffered as of the valuation date.

d. As is best practice when estimating damages, we calculate both the 'but-for' and actual value using only information on commodity prices, costs and other financial data that was available, or knowable, as of the Valuation Date. In this way we calculate damages immediately before the impending Coal Ban became known in such a way as to affect the value of Eemshaven. Considering data after the Valuation Date would contaminate our damages estimation, because it would be impossible to disentangle changes that are due to the Coal Ban from changes that are due to other causes.

32. The most recent edition of the Global Arbitration Review Guide to Damages in International Arbitration (the "GAR Guide"), discusses this approach, noting that:

> *"[t]he but-for premise considers the questions of what would have happened in the absence of the breach. To find an answer, the but-for premise compares the hypothetical situation without the breach and the actual situation with the breach".*[42]

III.C. Discounted cash flow valuation method

33. There are three main methods for determining a FMV:[43]

    a. An "income" approach, where the valuer establishes the FMV of an asset based on its future income (more specifically, its future free cash flows), most commonly measured using a DCF model;[44]

    b. A "market" approach, where the asset is valued based on other comparable companies. This method includes so-called 'multiples' approaches[45] and comparable market transactions;

    c. A "cost" approach, where the valuer establishes the FMV based on the cost of reproducing the asset.

34. However, in our experience, the standard way of determining the FMV for a power plant is by applying a DCF model. When assisting with mergers and acquisitions and also when assessing damages in arbitrations, we have routinely applied DCF models to value power plants and similar assets for many years. It is also the approach that we see clients in the industry apply in their internal valuation exercises, and when considering asset acquisitions or divestments.

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42 **Exhibit BR-21**, Global Arbitration Review, The Guide to Damages in International Arbitration, Third Edition, dated 1 December 2018, p. 114.

43 **Exhibit BR-20**, International Valuation Standard Council, International Valuation Standards, dated 31 January 2020, p. 29.

44 "The most common form of the income approach is to focus on cash (rather than an accounting measure like income) and use a discounted cash flow (DCF) method." **Exhibit BR-21**, Global Arbitration Review, The Guide to Damages in International Arbitration, Third Edition, dated 1 December 2018, p. 196.

45 A multiples approach is where an analyst values a business based on a multiple or ratio such as profit to value. For example, suppose an analyst knows the profit to value ratio of business 'A' is 10, and also knows the profit of the business being valued (business 'B') is 2. If the ratio of profit to value is the same for both business A and B, the analyst can calculate the value of business B as 10 x 2 = 20.

35. Third-party presentations and academic articles mirror our experience.[46] Other authoritative sources also endorse the use of a DCF model to establish an asset's FMV.[47] The DCF method is also commonly used by financial analysts preparing reports for investors, and financial managers seem to prefer the DCF method over any other.[48] Hence, any prospective buyer of Eemshaven would include a DCF calculation when establishing the FMV of Eemshaven. Moreover, the DCF is based on fundamental and accepted principles of financial economics.[49]

36. In the GAR Guide to Damages, the authors note that "[t]*he income approach [implemented through a DCF valuation] is the usual starting point for the valuation*".[50] The authors point out that the income method, as implemented through a DCF model, allows the valuer to take into account the specific characteristics of the asset.

37. In another chapter of the GAR Guide, the author notes that:

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46 For example, in a presentation on power plant economics, Alstom – a maker of equipment for the electricity sector – discussed alternative methods of evaluating power plant economics, and concluded that the DCF "method is preferred by economists and [power plant] developers". **Exhibit BR-22**, Alstom, Power Plant Economics, 2006, pp. 8-9.

47 For example the chapter on 'Expropriation and unilateral alterations or termination of contracts' in the World Bank's 'Guidelines on the Treatment of Foreign Direct Investment note that "such determination [of FMV] will be deemed reasonable if conducted as follows: (a) for a going concern with a proven record of profitability, on the basis of the discounted cash flow value". See **Exhibit BR-23**, World Bank, "Guidelines on the Treatment of Foreign Direct Investment," Foreign Investment Law Journal, Chapter IV Expropriation and unilateral alterations or termination of contracts, 1992, p.304.

48 Graham and Harvey (1999), for example, surveyed 392 Chief Financial Officers on the practices used to evaluate real asset investments and found that the two most popular techniques were the DCF and the Internal Rate of Return approaches. See **Exhibit BR-24**, Graham, J.R. and Campbell R.H., "The Theory and Practice of Corporate Finance: Evidence from the Field", Journal of Financial Economics, dated 10 December 1999, pp. 197-201.

49 Leading corporate finance specialists support the DCF as the preferred valuation methodology for income-earning assets. For instance, Reilly and Brown (2004) recommend this valuation methodology stating:

"These discounted cash flow valuation techniques are obvious choices for valuation because they are the epitome of how we describe value: that is, the present value of expected cash flows."

See **Exhibit BR-25**, Reilly, F., Brown, K.C., Investment Analysis & Portfolio Management, Chapter 11: An Introduction to Security Valuation, Seventh Edition, Thomson Southwestern, 2003, p. 378 Similarly, Copeland, Koller and Murrin (1994), in their leading textbook on valuation, state that:

"The DCF approach captures all the elements that affect the value of the company in a comprehensive yet straightforward manner. Furthermore, the DCF approach is strongly supported by research into how the stock markets actually value companies."

See **Exhibit BR-26**, Copeland, T., Koller, T., Murrin, J., Valuation Measuring and Managing the Value of Companies, Second Edition, John Wiley & Sons, Inc., 1994, p. 70.

50 **Exhibit BR-21**, Global Arbitration Review, The Guide to Damages in International Arbitration, Third Edition, dated 1 December 2018, p. 198.

> *"In fact, the DCF method is the most common methodology used in valuation analyses involving assets in the energy and natural resources industries (as well as most other industries). First, it is widely supported by professional literature, and its workings are well understood. Indeed, most investors rely on a DCF analysis to determine whether or not to undertake a particular project. Second, the DCF approach is a widely accepted method to estimate damages and fair market valuations in international disputes; in many energy and mining cases panels have adopted the DCF method without hesitation."*[51]

38. With regard to the acceptance of DCF models by Tribunals and Courts, a 2015 ICSID award noted that "[T]he DCF method is widely accepted as the appropriate method to assess the [fair market value] of going concerns."[52]

39. A DCF method is particularly appropriate to establish the FMV of Eemshaven, because Eemshaven was, at the valuation date, an operating asset. Its technical characteristics, for example how costs vary with the level of electricity production – were well understood, as were its main revenue drivers. In particular, as we explain in more detail in Sections IV to VI below, the data needed to project its revenues and costs were readily available. In particular, to determine the plant's key revenues and costs, the forward prices and forecast prices of the relevant commodities were available, as was data on the volatility of prices of these commodities.

40. Given that, by construction, DCF models can integrate a wide array of assumptions, interactions, and probabilities, the DCF method permits us to account for all relevant value drivers in an objective and transparent manner, including the effect of different possibilities about the future development of commodity prices.

III.D. Other valuation methods considered

41. In this section, we explain the alternative methods for valuing Claimant's losses that we considered, but ultimately rejected.[53]

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[51] **Exhibit BR-21**, Global Arbitration Review, The Guide to Damages in International Arbitration, Third Edition, dated 1 December 2018, pp. 358-359, emphasis added. The GAR Guide also notes that "[a]s has been discussed in other chapters of this book, the discounted cash flow (DCF) model has become an established tool in calculating damages claims in international arbitrations." (p.232).

[52] **Exhibit BR-27**, Quiborax S.A. v. Plurinational State of Bolivia, ICSID Case No. ARB/06/2, Award, dated 16 September 2015, ¶ 344.

[53] For a discussion of alternative valuation methods, see **Exhibit BR-20**, International Valuation Standard Council, International Valuation Standards, dated 31 January 2020, pp. 29-49.

III.D.1. Analysis of RWE AG's share price

42. One sub-category of the "market" approach to valuation is to look at share price movements. RWE AG, the ultimate parent of RWE Eemshaven, has shares that are publicly traded, and the prices of which are readily available. Hence, looking at changes in the RWE AG share price around October 2017 could have been one way to measure the loss in value resulting from the Coal Ban. However, in the present case an analysis of RWE AG's share price will not yield a reliable estimate of loss for several reasons.

43. First, our instruction was to take a Valuation Date immediately before the Coal Ban had any effect on the value of Eemshaven and also to consider the full effect of the Coal Ban. In practice, the probability that the Coal Ban would become law, and, particularly, that there would be only very limited compensation for the early closure of Eemshaven, increased between October 2017 and the end of 2019. Hence, the effect of the Coal Ban on RWE's share price increased gradually over the period between October 2017 and the end of 2019, when the Coal Ban entered into law. During the period between October 2017 and January 2020 there were many other events that caused RWE's share price to change. These events mean that it is not possible to discern the effect of the Coal Ban on the share price over such an extended period.

44. Moreover, RWE AG is active in a wide range of geographic and product markets, and its share price represents the sum of the value of all of these diverse activities. Hence, untangling the various influences on RWE AG's share price over time would inevitably result in precisely the kind of DCF valuation exercise that we have undertaken.

45. Second, even if RWE AG's share price was only influenced by developments in the Dutch electricity market, its movements would have reflected not only the losses resulting from the Coal Ban, but also investors' expectations that the Dutch government might compensate the Claimant for its losses. If the market expected Eemshaven would receive some compensation, then any change in the share price would underestimate the losses resulting from the Coal Ban. For example, while RWE's 2017 financial accounts mentioned the Coal Ban for the first time, as of that date RWE could not be certain what, if any, compensation it would receive.[54] Accordingly, we conclude that an examination of changes in RWE AG's share price is not informative for an evaluation of the Claimant's loss.

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[54] "In mid-October 2017, the new Dutch government concluded its coalition agreement. […] One objective is for the country to stop generating electricity from coal completely by 2030. […] At present, it is impossible to predict the ramifications of the coalition agreement for the energy sector, as a lot depends on the details of the climate protection package." See **Exhibit BR-28**, RWE, Annual Report 2017, p. 36.

III.D.2. Comparable transactions

46. Another sub-category of the "market" approach to valuation is to look at comparable transactions. A comparable transactions approach is only possible if assets similar to the asset being valued were sold around the valuation date.

47. In the current case, a comparable coal-fired plant would need to have been sold around October 2017. The 'comparable' plant would need to have been recently completed, because otherwise it would be less efficient and have a shorter life than Eemshaven, leading to an underestimate of the loss in value. It would also need to have been located in the Netherlands or a market in which electricity prices were very similar to the Netherlands, as otherwise its future revenues, and therefore value, might differ significantly from those for Eemshaven. Similarly, a sale before or after the valuation date could mean that the value of the 'comparable' plant did not correspond to the value of Eemshaven as of the valuation date.

48. No sales of Dutch coal plants took place in the autumn of 2017. ENGIE sold its coal plants in the Netherlands and Germany in April 2019.[55] However, that sale took place eighteen months after the Coal Ban had been announced. Hence, the transaction price for the ENGIE plants will reflect the expected value of the plants with the Coal Ban in place as of April 2019 and may take into account some expectation of compensation. Accordingly, this transaction will not provide an accurate estimate of the loss in value for Eemshaven resulting from the Coal Ban.

49. We understand that in early December 2020, RWE AG accepted compensation from the German government for the expected early closure of the Westfalen and Ibbenbüren power plants in Germany. The Westfalen plant has a similar design and was completed at around the same time as Eemshaven. However, Ibbenbüren is significantly older than either Eemshaven or Westfalen, and so is not comparable to either.

50. This point aside, there are a number of reasons why it is not possible to estimate the Claimant's losses from the early closure of Eemshaven from the compensation it received for Westfalen/Ibbenbüren. We discuss three such reasons below.

51. First, Eemshaven operates in a different market than the Westfalen/Ibbenbüren plants, and Dutch wholesale prices have consistently differed from those in Germany.

52. Second, the years of lost production for Eemshaven and the German plants differ, and so are not comparable. Specifically, the compensation for lost electricity production in Germany

55 **Exhibit BR-29**, S&P Global Platts, Engie sells 2.3 GW German, Dutch Coal Plants to Riverstone Holdings, dated 26 April 2019.

was for the [redacted]-year period [redacted]. It is not meaningful to compare lost profits in this period to lost production for the 25-year period 2030 to 2054. It is clear from our modeling that prices develop very differently [redacted]. The longer time horizon in our valuation creates the possibility for a wider range of outcomes, including higher value cases that are less likely to occur in the period [redacted].

53. Third, due to differences between the valuation dates for Eemshaven (October 2017) and for Westfalen and Ibbenbüren ([redacted]), values are also expected to be different due to a variety of factors, including developments in commodity prices.

54. These three examples illustrate why the compensation that RWE received for the closure of its German plants is not a good guide to the loss of value for Eemshaven as a result of the Coal Ban.

III.D.3. Historical Earnings

55. A third valuation approach would be to value Eemshaven based on its historical earnings – so in other words, to assume that past earnings are representative of future earnings.

56. Looking at historical profitability can be a useful guide to future profitability for a process with stable input and output prices. However, it makes little sense for a coal-fired power plant, where the prices of both inputs and outputs can vary very significantly, even over short periods. Hence, for coal-fired plants, past profits or losses provide only a limited guide to expected future profits or losses. Valuing Eemshaven based on past profits would be equivalent to assuming that future commodity and electricity prices will be the same as the average commodity prices over the last few years. There is no reason to think that this will be the case. A rational buyer would value a coal-fired power plant considering its future cash flows, not its historical profits.

57. We also note that, as of the October 2017 Valuation Date, Eemshaven had only been in operation for one complete year, calendar year 2016. It would be unreasonable to use data from a single year to benchmark projected operations for the following 37 years. Moreover, we understand that the typical teething issues associated with a new plant affected may have affected 2016 operations.[56] Specifically, as we explained in section VI.A.5, Eemshaven's total operating costs were higher in 2016 and 2017 than they were forecast to be in subsequent years.

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[56] We rely on historical information from 2016 and 2017 to allocate RWE's costs across subcategories, such as maintenance and staff. We expect the cost allocation to remain relatively similar over time.

III.D.4. Cost approach

58. A fourth valuation approach, the cost approach, would involve looking at the replacement cost of Eemshaven, or some other measure of cost such as its net book value (NBV).[57]

59. The cost of replacing Eemshaven could provide a ceiling for damages.[58] However, in this case it will not provide an accurate measure of the loss in value. RWE spent around €3.2 billion in constructing Eemshaven.[59] Yet, RWE has recognised that the actual value of the plant – even absent the Coal Ban – was lower than its construction cost. Accordingly, to reflect this, RWE booked a tax-deductible impairment of [redacted] in [redacted].[60] In other words, even before the Coal Ban, the Eemshaven plant was worth significantly less than its replacement cost. Moreover, replacement value is more often used where there is a claim of direct expropriation. We understand that this is not the Claimant's claim.

60. RWE reached a bilateral agreement ("VSO" or "*Vaststellingsovereenkomst*") with the Dutch Tax Authorities that the tax book value of Eemshaven was of [redacted].[61] This value would represent a more accurate estimate of the plant's value than the replacement cost.[62] This is because the tax book value reflects the impairment discussed above. However a DCF model will result in a more accurate estimate of the loss in value than relying on book values. This is because, as outlined above, the DCF can account for the specific losses Claimant experienced as a result of the Coal Ban.

61. We also note that RWE recorded impairments for Eemshaven in [redacted]. However, these impairments are not relevant to an assessment of Eemshaven's FMV in October 2017. An impairment is a one-off change in a plant's lifetime value. For example, some of the impairments that RWE recorded related to [redacted]. [redacted]

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[57] Net book value refers to the value of a an asset recorded in the accounts, such as a plant or a building, after taking into account the building's loss of value due to economic obsolescence and technical depreciation.

[58] Analysts refer to this as the Depreciated Replacement Cost of DRC. The reference to depreciation means that the replacement asset should be in the same state or age as the original asset. So in the case of Eemshaven, as of October 2017 the plant would be about two years old. Hence, the DRC would be slightly lower than the New Replacement Value. **Exhibit BR-30**, Royal Institute of Chartered Surveyors (RICS). Depreciated Replacement Cost Method of Valuation for Financial Reporting, London: 1st Edition, November 2018, p. 4.

[59] Harris-Hesmondhalgh Workpapers, Tables G – Investments Model, Table G6.

[60] Harris-Hesmondhalgh Workpapers, Tables G – Investments Model, Tab 'Blad 1', Tax View Section.

[61] [redacted]

[62] Eemshaven's book value was [redacted] at the end of [redacted]. See Harris-Hesmondhalgh Workpapers, Tables G – Investment and Depreciation Model, Tab 'Blad1'. Hence, the book value would be slightly higher as of the valuation date, as less deprecation would have occurred.

[redacted]. Accordingly, impairments in [redacted] do not imply that the value of Eemshaven will continue to decrease, or that future impairments will be needed. In our forecasts, we have already accounted for the circumstances as of October 2017 – [redacted] – that were partially responsible for the impairments.

III.E. Specific approach adopted

62. The International Valuation Standards set out the five key steps for a DCF model as follows:[63]

   a. First, choose the most appropriate type of cash flow for the nature of the subject asset and the assignment (i.e., pre-tax or post-tax cash flows or cash flows to equity, real or nominal, etc.).

      i. We forecast post tax cash flows. We rely on post tax flows, because a buyer would pay taxes on any profits, and so post tax cash flows measure the amount a buyer would pay for the plant. We use nominal cash flows, because this facilitates the correct calculation of taxes.[64] And we use cash flows to debt as well as equity, because we understand that a buyer of the Eemshaven plant would not have to assume any debt associated with the plant.

   b. Second, determine the most appropriate explicit period,[65] if any, over which the cash flow will be forecast.

      i. The period of most interest is October 2017 to 2055, being the period from the valuation date to the end of the plant's technical life.[66]

   c. Third, prepare cash flow forecasts for that period.

      i. In the case of Eemshaven, this involves projecting the revenues and costs of the plant for each year of its future operation that we analyse, based on the data that would have been available to an informed and willing buyer as of the valuation date, 9 October 2017.

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63 **Exhibit BR-20**, International Valuation Standard Council, International Valuation Standards, dated 31 January 2020, pp. 37-38.

64 Companies pay taxes based on current year, nominal cash flows. Moreover, depreciation, which is also calculated based on nominal investment values, impacts the taxable base of a company.

65 'Explicit period' refers to the period over which cash flows are modelled explicitly – so there is a value calculated for each year - rather than being included in a terminal value calculation.

66 Eemshaven would close by the end of 2054. However, we extend the analysis to consider 2055, because there are some expenses that a power plants needs to incur after ceasing operations. We discuss these expenses in more detail in Section VI.B below. In terms of modelling, we focus on the period from 2020 to 2055 since it is the period most relevant for the Claimant's damages.

d. Fourth, determine whether a 'terminal value' is appropriate for the subject asset at the end of the explicit forecast period.

   i. The terminal value represents the value of the asset beyond the period that is modelled explicitly. Since we model the operation of the plant explicitly until its closure, we do not need a terminal value.

e. Fifth, determine the appropriate discount rate, and apply the discount rate to the forecasted future cash flow, including the terminal value, if any.

   i. This step recognises that cash flows from a distant future year are worth less at the valuation date than the same cash flows at the valuation date. We rely on standard techniques from corporate finance to determine an appropriate discount rate.[67]

63. Finally, all the discounted cash flows from all future years must be added together to determine their overall 'present value' and hence a value for Eemshaven on which informed and willing buyers and sellers could agree, namely the FMV.

64. To forecast cash flows as of October 2017, we start by forecasting so-called 'commodity margins' for each year. The commodity margin is the difference between the revenues the plant is expected to earn from generating and selling electricity, and the variable costs associated with generating that electricity.[68] The latter mainly consists of commodity costs, namely costs for coal, CO_2, and biomass. These commodity costs (plus those for gas) are also key factors influencing electricity prices, since they determine the costs of producing electricity for all the other fossil-fuel powered plants operating in the market.

65. The commodity margin of a plant in any given period typically determine when it will operate since, all other things being equal, it only makes sense to operate when the commodity margin is positive. We therefore use our forecasts of commodity margins to forecast how Eemshaven would operate i.e. at what times and what output levels it would be likely to be dispatched in each year. In this way, we determine the revenues and variable costs of the plant that are used in the financial model to determine the plant's FMV.

66. More specifically, as shown in Figure 3, to forecast Eemshaven's future cash flows as of October 2017 we adopt a three step process that we explain in more detail below.

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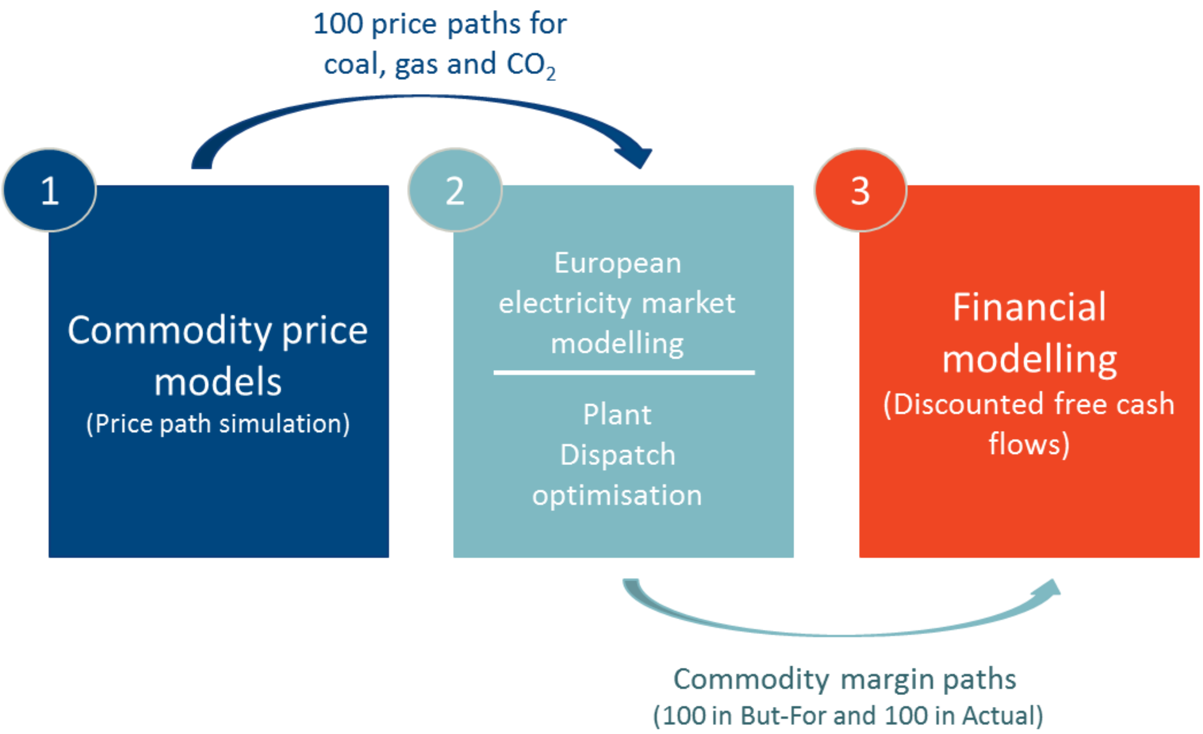
67 See Section VI.C below. See also Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital.

68 A variable cost is a cost that varies directly with output. For example, coal is a variable cost for Eemshaven, as every MWh of output requires a specific amount of coal to generate.

FIGURE 3: OUR THREE-STEP CALCULATION OF FREE CASH FLOWS



67. First we forecast commodity prices, and specifically prices for gas, coal and CO_2 permits. We use market-based forward curves and third party price forecasts to derive future commodity prices. Section IV of our report describes this process.

68. We recognise that there is not only one plausible path describing the future development of commodity prices out to 2054. We also recognise that there are some plausible commodity price paths under which Eemshaven's costs would have been expected to be too high for it to operate profitably. Under these price paths, Eemshaven might close before 2054 even absent the Coal Ban. However, there are also many other plausible commodity price paths under which Eemshaven would generate significant profits but-for the Coal Ban. To quantify and bound this range of outcomes, we have modelled 100 alternative price paths for each commodity.

69. The generation of multiple commodity price paths is an example of a 'Monte Carlo' simulation. A Monte Carlo simulation is a mathematical technique that generates random variables for modelling risk or uncertainty of a given system – in this case future commodity prices in the Netherlands. We describe this method in further detail in Section V.

70. Monte Carlo simulations are a widely accepted way of simulating variables for which a range of plausible values exist. For example, in May 2020 the European Commission (EC) approved the compensation the Dutch government offered to Vattenfall for the early closure of the

Hemweg plant.[69] The EC noted that "[t]*he compensation amount has been calculated as the present value of the net expected annual cash flows*"[70] and that:

> *"Expected gross margins have been estimated by multiplying the expected production volumes –based on past unplanned unavailability rate - with expected hourly power prices coming from* ***Vattenfall internal Monte Carlo "BOFIT" model****."*[71]

71. The EC's decision underlines both that other large operators such as Vattenfall apply Monte Carlo simulations in their plant valuations, and that the EC, as well as the Dutch State, accepted this valuation methodology. Major corporate finance textbooks also confirm Monte Carlo simulation as a way to model a range of outcomes. For example, in a book on the computational aspects of financing, Prof. Levy notes that:

> *"Monte Carlo simulation and random number generation are techniques that are widely used in financial engineering as a means of assessing the level of exposure to risk. Typical applications include the pricing of financial derivatives and scenario generation in portfolio management."*[72]

72. Second, we have to estimate what electricity prices result from those commodity prices, taking into account how the mix of power plants in the Dutch system will likely change over time and what the demand for electricity is likely to be. To do this, we use a computer model of the entire European electricity market, to predict the electricity prices that would result from the forecast commodity prices (see Section V). In essence, as explained above, the price of electricity at any moment depends in large part on the generating plant available, the demand for electricity, and the cost of the commodity inputs needed to generate the electricity. The model combines these factors to determine electricity prices over the relevant period. Given the electricity and commodity prices, we then model the revenues that Eemshaven would have earned, and the variable costs it would have incurred from generating electricity.

73. Third, we need to calculate Eemshaven's cash flows from our estimates of its future revenues – based on electricity prices and plant output – and operating and capital costs.

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69 **Exhibit BR-31**, European Commission, State Aid SA.54537 (2020/NN) - Netherlands Prohibition of Coal for the Production of Electricity in the Netherlands, dated 12 May 2020.

70 **Exhibit BR-31**, European Commission, State Aid SA.54537 (2020/NN) - Netherlands Prohibition of Coal for the Production of Electricity in the Netherlands, dated 12 May 2020, p. 3.

71 **Exhibit BR-31**, European Commission, State Aid SA.54537 (2020/NN) - Netherlands Prohibition of Coal for the Production of Electricity in the Netherlands, dated 12 May 2020, p. 4 emphasis added.

72 **Exhibit BR-3**, Levy, G., Computational Finance Using C and C#, Quantitative Finance Series, 2008, p. 50.

We deduct fixed operating costs from the commodity margins, as well as investments and taxes, to arrive at cash flows. In this way, we create 100 cash flow paths and, hence, 100 simulations of the future profitability of Eemshaven.

74. Above, we noted that some commodity price paths might, at some point, result in potential losses for Eemshaven. However, it is important to recognise that Eemshaven can limit the effect of any negative commodity price paths by ceasing operations. It is reasonable to expect that RWE would do so in a scenario in which Eemshaven's operation is expected to result in continuing losses – although importantly, by closing the plant RWE would also terminate the option to enjoy positive profits at some future date, should commodity prices move in a favourable direction. Hence, the value of the plant is not simply the average of a number of positive and negative price paths, because we can largely eliminate negative outcomes by closing the plant.

75. For example, suppose that in 60% of simulations Eemshaven made a profit of 20 (arbitrary units), and in 40% of simulations the plant would, if it continued to operate until 2054, make a loss of 30. Without the option to close, the expected profit would be 40% x -30 + 60% x 20 = 0.

76. However, the losses in the unfavourable cash flow paths can largely be eliminated by closing Eemshaven before 2054.[73] Accordingly, the expected profit would actually be 40% x 0 + 60% x 20 = 12. The ability to largely eliminate losses in simulations with unfavourable cash flow paths means that Eemshaven suffers a loss in value as a result of the Coal Ban, even if the plant would make losses if it continued operating to 2054 in some of the simulations.

77. We discount the free cash flows to October 2017, to calculate their present value as of that date and, hence, the FMV of the plant. We calculate the cash flows and FMVs under the actual and but-for cases for each of the 100 commodity price paths. Section VI explains this process in more detail.

78. Finally, to calculate the loss of Fair Market Value, we compare the 100 pairs of FMVs for the actual and but-for cases and so determine 100 estimates of the loss in FMV as a result of the Coal Ban. We combine these 100 results into a single figure in a statistically robust manner (see Section VII).

[73] We say 'largely eliminate', because as we discuss in section VI.B, the plant may tolerate losses for some years to preserve the option to produce electricity and make profits if commodity prices develop favourably in the future.

IV. Step 1: Commodity price models

79. To measure the Fair Market Value of Eemshaven, we must forecast the relevant commodity and electricity prices up to and including 2054. As we explain in the rest of this section, we have generated 100 different price paths for coal, gas and CO_2 prices. We use these commodity price paths to create 100 paths for electricity prices and we use the combination of the commodity and electricity price paths to determine Eemshaven's revenues and costs and, hence, its cash flows. We provide a detailed description of our methodology in Appendix B.

IV.A. Overview of stochastic modelling

80. A wide range of commodity price developments is possible in the period up to 2054, particularly given the inherent volatility of commodity prices. Accordingly, simply considering one "central" commodity price scenario would not, in our view, provide a reliable estimate of the FMV of Eemshaven. Instead, we take into account the full range of possible commodity price paths.

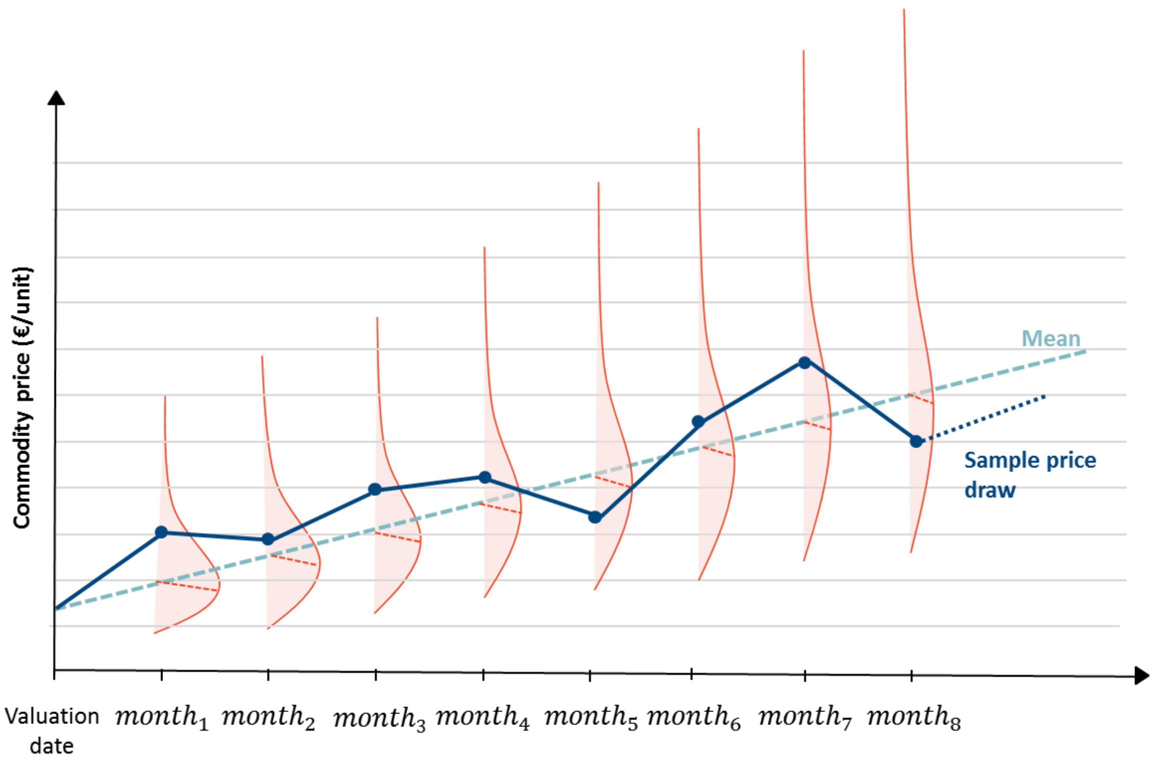
81. One possible way to deal with the range of future commodity prices is to employ scenarios. For example, it is common to see demand or prices forecasts that feature 'high', 'base' and 'low' scenarios. In more detail, scenario analysis consists of creating a series of alternative, internally coherent sets of assumptions – scenarios – and then assigning a probability to each scenario to arrive at a final damages estimate. Such an approach is commonly used when assessing the benefits of a particular course of action – for example, the purchase of a power plant – where it is important to understand what might happen in a worst case, what a very good outcome would look like, and what it is most reasonable to expect would happen.

82. When it comes to assessing damages, however, there are two main drawbacks to using scenario analysis. First, it is only feasible to construct a relatively small number of scenarios and these may be very different from each other so that under one scenario there may be no damages and under another there may be high damages. Consequently, simply averaging the results from the scenarios may produce misleading results particularly as a large number of alternative, equally plausible sets of assumptions are ignored. Perhaps more importantly, any attempt to overcome this problem by calculating a probability-weighted average is problematic because there is inevitably a high degree of subjectivity in assigning probabilities to each scenario.

83. Due to these drawbacks, we prefer to generate alternative commodity prices paths using a probabilistic or "stochastic" approach, known in the field as a "Monte Carlo" analysis.[74] A stochastic approach focuses on a smaller number of key drivers and considers these in much greater detail, taking into account the volatility in their values based on data available as of the valuation date.

84. We illustrate what we mean by a stochastic analysis by explaining in general terms how we create price paths for a single generic commodity, as shown in Figure 4. We first need to create a distribution of all the possible prices that the commodity could have at a given time period – these are the vertical lines shown in red in the figure, which represent the distribution of prices from highest to lowest.[75] We then pick a random price from the distribution of all possible prices, using a random number generator.

FIGURE 4: CREATING STOCHASTIC PRICE PATHS



85. To facilitate the selection of a random price, rather than calculate the probability associated with each monthly price shown schematically in Figure 4, we express the probabilities of individual prices occurring as a cumulative price distribution. In a cumulative price distribution, there is a zero percent chance of the commodity price being lower than the lowest price and a 100% chance that it will be lower than the highest price. In between these

74 See Appendix B for details.

75 The shading underneath each line is simply intended to highlight the region of the distribution where it is most probable that a price will lie.

extremes, each possible price level will be associated with a particular probability that prices will be no higher than that level. For example, there might be a 10% chance that the commodity price will be lower than 5 €/unit, a 50% chance that it will be lower than 15 €/unit and a 90% chance that it will be lower than 35 €/unit. We then pick a value between 0% and 100% at random. The randomly chosen figure determines what price we assume for that time period and price path. For example, if our random choice was 50%, then we would assume a price of 15 €/unit and so on.

86. We repeat this procedure for each month and, in this way, build up a 'path' of prices over time. In terms of Figure 4, we start from a price as of the Valuation Date. We then pick a price at random from the cumulative distribution of prices derived from the price distribution shown for Month 1. We then pick a price for Month 2, randomly choosing a price from the cumulative distribution of prices derived from the price distribution for Month 2, and so on.

87. Based on the history of the relevant commodity price, there are limits on how much its price is likely to change from one month to the next. Technically, the degree to which prices can change between periods is known as their 'volatility'. As we move from one month to the next we have to add together the volatilities relevant to deliveries in the current month that arise in each of the preceding months. This means that the "width" (technically, standard deviation) of each month's distribution increases.

88. Moreover, the random choice for one month affects the range of choices for the next month. That is, the random choice of price for the previous month[76] reduces the available choices for the next month - the range of prices for the next period is not 0% to 100% of the cumulative price distribution. The range is primarily determined by our historical analysis of the volatility in month-ahead prices. Accordingly, we constrain price changes between periods so that they are consistent with the month-ahead volatility levels for the commodity that would have been expected as of the Valuation Date. If a commodity has had relatively stable prices over time, the extent to which its price is likely to change from one month to the next is quite limited. If its expected volatility is higher, then a much wider range of prices are possible for the next month. For example, suppose that we arrived at a price of 20 €/unit for one month and the month-ahead volatility is 15%,[77] then, based on the characteristics of

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[76] In this context, by "previous" we simply mean the month immediately preceding the one being considered. Note that, broadly speaking, the very first month of the commodity price path will not have a price distribution, its price will equal the prevailing spot price. We discuss the methodology in greater detail in Appendix B.2.

[77] This is broadly consistent with the expected monthly volatility for gas and coal as of the valuation date. See Appendix B.2.ii.

a log-normal distribution, we would know that there is a 95% probability that the price for the next period would be between 14.90 €/unit and 26.80 €/unit.[78]

89. We create each price path in exactly the same way, starting from an initial price which is either fixed (the day-ahead price for gas prices) or only has a very narrow distribution (due to the volatility in month-ahead prices for coal prices) and then randomly choose prices, within the constrained range, for each subsequent month. Our final step for gas prices is to use historical data on the volatility of day-ahead prices to create daily prices from the monthly price paths that we have created.

90. The following sub-sections explain how we created the price distributions for coal, gas and CO_2 prices. In Section III.E above, we explain that to model electricity prices, we require forecasts of both electricity demand and the plants that will be available to generate electricity. We could also have treated these inputs stochastically, just as we do commodity prices. However, we concluded that it was not necessary to do so, except with respect to variations in the balance between renewable and fossil-fired generation. The relative prices of gas, coal and CO_2 are the main determinants of the electricity generation that Eemshaven could produce and the free cash flows that the generation would create. Variations in the demand and the fossil-fuelled plant mix will have a much smaller effect on the profitability of Eemshaven and these variations are, in any event, much less volatile than commodity prices. Accordingly, stochastically modelling the capacity of each plant type and demand would have significantly complicated the calculations, without delivering a material increase in the accuracy of the results.

IV.B. Coal and gas price paths

91. We derive our coal and gas price paths from the following data:

    a. 2017 forward prices[79] for the period up to 2022;

    b. A forecast from the International Energy Agency ("IEA") for coal and gas prices from 2023 to 2040, since there were no forward prices available for this period ;

    c. Historical data on the day-to-day variation in coal and gas prices – their "volatility"; and

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[78] This *confidence interval* follows from the model's assumption that prices follow a log-normal distribution, under the simplifying assumption that there is no change in the mean (expected) price. Note that simply adjusting the price up and down by the volatility factor (3 €/unit = 20 €/unit x 15%) does not yield a 95% confidence interval. Although the volatility indicates limits on typical changes in prices, such changes can significantly exceed this level. It is necessary to rely on the statistical properties of log-normal distributions to arrive at the confidence interval.

[79] A forward price is simply the price for which gas or coal for delivery during a future period can be purchased on a given day.

d. Historical data on the correlation between movements in coal and gas prices.

92. For short- to medium-term coal and gas prices, we have relied on forward curves.[80]For long-term coal and gas prices, we rely on IEA 2016 World Energy Outlook, which was published in November 2016, since it is the last long-term commodity price forecast produced by an independent, widely respected, international institution before the valuation date.[81] From the 2016 World Energy Outlook, we have selected the New Policies scenario which forms the IEA's central case. The projections are only provided for spot years – in this case 2020, 2030 and 2040. For the years between 2020 and 2030 and again between 2030 and 2040, we have simply assumed a linear progression from one data point to the next ("linear interpolation") to derive annual prices. After 2040, we have projected annual prices starting from the value of prices in 2040 and updating for inflation.[82]

93. We note that the IEA scenarios were developed after the Paris Agreement on climate change had been reached, stating that "[t]he goals set out in Paris, and the measures that governments have announced to achieve them, significantly influence the projections in this year's WEO"[83] and "the underlying assumptions have been reviewed carefully to reflect the post-Paris expectations for international co-operation on climate change".[84] The IEA also says that the New Policies scenario "incorporates existing energy policies as well as an assessment of the results likely to stem from the implementation of announced intentions, notably those in the climate pledges submitted for KOP21".[85]

94. The volatility of coal and gas prices is a key driver of the range of prices that it is reasonable to consider for the future. In line with standard practice, we assume that their volatility, as of the valuation date, is a reasonable predictor of their future volatility and therefore we

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80 Specifically, we rely on forward curves from July 2017. Anyone carrying out a Fair Market Value assessment as of 9 October 2017 would have had to begin their modelling several months earlier and it is for this reason that we rely on forward prices from July 2017 rather than October 2017. In any event, the difference between the July and October forward prices for the period beyond to 2020, which is the first year that we model, is minimal.

81 None of the institutions whose forecasts we would consider using, such as the EC or the European Network of Transmission System Operators – Electricity, published scenarios in 2017.

82 The IEA forecasts are of spot prices, so prices for immediate delivery, rather than forward prices. Forward prices and spot prices converge as the time to delivery for the forward product shortens but they are generally not identical. The theory underlying the stochastic model that we use to generate the price paths requires the forecast to be of forward prices, which is then converted into different possible spot price paths. Accordingly, we converted the IEA spot prices into an equivalent set of forward prices using standard techniques to make this conversion, see Appendix B.2.i for details.

83 **Exhibit BR-32**, International Energy Agency, World Energy Outlook, 2016, p. 32.

84 **Exhibit BR-32**, International Energy Agency, World Energy Outlook, 2016, p.33.

85 **Exhibit BR-32**, International Energy Agency, World Energy Outlook, 2016, p. 31.

have based our volatility analysis on data from 2013 onwards.[86] We need information on the volatility of prices in both the short-term (a few months from any given starting point) and the longer term (up to several years into the future) – this is known as a “term-structure”. Prices tend to be more volatile in the short-term than they are in the long-term, because the market participants generally consider that over the longer term there will be time for the market to recover from the effects of a short-term shock. Incorporating a term structure for volatility enables us to capture this effect.

95. Gas and coal prices do not move entirely independently of each other. This is hardly surprising since the two fuels are often substitutes for one another: if gas prices increase, making the use of gas less economic, then coal prices may also rise as coal is used instead of gas. However, the correlation is not perfect for a number of reasons, such as:

    a. differences in the range of end uses for which gas and coal can be used, so that demand patterns vary, with gas demand being more seasonal than coal demand;

    b. gas prices varying from region to region, whereas coal prices tend to be the same globally, once transportation cost differentials have been taken into account; and

    c. most hard coal in Western Europe being imported via ship so that shipping costs, which depend on world trade conditions and oil prices, influence coal prices whereas the majority of gas is delivered via pipelines.

96. As with the volatility of each commodity price, and again in line with standard practice, we rely on the historical information on the short and longer term correlations between coal and gas prices as a reasonable prediction for their future correlation.

97. Values for the forward and forecast prices for coal and gas, the volatility term structure of coal and gas prices and the correlation term structure between gas and coal prices are the only parameters we need to derive a set of 100 appropriately correlated spot price paths for these commodities. The precise method that we use is described in Appendix B.2 but the outcome of the process is shown in Figure 5 and Figure 6 below. The solid dark blue line in these figures represents the mean or average of the price paths on each day, whilst the light blue line represents the median – on any day, 50% of the price paths will have a price higher than the median and 50% will have a lower price. The top end of the dark grey band shows the 26th highest daily price and the bottom end of the dark grey band shows the 75th highest daily price. Similarly, the top end of the light grey band shows the 6th highest daily

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[86] 2013 was the start of the third phase of the EU Emissions Trading Scheme. Since this phase had significantly different implications for power plants than the first two phases, we considered that the relationship between coal and gas prices might have changed at this point and, hence, that it would not be reasonable to extend our analysis further back in time.

price and the bottom end of the light grey band shows the 95th highest daily price. Both figures indicate that the bulk of the price paths lie within a reasonably narrow range for most of the period[87] but that there are some more extreme paths, particularly on the high price side.

[87] For example, for gas prices, the annual average differences between the 75th percentile price and the 26th percentile price are [redacted] €/MWh in 2025, [redacted] €/MWh in 2030, [redacted] €/MWh in 2040 and [redacted] €/MWh in 2050. See Harris-Hesmondhalgh Workpapers, Tables D.2 – Coal and Gas Price Simulation, Tab 'M_charting'.

FIGURE 5: GAS PRICE PATH DISTRIBUTIONS[88]

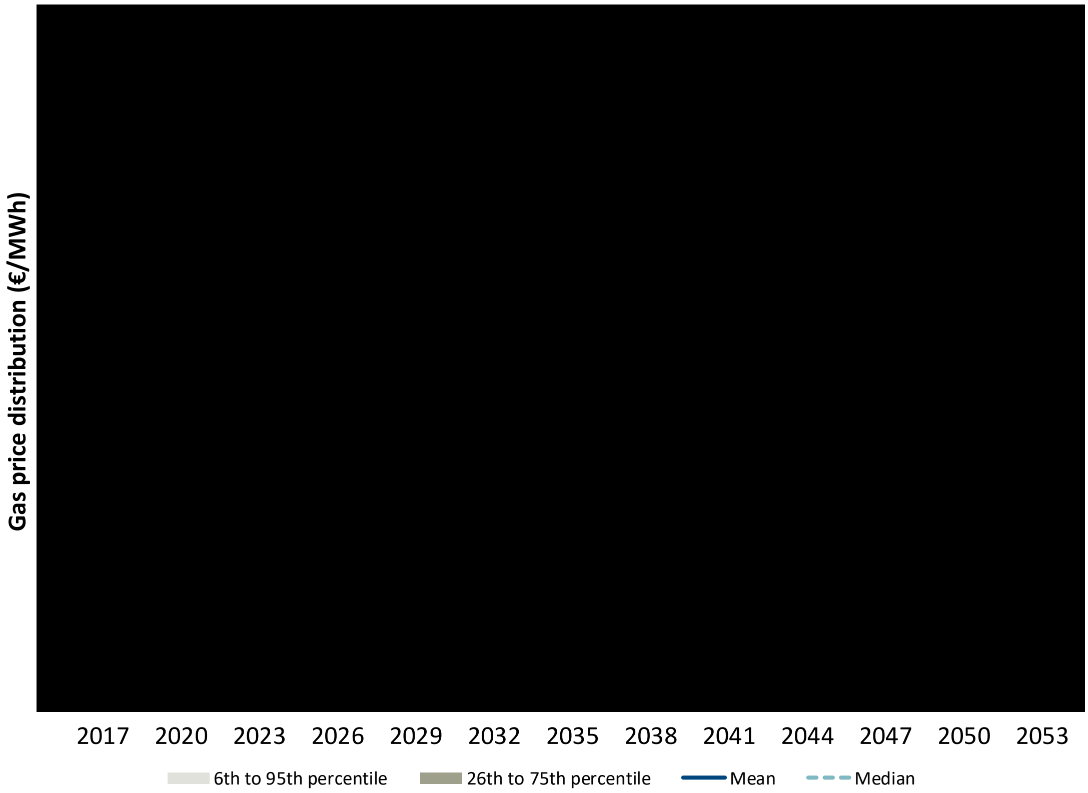
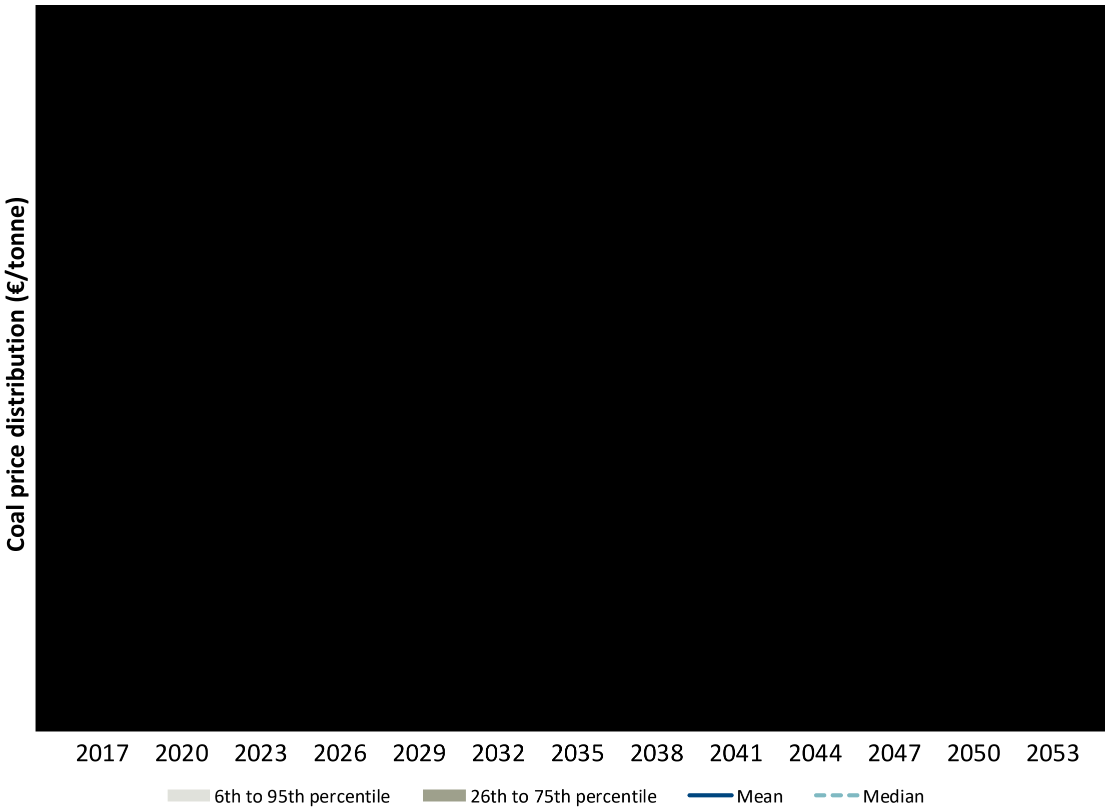


FIGURE 6: COAL PRICE PATH DISTRIBUTION[89]



98. The gas and coal prices shown in Figure 5 and Figure 6 are for the Dutch market. However, we also need coal and gas prices for other European markets because these are included in the electricity market model we use to project Dutch electricity prices. We assume that gas and coal prices for other markets can be derived from the Dutch gas and coal prices by adding on reasonable estimates of the costs of transporting the fuels from the Netherlands to the relevant market.

IV.C. CO_2 prices

99. Our approach to creating CO_2 price paths, is different to the approach we have used for gas and coal price paths. This is because CO_2 prices are driven more by policy decisions than by market forces. Specifically, the CO_2 price changes according to the number of CO_2 permits that are available each year. Whilst the general direction of the EU's climate change policy is known – the number of permits will be decreased over time – the precise trajectory that will be implemented is not yet fixed until 2054. There remains the possibility that additional measures will be introduced if the level of CO_2 emissions is not considered to be falling fast enough. For this reason, we have not included any correlations between CO_2 prices and coal/gas prices. In addition, as discussed above, coal prices tend to be global prices and so will not be affected to any significant degree by what happens to CO_2 prices in Europe since the European coal market is relatively small in global terms.[90]

100. We start from the forecasts contained in the same IEA report on which we rely for coal and gas prices.[91] In this case we rely on two of the scenarios contained in the report (the "450" and New Policies scenarios),[92] instead of only one (New Policies) as in the case of the coal and gas price paths. This is because the IEA CO_2 price scenarios reflect different policy developments that were considered possible at the valuation date and so we use them to

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88 Harris-Hesmondhalgh Workpapers, Tables D.2 – Coal and Gas Price Simulation, Tab 'M_chart'. Note that 'Commodity' in Table D.2.1 needs to be set to 'Gas' and VBA macro needs to be re-run.

89 Harris-Hesmondhalgh Workpapers, Tables D.2 – Coal and Gas Price Simulation, Tab 'M_chart'. Note that 'Commodity' in Table D.2.1 needs to be set to 'Coal' and VBA macro needs to be re-run.

90 According to the BP Statistical Review of World Energy 2020, in 2017 Europe accounted for only 8.5% of global coal consumption, and by 2019 its share had fallen to 7.2%. **Exhibit BR-33**, BP, Statistical Review of World Energy, 2020, p. 47.

91 **Exhibit BR-32**, International Energy Agency, World Energy Outlook, 2016, p. 45, which was published in November 2016 and so was the latest IEA forecast available.

92 There is a third scenario, Current Policies, but the CO_2 prices under this scenario are very close to those under the New Policies scenario. **Exhibit BR-32**, International Energy Agency, World Energy Outlook, 2016, p. 39.

determine the range of possible CO_2 price outcomes.[93] We use these two scenarios to create a distribution of possible CO_2 prices for each of the three years for which the IEA provides CO_2 prices (2020, 2030, and 2040). The 450 scenario incorporates the IEA's view of a high CO_2 price scenario and so we use it to set the upper limit[94] of the range of possible CO_2 prices, while the New Policies scenario represents the mean value.[95] These are the only two parameters that we need to be able to define our distribution of CO_2 prices. [96] We use the scenarios to create a distribution of possible CO_2 prices for each of the three years for which the IEA provides CO_2 prices.

101. We have also included a "policy ratchet" which means that CO_2 prices can only increase over time.[97] The rationale for imposing this ratchet is that it seems likely that if a price path sets off with a particular level of CO_2 prices, this reflects a world in which climate policy is focused on a particular pace of decarbonisation. Declining CO_2 prices would be inconsistent with such a policy. Since higher CO_2 prices tend to reduce the value of Eemshaven, imposing the policy ratchet is conservative because it may lead to an underestimate of the plant's actual loss in value.

102. All the IEA scenarios have the same CO_2 price for 2020. Hence, we do not have to pick from a distribution of prices for that year. For 2030, 2040 and 2050 we follow the procedure for creating a price path described in Section IV.A above to create 100 prices. We then rank the picked prices in each year from the one with the highest price to the one with the lowest price. So, in 2030, the price path with the highest price has rank 1, the path with the second highest price has rank 2 and so on. We repeat the exercise for the prices in 2040 and 2050.

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93 The third scenario (Current Policies) has CO_2 prices ([redacted] \$/tonne in 2015 prices for 2020/2030/2040) which are sufficiently close to the New Policies prices ([redacted] \$/tonne) to make it impossible to fit a standard distribution through these prices and those of the other two scenarios. This also means that the third scenario prices fall within the distribution of prices that we consider but that our approach enables us to consider higher CO_2 price possibilities than would be the case if we attempted to include the Current Policies prices. See *Ibid*.

94 More accurately, we assume that the 450 scenario prices are equal to the 97.5th percentile prices since there will always be the possibility of some outliers that are not captured by a scenario. This assumption defines the width of the distribution in terms of a 95% confidence interval, which is standard practice.

95 We do not adopt this approach for coal and gas prices because we rely on volatility levels derived from data available as of the valuation date to determine the width of the distributions. However, with a policy-driven price, such as CO_2 prices, historical volatility levels are unlikely to be a good predictor of the range of possible future CO_2 prices.

96 Following standard practice, we assume that they follow a "log normal" distribution, see **Exhibit BR-34**, Hull J.C., Options, Futures and Other Derivatives, 9th edition, pp. 322-323. Such distributions can be fully specified from only two parameters, the width of the distribution and its mean value.

97 Without the policy ratchet, a single CO_2 price path could incorporate rising prices for a time followed by falling prices.

The ratchet mechanism means that if, for example, a price path has rank 10 in 2030,[98] it cannot have a price in 2040 that has a lower rank than 10.[99] The ratchet also means that the price in 2040 must be equal to or higher than the price that the path had in 2030. Suppose that a price path has a price of 25 €/t in 2030 and is ranked 10th. If the price that we initially picked for that path in 2040 is 30€/t and it has rank 8, then we keep the price we initially picked. If, however, the price we initially picked for 2040 was only 22 €/t then we would replace our initial pick with the higher of 25 €/t (the 10th ranked price in 2030) and the price with rank 10 in 2040.

103. Once we have determined the prices for 2020, 2030 and 2040, we use linear interpolation to set the prices for the intervening years. Beyond 2040, we assume that the mean price will simply increase from its 2040 level in line with inflation and assume that the width of the distribution remains the same and apply the ratchet mechanism in 2050. We derive daily prices from the annual prices using the historical volatility of CO_2 prices.

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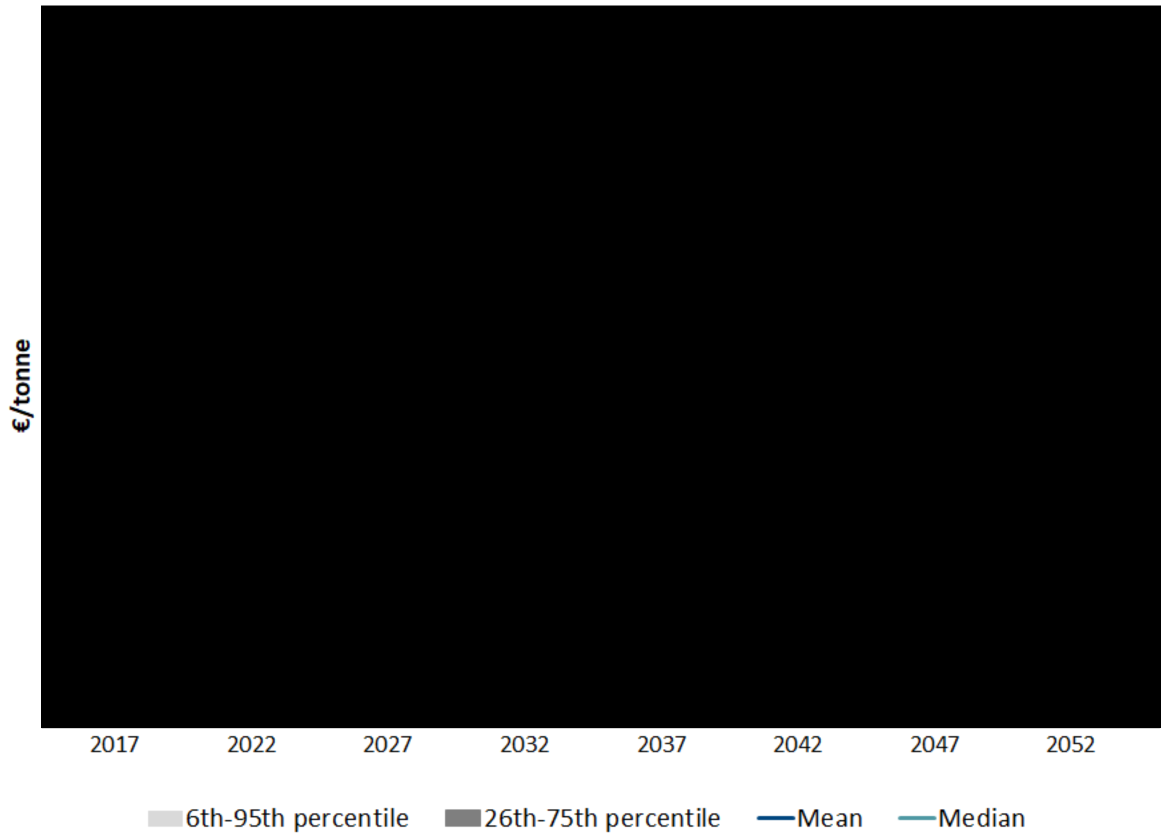
[98] We also rank the price picks in 2020 even though they all have the same value so that the ranking is random. However, we need to rank the 2020 prices in order to be able to apply the ratchet mechanism in 2030.

[99] The rankings can be thought of as reflecting possible policy paths. The fundamental assumption is that policies will never ease off i.e. drop to a higher rank or price, but can be tightened i.e. move to a lower rank.

FIGURE 7: CO_2 PRICE PATH DISTRIBUTION[100]



IV.D. Biomass Prices

104. When modelling biomass, we use a 2018 biomass price of [redacted], from RWE's "Eemshaven Cofiring Business Case".[101] We then increase this price with inflation.

105. Note that, unlike carbon, coal and gas prices, we do not perform any stochastic modelling of biomass prices, for two reasons. First, the historical price data we would need to be able to estimate correlations between biomass and other commodity prices is not available. Second, biomass prices do not affect damages. This is because Eemshaven stops burning biomass in 2027, before the Coal Ban takes effect.

V. Step 2: Electricity market modelling

[100] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

[101] **Exhibit BR-36**, RWE, Eemshaven Cofiring Business Case.

106. The revenues that Eemshaven could have been expected to earn over its remaining technical life are one of the key inputs in determining the loss in value it has suffered as a result of the Coal Ban. The plant earns revenues from selling its output into the Dutch electricity market. Accordingly, to estimate Eemshaven's future revenues it is necessary to:

a. Determine an appropriate set of assumptions regarding electricity demand and installed generation capacity, based on the information that would have been available at the valuation date (Section V.A, with further details provided in Appendix C);

b. Based on those assumptions, model how the Dutch electricity market might have been expected to develop until the end of 2054 , (Section V.B); and

c. Determine how those market developments would have influenced the output of Eemshaven and the revenues that it would have been expected to earn (Section V.C).

107. We have carried out the overall market modelling in conjunction with Baringa Partners ("Baringa"), a consultancy firm that specialises in electricity market modelling. We provided Baringa with the assumptions on commodity prices, plant capacities and demand that we wanted to be included in the market model. Baringa used this information to provide detailed electricity price projections,[102] for the actual and but-for cases. Baringa used PLEXOS® to perform its electricity market modelling. PLEXOS® is a commercially available third-party software widely used by electricity market participants including, for example, RWE and many transmission system operators.

108. We have taken the electricity prices produced by Baringa and used these to determine in detail how Eemshaven would have operated, taking into account its technical characteristics, and hence what revenues it would have earned and what operating costs it would have incurred.

V.A. Electricity demand and installed capacity

109. As discussed in Section III.E above, our estimate of the damages suffered by Eemshaven is based on data that would have been available in October 2017. We have, therefore, chosen to base our generating capacity and demand forecasts on the EU Reference Scenario 2016 ("EU Reference Scenario") published by the European Commission in August 2016.[103] The EU Reference Scenario was the scenario containing long-term, detailed, country-by country projections of generating capacity and demand produced by a reputable, independent

[102] A price for every four hour period of time from January 2020 until December 2054.

[103] **Exhibit BR-37**, European Commission, EU Reference Scenario, dated 15 July 2016. For more information visit: https://ec.europa.eu/energy/data-analysis/energy-modelling/eu-reference-scenario-2016_en.

institution that was published closest to the valuation date.[104] No such scenarios were published in 2017 by the EU or other respected international institutions.[105]

110. We chose to focus on the EU Reference Scenario because it is an independent, publicly available, view of the likely development of the European electricity market and so consistent with a Fair Market Value. For example, the EU scenarios are used to inform European energy policy decisions. The EU Reference Scenario is based on the assumption that the legally binding greenhouse gas and renewable energy targets for 2020 will be achieved and that the longer term policies agreed at EU and Member State level until December 2014 will be implemented.

111. The EU Reference Scenario provides assumptions for electricity demand and plant capacities by fuel type for every fifth year starting from 2015 and ending in 2050. For the intervening years, we have relied on linear interpolation. However, the EU Reference Scenario does not detail installed capacity and demand for all of the countries that are included in the market model used by Baringa. For installed capacity and demand projections of countries that are not included in the EU Reference Scenario or that are very distant from the Netherlands,[106] we relied on Baringa's proprietary Reference Case, which reflect Baringa's central or "best estimate" view of the evolution of European markets. Whilst it would have been preferable to use the same data source for all the countries modelled, the inclusion of data from Baringa Reference Case will not have any material impact on our analysis since the data are only used for markets that are remote from the Netherlands.

112. We deliberately rely mainly on a single capacity scenario for all the price paths, although we allow some variations in renewable capacity in response to CO_2 prices, as explained in the next sub-section. Adjusting capacities to reflect price movements can often lead to circularities - for example, if more renewable plants are assumed to be built in response to, say, high CO_2 prices then the likely outcome is that CO_2 prices will fall with the result that the decision to invest may no longer be justified. The alternative approach would have been to treat capacity additions as another stochastic variable. In order to include another stochastic variable, we would have had to increase the number of paths that we considered very considerably in order to ensure that we had a representative set of results. This would have added complexity to the calculations without materially increasing the accuracy of the results.

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[104] For example, the IEA World Energy Outlook scenario on which we rely for commodity prices does not contain such data.

[105] The next EU Reference Scenario was only published in 2020 and the next Ten Year Network Development Plan produced by the European Network of Transmission System Operators – Electricity was only published in 2018.

[106] Baringa models the whole of Europe but markets in countries such as Greece and Italy have essentially no impact on the Dutch market.

V.A.1. Renewable capacity

113. The level of commodity prices has an impact on the economic attractiveness of renewable energy plants, such as wind and solar plants: the higher the marginal cost of fossil-fired generation rises, the more the economics of renewable plants improve because they generally have very low or zero marginal costs. However, while the level of commodity prices is a driver of changes in renewable capacity in the medium term, in the long term it is the decarbonisation agenda and the targets for renewable capacity that drive the level of renewable capacity. Accordingly, while we take a single view on the capacity of renewables in 2050, in the years prior to that we adjust the share of renewable capacity away from that predicted in the Reference Scenario as commodity prices vary between price paths. We adopt this approach not just for the Netherlands but also for all the immediately surrounding markets.

114. If commodity prices in a particular price path are above the mean level of commodity prices, we increase the level of renewable capacity that is constructed (and then remains operating). Similarly, as annual commodity prices move below the expected mean level of commodity prices, we decrease the level of renewable capacity. To maintain the original capacity margin and ensure there are sufficient flexible plants available to deal with fluctuations in renewable output, we also adjust the capacity of fossil-fired plants and demand-side options. Further details of this methodology are described in Appendix C.2.i.b.

V.A.2. Differences between the actual and but-for cases

115. In almost all respects, the electricity market assumptions for the but-for and actual cases are identical. However, there is, of course, a difference in the plant mix in the Netherlands in the two cases. In the but-for case, Amer remains available until the end of 2032 and Eemshaven and the two coal plants in Maasvlakte [107] remain available until 2054, whereas there are no Dutch coal plants after 2030 in the actual case. We assume that the coal capacity that is closed in the actual case is replaced by new gas-fired plants with the same capacity.

V.B. Overall market modelling

116. Most electricity markets, including that in the Netherlands, have a day-ahead market in which generating plants bid to be dispatched and are selected in order of increasing bid prices until demand for each hour is met. The most expensive plant whose bid is accepted sets the price for that period: this is known as marginal pricing.

[107] Uniper's MPP3 and Riverstone's (formerly ENGIE's) Maasvlakte power plant. See Section II.B above.

117. Baringa uses PLEXOS® to simulate this process by dispatching plants in order of their "marginal generation costs", starting from the cheapest and working up through increasingly expensive plants until demand is met (the "merit order"). By marginal generation costs we mean the costs that a generator incurs per unit of output produced, namely: fuel costs (including any relevant transportation costs), CO_2 costs, and any other costs that vary with output.[108]

118. Due to the long period and the number of price paths for which we require electricity prices (out to then end of 2054),[109] Baringa has not modelled prices for every hour since this would be unfeasibly time consuming. Instead, Baringa has divided each year into four-hourly periods, with 2,190 periods for each year. It has then calculated the average demand for each period and determined the price for that period.

119. To project yearly electricity prices for the Netherlands, Baringa modelled the development of the entire European electricity market out to 2054. It is important to model a wider region than just the Netherlands because the Dutch electricity market is directly connected to the markets in Belgium (two connections), Germany (four connections), Denmark (one connection), Norway (one connection) and Great Britain (one connection) and connected to France through Belgium and Germany.

120. Baringa has produced two sets of 100 electricity price paths. One set of price paths for the but-for case (excluding the Coal Ban), see Figure 8, and one set of price paths for the actual case out to 2030 (including the Coal Ban). Figure 9 demonstrates that the differences between the electricity prices in the but-for and actual electricity prices are very small throughout the 2020's and, indeed, are [redacted] until [redacted]. [redacted]

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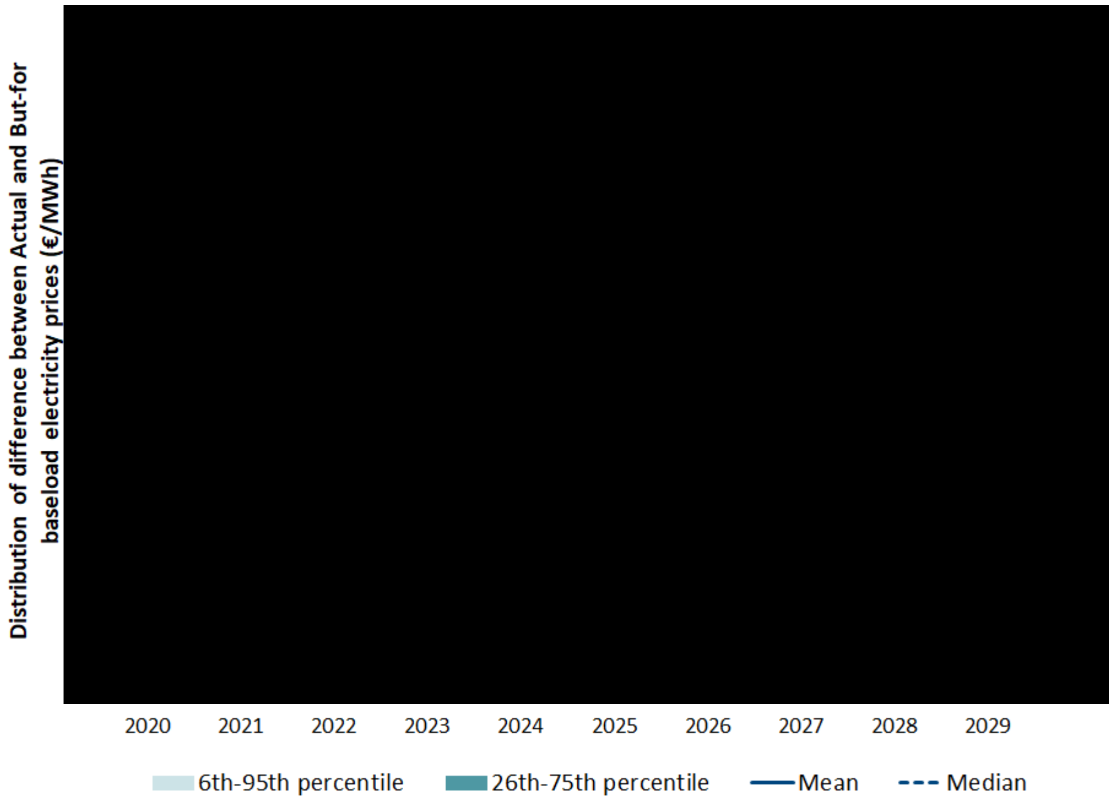
[108] For example, for coal plants, other costs varying with output include the costs of running the milling machines to prepare the coal for use and the costs of the chemicals needed to operate the "scrubbers" that remove sulphur dioxide from the exhaust gases.

[109] We do not model the market for the period 2017 to 2020 because the actual and but-for cases would be the same and Eemshaven could have hedged its output and commodity costs for this period using contemporaneous forward curves, which show a positive clean dark spread for a plant with Eemshaven's efficiency.

FIGURE 8: BUT-FOR ELECTRICITY PRICE PATHS[110]

FIGURE 9: DIFFERENCES BETWEEN BUT-FOR AND ACTUAL ELECTRICITY PRICES[111]



V.C. Modelling the operation of Eemshaven

121. To calculate the loss in value of Eemshaven that Claimant has suffered as a result of the Coal Ban, it is important to take into account the specific characteristics and costs of Eemshaven. However, the electricity market modelling carried out by Baringa uses generic assumptions for coal plants that vary by their age and size. This is entirely appropriate to avoid distorting the outcomes (electricity prices) by including specific assumptions only for Eemshaven but it means that it would not be reasonable to use the coal plant output data from the Baringa runs directly in our financial model.

122. Instead, we assume that the expected operation of Eemshaven can be determined simply on the basis of the projected electricity prices and its specific operating costs. This is a standard assumption when stochastically modelling power plants because it significantly simplifies the calculations without materially affecting the outcome. The reason that there is little or no impact is because on those occasions when Eemshaven is the marginal plant it will not make any contribution to its commodity margin. Hence, whether it operates or not has essentially no impact on the level of free cash flows it produces.

123. We have built a model that determines the output pattern of Eemshaven that maximises its commodity margins, given Baringa's forecast electricity prices, as well as coal and CO_2 prices and other operating constraints. In Section V.C.1, we explain how this model works and the results that it produces. Note that the assumptions in the model on how Eemshaven would operate vary depending on whether Eemshaven is burning only coal (after 2027) or a mixture of subsidised biomass and coal (from 2020 to 2027). We explain the differences in Section V.C.2.

V.C.1. Plant dispatch model

124. We use our plant dispatch model to calculate the annual commodity margins made by Eemshaven for each price path under the actual and but-for cases. To do this, we first calculate the marginal generation costs for each 4-hour price period based on:

a. the coal and CO_2 prices that apply in each period;

b. the maximum output of the plant, which varies with the prevailing temperature;

c. the efficiency of the plant, which depends on its maximum output; and

[110] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

[111] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

d. variable operating costs.[112]

125. The difference between the electricity price for a period and the marginal generation costs of a plant is known as the "clean dark spread" or "CDS".[113] At its simplest, a plant will generally want to operate and produce electricity whenever the CDS is positive and shutdown whenever it is negative. However, it is also necessary to take into account a number of technical constraints to determine, in practical terms, how a plant would actually want to run.

126. Since each period represents four hours, the decisions on when to operate a plant[114] and when to shut it down are relatively straight-forward because the minimum run time for Eemshaven is [redacted] and the minimum down time is [redacted].[115] However, every time a plant starts up, it incurs additional costs: it has to burn fuel just to get the turbines spinning before any useful electricity is produced and also has to use oil to start the combustion process. In addition, the rate at which a plant can increase its output is limited – this restriction is known as a "ramping constraint". The start-up costs and ramping constraint have to be taken into account in assessing whether it is profitable for the plant to generate or not. The more consecutive periods there are with positive CDSs, the more likely it is that the commodity margins from these periods will outweigh the start-up cost. In practice, this means that there are no occasions when the plant would want to run for only [redacted] and, hence, the minimum run time constraint has no impact on the results.

127. It can sometimes be cheaper to run the plant through a four hour period that has a slightly negative CDS because the losses involved are less than the start-up cost that would otherwise be incurred. In such a situation, it is generally cheaper to reduce the output of the plant to its minimum stable operating level, even though the efficiency at which the plant produces electricity will be lower than if it was producing its full output.

128. In addition, the coal and biomass that are burnt by Eemshaven are delivered to the plant by ship and RWE Eemshaven has a contract with the adjacent harbour to secure berths for these ships. [redacted]

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112 We consider fuel transportation and handling costs as well as other variable costs such as cooling water.

113 "Clean" because it takes into account the emissions costs associated with generating, "dark" because it relates to a "coal plant" and "spread" because it measures a difference between two quantities, the electricity price and the plant's costs.

114 Eemshaven consists of two identical units. We model the operation of a single unit and assume that the other unit would operate in an identical fashion.

115 We do not explicitly impose a minimum runtime of [redacted], as it is only in the rarest occasions that the plant would optimally want to run shorter than [redacted]. It only happens 32 times across all 100 simulations, at most in 6 out of 76,704 four hourly periods between 2020 and 2054 in a given simulation.

[redacted].[116] We incorporate both facets of the harbour contract into the dispatch model.[117]

129. We use a standard mathematical technique, called mixed integer programming, to take all these constraints into account in determining in which periods Eemshaven will run and in which periods it will be shut down.[118] We assume that there will be a [redacted] day maintenance period each [redacted].[119] In addition, to account for unplanned outages, i.e. breakdowns, we apply a [redacted]% reduction to the results for each block based on RWE's expectations in 2017.

130. As an example of the output of the dispatch model, Figure 10 plots the CDS in the first 3 months of 2030 for one price path (dark blue line, right axis) against the optimal running pattern generated by our dispatch model (light blue columns, left axis).

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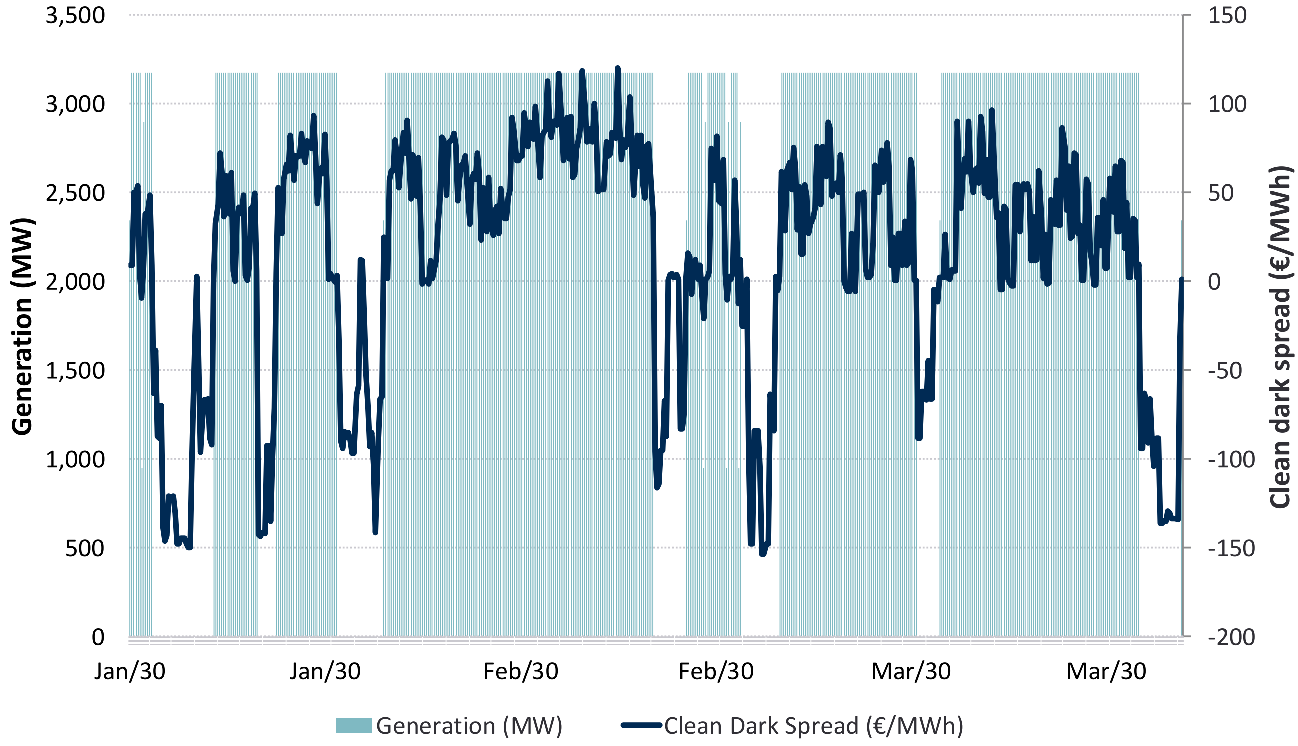
[116] **Exhibit BR-38.D**, RWE, Land Lease Akte II, dated 11 March 2009, article 22.8 and **Exhibit BR-38.A**, RWE, Schedule 22, dated 17 February 2009

[117] See Appendix D.3 for details.

[118] We explain the model in detail in Appendix D. [redacted] days represents an average of a long overhaul every [redacted] years and shorter outage periods in the intervening years.

[119] **Exhibit BR-39**, RWE, Cluster Eemshaven, MTP 2017 (2018-2022), dated 8 September 2017.

FIGURE 10: EXAMPLE GENERATION PATTERN[120]



Notes:
4 hourly periods (01/01/2030 - 31/03/2030).

V.C.2. Biomass subsidies

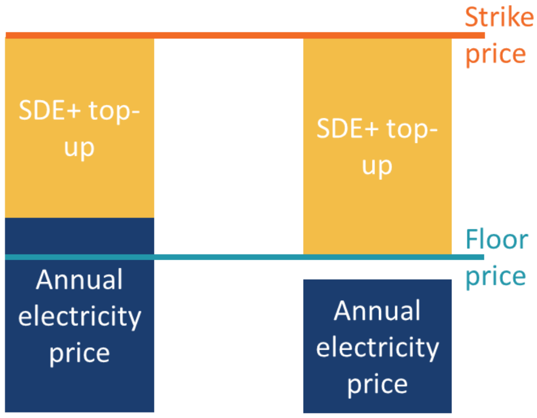
131. Under the *Stimulering Duurzame Energieproductie+* (SDE+) scheme, Eemshaven currently receives subsidies when it burns biomass instead of coal.[121] The SDE+ provides plants burning biomass with a "top-up" to electricity market prices for a pre-determined volume of electricity produced from renewable sources based on a 'strike price' that is designed to reflect the additional costs a plant incurs when burning biomass. The strike price and the maximum electricity volume that will be supported are specifically stipulated in each subsidy package awarded. As shown on the left-hand side of Figure 11, the top-up amount paid for a given year is normally equal to the difference between the strike price and the annual average electricity price for the Dutch market. However, if the average annual electricity

120 Harris-Hesmondhalgh Workpapers, Tables E.3 –Dispatch Model inputs.

121 **Exhibit BR-12**, National Enterprise Agency of The Netherlands, Eemshaven: Decision to Grant a Subsidy, dated 30 November 2016.

price falls below a floor price, as shown on the right-hand side of Figure 11, the top-up is limited to the difference between strike price and the floor price.[122]

FIGURE 11: OPERATION OF THE SDE+ SCHEME



132. Eemshaven has a single SDE+ scheme that will run until 2027. The details of the scheme, which were agreed before October 2017, are shown in Table 1. Even though the Coal Ban does not take effect until after Eemshaven's biomass subsidy has ended, it is a relevant consideration in calculating Eemshaven's loss in value because:

   a. the cash flows under the but-for and actual cases differ during the biomass subsidy period due to effects such as accelerated depreciation in the actual case because of Eemshaven's early closure, and

   b. we take into account the possibility that Eemshaven might wish to close before 2030 even absent the Coal Ban, under price paths that are particularly unfavourable to coal plants.

133. For both these reasons, it is important that we estimate the cash flows under the actual and but-for cases accurately during the period 2020-2030. For the period prior to 2020, Eemshaven would have been able to hedge its position based on the contemporaneous forward curves. Since the forward curves indicate that it would have been profitable for the plant to operate i.e. the clean dark spreads are positive, it follows that the cash flows in the actual and but-for cases would be identical and hence can be ignored when determining the loss in Eemshaven's fair market value as a result of the Coal Ban.

[122] Suppose the strike price is [redacted] €/MWh and the floor price is [redacted] €/MWh, If the average annual electricity price is equal to [redacted] €/MWh, the "top-up" is equal to [redacted] – [redacted] = [redacted] €/MWh. However if the average annual electricity price falls below the floor price to, say, [redacted] €/MWh, the "top-up" is only equal to the difference between the strike price and the floor price [redacted]-[redacted] = [redacted] €/MWh.

TABLE 1: EEMSHAVEN SDE + SUBSIDY[123]

Subsidy number		[1]	See note	SDE1693517
Original start date		[2]	See note	[redacted]
Expected start in Oct 2017		[3]	See note	[redacted]
Duration	years	[4]	See note	8
End date		[5]	[3]+[4]	30-Apr-2027
Annual generation limit	MWh	[6]	See note	1,788,889
Biomass capacity	MW	[7]	See note	256
Strike price, nominal	€/MWh	[8]	See note	[redacted]
Floor price, nominal	€/MWh	[9]	See note	[redacted]
Maximum total subsidy	€ mln	[10]	See note	[redacted]

Notes and sources:
[1], [4], [6], [7], [10]: Exhibit BR-73, National Enterprise Agency of The Netherlands, SDE Projects Available in Autumn 2016.
[2], [8], [9]: Exhibit BR-12, National Enterprise Agency of The Netherlands, Eemshaven: Decision to Grant a Subsidy.
[3]: Inputs from RWE.

134. For the period between 2020 and 2027, the plant dispatch model described in the preceding sub-section takes into account the impact of these biomass subsidies by assuming that Eemshaven will factor the subsidy that it received in the previous year into the biomass spread that it considers when deciding whether or not to burn biomass in a particular period.

135. Eemshaven has an environmental permit,[124] which only allows it to burn 800,000 tonnes of biomass every year. This prevents it from reaching its full subsidy level of 1.789 TWh, although it comes very close to this level.[125] Consequently, the dispatch model seeks to optimise when to burn biomass and when to burn coal subject to this limit. We discuss the optimisation models for the biomass subsidy period in greater detail in Appendix D.

136. [redacted]. We agree that this is a reasonable assumption.

[123] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

[124] **Exhibit BR-10**, RWE, Environmental Permit Eemshaven, dated 11 December 2007, pp. 90-92 for the granted request and **Exhibit BR-11**, KEMA Consulting, Application for Incorporation Permit, dated 20 December 2006, pp. 48-49 for the request details, see Table 3.1.2.

[125] Burning 800,000 t of biomass with an energy content of [redacted] and a maximum efficiency of [redacted] results in $800{,}000\ t \times$ [redacted] = [redacted] generated electricity from renewable energy sources.

V.C.3. Data transferred to the financial model

137. The following information from the plant dispatch model for each year, and for the 100 price paths, for both the but-for and actual cases is included in the financial model:

a. The commodity margins, which are the electricity revenues, including subsidies, in the year minus the costs of generating electricity, including fuel costs as well as other variable costs;

b. Number of hours of generation, since some of the fixed costs in the financial model depend on the number of running hours; and

c. Additional harbour fees [redacted].[126]

[126] See also ¶128 above for a more detailed explanation of the harbour contract.

VI. Step 3: Financial modelling

138. In this section, we describe the steps we take to derive Eemshaven's cash flows from the commodity margins produced in the previous step. We also discuss how we derive and apply a discount rate, which we apply to the cash flows to arrive at the FMV.

VI.A. Determining the cash flows

139. To calculate cash flows, we first add trading revenues to the commodity margins. We then deduct:

a. Additional operating costs, including corporate overhead costs;

b. Taxes; and

c. Additional capital expenditures required over the operating life of the plant.

140. To arrive at the "free" cash flows, economists consider all cash inflows and outgoings to the project, including those coming from operating activities – included in sub-bullets a) and b) above - and those from investment activities, included in sub-bullet c).

141. RWE Generation SE – which is the generation division of RWE AG – produces forecasts of the likely revenues and costs associated with operations for over 70 individual plants, including Eemshaven, in the course of its normal business. RWE Generation SE refers to these forecasts as Station Contribution Outlook or 'SCOut' reports.[127] [redacted].[128] Each SCOut report forecasts revenues, investment needs and operating costs for the next [redacted] years.

142. It seems reasonable to assume that any prospective buyer would have access to the most recent SCOut report as part of a 'due diligence' process, and in particular would base its valuation on the data in the October 2017 SCOut report. Accordingly, this report is one of the key data sources on which we rely to forecast cash flows.[129]

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[127] **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017.

[128] **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017.

[129] SCOut was published on 10 October 2017, one day after the valuation date of 9 October 2017. The information on which SCOut relies was available some time in advance. For example, SCOut performs its analysis based on market pricing data as of [redacted]. We would expect a third party buyer to have

VI.A.1. Trading revenues

143. In addition to selling electricity, RWE generates revenues from trading the coal, CO_2, gas and electricity that are needed for, or generated by, RWE's plants. This is a common practice in the energy industry, often referred to as 'Asset Backed Trading'.[130] RWE refers to this as Commercial Asset Optimisation or "CAO".[131] The reference to "Asset" in the names is because the trading that is carried out is associated with physical assets – in this case power plants.

144. As noted in Section I.A, we have been instructed to value losses based on a FMV perspective. FMVs look at the price that a buyer would be willing to pay for an asset. Hence, the question arises whether a buyer would consider CAO revenues when valuing Eemshaven. Potential purchasers who do not own any other plants, and have no other trading operations, would likely assume significantly lower CAO revenues than those that RWE could achieve. However, potential purchasers with a portfolio of plants would likely value CAO revenues at similar levels to RWE. This means that Eemshaven would be worth more to a larger, more sophisticated buyer and, hence, that the successful bidder would be such a buyer.[132] We conclude, therefore, that the calculation of the FMV should include the CAO revenues.[133]

145. CAO revenues arise as Eemshaven operations allow RWE to exploit price differentials, or arbitrage, to increase its profits.[134] We give a more detailed example in Appendix E, in which asset-backed trading involves 'time arbitrage'. Other forms of asset-backed trading include geographic arbitrage, where traders exploit price differences in a commodity at different locations, technical arbitrage, where a trader can take advantage of price differentials for different qualities of a commodity, and production arbitrage, where firms can vary physical production to exploit price differences in the underlying commodities.[135]

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access to the same information as of 9 October 2017. See **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017, pp. 47-48.

130 **Exhibit BR-41**, Basteviken, M., Pearson-Woodd, N., Asset-Backed Trading in the Energy and Resources Sector, International Tax Review, dated 5 March 2019.

131 **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017, pp. 127-131, 135.

132 Not least, precisely because it would factor profits from trading into the value it placed on Eemshaven whereas a company with no other assets would not do so. The higher value would make it more likely that RWE would accept the sophisticated company's bid.

133 Our analysis takes into account CAO revenues net of costs associated with trading. See **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017, p. 127.

134 **Exhibit BR-42**, Corporate Finance Institute, Arbitrage.

135 For a full description of Asset Backed Trading, see **Exhibit BR-41**, Basteviken, M., Pearson-Woodd, N., Asset-Backed Trading in the Energy and Resources Sector, International Tax Review, dated 5 March 2019. [redacted]

146. In practice companies such as RWE, which own several power plants, carry out this kind of trading optimisation across all their plants, rather than on a plant-by-plant basis. They will also typically carry out more complex trades, involving multiple commodities and geographies. Trading activities are an important part of the revenues of a sophisticated power generator, such as we assume would be the most likely willing buyer of Eemshaven.

147. We model commodity prices and commodity margins from 2020 onwards. Hence, for each of the 100 commodity price paths, we need to forecast CAO revenues from 2020 onwards. Moreover, the forecast CAO revenues need to be consistent with the commodity margins we forecast.

148. The October 2017 SCOut report includes estimates of the CAO revenues to be allocated to Eemshaven for the period [redacted].[136] These forecasts may not be consistent with the commodity price paths that we model. However, the October 2017 SCOut forecasts still provide a useful basis for establishing the relationship between CAO revenues and commodity margins. For the period [redacted] the ratio between CAO revenues and commodity margins [redacted].[137] Hence, it seems reasonable to suppose that this relationship would endure, and that future CAO revenues [redacted], and the plant revenues, [redacted]. Accordingly, we forecast CAO revenues for the period 2020-2054 based on the [redacted]. Naturally, CAO revenues cease after the plant ends operations.

VI.A.2. Fixed operating costs

149. Eemshaven, like other coal-fired plants, has two types of operating costs: variable costs, which vary with the amount of electricity produced; and fixed costs, which are largely independent of the plant's output. The commodity margins, which are the starting point for our financial model, already deduct the variable costs. These are mainly the cost of coal and

[redacted]

136 [redacted]

137 Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H18. We find that CAO revenues account for approximately [redacted] of EEM commodity margins.

CO_2 permits.[138] Accordingly, in the financial model, we need only to deduct fixed costs.[139] Fixed operating cost items include grid fees, environmental fees, the cost of the land lease, property taxes, salaries, and maintenance costs.

150. We base our operating cost forecasts on the October 2017 SCOut report.[140] [redacted]. There are a number of reasons why we need forecasts of some of the individual operating costs in our model.

151. [redacted], the land lease and property taxes, [redacted]. We discuss these items in more detail below.

152. Second, not all the notionally 'fixed costs' are fully independent of plant output. That is, some costs are only "semi-fixed". Some of the operating costs can vary depending on whether the plant is running for a relatively high or low number of hours in a year. For example, if the plant is consistently running for a lower number of hours, it will incur lower maintenance costs because maintenance is normally only required after a plant has operated for a fixed number of hours since its last overhaul. As Table 2 illustrates, RWE has provided us with data on the percentage of savings that is possible, based on the number of running hours a year, for specific types of cost. In particular, Eemshaven:

- [redacted]
- [redacted]
- [redacted]
- [redacted]

138 Harris-Hesmondhalgh Workpapers, Tables E.1 – Dispatch model, Table E.1.3.

139 The October 2017 SCOut report refers to fixed operating costs as "Total Controllable Costs" or "TCC". The October 2017 SCOut report refers also to "Internal Service Charges" or "ISC". We understand that these charges correspond to a cost category that is applicable to German plants but not to Dutch plants.

140 **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017 pp. 45, 47 and 48, "Total Controllable Costs/ ISC".

153. [redacted][141] We have reviewed these numbers, and find the savings as a function of operating hours to be reasonable.[142]

TABLE 2: VARIATION OF 'FIXED' COSTS WITH RUNNING HOURS[143]

		Running hours as share of yearly hours
Cost savings		[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

154. We forecast specific categories of costs based on the totals in the SCOut report, assuming that the share of individual costs will be the same as for the years 2016 and 2017, for which we have a breakdown of operating costs.[144] First, we remove the costs of property taxes and the land lease, which we model separately.[145] Then we apply the average 2016/2017 share of each cost to the remaining operating costs from the SCOut report, to obtain forecasts of individual operating cost categories. For example, staff costs averaged [redacted]% of total operating costs in 2016/2017. We assume that staff costs continue to represent [redacted]% of total operating costs from 2018 onwards. Table 3 below illustrates the percentage of each type of operating cost that we apply.

141 [redacted]

142 Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H24.

143 Harris-Hesmondhalgh Workpapers, Tables H – Financial Model.

144 Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H26.

145 The exact amount of property taxes to deduct depends on the property taxes that RWE expected to pay when preparing SCOut. We infer the expected payments as the values recorded for the but-for case in our model for the period 2020-2022. See Harris-Hesmondhalgh Tables H – Financial Model, Table H26, Table H27, and Table H28.

TABLE 3: SHARE OF OPERATING COSTS[146]

			Annual Costs, € mln		Share of costs, %		Average
			2016	2017	2016	2017	2016-2017
			[A]	[B]	[C]	[D]	[E]
							Average
					[A]/[9][A]	[B]/[9][B]	([C],[D])
Grid fees	[1]	Table H26	[redacted]				
Operations costs	[2]	Table H26	[redacted]				
Nature measures	[3]	Table H26	[redacted]				
Staff	[4]	Table H26	[redacted]				
Maintenance costs	[5]	Table H26	[redacted]				
Facility related costs	[6]	Table H26	[redacted]				
Several other smaller costs	[7]	Table H26	[redacted]				
Depreciation of stored goods	[8]	Table H26	[redacted]				
Total operating costs net of land lease costs and property taxes	[9]	Sum ([1]-[8])	[redacted]				

155. Having 'disaggregated' the SCOut operating cost forecasts into individual cost elements, we remove the non-cash item that accounts for the depreciation of unused stored goods.[147] We then forecast all the other costs assuming that they increase with our forecast of inflation. Finally, for each commodity price path and year, we adjust each semi-fixed operating cost based on the number of hours the plant runs.

156. Until 2029, operating costs are very similar in the actual and but-for cases. The small differences relate to the lower property tax payments.[148]

VI.A.3. Land lease

157. RWE has signed a [redacted]-year lease [redacted].[149] We forecast the annual land lease costs based on

[146] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model.

[147] The accounts and the SCOut report refer to these costs as "Afa Gangigkeiten". See Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, and **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017.

[148] Property taxes are based on the book value of the assets. Since we apply accelerated depreciation in the actual case relative to the but-for case, book values and hence property taxes are lower in the actual case than in the but-for case. See Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H22 and Table H23.

[149] See **Exhibit BR-38.C**, RWE, Land Lease Akte I, dated 16 March 2009, art 1.2.

the cost per square meter set out in the contract.[150] We apply a corresponding yearly price increase factor of [redacted]%.

158. In cases where Eemshaven closes, RWE would logically consider terminating the land lease, so as to avoid the associated costs. However, the decision to terminate the land lease involves three main factors:

a. First, if Eemshaven chooses to terminate the lease before [redacted], it will have to pay a fee. [redacted].[151]

b. Second, if Eemshaven terminates the land lease, it has the right to buy the land [redacted].[152]

c. Third, terminating the lease and fully dismantling the plant would relieve Eemshaven of the obligation to pay future land lease costs, as well as some property taxes and some other fees. In practice, these avoided costs are relatively small, that is, in the order of [redacted] per year as of 2020. [153]

159. Hence, in each year, Eemshaven would logically compare the cost of the termination fee and the cost of buying the land to the value of the land acquired and the avoided future costs.[154]

160. We find that the optimal time for Eemshaven to terminate the land lease and buy the land is [redacted].[155] If Eemshaven terminated the lease after this date, then the increase in the price of buying the land is larger than the reduction in the avoided lease payments. It would not be optimal for Eemshaven to terminate before [redacted], because waiting another year reduces the termination fee by more than the avoided lease payments.[156]

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[150] **Exhibit BR-38.C**, RWE, Land Lease Akte I, dated 16 March 2009, art. 9.1. The first land lease payment as of 2020 is [redacted]. See Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H27.

[151] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H27.

[152] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H27.

[153] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H28.

[154] In other words, Eemshaven has two options every period: an early termination and payment of a fee or continuing with the lease. By paying the fee, Eemshaven then has the option, but not the obligation, to purchase the land. [redacted]. See Harris-Hesmondhalgh Tables H – Financial Model, Table H27.

[155] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H27.

[156] [redacted]. Tables H – Financial Model, Table H27.

161. Note that the optimal year in which to buy the land is independent of the actual plant closure date, and so is the same in the actual and but-for cases. Hence, the choice has no effect on damages.

162. Additionally Eemshaven incurs costs in using the harbour to unload coal for use in the plant. The fee consists of a payment per ship, and so is broadly a variable cost. [redacted]

VI.A.3.i. Property taxes and other taxes

163. Eemshaven pays property taxes and various other taxes. Property tax payments are calculated with reference to the value of the land and buildings multiplying by the property tax rate of 0.75%.[160] We estimate the value of the land by reference to Eemshaven's lease, by assuming that the site's owner receives lease payments in perpetuity, and then computing the present value of the lease payments, using a discount rate appropriate to Eemshaven.[161] In addition, we also include the value of other land reported in the accounts.[162]

164. We use the value of the buildings from Eemshaven's accounts. We assume that the buildings are unique to the operations of the power plant, and hence fully depreciate them by the

[157] **Exhibit BR-38.D**, RWE, Land Lease Akte II, dated 11 March 2009, art. 22.8.

[158] **Exhibit BR-38.D**, RWE, Land Lease Akte II, dated 11 March 2009, art. 22.8 and **Exhibit BR-38.B**, RWE, Schedule 23, dated 17 February 2009

[159] Harris-Hesmondhalgh, Tables H – Financial Model, Table H9 and Table H27.

[160] **Exhibit BR-43**, Municipality of Eemsmond, Real Estate Tax. [redacted] However, we expect that in the event of particularly high or particularly low commodity prices and, respectively, low/high plant values, the plant owner and the municipality would renegotiate the property tax basis so that the tax payments better reflect the value of land and buildings. Hence, we calculate property tax payments by reference to the value of land and buildings payments over time, which remain stable across price paths.

[161] Financial theory indicates that the value of an asset is the value of the cash flows it can generate over time, after adjusting these cash flows for their risk and uncertainty. We assume the land's owner can receive payments equivalent to Eemshaven's payments over time.

[162] Harris-Hesmondhalgh Workpapers, Tables H - Financial Model, Table H28. The land lease includes an annual inflation factor of [redacted]%. See Harris-Hesmondhalgh Workpapers, Tables H - Financial Model, Table H27 and Table H28.

time the plant closes.[163] This assumption will tend to underestimate damages, relative to an assumption that the buildings depreciate independently of the operation of the power plant. This is because linking depreciation to the operation of the power plant means that in the actual case the buildings become obsolete earlier than in the but-for case. Hence every year the building-related portion of the tax payments are lower in the actual case than the but-for case, reducing damages.

165. Eemshaven's accounting data combines property taxes and other taxes in a single category. Based on the analysis of property taxes above, we back out the portion of the overall tax amount that relates to other taxes. We understand that other taxes include taxes on energy used for own buildings, and water charges. As explained in the preceding sub-section, we assume that, regardless of the year in which it closes, Eemshaven will retain the site. Based on discussions with RWE, we understand that retaining the site will result in Eemshaven incurring [redacted]% of its other tax payments after closure.[164]

VI.A.4. Overhead costs

166. A potential buyer of Eemshaven would consider the effect of the acquisition on its corporate overhead costs. Overhead costs are expenses incurred to support the business that are not directly related to a specific product or service – in this case generating electricity from coal. The costs of the CEO and the board, legal and human resources, office rent and insurance are all typical examples of overhead costs.

167. Clearly, acquiring a plant such as Eemshaven would only affect some types of overhead costs. For a large buyer, it seems unlikely that the costs of the CEO or the costs of office rental would increase as a result of the acquisition of Eemshaven. To estimate the increase in a potential acquirer's overhead costs as a result of purchasing Eemshaven, we consider how RWE treats overhead costs.

168. RWE divides its overhead costs into central business unit (BU) costs.[165] RWE estimates that, on closing Eemshaven, around [redacted]% of the overheads allocated to Eemshaven would be eliminated.[166] This implies that, upon acquiring Eemshaven, a buyer's overhead would

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163 Under some commodity price paths, Eemshaven shuts down early in the actual and/or the but-for case. In these instances, we assume Eemshaven fully depreciates the remaining book value of the buildings in its last year of operation, which means that Eemshaven does not incur taxes on the buildings after its closure.

164 Harris-Hesmondhalgh Workpapers, Tables H - Financial Model, Table H28.

165 [redacted]

166 **Exhibit BR-44**, RWE, Consideration of Overhead Costs When Evaluating Assets and Contracts, dated 30 September 2015.

increase by the same amount. For example, suppose a BU had overhead of 100, and allocated 30 of the overhead to Eemshaven. Upon closure of Eemshaven, the overhead would fall by [redacted]. Hence, a buyer of Eemshaven would experience an increase in overhead of [redacted].

169. We consider that RWE's overhead costs provide a reasonable estimate of the overhead costs of any potential buyer. If the buyer of the asset did not have any corporate functions – for example, because the plant was the buyer's only asset – it would need to recreate the corporate overhead services. The cost of the services would likely be greater than RWE's allocated overhead, because the services would not be shared among several assets.

170. If the buyer was a firm like RWE Generation SE, then the corporate overhead costs should be similar to RWE's current corporate overhead. The projected overhead costs in the October 2017 SCOut report were subject to a review by the Board of RWE Generation SE. Historical overheads have been subject to external accounting audits, and contribute to RWE's declared profits and hence taxes. [redacted].[167] This kind of overhead allocation method is standard and consistent with other overhead allocation practices that we have seen.

171. Accordingly we estimate the increase in a potential buyer's overhead costs, resulting from the acquisition of Eemshaven, as [redacted]% of the overhead RWE allocates to Eemshaven. Specifically, we use the SCOut overhead cost forecast for years [redacted] inclusive. After [redacted], we increase the [redacted] forecast cost with inflation.

172. Upon plant closure, the overhead costs associated with the Eemshaven plant fall to zero. This is logical, since the overhead costs associated with Eemshaven were zero for the third party before it acquired Eemshaven, and so they would return to zero after its closure.

VI.A.5. Benchmarking fixed operating costs and overhead

173. We check the forecast operating costs, including direct overheads, in the SCOut report in two ways. First, we check that the total forecast costs correspond to the historical operating costs for 2016 and 2017. The SCOut report contains annual operating costs of [redacted] in the period 2020-2022. The accounts report total operating costs of [redacted] and [redacted].[168] Hence, SCOut forecasts slightly lower operating costs than the plant experienced in 2016 and 2017. This makes sense given that we would expect the plant to

[167] **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017 pp. 132 and 135.

[168] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H26.

'learn by doing' and realise some operating cost savings after the first few years of operation.

174. Second, we benchmark the costs against fixed cost estimates for coal plants published by Forbes – Energy Innovation,[169] the Energy Information Administration ("EIA")[170] and the National Renewable Energy Laboratory ("NREL").[171] These publications all present fixed costs in US Dollars for different years. We have converted the costs to Euros using two different approaches. First, we relied upon the contemporaneous market exchange rate. Second, we used a purchasing power parity (PPP) exchange rate.[172] This is a theoretical exchange rate that allows you to buy the same product or service in different countries.[173] We apply a PPP exchange rate to account for the possibility that the dollar may have been unusually strong against other currencies during the relevant period, which would lead to an overestimate of fixed operating costs in Euros.

175. After converting the operating costs to Euros per MW, we apply Eurozone inflation to bring the fixed costs to 2020 prices. Finally, we apply Eemshaven's capacity to yield costs in Euros. We compare the benchmark costs against our October 2017 forecast of Eemshaven's fixed operating costs for 2020. As discussed above, our forecast is based on the SCOut forecast plus direct overhead costs, which yields a 2020 cost of [redacted]. [redacted]

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[169] **Exhibit BR-45**, Forbes - Energy Innovation: Policy and Technology, Carbon Capture And Storage: An Expensive Option For Reducing U.S. CO2 Emissions, dated 3 May 2017.

[170] The EIA collects, analyses and disseminates energy related information as part of the U.S. Department of Energy. **Exhibit BR-46**, EIA, Assumptions to The Annual Energy Outlook: Cost and Performance Characteristics of New Central Station Electricity Generation Technology, 2015.

[171] NREL is a government-owned contractor-operator facility. That has more than 40 years of experience in renewable energy and energy efficiency research. **Exhibit BR-47**, NREL, Annual Technology Baseline 2017

[172] OECD 2020, PPPs and exchange rates, available at http://stats.oecd.org/. See **Exhibit BR-48**, OECD, Purchasing Power Parities (PPP) 2008-2019.

[173] For example, if a hamburger costs $5 in the US but an identical hamburger costs €4, then the PPP exchange rate is 5/4 = 1.25 US Dollars per Euro. The market exchange rate may be different.

TABLE 4: FIXED COST BENCHMARKING[174]

			2020 € mln [A]	2020 PPP € mln [B]
Forbes	[1]		[redacted]	
EIA	[2]	Table H34	[redacted]	
NREL	[3]	Table H34	[redacted]	
Average	[4]	Average([1] to [3])	[redacted]	
Forecast				
Brattle	[5]	Table H34	[redacted]	

VI.A.6. Capital expenditure

176. RWE Eemshaven is not claiming for the roughly €3 billion of capital investment that it has made in the Eemshaven plant. This capital expenditure is a sunk cost,[175] and so irrelevant to a calculation of Eemshaven's FMV as of October 2017. However, capital expenditures remain relevant to the Claimant's damages for two reasons. First, past capital expenditures give rise to a depreciation expense, which the plant owner can use to reduce taxes, which we discuss in the next section. Second, future capital expenditures use up cash, and so reduce free cash flows.

177. We understand that RWE expects capital expenditures for Eemshaven to follow a cyclical pattern, which reflects smaller ongoing capital expenditures for [redacted] years coupled with larger investments every [redacted] year. In our experience, this kind of 'cycle' of major overhauls and investments for coal-fired plants, and the level of capital expenditure, is typical in the power sector. The 2017 SCOut report forecasts the smaller capital expenditures for the period [redacted]. We forecast the smaller capital expenditures beyond [redacted] by applying inflation to the forecast [redacted] small expenditures. As of [redacted], the smaller expenditures are about [redacted] per year.[176]

178. The large investments every [redacted] years involve periodic overhauls.[177] Overhauls refer to maintenance activities that, due to their relatively high costs and scope, would not be

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174 Harris-Hesmondhalgh Workpapers, Tables H – Financial Model.

175 In this context, a sunk cost refers to costs that have already been incurred and can no longer be recovered.

176 Harris-Hesmondhalgh Workpapers Tables G – Investments Model, Table G4.

177 In particular, Eemshaven has two units: Eemshaven A and Eemshaven B, both of identical size. SCOut 2017 foresees that investments in each unit will take place in [redacted]. [redacted]. See Harris-Hesmondhalgh Workpapers,

appropriate to include as normal operating expenses but instead are capitalised. We project the cost of the periodic overhauls based on the SCOut report, applying inflation after [redacted]. As of [redacted], the cost of an overhaul amounts to approximately [redacted].[178]

179. [redacted] Carrying out a major overhaul just before closing the plant would be like paying for a car to be serviced just before taking it to the scrapyard. In particular, in the actual case where the plant closes at the end of 2029, we assume RWE would avoid [redacted]% of the planned overhaul costs in 2029.[179]

180. Similarly, in the but-for case we apply a reduction of [redacted]% of the overhaul cost when overhauls take place in the last operating year. We assume no savings in overhauls taking place one year before closure, on the basis that there may not be sufficient notice of closure to realise overhaul cost savings. In the but-for case, when Eemshaven closes in 2054, we assume that the plant can save [redacted]% of the 2053 overhaul costs, since the owner would know that closure will occur in 2054.

VI.A.7. Working capital

181. Typically, there will be a delay between when a company records revenue in its accounts, and when the company is actually paid. Similarly, there is usually a difference between when a company incurs a cost, and when it actually pays for the goods or services. Businesses need so-called 'working capital' to account for these timing differences. Technically, working capital is usually defined as receivables, amounts that the company is owed, less trade payables, amounts that the company owes its suppliers, plus inventory, stocks of goods, and other short term assets, like cash.

182. [redacted] However, we understand from RWE that the working capital required for Eemshaven is [redacted]

Tables G – Investment and Depreciation Model, Table G4. The dispatch model equally assumes outages corresponding to overhauls every [redacted] years, but-for simplification assumes the corresponding annual equivalent every year.

178 The investment covers only one of Eemshaven blocks. See footnote 177.

179 [redacted].

[redacted] This also means that working capital [redacted].

183. [redacted] we take the working capital for 2017 for Eemshaven, and inflate this value over time.[180]

VI.A.8. Depreciation and taxes

184. In the sub-sections above, we have described how we estimate all the operating costs that we deduct from Eemshaven's revenues. However, to calculate Eemshaven's taxable income, we must also deduct depreciation.

185. Depreciation and capital expenses can be thought of as two sides of the same coin. Capital expenditures are not included in the profit and loss statements that companies prepare to compute their taxable income. Instead, when a firm undertakes a capital expenditure, the expense is recorded as a depreciable asset.[181] The depreciable asset is expensed over time in the firm's income statement. The capital expenditure reflects the actual cash outlay, but depreciation is the accounting construction used to spread the cost of the capital expenditure over time. Hence, depreciation expenses are what economists call a 'non-cash expense'. Ultimately, total depreciation expenses over the life of an asset match the total original capital expenditure.

186. Our financial model forecasts depreciation by modelling past and expected capital expenditures by type of expense.[182] The period over which a company may depreciate a specific type of asset (its "tenor") is typically set out in the relevant tax legislation. For example, RWE depreciates the capital expenditure it incurs in constructing power plants over roughly [redacted] years.[183] This makes sense, because plants are long-lived assets. RWE depreciates other capital expenses, such as software and other IT-related investments, over only [redacted] years. The shorter period reflects that these investments become technologically obsolete after a relatively short time. Based on information from RWE, we apply the depreciation tenor specific to each type of capital expense. We then sum up the depreciation expense for each type of capital expenditure by year, to obtain the total yearly depreciation expense.

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[180] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H10.

[181] There are exceptions, the most notable being land purchases, which are a capital expense but not typically depreciated.

[182] RWE provided us with detailed depreciation reports under IFRS accounting rules, which differ from those presented to tax authorities. In Appendix F, we explain the steps to approximate depreciation for tax purposes from the detailed IFRS accounts.

[183] Harris-Hesmondhalgh Workpapers, Tables G – Investment and Depreciation Model.

187. Depreciation increases the accounting expenses of Eemshaven, allowing it to record lower taxable profits [redacted]

188. [redacted]

189. [redacted] Specifically, as of 2017, Dutch tax legislation allowed for a tax carry forward of nine years.[185] If after nine years losses from a given year have not been used to offset profits, the tax carry forward is lost. Accordingly, we allow Eemshaven up to nine years to consume the depreciation related losses.

190. Most of Eemshaven investments are long-lived, and would normally be expected to have an accounting value even after 2030. However, the Coal Ban leads to a reduction in the useful life of most of these assets – they need to be fully depreciated by the end of 2029. Shortening the depreciation tenors increases the annual depreciation expenses in the actual case. Therefore, depreciation expenses are higher in the actual case than in the but-for case during the 2020's. [redacted][186]

191. In the but-for case, Eemshaven may also wish to shut down before 2054 under some price paths. Such closures would not be planned in the same way as the Coal Ban closure, and so would leave some depreciation allowances unused at the time of closure.

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[184] In accounting terms, the losses create a tax asset.

[185] **Exhibit BR-49**, Deloitte, Netherlands Alert, New Policy Goals Include Corporate Income Tax Rate Reduction, Abolition of Dividend WHT, dated 13 October 2017. For example, suppose a total initial unused loss of 120, and profits of 40 per year. Each year, the company could consume 40 units of the loss. After three years, the group would consume, 120 units, the entire loss, and avoid paying any taxes.

[186] Apart from transferring losses over time, a third party buyer could also transfer yearly losses across subsidiaries. We understand that Dutch legislation allows subsidiaries of the same parent company to consume the losses of other subsidiaries to reduce their tax payments, a practice more commonly known as group relief. Suppose that Company A owns two subsidiaries: Company B, which recorded losses of €50, and Company C, which recorded profits of €50. Because group relief allows for losses to be transferred across subsidiaries, Company C can offset its €50 profit with Company's B €50 losses, and pay no taxes. See **Exhibit BR-50**, PWC, Corporate - Group Taxation, Netherlands, dated 6 September 2020. However, to the extent of our knowledge, there is no energy company with a large and profitable enough portfolio in the Netherlands to use the additional large depreciation losses that Eemshaven generates in the actual case compared to the but-for case.

192. Profitable operations of Eemshaven after 2030 will result in taxable profits – so positive net income – when Eemshaven has exhausted its tax credits. Where there are taxable profits, we calculate Eemshaven's taxes by applying the prevailing corporate tax rate in the Netherlands as of October 2017, 25%,[187] to Eemshaven's taxable income.

193. To conclude, the Brattle financial model computes free cash flows by taking into account all cash outgoings, including ongoing operating expenses, capital expenses, and tax payments to calculate after-tax cash flows in each year. At the same time, it adds back depreciation, which does not reflect any cash outlay.

VI.B. Closure decisions

194. As we explain above, we generate 100 price paths for gas, coal, and CO_2 prices. Hence, we generate 100 'pairs' of free cash flow paths for both the actual and but-for cases. Some of the combinations of commodity prices result in cash losses[188] for Eemshaven in some years, in the sense that the plant is unable to cover its fixed and variable costs, excluding depreciation.

195. However, Eemshaven has the option to shut down, if it finds itself making cash losses, and it expects the losses to continue. Economists refer to this kind of option as a 'real option'.[189] Eemshaven's ability to close limits losses in simulations with unfavourable commodity price paths. That is, we can, in effect, reduce the impact of loss-making commodity price paths by closing the plant.

[187] **Exhibit BR-49**, Deloitte, Netherlands Alert, New Policy Goals Include Corporate Income Tax Rate Reduction, Abolition of Dividend WHT, dated 13 October 2017, **Exhibit BR-51**, PWC, Netherlands Corporate Taxes on Corporate Income, dated 6 July 2020. The corporate tax rate in place and expected as of October 2017 was 25%. Later plans announced the intention to reduce the corporate income tax rate to 21.7%, but this was not known at the time of the valuation. The 21.7% rate has not been implemented.

[188] We distinguish between cash losses, whereby the plant does not cover its operating costs, and accounting losses, whereby the plant does not cover operating costs plus depreciation. A year in which the plant makes an accounting loss may well have positive cash flows. Hence, shut down decisions would be based on cash losses, not accounting losses. Note that we do not include investments when calculating cash losses, since a one-off investment could give a misleading impression of cash losses that would not in fact continue in the future.

[189] The term real option reflects that managers of physical assets, such as plants, have the flexibility to decide when and how much to operate. Economists use the term real to distinguish it from financial options, a related but separate field in economics. Real options is a mainstream approach to valuation in academic circles. Professor Stewart Myers of the MIT Sloan School of Management first coined the term 'real options' in 1973. **Exhibit BR-52**, Myers, S.C., Determinants of Corporate Borrowing, Sloan School of Management, MIT, September 1976. Real options has evolved to become a standard valuation method. It is discussed in hundreds of dedicated research articles, chapters in general corporate finance textbooks, MBA programs, and even entire textbooks. See for example **Exhibit BR-4**, Berk, J.B., DeMarzo, P.M., Corporate Finance, Third Edition, Chapter 22: Real Options and **Exhibit BR-53**, Guthrie, G., Real Options in Theory and Practice, Oxford University Press, 2009.

196. The decision as to whether to close the plant at a given date is complex. A rational plant owner would need to consider:

   a. The operating costs that could be avoided, if the plant closed. Note that some costs, such as the land lease, some taxes and the [redacted] would continue even after closure. Hence, these costs would not play a role in any closure decision. We refer to the operating costs that would cease when the plant stops operation as 'avoidable fixed costs';

   b. The one-off costs that closure would incur from closing the plant, such as redundancy costs and the cost of dismantling the plant. We discuss the costs that closure would trigger in more detail below;

   c. The possibility that future years may be profitable.

197. For example, logically Eemshaven would not close after one year of losses, if it expected to make profits for the remainder of its useful life. However, it would not be realistic to assume that Eemshaven has perfect foresight, and can perfectly predict the future paths of commodity prices from any given date. Accordingly, we implement a simplified 'shut down rule', whereby Eemshaven will close after two years of cash losses in the but-for case if it expects that it will also make losses in the next year. In effect, we assume that Eemshaven management can reasonably distinguish between temporary negative events and longer term trends.

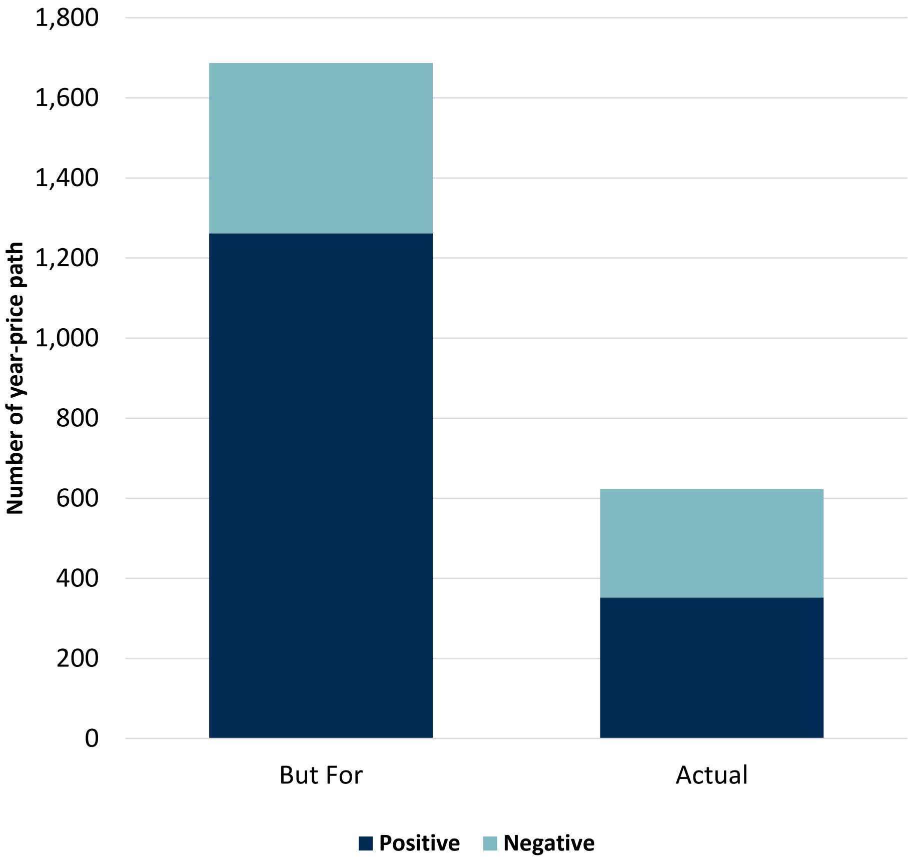
198. In the actual, we shorten the shut-down rule by one year. That is, if Eemshaven makes losses in one year and expects to make losses in the next year, it closes. We adopt a shorter shut down rule in the actual case because the remaining life of the plant is so much shorter than its potential life in the but-for case. It makes sense for the plant to be less willing to accept an additional year of losses in the actual case, because the prospect of future profits offsetting the losses is lower when the plant must close at the end of 2029, relatively to a situation where the plant could run until 2054.

199. For example, suppose that for a given commodity price path, Eemshaven had a negative cash flow of €10 million in 2039, €10 million in 2040 and that the given commodity price path would result in a loss of €5 million in 2041. We would assume that Eemshaven closes at the end of 2040, and generates no positive cash flows from 2040 onwards. Hence for this commodity price path, from 2040 onwards there will be no further loss in Eemshaven's fair market value, since there are no differences in the cash flows under either the but-for and actual cases.

200. Figure 12 illustrates the effect of this shut-down rule for Eemshaven. The figure shows the number of years across all the price paths with positive cash flows in dark blue, and the

number of years with negative cash flows in light blue.[190] In the but-for case, the total number of modelled years in which Eemshaven runs and generates positive cash flows is substantially higher than in the actual case. There are some years with negative cash flows, but these are offset by a higher share of profitable years for the price paths where Eemshaven continues operations. In the actual case, operations are limited to 2029, and so the number of years in which Eemshaven can make profits is reduced. As a result, the share of years with negative cash flows is increased.

FIGURE 12: DISTRIBUTION OF CASH FLOWS WITH A SHUTDOWN RULE[191]



201. Our shut down rule likely underestimates the FMV in the but-for cases for two reasons. First, our analysis does not consider the possibility of 'mothballing' the plant. Mothballing refers to a temporary closure of the plant. Mothballing incurs costs to partially decommission the plant, costs to maintain the plant while it is in a mothballed state, and costs to recommission the plant and bring it back into operation. However, mothballing preserves the option to

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[190] Suppose there were only two price paths. Under one price path, the plant closes after 10 years and under the other it closes after 15 years even though its technical life was 20 years. The total number of year price-paths would be 25 (10 +15). If we further assume that the plant only makes losses in the two years before it closes, there would be 8 positive years for the first path and 13 for the second path, so there would in total be 21 positive year-price paths and 4 negative year-price paths.

[191] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model.

restart the plant, which can be very valuable. We find that there are price paths where negative cash flows for a number of years are then succeeded by positive cash flows. Mothballing, rather than closing, the plant would enable Eemshaven to take advantage of the later more profitable years.

202. However, we do not currently have data on the costs of mothballing the Eemshaven plant, [redacted]. To calculate mothballing costs, we would need to make assumptions about what work would be done to place the plant in a 'mothballed state', how many staff would be retained while the plant was in mothballs, the kind of maintenance regime that RWE would apply and so on. To calculate these numbers would be a complex undertaking.

203. Second, while the downside in negative cash flow years is limited to Eemshaven's avoidable fixed costs, the upside of positive cash flow years can be substantial. We note that remaining open would, for most simulations, result in a higher value than closing based on our shut-down rule. This is because a series of negative years are sometimes followed by a series of very profitable years. Indeed, if we did not apply any shut down rule and simply assumed the plant would remain open until the end of 2054 in the but-for case, then the average FMV of the but-for case increases to [redacted] from [redacted]. On the other hand, if we assumed that the plant always remains open until the end of 2029 in the actual case, the FMV of the actual case falls to [redacted] from [redacted].[192] Hence, the lost FMV, and so damages, would be higher if we did not apply our shut down rule.[193]

204. If Eemshaven shuts down before 2054, the most significant impact is, of course, the plant's inability to realise any further operating revenues or incur operating costs. However, the plant's closure will trigger several additional costs and savings. Our analysis identifies six impacts on the FMV that result from a closure decision.

205. We have discussed two of the savings from closure in the preceding sub-sections. First, as explained in Section VI.A.4 above, the closure of the plant would eliminate its related corporate overhead costs. Second, as we explain in Section VI.A.6, the plant can avoid costly overhaul capital investments in the run up to closure. This creates a cost saving, which increases the FMV of the plant compared to a calculation in which this effect is not taken into account.

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192 Harris Hesmondhalgh Workpapers, Tables H – Financial Model, Table H2.

193 As we explain in Section VII below, we remove certain outlier outcomes to arrive to loss in FMV. After removing outliers, the but-for scenario would increase from [redacted] to [redacted] if we did not apply a shut down rule, and the actual scenario would decrease from [redacted] and [redacted]. See Harris Hesmondhalgh Workpapers, Tables H – Financial Model, Table H2.

206. [redacted]

207. While the first three issues result in cost savings, which increase the FMV in the actual case, the fourth issue –decommissioning costs – reduces the FMV in the actual case. As explained above, Eemshaven has the option to buy the land on which the plant sits. Hence, even if the plant closes before 2054, the owner can keep the plant in place and postpone the dismantling costs until at least 2054.[194] However, we understand that there is a requirement that parts of the plant that have mild radioactive contamination resulting from coal ash – specifically the boiler – must be dismantled and removed within two years of the plant closure.[195] We assume that the costs of disposing of the contaminated boiler are equal to [redacted]% of the costs of dismantling the entire plant.[196] Incurring costs closer to the valuation date increases their present value, relative to a scenario where a plant operator is able to defer decommissioning costs to a later date. Hence, with respect to decommissioning costs earlier closure reduces the FMV, relative to a price path under which Eemshaven closes in 2054.

208. Fifth, closing the plant leads to redundancy payments for plant staff and related corporate personnel.[197] A third party buyer would face similar obligations to RWE, which are largely determined by sectorial and national labour laws, and plant requirements, such as the number of staff needed to operate Eemshaven. [redacted]

209. [redacted] For example, for an 'orderly' closure – so a closure that RWE could anticipate 5-6 years ahead – RWE can reduce redundancy costs by replacing staff that retire in the run up to closure with external contractors. [redacted]. An external contractor's compensation exceeds that of a full time employee salary, but the former does not attract any redundancy

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[194] See ¶158.b above and Harris Hesmondhalgh Workpapers, Tables H – Financial Model, Table H27, **Exhibit BR-38.C**, RWE, Land Lease Akte I, dated 16 March 2009.

[195] **Exhibit BR-54**, Overheid.nl, Decree on Basic Safety Standards for Radiation Protection, dated 23 October 2017.

[196] Harris Hesmondhalgh Workpapers, Tables H – Financial Model, Table H30. We expense the disposing of the contaminated boiler in the first year of closure.

[197] We assume an equal distribution of redundancy expenses in the two years covering the last operating year and the year after operations cease.

costs when the plant shuts down. Ultimately, the savings from avoided redundancy costs exceed the additional compensation costs for external hires, making this strategy beneficial.

210. On the other hand, as outlined above, there are price paths under which Eemshaven closes unexpectedly early under the but-for cases. These outcomes result in higher redundancy costs. The lack of closure notice means that RWE would replace retiring employees with new employees, even in the run-up to an unanticipated closure. Once closure takes place, Eemshaven would face redundancy costs for the new employees. Hence, an unexpected closure increases redundancy costs relative to an orderly closure, and so reduces Eemshaven's value in the but-for case.

211. As we noted above, closure will also reduce some corporate overhead costs, including staff costs. Hence, some corporate employees will also become redundant following Eemshaven's closure. RWE considers that redundancy costs of corporate staff are equivalent to [redacted].[198]

212. Sixth, we release working capital, in the form of cash and inventory, following the plant's closure, which results in a positive cash flow. Since working capital is released earlier in the actual case, this tends to increase the value of the actual case and reduce damages, relative to a case where there was no release of working capital.

VI.C. Discount rate, present value and risk

213. The 100 commodity and electricity price paths lead to 100 different free cash flow projections from 2020 onwards for the actual and but-for cases. The cash flows are in nominal terms, or 'money of the day'. To calculate what these cash flows imply for the FMV of Eemshaven, we need to discount each year's free cash flows back to the valuation date, October 2017. This procedure is known as calculating the "net present value" of the free cash flows and the FMV is simply equal to the net present value of the free cash flows.

214. Discounting reflects the fact that a euro today is worth more than a euro tomorrow, and that future projected cash flows are often subject to risk. Financial analysts discount future cash flows to reflect the time value of money and risk, thereby making the cash flows comparable

[198] This assumption is likely conservative for damages. [redacted], we estimate relatively lower redundancy costs in both the actual and but-for cases. Because the redundancies are incurred earlier in the actual case, assuming lower redundancy costs increases the value of the actual case. [redacted]

with a certain, or guaranteed, cash flow today. For example, suppose that a project is forecast to generate €10 in one year's time. An analyst might assess the various risks, and conclude that the promise of €10 in one year's time from the project is worth the same as €8 for certain today. A reasonable investor would be indifferent between the two possibilities. In this example, the discount is €2 (being €10-€8) or 20% (€2/€10).

215. Financial theory tells us that future cash flows should be discounted at the project's opportunity cost of capital,[199] which is the return that an investor would expect to earn from another project with the same risk. Investors wish to ensure that they are being appropriately rewarded for the risks they are taking. Hence, they would discount the future cash flows at the opportunity cost of capital, and check that the sum of the discounted cash flows is positive. If it is not, the investors are better off investing in another project, since they can get a better return for the same risk.

216. Investors need to be compensated for the risks they assume. In practise, investors are able to eliminate much of the risk of an investment by 'diversification' – that is, holding a wide portfolio of investments. In a portfolio of investments, some investments may be successful while others are not. Hence some of the risk of good and bad outcomes cancel one another out. Economists call this 'diversifiable risk'. It is the risk that an investor can eliminate by holding a portfolio of investments. It is considered that "a risk that can be diversified away when held along with other investments in a portfolio is, in a very real way, not a risk at all".[200] The remaining risk is the called 'systematic risk' because it is the risk that applies to the entire portfolio. For example, the risk of an economic depression will negatively affect the value of most of the investments in a portfolio, to one extent or another. Hence an investor cannot eliminate this risk by diversification. Accordingly, investors only need to be compensated for the risks that they actually bear, which are the systematic risks. Hence, the opportunity cost of capital of an investor – in other words the discount rate – only reflects systematic risk.

217. A prospective buyer is likely to finance the purchase of Eemshaven with a mixture of equity and debt. Accordingly, standard practice is to calculate the opportunity cost of capital by combining the cost of equity and the cost of debt taking into account the share of debt and equity used to finance the project, and so determine the Weighted-Average Cost of Capital ("WACC").[201] We note that there is no debt specifically associated with Eemshaven.

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[199] See, **Exhibit BR-55**, Brealey, Myers, and Allen, Principles of Corporate Finance, 10th edition, (The McGraw-Hill Companies, 2011) Chap. 9.

[200] **Exhibit BR-56**, Perold A.F., The Capital Asset Pricing Model, Journal of Economic Perspectives - Volume 18, Number 3, Summer 2004, p. 3.

[201] We provide more details in Appendix G.

Accordingly, we determine the proportion of debt and equity for Eemshaven based on the average debt ratio of companies in the business of coal-fired generation and trading.[202]

218. A standard way to measure the equity cost of capital for a project is to use the Capital Asset Pricing Model ("CAPM").[203] We have applied the CAPM to measure the cost of equity in other projects, and in particular for energy and telecoms regulators who use the cost of equity as an input to set tariffs for firms that have market power. We calculate the cost of equity for an operating coal-fired plant, based on the historical stock price performance of companies which earn a significant percentage of their revenues from coal-fired generation and trading activities. We explain the details of the CAPM, and the cost of capital calculation, in Appendix G.

219. The cost of debt reflects the interest associated with loans to an operating coal-fired plant. Specialised financial institutions such as Standard and Poor's routinely grade companies' debt, which provides a benchmark to determine a company's creditworthiness. We find that a Standard and Poor's debt credit rating of BBB was typical for Western European companies operating in the power sector in October 2017.[204] We compute the cost of debt based on a set of Western European companies with BBB or equivalent credit ratings.

220. Based on the above considerations, we calculate an after-tax WACC of 3.85%. Table 5 summarises the elements of the WACC calculation. Appendix G gives details of the calculations.

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[202] See Appendix G.3. for details of the comparable companies. RWE's debt to equity ratio is very similar to the average of comparator firms. See Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital, Table F3. When valuing a firm, debt is relevant for two reasons. First, debt is relevant to compute interest payments, which are tax deductible. By assuming an integrated buyer with a firm-wide debt target, our methodology allocates more interest-related tax savings to Eemshaven when it performs well, and less interest-related tax savings when it performs worse. Second, debt is also relevant to assess whether a firm can enter into bankruptcy. There is no realistic prospect that the Eemshaven entity would declare bankruptcy, and indeed it is not directly responsible for any debt. So the only risk is that the integrated buyer company goes bankrupt because of Eemshaven's closure, and this risk is the same in the actual and but-for cases. We would expect this risk to be small for an integrated buyer. For example, the creditworthiness of RWE AG, as measured by credit rating agencies, has remained stable since early 2016 despite the announced closures of coal plants in the Netherlands and Germany. See Harris-Hesmondhalgh, Tables F – Cost of Capital. See also **Exhibit BR-57**, RWE, RWE Bonds and Credit Ratings, dated 30 November 2020.

[203] See, *e.g.*, **Exhibit BR-55**, Brealey, Myers, and Allen, Principles of Corporate Finance, 10th edition, (The McGraw-Hill Companies, 2011) Chapter 8, page. 192.

[204] As of October 2017, RWE AG had a Moody's credit rating of Baa3, equivalent to a BBB- rating from Standard & Poors. Harris-Hesmondhalgh Workpapers, Tables F.

TABLE 5: COST OF CAPITAL[205]

Date	[1]	See note	09/10/2017
Risk-free rate	[2]	See note	[redacted]
Beta (unlevered)	[3]	Table F3	0.47
MRP over long-term bonds	[4]	Assumed	5.50%
Beta (levered)	[5]	See note	0.70
Cost of levered equity	[6]	[2]+[5]x[4]	[redacted]
Cost of debt	[7]	See note	[redacted]
Tax rate	[8]	See note	25.0%
Target debt ratio	[9]	Table F3	39%
WACC	[10]	See note	3.85%

Notes and sources:
[1]: Valuation date.
[2]: EuroSwap (20 years).
[5]=[3]*(1+(1-[8]))*[9]/(1-[9])
[7]: BVAL composite index, BBB rating 20Y maturity as of 9/10/2017.
[8]: Exhibit BR-81, KPMG, Corporate Tax Rates.
[10]: [6]x(1-[9])+[7]x[9]x(1-[8]).

205 Harris-Hesmondhalgh Workpaper, Tables F - Cost of Capital, Table F1.

VII. Step 4: Damages

VII.A. Loss in Fair Market Value

221. In the previous sections, we describe how we generate 100 'pairs' of free cash flow paths for both the actual and but-for cases. We then use a discount rate to calculate the present value of each set of cash flows, as of the valuation date. Hence, from the previous steps, we have 100 'pairs' of present values, where each present value represents the FMV of Eemshaven for a given set of circumstances. Specifically, each pair consists of a present value, or FMV, in the actual case (where the Coal Ban is in place), and a present value, or FMV, for the but-for case (without the Coal Ban), for a given commodity price path.

222. In this section, we calculate the loss in value of Eemshaven resulting from the Coal Ban as the difference between the FMV in the but-for case and the FMV in the actual case for each commodity price path. Figure 13 illustrates the 100 pairs of but-for and actual FMVs.

FIGURE 13: BUT FOR FMVS[206]

[redacted]

1 6 11 16 21 26 31 36 41 46 51 56 61 66 71 76 81 86 91 96

Price Paths

FIGURE 14: CORRESPONDING ACTUAL FMVS BASED ON BUT-FOR FMV[207]

[redacted]

1 6 11 16 21 26 31 36 41 46 51 56 61 66 71 76 81 86 91 96

Price Paths

223. Based on these pairs, we calculate 100 estimates of loss in value of Eemshaven, corresponding to the 100 commodity price paths. Figure 15 below illustrates the sorted

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[206] Price paths are ordered in ascending order of FMV.

[207] Price paths are ordered based on the corresponding FMV in the But-For scenario.

distribution of the 100 estimates of loss in value of the plant, with the lowest loss in value on the left hand side of the figure and the highest loss in value on the right hand side of the figure.

224. We note that any DCF valuation must account for the fact that many different cash flows are possible for a project. For example, costs could be higher than expected, or revenues could be lower. A DCF valuation should be based on the average or expected cash flows. The use of expected cash flows in a discounted cash flow model is standard practice for <u>any</u> valuation. For example, the seminal corporate finance text book by Brealey & Myers notes that:

> *"When you are working with cash-flow forecasts, bear in mind the distinction between the expected value and the most likely (or modal) value. Present values are based on expected cash flows—that is, the probability-weighted average of the possible future cash flows. If the distribution of possible outcomes is skewed (…), the expected cash flow will be greater than the most likely cash flow."*[208]

225. There are several ways to arrive at expected cash flow. One could try and develop a "central" cash flow forecast, which is somewhere in the middle between higher and low cases. A reliable central cash flow forecast would generally have a 50% chance of being above the actual cash flows and a 50% chance of being below the actual cash flows. Accordingly, if an investor buys an asset based on a central cash flow projection, it would have a 50% risk of having paid too much, with the benefit of hindsight. Of course, the investor also has a 50% chance of paying less for the asset than it turns out to be worth.

226. One could also apply a 'scenario' based approach, generating for example high, medium, and low cash flow forecasts. However, as we discussed in section IV.A above, the disadvantage of a scenario based approach is that it involves subjective judgements about the probability of each scenario occurring. Similarly, creating a central cash flow scenario involves subjective judgements about the probability of different outcomes.

227. In contrast, the Monte Carlo simulation we use to generate the 100 outcomes is simply an advanced technique to estimate the expected cash flows. It is more precise than simply looking at the most likely outcome, or making subjective judgements regarding 'high' and 'low' scenarios. The simulations examine a wider range of potential outcomes with a probability for each one that derives from standard statistical techniques. The technique

[208] **Exhibit BR-55**, Brealey, Myers, and Allen, Principles of Corporate Finance, 10th edition, (The McGraw-Hill Companies, 2011), p. 252

makes the calculation of the average outcome more reliable than other methods. But in concept it is the same principle seen in any valuation. Our Monte Carlo method simply makes explicit – in the form of multiple alternative price paths – what is hidden and implicit in an alternative approach such as a central price path analysis.

228. Having generated 100 outcomes, as in any DCF analysis we need to combine them into a single expected cash flow forecast. By construction, each of the 100 outcomes is equally likely. [209] Hence we estimate the expected cash flows by taking the average of the 100 outcomes. As the quote above highlight, to use anything other than mean or average cash flows would be incorrect.

229. Taking the average of the loss in value across all the price paths results in a damage amount of [redacted].[210] In other words, a rational potential buyer would pay [redacted] less for the Eemshaven plant with the Coal Ban than without the Coal Ban.

230. However, Figure 15 below shows that a few of the price paths lead to particularly high damages. The highest damages case exceeding [redacted]. There is nothing inherently surprising about this result. Given 100 outcomes, there are bound to be some that are extremely favourable to Eemshaven. There are also commodity price paths that are unfavourable to Eemshaven. However, the unfavourable outcomes result in the closure of the Eemshaven plant, rather than commensurately large losses. Hence, the 'skew' of the distribution of the losses towards high positive values reflects the fact that Eemshaven represents a real option. That is, the plant has the option to stay open when commodity prices are favourable, and close when they are not.

231. However, to avoid a situation where a few price paths have a very large effect on the damages, we remove the highest and lowest 5% of values. Figure 15 shows these 'outlier' simulations in black. Adopting this approach reduces our damages estimate, as of 9 October 2017, from [redacted] to [redacted].[211]

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[209] We note that even though the 100 price paths we draw have equal weight, the underlying statistical distribution from which we draw the price paths is such that there will be more draws of price paths closer to the mean of the distribution than those further away from the mean.

[210] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H2.

[211] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H2.

FIGURE 15: SORTED DISTRIBUTION OF THE LOSS IN VALUE OF EEMSHAVEN DUE TO THE COAL BAN[212]

[redacted]

1 6 11 16 21 26 31 36 41 46 51 56 61 66 71 76 81 86 91 96

Sorted price paths by Lost FMV

232. Our analysis shows that, in the 'but for' scenario, in some cases the buyer of Eemshaven could end up with an asset worth considerably more than [redacted], while in other cases the value of Eemshaven would be close to zero. Our calculated FMVs for the 'but for' scenario reflect these possibilities.

233. However, such risks are typical with many investments. As we explained above, an investor could eliminate the risk through diversification. In this way, a negative outcome for Eemshaven would be offset by a positive outcome for another investment. Similarly, losses in other investments in the portfolio would, on average, offset a highly positive outcome for Eemshaven. This is why a diversified investor would be prepared to pay the average of the 100 outcomes.

234. Our finding – that Eemshaven has significant value under many commodity price paths – is consistent with analysis published around the valuation date. For example, a report by Carbon Tracker ("CT"), published in December 2017 after the Valuation Date,[213] found that the most efficient coal-fired power plants, such as Eemshaven, would still be profitable in 2030. This study considers a single set of commodity prices, so it does not take into account

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[212] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model.

[213] Exhibit CLEX-03.

the additional value associated with the optionality associated with coal-fired plants. Our range of possible price paths gives rise to some paths where coal-fired plant could be profitable as well as some where they are unlikely to be profitable over the longer term. Indeed, the need for the Coal Ban law can itself be viewed as indicating that at least some coal-fired plants, such as Eemshaven, will be profitable even by 2030.

VII.B. Interest

235. We calculate the financial damages to Eemshaven as of 9 October 2017. However, RWE will only receive compensation after an award is rendered, which could be five or more years after this Valuation Date.[214] To illustrate the impact that interest will have on the overall payments to be made, we have calculated the interest that will accrue between the Valuation Date and 18 December 2021, the date of submission of this report.

VII.B.1. The Appropriate Interest Rate

236. Counsel for RWE has instructed us that the ECT calls for the application of pre-award interest using a commercial rate established on a market basis. A commercial interest rate is conceptually similar to the concept of a fair market value, except that it applies to the interest rate that a willing borrower and a willing lender would agree to.

237. LIBOR (the London inter-bank overnight borrowing rate) and its European equivalent, EURIBOR, are two of the most commonly quoted commercial interest rate benchmarks. LIBOR is established on the basis of commercial, market-based agreements between large banks,[215] as is EURIBOR. Other tribunals in Investor-State arbitrations have confirmed this. For example, one tribunal noted that the EURIBOR rate "represents an objective, market-oriented rate".[216] Hence, LIBOR/EURIBOR is consistent with the concept of a "commercial rate established on a market basis".

238. However, most companies cannot borrow at the LIBOR/EURIBOR rate. Rather, they borrow at the LIBOR/EUIBOR rate plus a premium. Hence, LIBOR/EURIBOR plus two percentage

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[214] Following the discussion on the time value of money above, the delay in compensation has a cost. For example, if a claimant was owed $10 five years ago, it would not be sufficient to simply give the claimant $10 today. Because of inflation the purchasing power of $10 reduces over time. To provide adequate compensation, the claimant should receive an additional amount, rather than the $10 that was owed five years ago.

[215] Specifically, LIBOR is the borrowing rate between banks in London, and EURIBOR is the lending rate for banks in the European Union.

[216] **Exhibit BR-21**, Global Arbitration Review, The Guide to Damages in International Arbitration, Third Edition, dated 1 December 2018, p. 311 quoting the award in ARB/05/24.

points represents a typical commercial rate of interest. This is reflected in a recent ICSID award, where the respondent proposed a pre-award interest rate of LIBOR plus two percentage points, and the claimant proposed a higher rate based on its own borrowing costs. The Tribunal found that LIBOR plus two percentage points "is a commercially reasonable rate".[217] Recent research reveals that LIBOR plus a 2% premium is emerging as a standard for pre-award interest in Investor-State awards.[218]

VII.B.2. Compound Interest

239. A typical long-term commercial loan would apply compound interest – which is to say that interest accrues on interest owed. From an economic perspective, applying compound interest is the only way to compensate a claimant fully. This is because the claimant has not only lost the interest on the amounts owed, but has also lost any interest that could accrue on the interest. Hence, applying simple interest would not provide full compensation. As the GAR Guide to damages explains:

> *"in most situations economists favour compound interest for pre-award interest. The reason is that yields (which are based on compounding) are the economic benchmark of market interest rates. While financial contracts with simple interest do exist and are straightforward to value, the market values of such contracts are 'reverse – engineered' to make sure that they trade at market yields. Applying a market yield without compounding would not make the claimant whole."*[219]

240. The frequency with which interest is compounded must be consistent with the interest rate applied. For example, EURIBOR rates are available for loan periods of one week, one month, three months, six months, and 12 months.[220] If we applied a one month EURIBOR rate, we would need to calculate interest for each month, update the interest rate, and then apply the new rate to the principal owed and the calculated interest for the previous month.

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217 **Exhibit BR-21**, Global Arbitration Review, The Guide to Damages in International Arbitration, Third Edition, dated 1 December 2018, p. 311 quoting the award in ARB/07/23.

218 The GAR Guide to Damages includes a chapter on pre-award interest, which provides a comprehensive list of investor state cases published on the ICSID website. The review concludes a majority of awards add interest based on a base rate (such as BRIBOR, EURIBOR, LIBOR and ROBOR, in 46 of 60 cases). The review also shows that the most commonly used base rate is LIBOR (in 21 of the 60 cases) and that the most commonly used spread was 2% (in 14 of the 21 cases applying a spread). See **Exhibit BR-21**, Global Arbitration Review, The Guide to Damages in International Arbitration, Third Edition, dated 1 December 2018, Section 22.

219 **Exhibit BR-21**, Global Arbitration Review, The Guide to Damages in International Arbitration, Third Edition, dated 1 December 2018, p. 306, emphasis added.

220 **Exhibit BR-58**, EMMI, Euribor Rates.

241. In our view, applying a 12 month EURIBOR rate and compounding annually is reasonable. Using more frequent compounding intervals, combined with consistent interest rates, could also be reasonable, but would make little difference to the overall amount of interest owed, while adding to the complexity of the interest calculations.

VII.C. Damages Including Interest

242. Table 6 shows that, based on damages of [redacted], interest of [redacted] will have accrued by 18 December 2021. Accordingly, including pre-award interest, damages amount to [redacted].

TABLE 6: DAMAGES INCLUDING INTEREST

Damages	€ mln	[1]	See note	[redacted]
Interest adjustment factor		[2]	See note	1.07
Damages including Interest as at 18 December 2021	€ mln	[3]	[1]x[2]	[redacted]

Notes and Sources:
[1]-[2]: Harris-Hesmondhalgh Workpapers - Tables H.

VII.D. Avoided carbon costs

243. We calculate that, on average, closing Eemshaven in 2030 will result in nearly 210 million tons of avoided CO_2 emissions.[221] This is the average reduction based on the 90% of fair market value simulations that remain after removing outliers.

244. To put the claim for loss in value into context, we can recalculate the compensation claimed in terms of the price that the Netherlands would be paying for each ton of avoided CO_2 emissions. This is analogous to the logic of the Kyoto Protocol's Joint Implementation (JI) mechanism, whereby companies could invest in a project that will reduce greenhouse gas emissions, and use the reduction in emissions to offset their own carbon emissions.[222] Between 2007 and 2012, the Netherlands approved over 200 such projects.[223]

[221] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H7.

[222] More specifically, the sponsoring company would be granted emission reduction units (ERUs) which it can use towards fulfilling part of their obligations under the EU ETS until 2020. **Exhibit BR-59**, United Nations Climate Change, Joint Implementation. For more information about the Kyoto Protocol, visit: https://unfccc.int/kyoto_protocol.

[223] The Netherlands did not approve JI projects after 2012 due to limits in the use of the credits generated for the ETRS mechanisms, see **Exhibit BR-60**, Overview of NL Issued Letters of Approval for Participation in a JI Project Activity, Last Update Nov. 2013.

245. For each of the 90 simulations that determine our final damages, we calculate the after-tax loss in value for each operational year – which is the basis for the claim – and divide this by the CO_2 emissions that Eemshaven emits in the but-for case, and that would be avoided in the actual case. For each case, this results in a price reduction, expressed in €/ton of CO_2 – for each year between 2030 and 2054. We then discount the reduction price at the WACC back to October 2017. Discounting reflects that earlier reductions in emissions are more valuable than later emissions reductions. After discounting, we calculate the average discounted reduction price for each of the 90 simulations. Finally, we take the average of the average yearly reduction price for the 90 simulations.

246. We calculate that on average, the claim is equivalent to the Netherlands paying around €16 for each ton of avoided CO_2 emissions.[224] This price is significantly lower than the average carbon price of 37 €/t of CO_2 that we apply in our model or the actual market price of CO_2 since 2018.[225]

VIII. Mitigation

247. Finally, we comment briefly on the feasibility of Eemshaven mitigating damages from the Coal Ban by converting to burn only biomass.

248. Clearly, Eemshaven cannot continue to burn a mixture of 15% biomass and 85% coal after 2029, since this would violate the Coal Ban. Possible alternatives would be to convert the Eemshaven plant to burn 100% biomass.

249. Claimant has retained another expert firm, NERA, to investigate the feasibility of these conversions providing mitigation.[226] NERA finds that it would not be feasible to convert Eemshaven to 100% biomass, absent subsidies. This means that, according to NERA, mitigation of damages by conversion to biomass is not possible, since all biomass subsidies are expected to end in 2027.

250. We have reviewed the NERA report and consider that NERA's conclusions are reasonable. We also note that while some coal-fired plants have been converted to natural gas in the United States, this was only economic because US gas prices are relatively low, due to an excess of gas that US producers now export in the form of LNG. In contrast, the Netherlands

[224] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H7.

[225] See Harris-Hesmondhalgh Workpapers, Tables H – Financial Model, Table H7 and Appendix H.

[226] Nera Report.

and the EU more generally is a net gas importer, with relatively high gas prices. Similarly, we are unaware of any coal plants that have been converted to 100% biomass without subsidies.

IX. Declaration

251. We confirm that insofar as the facts stated within this report are within our own knowledge, we believe them to be true and that the opinions expressed represent our true and complete professional opinion.

[redacted]

Serena Hesmondhalgh

18 December 2021

London, UK

[redacted]

Dan Harris

18 December 2021

Rome, Italy

Appendix A : Curriculum vitae

Dr. Serena Hesmondhalgh has worked as a consultant in the energy sector for more than twenty-five years, predominantly in the electricity and gas sectors. She has provided advice on a wide range of topics: litigation and arbitration, commercial damages, competition cases, asset valuation, the design of trading arrangements and price controls.

In recent years she has provided expert testimony for around fifteen gas contract arbitrations, mostly focused on north-west Europe, as well as arbitrations on issues including billing system problems, electricity contracting restrictions, market manipulation, failure to respect regulatory guarantees and due process in relation to electricity and gas networks, expropriation of district heating assets, warranty violations and insurance claims for power stations.

Dr. Hesmondhalgh has also worked extensively with EU energy regulators, particularly in Great Britain, on competition and regulation issues. On behalf of Naftogaz of Ukraine, Dr. Hesmondhalgh analyzed the potential anti-competitive effects of the Nord Stream 2 pipeline unless various commitments regarding its use and pricing were to be imposed – the analysis was submitted to the European Commission. She has also conducted investigations into potential electricity market abuse undertaken by the GB regulator, as well as providing advice on the redesign of trading arrangements (GB, the Netherlands, Belgium), transmission network access (EU, GB, Greece), transportation tariffs (GB, Ukraine) market monitoring, quality of supply obligations (GB, Germany, Australia) and price controls and incentives (GB, Germany, Australia).

Dr. Hesmondhalgh's modelling skills have been used to develop a range of tools for asset valuation including electricity dispatch modelling, power plant asset valuation, price control revenue assessments, interconnector trading arrangement impacts and pan-European gas flows.

EDUCATION

1981-1985 University of Oxford
Oxford, United Kingdom
D.Phil. in Experimental Nuclear Structure Physics

1977-1981 Sussex University
Brighton, United Kingdom
B.Sc. Physics with Mathematics (First Class Honours)

AREAS OF EXPERTISE

- Antitrust/Competition
- Electric Power
- International Arbitration
- Natural Gas
- Utility Regulatory Policy and Ratemaking

EXPERIENCE

Litigation and Arbitrations

- North-West European gas arbitration against Gazprom – Dr. Hesmondhalgh acted as an expert witness for a gas buyer, primarily focusing on the analysis of import prices and the value of flexibility. This arbitration involved multiple contracts, with different delivery points, different prices and different flexibility terms.
- Ukrainian gas supply and transit arbitrations against Gazprom – Dr. Hesmondhalgh acted as an expert witness for a gas buyer, providing analysis of the value of gas in north-west Europe, cost-related gas transit tariffs that followed the principles laid out in the TAR and CAM network codes, and competition issues related to both supply and transit. The supply arbitration resulted in the replacement of a 100% oil-linked contract price with one 100% linked to German hub prices.
- South-east European gas arbitration – Dr. Hesmondhalgh acted as an expert witness for a gas buyer, providing analysis of the value of gas in Western Europe and on changes in the western European gas market since the late 1990's.
- North-west Europe gas arbitrations – Dr. Hesmondhalgh has acted as an expert witness for a gas producer, providing analysis of the value of flexibility and the relevance and applicability of German import prices for a variety of different claim dates.
- Independent expert – Dr. Hesmondhalgh acted as an independent expert for a Tribunal in a gas contract arbitration involving a central European country. She provided assistance in relation to translating its decision into a revised price formula and on different ways of reaching a fair and equitable solution.

- Gas contract arbitrations – Dr. Hesmondhalgh has acted as an expert for a major oil & gas utility who is both a buyer and a seller of gas. She acted as an expert for the company in its role as a gas buyer and she previously acted as an advisor to its production arm in three gas arbitrations brought by a large European utility, who has requested a complete change in pricing methodology.
- Norwegian gas contract disputes - Dr. Hesmondhalgh has appeared as an expert witness for two gas price arbitrations and five price reviews involving deliveries of Norwegian gas to Germany and central Europe.
- German gas contract disputes - Dr. Hesmondhalgh has acted as an expert witness for three gas contract arbitrations for the same buyer involving deliveries of gas within Germany. She has also prepared expert witness testimony for a further two arbitrations which were settled before the oral hearing.
- Czech gas contract disputes – Dr. Hesmondhalgh acted as an expert witness for price reviews involving deliveries of gas within the Czech Republic.
- Gas price arbitration in Spain - Dr. Hesmondhalgh formed part of the Brattle team hired to provide expert witness testimony in a gas supply agreement arbitration involving gas deliveries to Spain.
- Other gas contract disputes - Dr. Hesmondhalgh has formed part of Brattle teams that have provided advice on gas contract disputes in Italy, Belgium and France.
- Gas distribution and supply company in Hungary: – Dr. Hesmondhalgh acted as an expert witness for the claimant on regulatory matters before the ICSID in an arbitration regarding whether the regulatory treatment of the company was fair and equitable given the economic situation in Hungary and the high levels of energy poverty in the country. This involved comparing the Hungarian regime to the cost-reflective principles embodied in the Third Gas Directive.
- Discriminatory impact of zonal losses on an offshore wind farm in Scotland – Dr. Hesmondhalgh is co-author of an export report on the discriminatory impact of the unexpected introduction in GB of zonal losses on the profitability of an offshore wind. As well as quantifying the damages associated with the introduction of zonal losses, Dr. Hesmondhalgh also explained why the way that zonal losses had been introduced was incompatible with both the government's support for renewable energy and the stated aims underlying the introduction of zonal losses.
- Impact of a cooling tower fire on a UK power plant's profitability – Dr. Hesmondhalgh has developed a model to estimate the impact that the extended outage at and subsequent constrained operating regime of a UK power plant had on its profitability as a part of a disputed insurance claim that is being disputed in the High Court.

- Supply Contract Agreement – Dr. Hesmondhalgh is acting as an expert witness in a dispute between a CHP generator and the company to whom it sells its heat and power regarding the apportionment of the costs of the impact of the removal of Climate Change Levy Exemption Agreements and the treatment of fixed distribution and transmission costs.
- Gas production agreement – Dr. Hesmondhalgh is acting as an expert witness in a Stockholm Chamber of Commerce arbitration regarding the damages suffered by a gas producing company in Eastern Europe as a result of the failure of the other parties to a joint activities agreement to meet their contractual obligations to modernise its production facilities.
- Contract termination arbitration – Dr. Hesmondhalgh acted as an expert witness in an UNCITRAL arbitration regarding the damages suffered by a trading company as a result of the early termination of a power purchase agreement that it held with a major Romanian generator.
- Electricity network and supply arbitration - Dr. Hesmondhalgh acted as an expert witness in an ISCID arbitration regarding the damages suffered by the foreign purchaser of two eastern European electricity networks and supply companies due to the failure to respect regulatory guarantees and due process.
- District heating arbitration – Dr. Hesmondhalgh acted as an expert witness in an arbitration before the ICSID regarding the expropriation of district heating facilities in Latvia. She has calculated the damages owing to the majority owner of the facilities.
- Electricity supply contract dispute – Dr. Hesmondhalgh acted as an independent expert on behalf of a client in a claim for misrepresentation and breach of contract concerning an allegation that the client's refusal to allow a third-party to sell back electricity or terminate its contract caused damages.
- Billing systems dispute – on behalf of a client who supplied a billing system to a major utility, Dr. Hesmondhalgh rebutted the damages claimed by the purchaser, who alleged that the billing system had failed to work properly.
- Power station damages – Dr. Hesmondhalgh managed a team calculating the damages associated with the failure of a large power station to operate in the manner guaranteed by the warranties provided by the seller at the time that the power station was sold to Dr. Hesmondhalgh's client.
- Gas storage facility testimony, GB - Dr. Hesmondhalgh provided testimony regarding the economic case for a new gas storage facility in the GB at a public planning enquiry on behalf of the local council in whose area the facility would be built.

- Advice on the GB renewable obligations certificate (ROC) market – as part of a US case concerned with the alleged failure of a renewable power investment fund to meet its obligations to its investors, Dr. Hesmondhalgh provided evidence regarding the operation of the GB ROC market and the likely revenues that could have been anticipated for energy from waste plants.

Gas Market Regulation and Competition

- Competition complaint relating to the Nord Stream 2 - Dr. Hesmondhalgh contributed to the economic analysis for a complaint lodged by Naftogaz (and subsequently withdrawn as part of a Settlement Agreement between Naftogaz and Gazprom) with the European Competition regarding the potential anti-competitive effects of the Nord Stream 2 pipeline unless various commitments regarding its use and pricing were imposed on Gazprom.
- Competition complaint relating to the relaxation of the exemption conditions for the OPAL pipeline – on behalf of Naftogaz, Dr. Hesmondhalgh helped draft an expert report on the consequences for the European gas market of the relaxation of the exemption conditions for the OPAL pipeline in 2016/17.
- TAR Network Code – Dr. Hesmondhalgh provided advice to the Ukrainian regulator on the requirement of the TAR Network Code in respect of introducing transportation tariffs in Ukraine that were consistent with the Third Gas Directive.
- Draft gas balancing network code for the EU – Dr. Hesmondhalgh advised Ofgem on whether the draft balancing network code for the EU, which was to be published by the European Network of Transmission System Operators for Gas (ENTSOG), met the requirements laid out in the Framework Guidelines issued by the Agency for the Cooperation of Energy Regulators (ACER). The work was commissioned by Ofgem on behalf of ACER – Ofgem.
- Impact assessment for changes to transportation capacity in GB – for the GB regulator, Dr. Hesmondhalgh drafted an impact assessment for changing the arrangements for obtaining exit capacity in the gas transportation system. The work involved analysis of the costs that market participants estimated they would incur, of potentially avoided investment costs, and of the effects on competition, discrimination and consumers.
- Competition complaint relating to the relaxation of the exemption conditions for the OPAL pipeline – on behalf of Naftogaz, Dr. Hesmondhalgh helped draft an expert report on the consequences for the European gas market of the relaxation of the exemption conditions for the OPAL pipeline in 2016/17.

- Gas cost calculations – Dr. Hesmondhalgh has examined how the gas tariffs paid by Russian fertilizer producers compare to Gazprom's underlying production & delivery costs, and whether they pay an unfairly low price.
- Assistance to Ofgem in developing system operator (SO) incentives for 2013 – Dr. Hesmondhalgh was part of the Ofgem team working on the long-term SO incentives for electricity transmission to align the current schemes with to the TO price control (RIIO T1).
- Analysis of gas contract flexibility - On behalf of an international oil and gas company, Dr. Hesmondhalgh valued the flexibility included in a gas supply contract in comparison with the flexibility in typical German import contracts. Also, for a Dutch utility, Dr. Hesmondhalgh built a model to assess the relative value of different types of gas flexibility: swing in gas contracts, gas storage, linepack and conversion between L-cal and H-cal gas.
- German gas market study – On behalf of a major international energy company, Dr. Hesmondhalgh produced a study of the gas market in Germany for use in potential price review arbitrations.
- Supply contract margins – For an European energy company, Dr. Hesmondhalgh calculated the margin the company could have expected to earn on its supply contracts. As well as providing analysis on contract margins, Dr. Hesmondhalgh also provided advice on the relevance of German import prices to the obtainable value.
- Damages associated with alleged abuse of dominant position – Dr. Hesmondhalgh was part of a Brattle team that estimated the damages associated with the alleged abuse of a dominant position in the non-provision of the SIPs database to competing retail companies.
- Transit tariff benchmarking study – Dr. Hesmondhalgh led a study that compared the Ukrainian transit tariff to tariffs charged by other European pipeline companies.
- Retail competition – on behalf of an energy trading company, Dr. Hesmondhalgh reviewed and provided comments on a proposed submission to Ofgem on retail competition.
- Gas price controls, Belgium - Dr. Hesmondhalgh managed a study for Fluxys that explained the rationale for multi-year tariffs, reviewed the application of multi-year tariffs in other jurisdictions, and recommended measures for Belgium.
- Analysis of the opportunity costs associated with providing gas to Ireland rather than GB - as part of a mediation process, Dr. Hesmondhalgh directed a project that modelled the development of electricity prices in GB and Ireland in order to determine what value would be lost from providing gas in Ireland rather than GB. She

subsequently gave extensive advice on how the contract terms should be adjusted to reflect the changing way in which power prices are determined in Ireland.

- Determination of the fair price for gas supplies to industrial consumers in Russia – Dr. Hesmondhalgh directed a project that assessed what it would have been reasonable for an industrial consumer in Russia to pay for gas. The work was undertaken to provide a defence against a US Department of Commerce allegation of dumping in relation to the goods produced using the gas.
- Impact of potential gas price discrimination on the Spanish electricity market - as part of an analysis of the likely effects of the proposed mergers between Gas Natural and Iberdrola and Gas Natural and Union Fenosa, Dr. Hesmondhalgh was responsible for modelling the impact on prices and generator profits of possible gas price discrimination strategies pre- and post-merger.
- Analysis of the value of gas storage facilities, Europe - for a gas storage owner, Dr. Hesmondhalgh carried out an option based analysis of the value of its storage facilities and also benchmarked this value against other storage facilities, taking into account their different operating characteristics.
- Drivers of gas storage value, the Netherlands – for a Dutch utility considering investment in a gas storage project, Dr. Hesmondhalgh directed a study that assessed the supply of and demand for peak capacity in the Netherlands, and identified the key risks to the future value of gas storage facilities in the Netherlands.
- Gas price control regime for Germany – in conjunction with E-Bridge Consulting, Dr. Hesmondhalgh developed proposals for a gas price control regime for Germany for a major Germany utility. The proposals were subsequently presented to the German regulator.
- Harmonisation of gas tariffs, Ireland - Dr. Hesmondhalgh managed a project exploring potential options for harmonising gas tariffs in the Republic of Ireland and Northern Ireland.
- Gas contract advice, GB, Ireland and Spain - for major gas suppliers in GB, Ireland and Spain, Dr. Hesmondhalgh led projects reviewing the economic and commercial consequences of draft gas contracts with potential new power stations. The contract terms varied from straightforward oil product price indexation through power price indexation to tolling contracts, with a variety of re-opener clauses and other terms.
- Gas market design and liquidity - for the Dutch regulator, Dr. Hesmondhalgh directed a project investigating which market features were necessary to ensure the development of a liquid and well-functioning market. This work involved analysing a number of gas markets around the world, including the UK and US gas markets.

- Investment incentives, GB – Dr. Hesmondhalgh was extensively involved in drafting the GB regulator's proposals for the new deep incentive regime for Transco as operator of the high pressure gas transmission system.
- Gas/electricity arbitrage opportunities, GB – Dr. Hesmondhalgh conducted a review of the opportunities for and implications of arbitrage between electricity and gas markets for the GB gas regulator.
- Introduction of the Network Code, GB – on behalf of the GB gas regulator, Dr. Hesmondhalgh was the manager of a team responsible for reviewing the state of readiness of the gas industry for the introduction of daily balancing and the Network Code.
- Gas pipeline transit capacities, Belgium - Dr. Hesmondhalgh directed a project for the Belgian regulator (CREG) on future prospects for European transit activities and the need for investment in network capacity in Belgium. This involved assessing all of the key drivers of gas flows across Europe including liberalisation, hub trading, security of supply requirements, and supply and demand patterns.
- Security of supply review, GB - Dr. Hesmondhalgh reviewed security of supply issues for the GB regulator, which involved in-depth analysis of the supply/demand position in GB, uses and costs of storage, and the economics of interruption.
- Gas storage valuation, UK – Dr. Hesmondhalgh has produced a gas storage valuation in relation to negotiations to buy back rights to storage capacity that had been sold under a 5-year contract.

Electricity Regulation

- Assistance to Ofgem in developing long-term system operator (SO) incentives from 2013 – Dr. Hesmondhalgh was part of the Ofgem team working on the long-term SO incentives for electricity transmission to align the current schemes with to the TO price control (RIIO T1), including reviewing NGET's proposals.
- Proposals for the reform of the Spanish electricity and gas wholesale markets – for a major Spanish utility, Dr. Hesmondhalgh managed a team that provided proposals for ways in which the Spanish energy markets could be improved.
- Investigation of potential sources of demand response in GB – for Sustainability First's Demand Forum, Dr. Hesmondhalgh developed a bottom-up model of demand use by sector, end-use and half-hour in GB. She used this model to estimate the potential for demand response and reduction at different times of the day and year and the impact that such demand changes might have on electricity prices and carbon emissions.

- Incentive design for electricity system operations, Spain – Dr. Hesmondhalgh advised Endesa on the design of incentives for electricity system operations which was used to assist Endesa in negotiations over EU and Spanish regulations.
- Incentive arrangements for offshore wind transmission owners, GB - for the GB regulator, Dr. Hesmondhalgh was responsible for developing a set of availability incentive arrangements that took into account the very wide range of outages that can be associated with offshore wind cables.
- Analysis of the advantages and disadvantages of a centralised renewables market - for the GB regulator, Dr. Hesmondhalgh was responsible for analysing whether a centralised renewables market would facilitate the construction of renewable power plants. The resulting report was published by the regulator and can be found at
  - http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=169&refer=Markets/WhlMkts/Discovery.
- GB industry code governance arrangements - in conjunction with Simmons and Simmons, Dr. Hesmondhalgh led a project looking at the governance arrangements for the codes that specified how the GB electricity and gas markets work and made recommendations as to how the governance arrangements could be improved. This review was published by the GB regulator and can be found at
  - http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=66&refer=Licensing/IndCodes/CGR.
- Treatment of zonal losses in GB electricity market and impact of carbon support mechanism - for the GB regulator Dr. Hesmondhalgh analysed the impact of introducing a zonal system for losses and the impact of the carbon support mechanism. She also critiqued a report on the impact of zonal losses prepared by a third-party consultancy as well as providing her own qualitative assessment of the likely impact.
- Cross border system operator incentives - on behalf of a Spanish client, Dr. Hesmondhalgh led a team that produced a report on the interactions between domestic and cross border congestion constraints. This report was submitted to the Council of Europe Energy Regulators in response to a consultation that they published on the same subject.
- Mechanisms for improving electricity market liquidity in GB - for the GB regulator, Dr. Hesmondhalgh was responsible for developing ideas on potential regulatory mechanisms to increase electricity market liquidity and was heavily involved in drafting the subsequent consultation document.
- Analysis of the impact of early connection rights for renewable generators in GB - for the GB regulator, Dr. Hesmondhalgh directed a project to analyse the impact of

allowing renewables generators to connect to the grid before the consequential wider reinforcement works were completed. The analysis looked at the impact on congestion costs, CO_2 emissions and power prices.

- Advice on renewable integration in the Spanish electricity market - Dr. Hesmondhalgh worked for a large Spanish electricity firm developing market rules that would better accommodate the growing capacity of wind power in the Spanish electricity market. Issues included (i) the need for adequate remuneration for an efficient mix and amount of conventional plant; (ii) sharper demand-side management signals; (iii) incentives to build flexibility into the system in order to absorb the renewable energy and to store it; (iv) appropriate incentives for renewable generators; and (v) measures to ensure that the generators of renewable energy bear an adequate share of the back-up costs they impose on the system.
- Assessment of alternative congestion management arrangements in the Netherlands - Dr. Hesmondhalgh oversaw a project that developed and quantitatively assessed alternative methods for congestion management in the Netherlands. The work involved an assessment of the costs and benefits to different groups, as well as an assessment of how various mechanisms would be able to cope with market power. The report was published and submitted to the Dutch parliament as part of the decision making process for a new law on congestion management.
- Reform to transmission access regime & review of TenneT's connection policy - Dr. Hesmondhalgh was involved in assessing possible reforms to the transmission access regime in the Netherlands. The work examined several proposals including auctioning available transmission capacity, forced site auctions, the use of tradable transmission rights, greater publication of relevant congestion information, a "connect and manage" approach and the use of locational transmission charges. Dr. Hesmondhalgh took part in a number of workshops in which generators and other industry representatives gave feedback on the proposals and detailed their concerns and ideas for connection policy. The work was subsequently published by TenneT.
- Analysis of the impact of Enel's asset sales on liquidity - for an Italian utility, Dr. Hesmondhalgh investigated the impact that Enel's asset sales could have on market liquidity and on market power concerns. Dr. Hesmondhalgh showed that the way in which the assets were sold would be likely to limit the effectiveness of the process although there should be some impact.
- Critique of proposals designed to increase liquidity in the Belgian power market - for Electrabel, Dr. Hesmondhalgh analysed proposed forced asset sales to investigate whether they could contribute significantly to market liquidity. She concluded that the proposals were unlikely to have a significant effect on liquidity since there were

other aspects of the market, such as interconnector trading arrangements, that were more significant constraints on liquidity.

- Critique of Greek Electricity Distribution Code - Dr. Hesmondhalgh led a project to provide advice to the Greek regulator (RAE) on the proposed distribution code. The code included a number of performance incentives and part of the project involved comparing those incentives to others implemented across Europe. In addition, Dr. Hesmondhalgh provided detailed comments on the algebra and drafting of the proposed code.
- NGC's System Operator Incentives, GB - Dr. Hesmondhalgh was involved in the development of NGC's incentives. This involved analysing how NGC contracts for ancillary services and the costs it incurs in so doing, NGC's use of the balancing mechanism under NETA, and the form and parameters for NGC's financial incentive scheme. She also assisted with drafting licence conditions, including those relating to the publication of information on procurement mechanisms and balancing principles.
- Overview of international approaches to the regulation of electricity networks, E.ON - Dr. Hesmondhalgh provided a report comparing and contrasting approaches to the regulation of electricity networks in liberalised markets around the world.
- Long term reserve contracts as an aid to security of supply, NMa – Dr. Hesmondhalgh analysed the extent to which long term reserve contracts might improve security of supply in the Netherlands by encouraging marginal generators to remain on the system. The project also involved a cost-benefit analysis of the proposed scheme and looked at the problem of market power in the reserve market and the implications that this had for the wider wholesale market.
- Regulation of transmission and distribution companies in the Netherlands – for SEP, the umbrella body who owned the Dutch transmission network operator/owner TenneT, Dr. Hesmondhalgh drafted a response to the consultation paper on the regulation of transmission and distribution companies in the Netherlands produced by the DTe. The document covered international regulatory approaches, the calculation of appropriate rates of return on capital, an explanation of relevant considerations in the determination of a regulatory asset base and the limitations of benchmarking exercises for transmission companies.
- The need for and role of a GB system operator under BETTA in GB - as part of the work on the integration of the GB electricity market, Dr. Hesmondhalgh provided advice to Ofgem on how a single set of wholesale trading arrangements would be most efficiently managed by a single system operator (SO). She considered options for the extent to which a GB SO should be responsible for transmission planning and

how such planning should be co-ordinated across the three transmission network owners.

- Transmission system access and pricing arrangements in GB - Dr. Hesmondhalgh provided economic advice and policy support to Ofgem on issues associated with future transmission network access and pricing arrangements.
- Review of connection policies for transmission and distribution in GB – for Ofgem, Dr. Hesmondhalgh compared and contrasted the approaches to connection costs (e.g. deep versus shallow) for transmission and distribution networks in electricity and gas. She reviewed NGC's proposals to move to a "super shallow" connection policy with more sharply differentiated use of system charges.
- Assistance in preparing responses to proposed distribution price control for distribution companies - for two UK distribution companies, Dr. Hesmondhalgh helped draft responses to the regulator's consultation documents and prepare evidence to support the arguments that were being made.
- New Electricity Trading Arrangements in GB - Dr. Hesmondhalgh advised the Director General of Electricity Supply throughout the process of reviewing and restructuring the electricity trading arrangements. She was responsible for drafting most of the key documents relating to the economic aspects of the proposed changes, including reviewing arrangements in other liberalised markets. She also assisted in the preparation of various reviews of NETA prepared by Ofgem and provided advice on modifications to the trading arrangements.
- Competition Commission referral, GB - Dr. Hesmondhalgh provided economic advice to Ofgem in relation to the referral of two generators to the Competition Commission following their refusal to accept a licence condition prohibiting market abuse. This involved, amongst other things, analysing past examples of Pool price manipulation and considering what the potential for market abuse may be under NETA.
- Alternative market mechanisms for Italy – on behalf of Edison, Dr. Hesmondhalgh led a four day workshop exploring various aspects of potential market mechanisms for Italy. This included developing a simulation model, which allowed the workshop participants to experiment with different strategies under different sets of Pool rules. Subsequently she presented the key conclusions emerging from the workshop to the Ministry of Energy and Industry, at the request of the client.
- Preparation for market liberalisation, Union Fenosa, Spain - Dr. Hesmondhalgh directed the on-site team advising Union Fenosa on its preparations for electricity market liberalisation, specifically in the areas of company restructuring, economic

assessment of proposed market rules, and modelling of electricity prices and revenues of generating plant in a competitive environment.

- CHP and renewables policy under NETA, Ofgem - Dr. Hesmondhalgh was involved in drafting Ofgem's "Report to the DTI on the Review of the Initial Impact of NETA on Smaller Generators". Previously, she had advised Ofgem on policy for CHP plant and generation from other renewable sources of energy under NETA.
- Emission constraint modelling, Ofgem - Dr. Hesmondhalgh managed a project that modelled the effects of Environmental Agency proposals for changes to sulphur dioxide emission limits for generating plant. The project investigated the incentives placed on coal-fired generators to invest in and use flue gas desulphurisation equipment as a result of changes in company-wide and plant-specific sulphur emission limits. She also investigated the effects that these changes would have on overall generation patterns.
- Analysis of generators' ancillary services revenues, NGC - Dr. Hesmondhalgh undertook a top-down analysis of the revenues that generators were earning from ancillary services and the Pool to see if there was any correlation between their behaviour in the Pool and the ancillary services market.
- Pool price enquiries, OFFER (one of the precursors of Ofgem) - Dr. Hesmondhalgh provided economic and analytical support for OFFER's various inquiries into the operation of the initial wholesale trading arrangements in England and Wales (the Pool).

Markets & Investments

- Due diligence on two UK offshore wind farms – on behalf of a potential buyer, Dr. Hesmondhalgh led a team in 2019 assessing the value of two offshore wind farms receiving compensation under the Renewables Obligation scheme.
- Analysis of proposed offshore wind farm and electricity interconnector project – on behalf of TenneT and Energienet, Dr. Hesmondhalgh analysed the value for the proposed COBRACable between the Netherlands and Denmark under various different assumptions regarding how an offshore wind farm might be connected to the cable.
- Advice on potential acquisitions in the Netherlands and Belgium - for a major utility, Dr. Hesmondhalgh carried out extensive analysis of the potential value of different acquisition targets in these markets.
- Valuation of a potential IGCC plant in Belgium - for an independent power producer, Dr. Hesmondhalgh was involved in producing power price projections and a financial

model for a potential new IGCC power plant. She tested the sensitivity of the valuation to different scenarios regarding the development of the Belgian electricity market and also the interactions between carbon prices, coal prices and gas prices.

- Interconnector valuations - Dr. Hesmondhalgh has carried out studies to value (congestion rent, reserve) of proposed interconnectors between GB and the Netherlands, Belgium and Ireland. This work has involved stochastic analysis of power prices since the value of interconnectors mainly derives from fluctuating price differences in the two connected markets. She has also provided revenue forecasts for a new interconnector between Belgium and Germany for a number of alternative scenarios. The projects also involved estimating the impact of the interconnectors on renewables, CO_2 and consumer and producer welfare.
- Power contracting strategies – for Tennet, Dr. Hesmondhalgh has provided advice on a power contracting strategy during the commissioning of the BritNed cross-border cable between GB and the Netherlands.
- Trading arrangements, Norned cable – at the request of Tennet, Dr. Hesmondhalgh analysed alternative trading arrangements for the NorNed cable. She also presented proposals regarding trading arrangements to Dutch electricity traders at a seminar arranged by TenneT.
- Electricity price projections – for an investment bank, Dr. Hesmondhalgh produced electricity price projections for Switzerland, Hungary, Czech Republic and Italy. She also produced green certificate projections for Italy.
- Valuation of electricity assets in Singapore - Dr. Hesmondhalgh carried out detailed modelling of the Singapore electricity market, taking account of the possible effects of high levels of vesting contracts, the reserve market and opportunities to exercise market power.
- Analysis of EU energy and climate change policy and the implications for carbon capture and storage - for Alstom, Dr. Hesmondhalgh produced a published report analysing likely power market developments that will have an impact on the demand for carbon permits.
- Acquisition advice relating to Viesgo, Spain - Dr. Hesmondhalgh provided valuation advice relating to the generation, supply and distribution businesses for this spin-off from Endesa.
- Analysis of the impact of different trading arrangements on the value of various proposed interconnectors - Dr. Hesmondhalgh undertook probabilistic studies of the value that could be derived from various proposed interconnectors in NW Europe

and the impact that different trading arrangements (market coupling or explicit auctions) might have.

- Economics of renewable plants in GB, Ireland, Spain, Denmark and the Netherlands - Dr. Hesmondhalgh has directed projects analysing the economics of renewables plants of various types – wind, min-hydro, solar – receiving various types of subsidies.
- Economics of independent power plants in GB, Spain, Germany, Netherlands, Italy and Ireland (north & south) - Dr. Hesmondhalgh has directed numerous projects analysing the economics of various independent power plant projects across Europe. To do this, she helped develop an integrated financial asset modelling methodology, which uses both market-based data and cost-based equilibrium market modelling.
- Tolling contract advice, Ireland and Spain – Dr. Hesmondhalgh has led projects reviewing the economic and commercial consequences of draft tolling contracts with potential new power stations for major gas suppliers in Ireland and Spain.
- Value of stranded contracts, the Netherlands - the umbrella group for Dutch generators entered into a number of long term contracts with power producers in other countries, which subsequently proved to be out of the money. For a number of different parties at different times, Dr. Hesmondhalgh analysed the stranded costs locked into these contracts and assisted in negotiations regarding the discount that should be paid for the generating companies saddled with these contracts.
- Market risk advice, AES - Dr. Hesmondhalgh advised AES on the market risks to which its Barry plant would be exposed. She has also led a team providing market advice to both AES and the syndicating banks relating to the £1.9 billion acquisition of the 4,000 MW Drax coal fired station. For AES, she has also directed projects looking at a number of other markets including NordPool, Poland and Spain.
- Analysis of pumped storage assets - Dr. Hesmondhalgh assisted Kleinwort Benson in the preliminary bidding process for First Hydro, the pumped storage plant then owned by National Grid Company. She was subsequently advisor to Dominion Energy on its proposed acquisition of the £653 million business.
- Advice on the acquisition of an English electricity supply and distribution company, Singapore Power - Dr. Hesmondhalgh directed a project providing market and regulatory advice for Singapore Power when they were bidding for a supply and distribution company. This included modelling the future supply and regulated distribution revenues, providing advice on the concerns of the regulator and negotiating with a potential joint bidder.

Electricity & Gas Market Modelling

Dr. Hesmondhalgh has developed a number of models to simulate the operation of competitive electricity markets. These have been extensively used to value over 40 power plant projects across Europe and beyond. One of her models, the Brattle Annual Model, enables prices across Europe to be estimated by representing the region as individual electricity markets interconnected by transmission lines. Whilst primarily a cost-based model, it has been designed to facilitate including shaped price add-ons to match historic price shapes and forward curve data.

She has also developed a number of bespoke models to value long term contracts in electricity and gas markets and a model of the European gas network, designed to assess flows between markets and prices in those markets on the basis of existing and proposed supply sources, storage costs and price-sensitive demand.
Dr. Hesmondhalgh has also directed a number of other projects which required an in-depth understanding of modelling issues. These include:

- A study of the impact of different connection policies on congestion costs in GB.
- A study of the impact of the introduction of an LMP market on wind generators in Ireland.
- The impact of environmental measures (the Large Combustion Plant Director, the EU Emissions Trading Scheme) on the pattern of electricity flows around Europe.
- An analysis of the likely costs of operating the UK electricity transmission system, based on a probabilistic assessment of the costs of different ancillary services.
- An investigation into potential market abuse in the England & Wales power pool.

Other

- Investigation into wind farm delay in Ireland – Dr. Hesmondhalgh was contracted by Art Generation, a developer of wind farms in Ireland, to investigate why the allowed connection date for its two wind farms had been pushed back from 2015 to 2019.
- Carbon auctions, CEFIC – Dr. Hesmondhalgh provided advice to the European Chemical Industrial Council (CEFIC) on carbon auctions and their impact on chemical companies.
- Carbon issues, GB – Dr. Hesmondhalgh helped the GB regulator draft a paper on the approach that the regulator should take when interacting with the government on low carbon issues.

PUBLICATIONS

"GB Electricity Demand – 2012 and 2025. Impacts of demand reduction and demand shifting on wholesale prices and carbon emissions. Results of modelling", for the Sustainability First Smart Demand Forum, Serena Hesmondhalgh, Gill Owen, Maria Pooley and Judith Ward, December 2013.

"A Trip to RIIO in Your Future?", Peter Fox-Penner, Dan Harris and Serena Hesmondhalgh, Public Utilities Fortnightly, October 2013.

"GB Electricity Demand – 2012 and 2025. Initial Brattle Demand-Side Model – Scope for Demand Reduction and Flexible Response", for the Sustainability First Smart Demand Forum, Serena Hesmondhalgh and Sustainability First, December 2012.

"Easing the Transition from Oil-Indexation", Serena Hesmondhalgh and Dan Harris, Petroleum Economist, August 3, 2011.

"BSC Modification 229: Potential interactions with options for changes to transmission charging", Serena Hesmondhalgh and Dan Harris, The Brattle Group, Ltd., May 23, 2011.

"A Review of LE/Ventyx's Cost-Benefit Analysis of Modification, P229, Lot 3 Additional Analysis", Serena Hesmondhalgh and Dan Harris, The Brattle Group, Ltd., September 2, 2010.

"A Review of LE/Ventyx's Cost-Benefit Analysis of Modification, P229, Lot 1 Report", Serena Hesmondhalgh and Dan Harris, The Brattle Group, Ltd., September 2010.

"Alternative Trading Arrangements for Intermittent Renewable Power: A Centralised Renewables Market and Other Concepts", Serena Hesmondhalgh, Dan Harris and Penelope Wilson, The Brattle Group, Ltd., April 2010. Published by Ofgem at (www.ofgem.gov.uk).

"EU Climate and Energy Policy to 2030 and the Implications for Carbon Capture and Storage: A Report for ALSTOM Power Systems", Serena Hesmondhalgh, Toby Brown and David Robinson, The Brattle Group, Inc., March 2009.

"Is fuel diversity the answer to security of supply?", Serena Hesmondhalgh and Dan Harris for the 9th IAEE European Energy Conference "Energy Markets and Sustainability in a Larger Europe," Florence, Italy, June 2007.

"Critique of the Industry Codes Governance Arrangements", Serena Hesmondhalgh, Boaz Moselle and Toby Brown, The Brattle Group, Inc., June 2008.

"A Review of TenneT's Connections Policy", Serena Hesmondhalgh, Carlos Lapuerta and Dan Harris, The Brattle Group Ltd., July 2007.

"Can Wind Work In An LMP Market?", Serena Hesmondhalgh, Philip Q Hanser and Dan Harris, Natural Gas & Electricity, November 2005.

"Long-Term Reserve Contracts in the Netherlands", Serena Hesmondhalgh, Carlos Lapuerta and Dan Harris, The Brattle Group Ltd., June 2004.

"A Study on Renewable Energy in the New Irish Electricity Market", Serena Hesmondhalgh and Dan Harris, The Brattle Group Ltd., June 2004.

PRESENTATIONS

"Global Gas Supply & Demand – Impact on Hub Prices Query" presented at C5 Conference in Frankfurt, Germany, December 2011.

"An Economic Analysis of the Remit Proposals", presented at the 16th European Gas Conference in Oslo, Norway, June 2011.

"Resource Adequacy and Renewable Energy in Competitive Wholesale Electricity Markets", Serena Hesmondhalgh, Johannes P. Pfeifenberger and David Robinson, The Brattle Group, Inc., presented at the 8th Annual British Institute of Economics Academic Conference, September 23, 2010.

"Oil Indexation & Gas Prices: Is Current Pricing for Gas Sustainable?", presented at the Flame 2010 Conference, Amsterdam, The Netherlands, March 2010.

"How Do You Value Storage in Emerging Gas Markets?", presented at the Sparks and Flames Conference, Rotterdam, The Netherlands, December 2009.

"Liquidity in wholesale electricity markets", presented at an Ofgem Seminar, London, United Kingdom, August 2009.

"How Open are Europe's Energy Markets?", presented at 13. IIR-Jahrestkongress fur die Energiewirtschaft, Austria, April 2008.

Mr. Dan Harris has more than fifteen years of experience as an expert in valuation and quantification of damages. He has been retained by major law firms and their clients to testify on damages and quantum in international arbitration proceedings in a variety of forums including the International Centre for Settlement of Investment Disputes, the International Chamber of Commerce and the Permanent Court of Arbitration. He has acted as an expert witness for Nigeria in an ICSID dispute in the oil sector, and is currently acting as an expert witness in a commercial arbitration for a private client in Nigeria. Mr. Harris is listed as one of the world's leading arbitration experts in *Who's Who Legal: Arbitration*.

Mr. Harris is a regular speaker at gas and electricity conferences, and lectures at the Florence School of Regulation. Prior to joining The Brattle Group in 2002, Mr. Harris worked for Shell's upstream oil and gas business in the Netherlands for five years in a variety of roles, including the development of economic models for new oil and gas field developments.

EDUCATION

2001-02	London School of Economics London, United Kingdom- MSc. Economics (Merit)
1991-95	Imperial College London, United Kingdom - M. Eng. Chemical Engineering (First Class Honours)

AREAS OF EXPERTISE

International Arbitration
Commodities
Natural Gas
Electric Power

SELECTED EXPERIENCE

Commercial and Investor-State Arbitration

- Mr. Harris is the testifying expert in commercial dispute in the Middle East involving a Joint Venture to manufacture Heat Recovery Steam Generators used in gas-fired power plants. The work involves estimating damages resulting from alleged breaches of one of the JV partners.
- In an ICSID dispute, claimants have appointed Mr. Harris as the damages expert in a claim involving expropriation of a waste collection and treatment business in Egypt.

- In an ICC arbitration, Respondents appointed Mr. Harris as an expert to review claims resulting from the early termination of a contract to supply Liquid Petroleum Gas in West Africa.
- Mr. Harris is the testifying expert in a commercial dispute involving the early termination of a long-term contract to use a Liquefied Natural Gas terminal. The work involves determining how much the terminal user should pay for early termination, with claims in excess of $1 billion.
- Respondents in a commercial arbitration have retained Mr. Harris as an expert witness to analyses the damages resulting from claims by the joint venture partner. The issues relates to an alleged underinvestment in a large chain of petrol stations in West Africa, and the resulting loss of profits.
- In the context of an ICC arbitration, Mr. Harris has been appointed as an expert to rebut claims made against a buyer of power from a large-scale photovoltaic project in South Asia. The issues involve an assessment of any benefits and costs for the buyer resulting from the delay of the project.
- Mr. Harris acted as an expert witness for Nigeria in an ICSID dispute involving the value of an alleged expropriation in the oil sector. The work involved valuing oil and gas assets, assessing the reasonableness of costs and production forecasts, and opining on the appropriate damages methodology.
- Mr. Harris is acting as a quantum expert in the context of an investor-state dispute in Eastern Europe. Specifically, the claimant has retained Mr. Harris to value losses associated with the alleged expropriation of a chain of petrol stations, and the lost opportunity to develop petrol stations in the region.
- Mr. Harris co-authored a report which estimated damages to the developer of a cancelled power station project in Turkey, and re-rebutted claims of damages from the developer's expert (ICSID arbitration).
- Mr. Harris acted as an expert in an investor-State dispute in south-east Europe, relating to a dispute involving the processing of copper concentrate and repayment of loans. The work involved the valuation of a copper mine at various points in time and an assessment of the mine's ability to re-pay debts.
- Mr. Harris acted as a quantum expert advising in an Energy Charter Treaty dispute between an investor in energy distribution networks in an Eastern European EU Member State and the Government. The work involves an assessment of damages as a result of the measures taken by the regulator, including a valuation of the regulated gas distribution business.

- In the context of an ICSID dispute, Mr. Harris acted as a quantum expert for a construction company claiming damages against a Middle Eastern country for the alleged early termination of a long-term oil-field services contract. The work involved estimating the value of the contract at termination as well as financial damages resulting from various alleged actions by the State.
- Mr. Harris acted as an expert witness in an ICC dispute involving a large power and water production plant in the Middle East. The work involves testimony on the financial effects of various delays which the project experienced, as well as addressing a claim by the offtaker that the plant's tariff should be reduced because of alleged non-conformity with the contract specifications.
- A large industrial user of natural gas in Nigeria retained Mr. Harris to act as an expert to determine whether they qualify for revised contract terms under the 'hardship' clause. The work involves an analysis of the relevant markets in Nigeria, and an assessment of the firm's accounts to determine if the losses the firm experienced were due to circumstances beyond its control.
- Mr. Harris is acting as an expert for a CIS State-owned oil and gas company in a Joint Venture dispute before the SCC. The work involves quantifying damages to an oil and gas joint venture resulting from the alleged failure of one of the parties to invest the promised funds. Mr. Harris quantified damages from the alleged failure to invest, valued the assets at the termination of the JV, and determined the division of the assets between the JV parties on the basis of the investments they had made.
- In the context of an ICC dispute, Mr. Harris advised claimants with respect to, among other things, the upstream gas resources available to the respondent and the sensitivity of reserves to changes in the price paid for gas.
- In the context of an ICC dispute, Mr. Harris analyzed a financial model of an LNG liquefaction facility, prepared a report critiquing the assumptions in the model, and analysed the consequences of alternative assumptions for liquefaction tariffs.
- Mr. Harris acted as an expert witness for a buyer of gas in south-east Europe in arbitration before the ICC with its seller. Mr. Harris authored expert testimony on the damages arising from a failure of the seller to supply LNG to the buyer, and gave oral testimony regarding his reports.
- Mr. Harris acted as an expert witness in a dispute regarding the supply of gas produced from the North Sea in Europe. Mr. Harris was been retained to give evidence on the value of unusual delivery terms in the contract, relative to a more standard contract.

- In the context of an appeal of the proposed regulated gas tariffs in South Africa, a group of large gas users commissioned Mr. Harris to write a report critiquing the methodology that the regulator had proposed to set gas prices. The work analysed the economic logic of the regulator's proposed method, addressed supporting arguments from the regulator's economic experts, explained the history of gas pricing in Europe and how it had developed, and contrasted the regulator's method with the regulatory methodologies of other regulators. The report was submitted to the South African High Court.
- Mr. Harris advised in an investor-State dispute in south-east Europe, relating to an investment in the petroleum sector.
- Mr. Harris has authored testimony in a dispute before the Irish High Court between an LNG terminal develop in Ireland and the Irish regulator, regarding the proposed tariffs for the Irish natural gas transport system.

SELECTED PUBLICATIONS

"The potential for price disputes in hub-indexed gas contracts", Chapter in 'Gas and LNG Price Arbitrations: A Practical Handbook' Second Edition, March 2020, published by Globe Law and Business, ISBN: 1787421929 with Valentina Bonetti and Carlos Lapuerta.

"Risk and Return for Regulated Industries", published by Elsevier, with Bente Villadsen, Mike Vilbert and Larry Kolbe, 1st May 2017, ISBN: 9780128125878.

Review of Approaches to Estimate a Reasonable Rate of Return for Investments in Telecoms Networks in Regulatory Proceedings and Options for EU Harmonization, with Richard Caldwell, Francesco Lo Passo, and Lucia Bazzucchi, July 18, 2016, Prepared for the European Commission's Directorate-General for Communications Networks, Content and Technology (DG Connect).

"A Subject of Interest: Pre-award Interest Rates in International Arbitration" Dan Harris, Richard Caldwell, and M. Alexis Maniatis Published by The Brattle Group, Inc. June 1, 2015.

"A Tale of Two Crises: The Betas of EU Networks", August 2013 Dan Harris and Francesco Lo Passo Published by The Brattle Group, Inc.

"International Experience in Pipeline Capacity Trading", Dan Harris, Toby Brown, Alessandro Massolo, 5 August 2013, prepared for AEMO.

"The Difference Between Winning & Losing: Engaging the Vital Role of Expert Witnesses in Arbitration" Presented at 'Successfully Negotiating & Renegotiating Long Term Gas Supply Contracts,' July 2013 Berlin, Germany.

'The WACC for the Dutch TSOs, DSOs, water companies and the Dutch Pilotage Organisation', Dan Harris, Bente Villadsen, Jack Stirzaker, 4 March 2013, prepared for NMa.

'Calculating the Equity Risk Premium and the Risk-free Rate' Dan Harris, Bente Villadsen, Francesco Lo Passo, 26 November 2012, prepared for the NMa and OPTA.

'Impact Assessment for the Framework Guidelines on Harmonised transmission tariff structures', Dan Harris, Penelope Wilson, 6 August 2012, prepared for ACER.

'Shift From Conventional To Unconventional Resources – What Does This Mean For Downstream Gas Players?' 27th – 28th March 2012: Unconventional Gas &Oil Global Summit, Warsaw, Poland.

'A Comparison of Anti-Manipulation Rules In US and EU Electricity And Natural Gas Markets: A Proposal For A Common Standard', with Shaun Ledgerwood, Energy Law Journal, Volume 33, No. 1 2012.

"REMIT: Issues For LNG trading", Presented to the LNG Global Conference September 27 2011

"Easing the Transition from Oil-Indexation," by Serena Hesmondhalgh and Dan Harris, Petroleum Economist, August 3, 2011.

"Research Into Gas Flexibility Services: Method Decision Flexibility Services," by Dan Harris, José Antonio Garcia, and Ilinca Popescu, The Brattle Group Ltd, prepared for the NMa Energiekamer (NMa), August 2, 2011.

"What Can Be Done at a Commercial Level to Resolve Contractual Disputes?" Presented at 'Commercial and Legal Strategies for Managing Risk in Long Term Gas Supply Contracts,' taking place July 11-12 2011 Berlin, Germany.

"Defining Market Manipulation in a Post-REMIT World," by Shaun D. Ledgerwood, Dan Harris, Bin Zhou, and Pinar Bagci, The Brattle Group, Inc., June 2011, available at www.brattle.com.

"Are your tariffs compliant with the 3rd Gas Directive?" Presented at the 4th Annual European UGS and Infrastructure Forum Berlin, 5th April 2011.

"Economic Impact of the Dutch gas Hub Strategy on the Netherlands", December 2010 with Coleman Bazelon and Penny Dickson. Available at www.brattle.com.

"A Review of the OXERA Report: 'Quantifying Antitrust Damages: Towards non-binding guidance for courts'," with Richard Caldwell and Carlos Lapuerta, Journal of European Competition Law and Practice (September 2010).

"La stima dei Danni nel dritto della concorrenza", with Richard Caldwell and Carlos Lapuerta, Dritto e Practica della Società, (June 2010), 35-44.

"Alternative Trading Arrangements for Intermittent Renewable Power: A Centralised Renewables market and Other Concepts", April 2010, with Serena Hesmondhalgh and Penny Dickson. Published by Ofgem at (www.ofgem.gov.uk).

"Assessment of the method to determine the value of the regulatory asset base (gas connections) managed by Dutch gas distribution network operators" May 2010, Dan Harris, Carlos Lapuerta. Published by the Energiekamer.

Faruqui, Ahmad, Dan Harris, and Ryan Hledik. "Unlocking the €53 Billion Savings from Smart Meters in the EU: how increasing the adoption of dynamic tariffs could make or break the EU's smart grid investment." Energy Policy, October 2010.

"Alternative Trading Arrangements For Intermittent Renewable Power: A Centralised Renewables Market and Other Concepts" April 2010, with Serena Hesmondhalgh and Penny Dickson, available at www.ofgem.gov.uk.

Faruqui, Ahmad, and Dan Harris. "On Demand." Utility Week 12 Mar. 2010: 24.

"Oil Indexation & Gas Prices: Is Current Pricing for Gas Sustainable?" presented at the Flame 2010 Conference, Amsterdam, the Netherlands, March 2010.

"How Do You Value Storage In Emerging Gas Markets?" presented at the Sparks and Flames Conference, Rotterdam, the Netherlands, December 2009.

"Unlocking the €53 Billion Savings from Smart Meters in the EU," by Ahmad Faruqui, Dan Harris, and Ryan Hledik, October 2009, Brattle discussion paper (available at www.brattle.com)

"Valuing gas storage without reliable prices", Flame gas conference, Amsterdam, the Netherlands, March 2009.

"Beating the Queue - Connection Policies for a Liberalised Market," presented at PowerGrid Europe, by Dan Harris, The Brattle Group, June 2008.

"A Review of TenneT's Connections Policy," by Carlos Lapuerta, Serena Hesmondhalgh, and Dan Harris, The Brattle Group Ltd., July 2007.

"Assessing Pipe-to-Pipe Competition: Theoretical Framework and Application to GTS," by Boaz Moselle and Dan Harris, The Brattle Group, December 2007.

"Is fuel diversity the answer to security of supply?" Prepared with Serena Hesmondhalgh for the 9th IAEE European Energy Conference "Energy Markets and Sustainability in a Larger Europe", June 2007.

"Independent System Operators for EU Energy Markets" February 2007, with Boaz Moselle, published as a Brattle Energy newsletter Issue 01 2007.

"Factors affecting geographic market definition and merger control for the Dutch electricity sector" June 2006, with Boaz Moselle and Prof. David Newbery. Published by NMa/DTe.

"Can Wind Work In An LMP Market?" November 2005, with Serena Hesmondhalgh and Philip Q Hanser, Published in Natural Gas & Electricity.

"Study on Renewable Energy in the new Irish Electricity Market" June 2004 prepared for Sustainable Energy Ireland with Serena Hesmondhalgh.

"Long Term Reserve Contracts in the Netherlands", June 2004, prepared for the Dutch Ministry of Economic Affairs.

"A Study on Locational Signals in Europe" September 2004 prepared for ETSO with Carlos Lapuerta.

"Wholesale Gas Competition in the Netherlands and Implications for Phase III Customers", June 2003, with Carlos Lapuerta. Published by NMa/DTe.

"Incentive Regulation" presented at the EMART Energy conference in Paris, October 2002.

"The Development of a spot market exchange infrastructure for Belgium", (February 2003) with Carlos Lapuerta and Boaz Moselle, prepared on behalf of the APX and Elia.

Appendix B : Commodity price modelling

252. In this appendix, we set out in more detail how we determined the commodity prices we used in our analysis. As discussed above,[227] commodity prices (coal, gas, and CO_2) are relevant both because they are a driver of electricity prices and because they are costs RWE incurs when operating Eemshaven. Over the period to 2054, these commodity prices could develop in different ways. Therefore, we assess 100 plausible price paths for these commodities, taking into account the extent to which movements in the different commodities are correlated. As we explain further, in Appendix C.2.i.b below, we also use these commodity price paths to vary our assumptions on the level of renewable capacity in the key European electricity markets that we model.

253. As explained further in this appendix, we have created the price paths using the probabilistic Monte Carlo method. We first explain how we identified the relevant variables to treat probabilistically ("stochastically") in Appendix B.1 and then describe in more detail the models we developed for creating the different price paths. For coal and gas, as discussed in Appendix B.2, we rely on a "two factor" model, which enables both long and short term effects to be captured and is frequently used in commodity trading or risk management. This approach is not suitable for modelling CO_2 prices primarily because CO_2 prices are highly policy dependent but also because the ETS system currently allows participants to submit their purchased permits at any point in the future so CO_2 prices cannot be associated with a particular delivery period, unlike coal and gas prices. We therefore adopt a different model, which is described in Appendix B.3.

B.1 Underlying data

254. To create our 100 commodity price paths, we need first to identify a starting set of data for prices into the future from which we can use as the basis of our probabilistic analysis. Market prices (forward curves) for commodities are only available for at most a few years into the future. Consequently, we also rely on published forecasts by the International Energy Agency ("IEA"). These extend further into the future (to around 2050) but show a broad range of possible outcomes. It is this range of possible outcomes that we incorporate into our probabilistic approach.

255. Renewable generation capacity is also an important consideration since many types of renewable generation have essentially zero marginal generation costs and so will always run when they are able to do so. Hence, a high level of renewable generation capacity may limit

[227] In Section IV.

the ability of Eemshaven to generate electricity and will reduce electricity prices, to Eemshaven's detriment.

B.2 A Stochastic model of coal and gas prices

256. To determine the price paths for coal and gas, we combine forward prices and price projections available on the valuation date with information on the volatility of coal and gas prices and their correlation available at the valuation date.

257. Effectively, we start with forward prices available on the valuation date for deliveries in a future period, and trace how the price might change in reaction to new information or events as time evolves. These changes in prices have to reflect our best estimate of the magnitude of the impact that new information will have in a structured and coherent way. We achieve this by adopting a specific model for the behaviour of coal and gas prices, which is routinely used by traders. It is known as a "two factor" model because it distinguishes between two types of information, short-term and long-term information. Commodity forward contracts with a long time until delivery only react to long-term information, whereas contracts where deliveries will start soon also react to short-term events, such as temporary imbalances in supply and demand.

258. The theory underpinning the two factor model is that coal and gas prices will vary from their forward curve levels in response to new information or events following what is known as a "random walk". A random walk implies that, for example, the coal price will change from one month to the next in an uncertain fashion that does not depend on how the coal price has changed up until that point.[228] This uncertain, "random", change is best assessed by probabilistic analysis. The extent to which the coal prices are likely to vary from one month to the next depends on their volatility – if the volatility of coal prices is high, then it is possible that prices could change very significantly from one month to the next whereas if their volatility is low this is much less likely.

259. The assumption that coal and gas prices follow a random walk over time, allows us to use the historical volatility and correlation in their historical forward prices to determine the

[228] Although, of course, the coal price at the start of the month does depend on the changes that have occurred in previous months. In other words, if the coal price increased from, say 50 €/t to 52 €/t between months A and B, the 2 €/t increase has no influence on whether the coal price goes up or down from month B to month C, although it does determine the price to which the next change is applied (52 €/t). Moreover, the likelihood of any given change depends on the volatility of coal prices so very large changes are less likely than smaller changes.

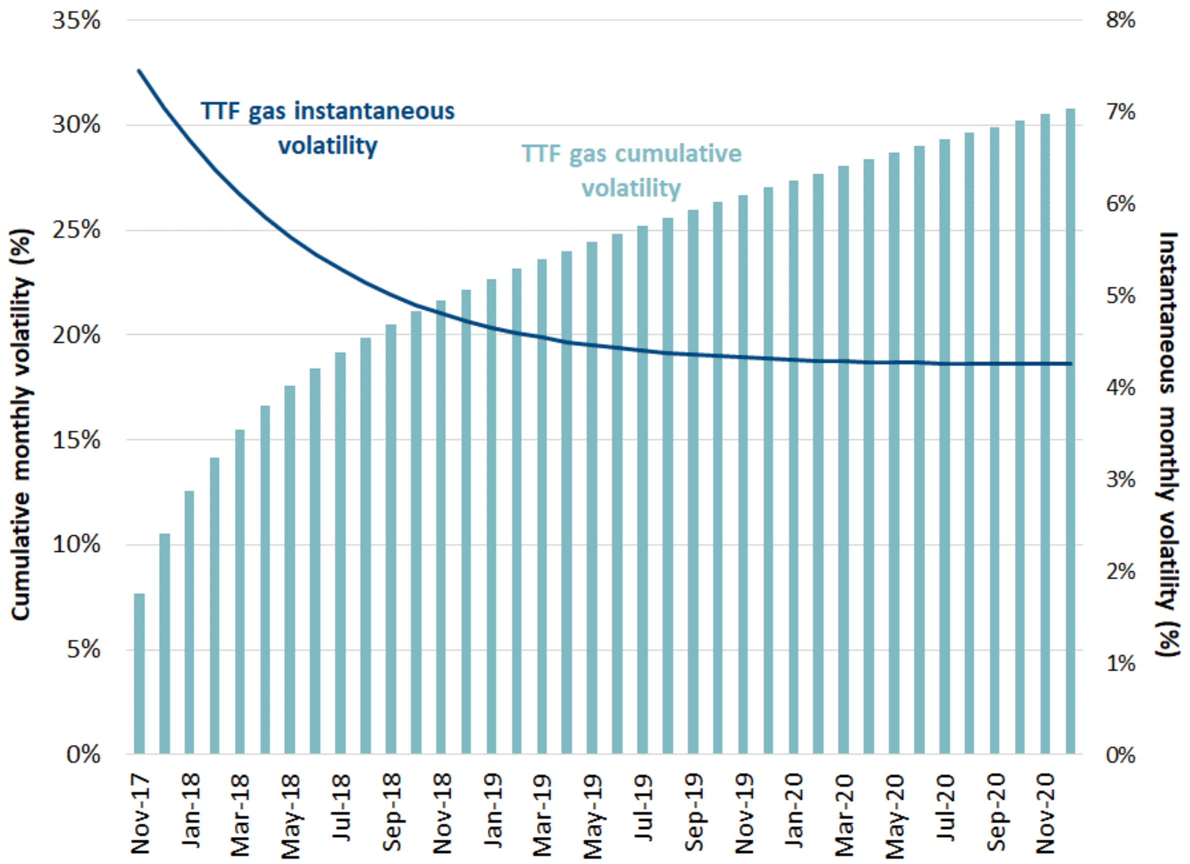
distribution of credible outcomes for any forward contract.[229] In line with standard practice, we draw from these distributions multiple times – in this case, 100 times, to build up 100 price paths for each commodity. The process is known formally as Monte Carlo analysis, and was developed by prominent mathematicians in the 1940s who worked on the Manhattan Project. Monte Carlo analysis use a sequence of random numbers to pick values from a pre-determined probability distribution of different outcomes derived from an analysis of volatility data.

260. To illustrate the ideas underlying our approach, Figure 16 shows an illustrative example of possible price changes in TTF gas prices over 38 months. Given that forward contracts with a short time to delivery react to both short-term and long-term information, we expect them to exhibit a higher volatility than contracts with a longer time to delivery. This makes sense, as short-dated forward prices are extremely sensitive to recent information and events. The prices in long-dated contracts tend to be more stable, as at any given point in time traders reason that the market will have time to restore equilibrium in response to short-term supply and demand imbalances. Thus, in any month, the market price of a contract for deliveries twelve months ahead will tend to change by a lower percentage than the price of a contract for deliveries one month ahead.

261. However, because this "instantaneous volatility" accumulates over time, the longer the time to delivery of a forward contract, the larger its *cumulative* volatility. These features of commodity prices are commonly referred to as the "volatility term structure".

[229] Focusing on forwards is standard practice, in part because it simplifies the mathematics necessary to construct a random walk, and in part because, the price of a commodity forward at maturity will converge with the spot price. The overall price outcome for any commodity forward contract between now and maturity will naturally reflect the combination of the potential period-to-period price changes during the interim. We build a forward curve model as described in **Exhibit BR-61**, Clewlow L., and Strickland C., Energy Derivatives: Pricing and Risks Management, Lacima Publications, 2000 "Forward Curve Models", Chapter 8.

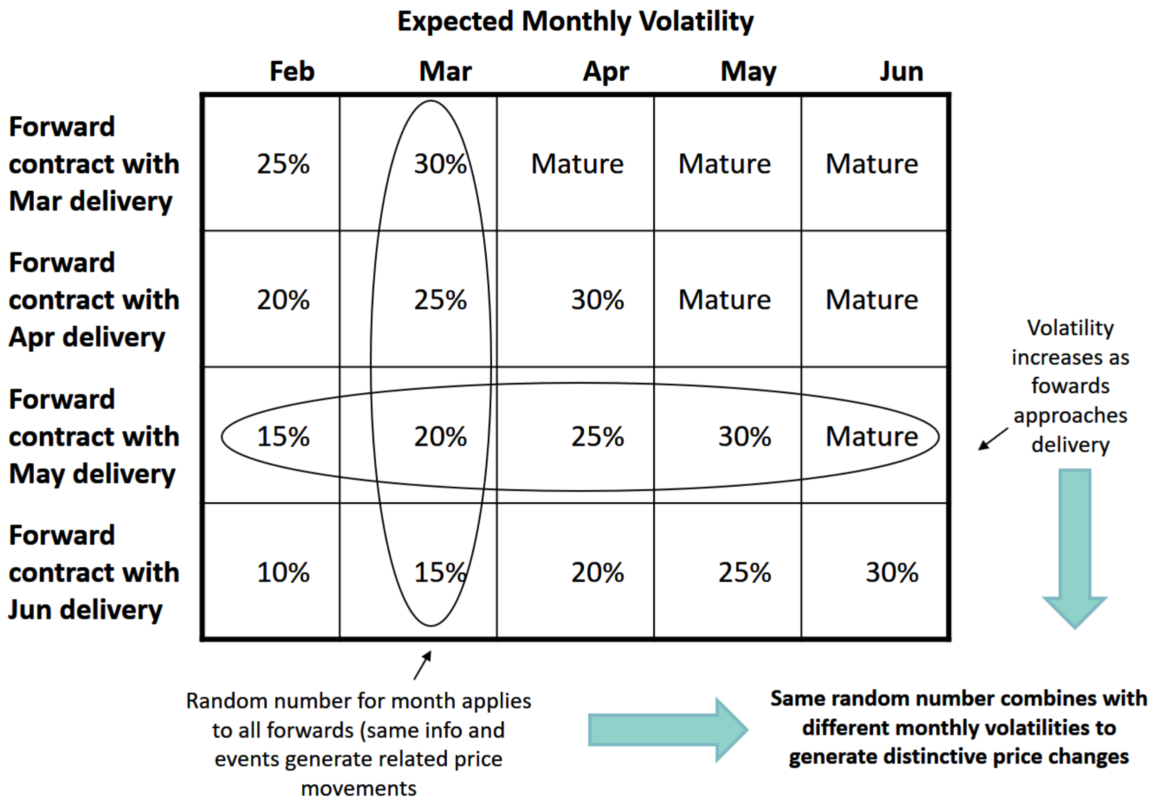
FIGURE 16: CUMULATIVE VOLATILITY IN TTF GAS PRICES (EXAMPLE)[230]



262. Knowing a forward contract's time to delivery and its corresponding volatility allows us to determine how the price of the contract will react to new information at the valuation date. Figure 17 illustrates how we use the volatility term structure to simulate (spot) prices. In this hypothetical example, we assume that the instantaneous volatility in the forward price decreases by 5 percentage points with every month. The rows represent forward contracts with different maturities (delivery periods) and the columns show different months. Each cell of the matrix represents the volatility of a forward contract (defined by the row) at a given time to delivery (defined by the column). In each month all forward contracts are exposed to the same information (short-term and long-term). It is only due to their different times to delivery that they react differently to it. We trace the reactions of a given forward contract over time by summing all its reactions to news across the columns in Figure 17. So, for example, a contract with a delivery date in May will have a volatility of 15% when it is traded in February and of 20% if traded in March. As a forward contract reaches delivery, by definition, it must converge to the spot price.

[230] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

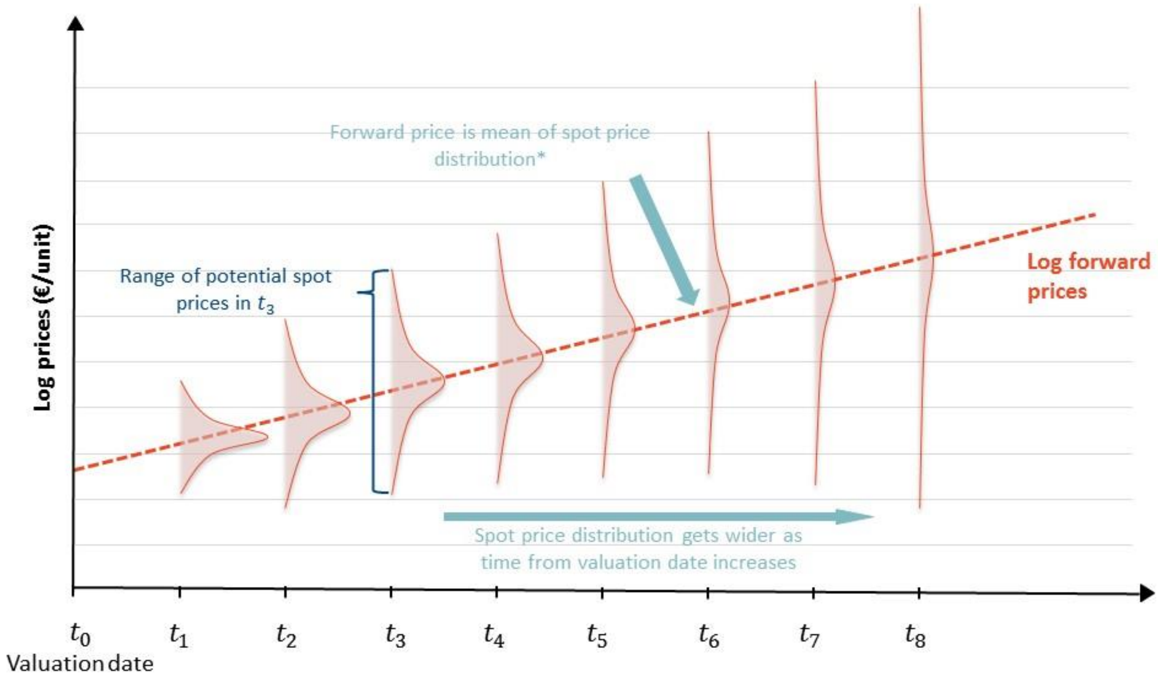
FIGURE 17: THE VOLATILITY TERM STRUCTURE AND CUMULATIVE PRICE CHANGES



263. As discussed above, we assume that commodity prices follow a random walk. This implies that the natural logarithms of the prices are normally distributed,[231] or, equivalently, that prices follow a "log-normal" distribution. Figure 18 illustrates the distribution of future log prices in our model. It demonstrates that, in line with the preceding discussion on cumulative volatility, the width of the distribution of potential prices increases as the period between the valuation date and the delivery date increases.

[231] A normal distribution is a probability distribution often referred to as a bell curve for its resemblance to a bell. The mean is the expected value with the highest probability. Deviation from the mean is symmetric, which means that a deviation from the mean of +2%, for example, has the same probability to occur of a deviation of -2%. The standard deviation of the distribution determines how likely a given deviation from the mean is. A random walk assumes that returns are normally distributed.

FIGURE 18: ILLUSTRATIVE DISTRIBUTIONS OF FUTURE PRICES

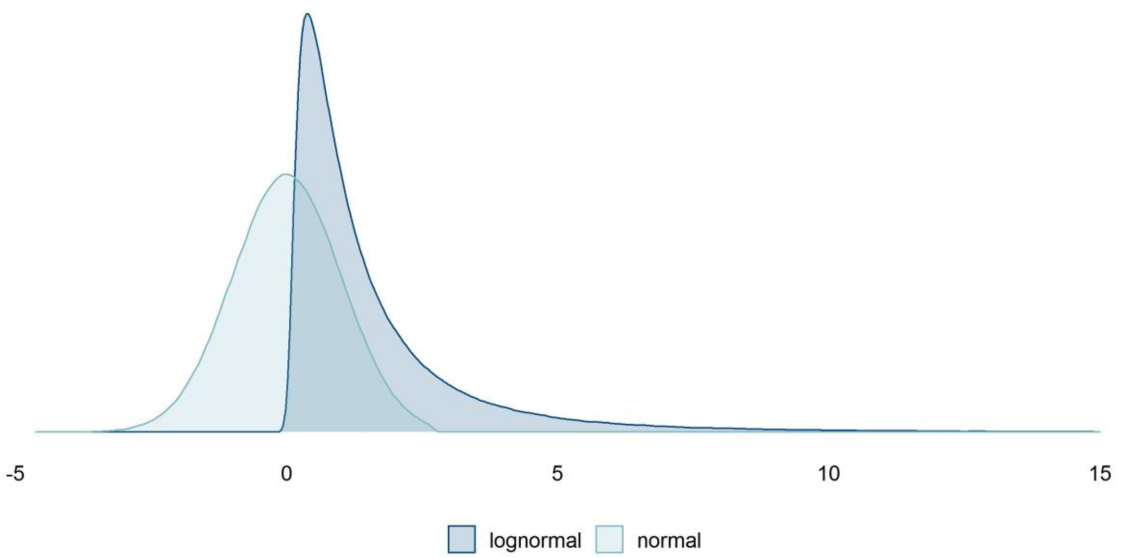


Note: *In an additional step, we turn these *risk-neutral* prices into *actual prices*.

264. A corollary of the assumption that the logarithms of commodity prices are normally distributed is that actual simulated prices follow a log-normal distribution. Figure 19 shows the values of a log-normal distribution that correspond to a standard normal distribution of its log values. The log-normal distribution has several advantageous features for the simulation of prices, including that all prices drawn from this distribution are positive.[232]

[232] While some commodity markets have seen negative price episodes in recent years, including electricity and oil markets, it is rather uncommon or even unheard of in the European gas market and global coal markets. Hence, restricting the possible price outcomes to the positive number space by design is helpful.

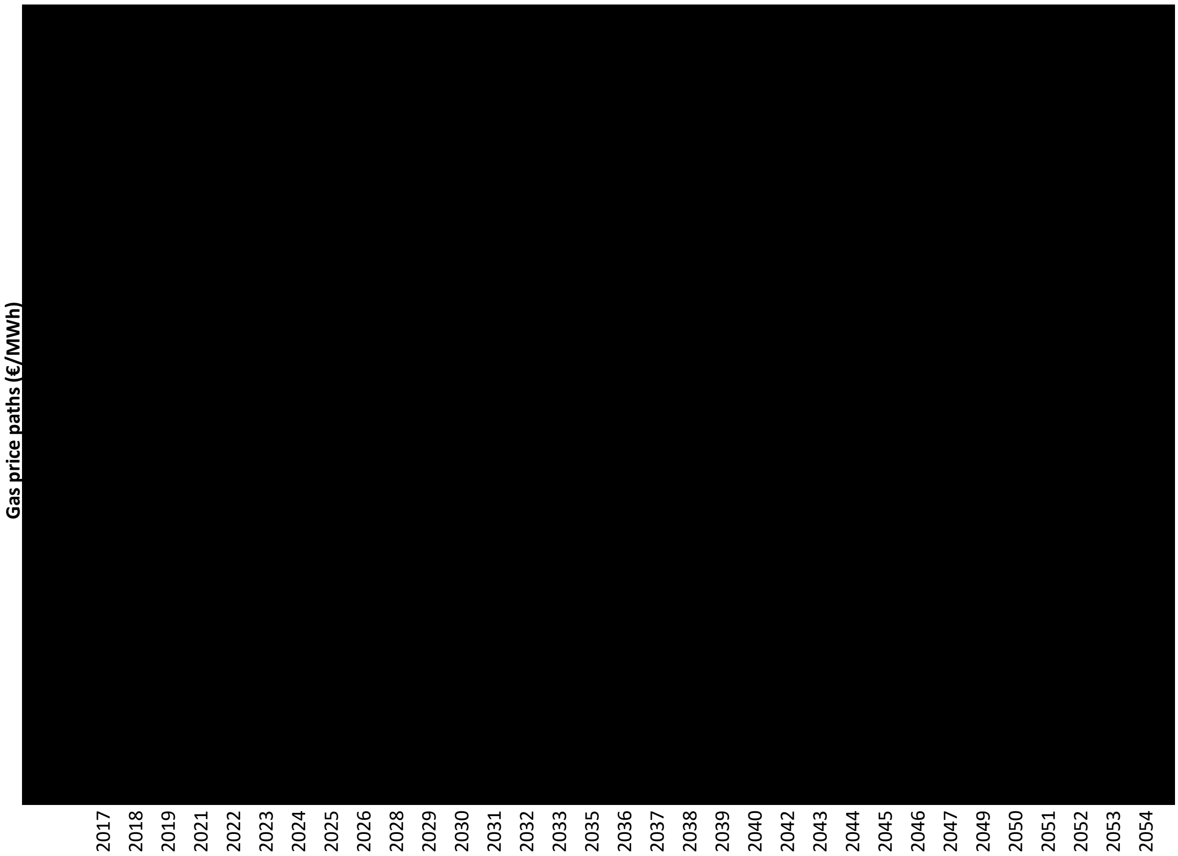
FIGURE 19: NORMAL VS LOG-NORMAL DISTRIBUTION (STYLISED)



265. The methodology we have described determines how forward prices react to new information. We trace the changes of the price of a forward contract until it matures, i.e. deliveries start under the contract, to obtain a simulated spot price. Combining all the spot prices for all the contract maturities gives us a price path for a given commodity.[233] We have repeated the process 100 times and we obtained the price paths shown in Figure 20 for gas traded at TTF and in Figure 21 for coal delivered in the Amsterdam-Rotterdam-Antwerp ("ARA") region in the Netherlands.

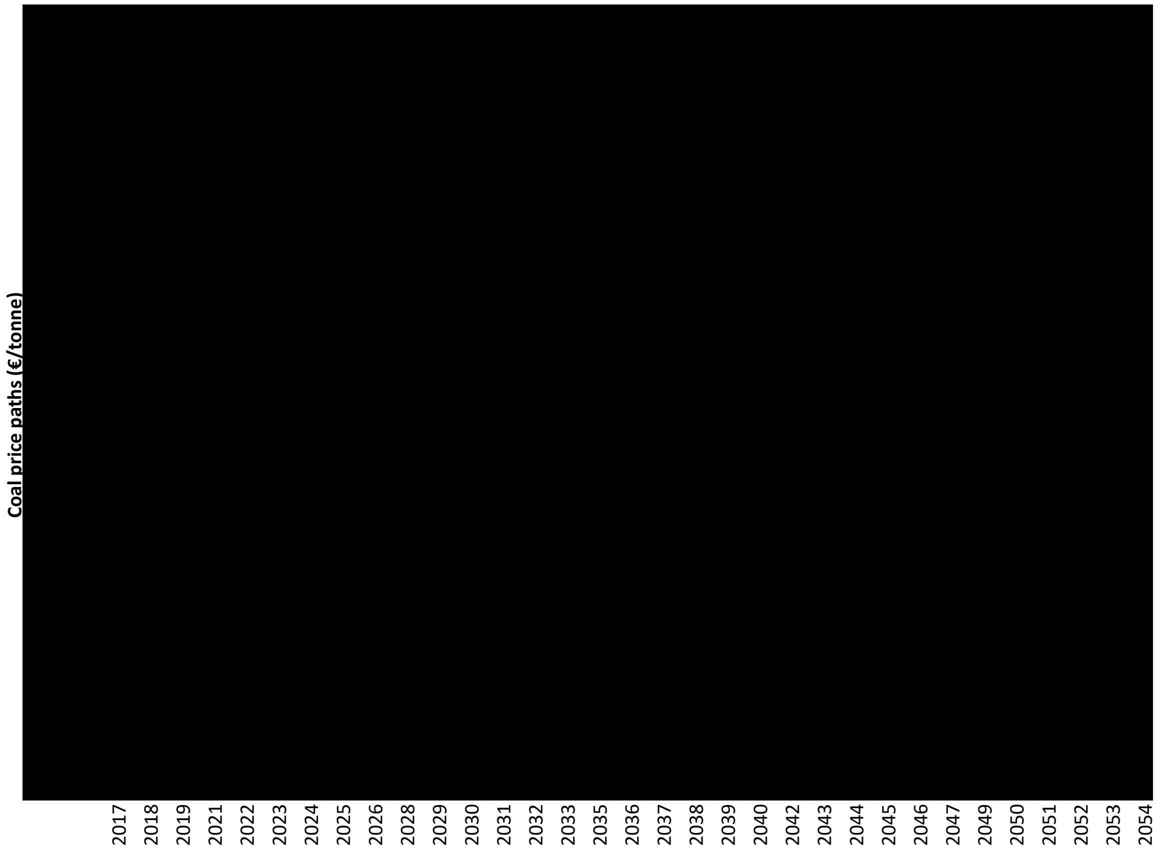
[233] The described methodology produces *risk-neutral* spot prices, where the mean of the spot price distribution in a given period T is equal to the forward price $F(t_0, T)$, where t_0 is the Valuation Date. As discussed below, expected spot prices are generally more risky than forward prices and we make an adjustment to account for this risk. A discussion of risk-neutral discounting can be found in: **Exhibit BR-34**, Hull J.C., Options, Futures and Other Derivatives, 9th edition, Chapter 15.

FIGURE 20: 100 PRICE PATHS OF TTF GAS PRICES BETWEEN 2017 AND 2054[234]



[redacted]

FIGURE 21: 100 PRICE PATHS OF ARA COAL PRICES BETWEEN 2017 AND 2054[235]



[redacted]

266. In summary, to implement our stochastic approach we have had to:

a. Create expected forward curves for coal and gas prices from around the valuation date;

b. Measure the volatility of coal and gas prices as of the valuation date; and

c. Determine the historical correlation between coal and gas prices.

267. The following sub-appendices explain in more detail how we have carried out each of these tasks.

B.2.i Forward price expectations

268. We start by creating a forward price curve from data available as at the valuation date that covers the entire period in which we are interested i.e. 2017 to 2054. A forward curve is simply the set of forward prices for different maturities (delivery periods) available on a given trading day.

269. Ideally, we would rely entirely on forward price data to create our price paths. However, this is not possible because the forward curves for coal and gas prices goes from around the valuation date extended at most 5 years into the future. Consequently, we also rely on the New Policies price forecasts contained in the IEA's 2016 World Energy Outlook,[236] the latest long-term forecast produced by a reputable international body that would have been available at the valuation date.

270. In order to combine the forward curve data with the IEA projection into a single coherent dataset, we (i) convert all prices into nominal (money of the day) Euro terms, (ii) estimate the forward prices consistent with the IEA spot price projection, and (iii) use interpolation to provide data for years for which no data are available.

B.2.i.a Converting prices to nominal Euro terms

271. While our forward prices are already expressed in terms of nominal Euros, the spot prices in the IEA scenario are provided in 2015 US Dollars as shown in the top half of Table 7. We convert the IEA prices to Euros using the average 2015 US$/€ exchange rate, and inflate them using a contemporaneous International Monetary Fund inflation forecast.[237] In this

[234] Harris-Hesmondhalgh Workpapers, Tables D.2 – Coal and Gas Price Simulation, Tab 'Path_chart'.

[235] Harris-Hesmondhalgh Workpapers, Tables D.2 – Coal and Gas Price Simulation, Tab 'Path_chart'. Please note that you need to use the switch in the Workpaper D.2 to get the chart for gas and coal respectively.

[236] We explain why we have chosen this scenario in Section IV.B above.

[237] **Exhibit BR-62**, International Monetary Fund, World Economic Outlook Database, October 2017.

way, we obtain nominal spot price forecasts in €/tonne for coal and €/MWh for gas shown in the bottom half of Table 7.

TABLE 7: IEA - WORLD ECONOMIC OUTLOOK 2016 – COMMODITY PRICE FORECASTS[238]

[redacted]

Notes and sources:
[1]-[5]: See Harris-Hesmondhalgh Workpapers, Tables B - Commodity Betas, Table B13.
[6]: [3]x[5]/([1]x[2]).
[7]: [4]x[5]/[2].

B.2.i.b Converting spot prices to forward prices

272. As noted above, the IEA projection is of spot prices but the theory underlying our stochastic model requires that the price inputs to the model are forward prices. Accordingly, we have to convert the IEA spot prices into equivalent forward prices.

273. Expected spot prices are generally not equal to forward prices due to market sentiment and conditions changing over time. As a results, a price agreed on, say, 21 October 2020 for delivery over January 2021 is unlikely to equal the average of the spot (day-ahead) prices during January 2021. Buying a forward contract fixes the price and so removes risk associated with only discovering what the price will be the day-before delivery. This means that, compared to forward prices, spot prices contain a risk premium.

274. To estimate this embedded risk premium in spot prices, we apply a method that is a widely used in corporate finance, the Capital Asset Pricing Model, or CAPM.[239] The CAPM predicts that the risk premium of an asset is equal to the risk premium for the entire market, the market risk, multiplied by a factor that measures the degree to which the asset's price

[238] Harris-Hesmondhalgh Workpapers, Tables B – Commodity Forward Curves and Commodity Betas.

[239] For a derivation of the relationship between expected spot prices and forward prices see **Exhibit BR-63**, Pindyck, R.S., The Dynamics of Commodity Spot and Futures Markets: A Primer, The Energy Journal, 2001, Vol. 22, No. 3, p. 16.

moves in line with the market, i.e. its market exposure or beta.[240] We explain the CAPM model in greater detail in Appendix G, in the context of determining the appropriate discount rate to use in calculating a fair market value.

275. To apply the CAPM and estimate the betas for gas prices, we consider the hypothetical value of a company that sells gas for delivery at different times in the future. We assume that the company sells gas for delivery during every month of the forward curve, starting with the next month and ending with the latest possible delivery month for which one can buy a forward contract. We discount the value of these sales at the risk-free rate[241] to compute a net present value of these companies.[242] We repeat this process for every trading day from 2013 to 2017 allowing us to record changes in the net present values (returns) of the companies.

276. We compute the beta by comparing the change in the net present values of the company to the change in the reference market, for which we have chosen the FTSE World Index.[243] For example, if, on average, the net present value (the price) of the company changes by 0.5% in response to a 1% change in the market, then it has a beta of 0.5. We compute weekly returns for the FTSE World Index to avoid any temporary illiquidity issues that might arise if we used daily data.[244]

277. We carry out exactly the same procedure to determine the beta of coal prices. We find that the beta of gas is 0.23 and that for coal is 0.45 (see Table 8).

278. The other component of the CAPM model, the market risk, is determined by multiplying a risk-free rate by an appropriate market risk premium. In line with standard practice, we use a EURIBOR rate as a proxy for the risk-free rate and apply a standard market risk-premium of 5.5%.[245]

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[240] A beta is the covariance of company returns and market returns scaled by the market variance.

[241] We rely on the risk free rate because, as just described, forward prices are fixed and so riskless.

[242] We rely here on one of the fundamental theories in corporate finance: We implicitly, assume here that the companies sell gas or coal by locking in the forward rate. Hence by the time of the company valuation, all future prices are known. However, we would arrive at the same value if we assumed that the company sold the gas or coal at the spot rate, as long as we applied an appropriate discount rate, reflecting the risk associated with the cash flows.

[243] A beta is a number that measures the relationship between the movements in the returns of an asset (in this case a commodity) and the returns of the overall market. We select FTSE All World as the reference market because it reflects a liquid set of globally traded companies, diversified across sectors, to reflect a wide class of returns. **Exhibit BR-64**, FTSE Russell, FTSE All-World Index, dated 29 January 2021.

[244] This problem was first discussed by Dimson (1979), **Exhibit BR-65**, Dimson, Risk Measurement When Shares are Subject to Infrequent Trading, Vol. 7, No. 2, dated 1 May 1979.

[245] See Appendix G.

TABLE 8: COMMODITY CAPM PARAMETERS[246]

		Coal	Gas
		[A]	[B]
Risk-free rate	[1]	1.52%	1.52%
Commodity beta	[2]	0.45	0.23
Market risk premium	[3]	5.50%	5.50%
Commodity discount rate	[4]	3.99%	2.80%

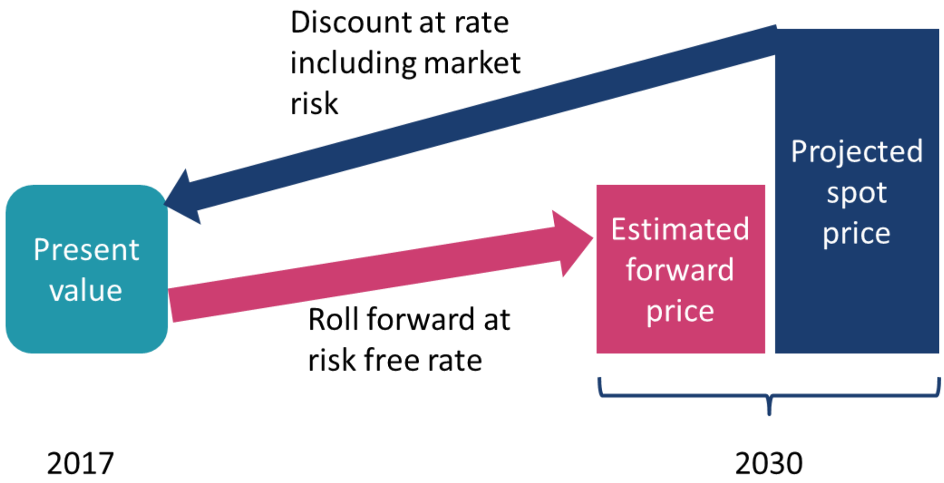
Notes and sources:
See See Harris-Hesmondhalgh Workpapers, Tables B - Commodity Betas.
[1]: 20-Year EURIBOR rate.
[3]: See Exhibit BR-64, Damodaran, A., Equity Risk Premium (ERP): Determinant, Estimation and Implications - A post Crisis Update, Stern School of Business, p. 67.
[4]: [1]+[2]x[3].

279. To deduct the risk premium from the spot prices we have derived from the IEA forecasts, we discount each forecast price back to the valuation data at the CAPM rate (row [4] of Table 8), and then "roll it forward" again at the risk-free rate to obtain a forward price for 2020, 2030 and 2040, the years for which the IEA provides a price forecast. This process is illustrated with a hypothetical example for 2030 in Figure 22. We also apply this methodology to obtain a price forecast for 2054 by assuming that the forecast prices between 2040 and 2054 remain constant in real terms.[247]

[246] Harris-Hesmondhalgh Workpapers, Tables B – Commodity Forward Curves and Commodity Betas.

[247] Harris-Hesmondhalgh Workpapers, Tables B – Commodity Forward Curves and Commodity Betas.

FIGURE 22: ILLUSTRATIVE EXAMPLE OF THE DISCOUNTING/ROLL BACK PROCEDURE

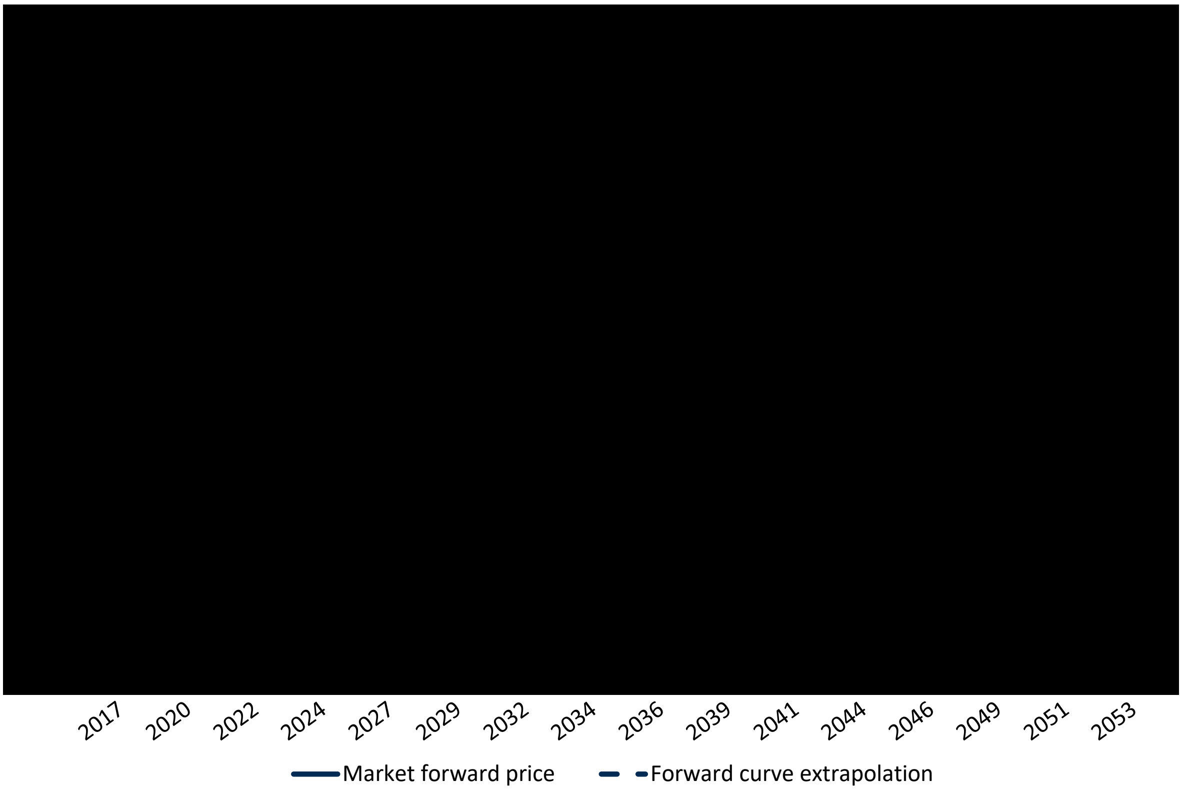


B.2.i.c Interpolating for years without data

280. The IEA forecast only specifies prices for 2020, 2030 and 2040. Since we also need prices for the intervening years, we derive these values by using linear interpolation, i.e. assuming that the change in prices from, say, 2020 to 2030 is the same for each year, in other words, follows a straight line. In this way, we obtain annual forward prices from 2030 to 2054.

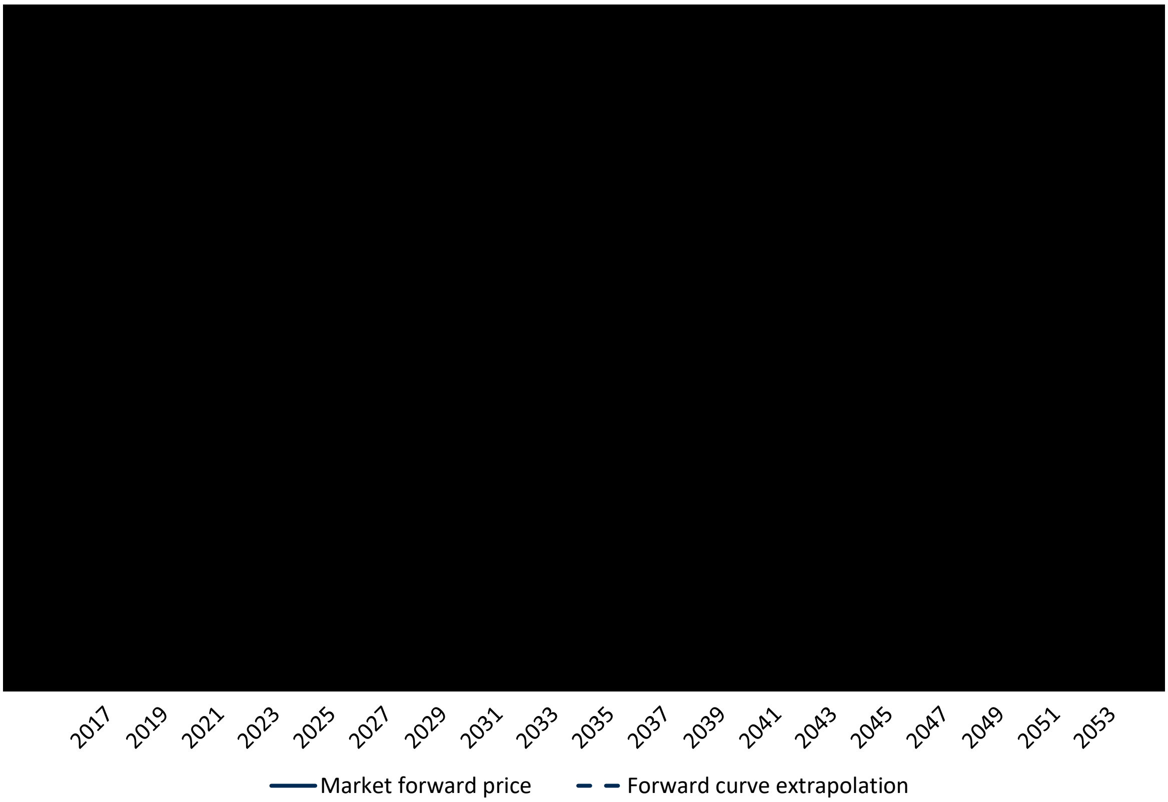
281. However, for the period prior to 2030, we rely on actual forward market data, where available, and only interpolate from the end of the forward curve to our 2030 forward price estimates. Figure 23 and Figure 24 present the resulting extended forward curves for deliveries of coal and gas respectively. The solid line shows the actual forward prices from around the valuation date whilst the dashed line represents the forward prices derived from the IEA forecast prices.

FIGURE 23: EXTENDED COAL FORWARD CURVE[248]



[248] Harris-Hesmondhalgh Workpapers, Tables B – Commodity Forward Curves and Commodity Betas.

FIGURE 24: EXTENDED GAS FORWARD CURVE[249]



B.2.ii Volatility

282. Volatility is a measure of how much prices react to new information. If the volatility of a commodity price is high, the chance of a large price change from one period to the next is high. Conversely, if the commodity's volatility is low, large price changes between periods are unlikely. Accordingly, in order to create the distributions for coal and gas prices from which we derive our commodity price paths, we need to estimate the volatility of coal and gas prices as their volatility will determine the width of the distributions.

283. There are two common approaches to estimating volatility:

a. Using the historical month-to-month volatility of forward contracts. The idea is258 that past volatility provides insight into the future.

b. Using European option prices on forward contracts. Such options are financial contracts that grant the possibility (but not the obligation) to enter a forward contract for the purchase of a commodity (call option) or to enter into a forward contract for the sale of a

[249] Harris-Hesmondhalgh Workpapers, Tables B – Commodity Forward Curves and Commodity Betas.

commodity (put option) at an agreed price at a given date.[250] This approach assumes that the prices of put and call options depend on the expected volatility of future prices. We can, therefore, infer the level of expected volatility by studying the volatility that is reflected in option prices ("implied volatility").

284. Both approaches have advantages and disadvantages. An abundance of objective data offers a key advantage to studying historical volatility of forward contracts. A disadvantage is that the volatility of prices may change over time, so the past might not be representative of the future. In contrast, the market prices of options contracts traded in 2017 will reflect most directly the market's contemporaneous expectations of future price volatility.[251] We consider that it is more consistent with our general approach to focus on expected price volatility and hence to rely on the option approach as far as possible. However, there are no relevant options for gas prices and so we rely on an analysis of the historical volatility of forward gas prices to determine their volatility term structure.

285. We estimate the future volatility term structure of coal and gas prices using a two-factor model,[252] which, as outlined above, calculates the volatility of the price of a contract with a given time before expiration ("time to maturity") on the basis of a combination of the short term volatility of the price, which reflects how price react to transitory information, its long-term volatility, which reflects how the price of the contract reacts to permanent (long-term) information, and a parameter that reflects how quickly the influence of the short-term volatility dies away as the time to maturity increases ("decay rate").

B.2.ii.a Volatility of coal prices

286. We estimated the implied volatility of coal prices from prices of European options on ARA coal forward contracts with different maturities using the so called "Black model". The model is named after Fisher Black, who proposed it in 1976 as a pricing model for European options on futures.[253] Since then, the Black model has been routinely used to price options on forward and future contracts.[254]

287. The Black model expresses the price of a European option as a function of: the time to maturity, the exercise price of the option and the expected volatility of the underlying

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[250] Options can be exercised either at maturity (European options) or at any time up to maturity (American options).

[251] Of course, in a sense, the options approach is also historical in that it reflects expectations as of the valuation date and not now.

[252] By "two factor" we simply mean a model that consists of both a short-term volatility term and a long-term volatility term, see discussion beginning at ¶258 above.

[253] **Exhibit BR-34**, Hull J.C., Options, Futures and Other Derivatives, 9th edition, pp. 392-393.

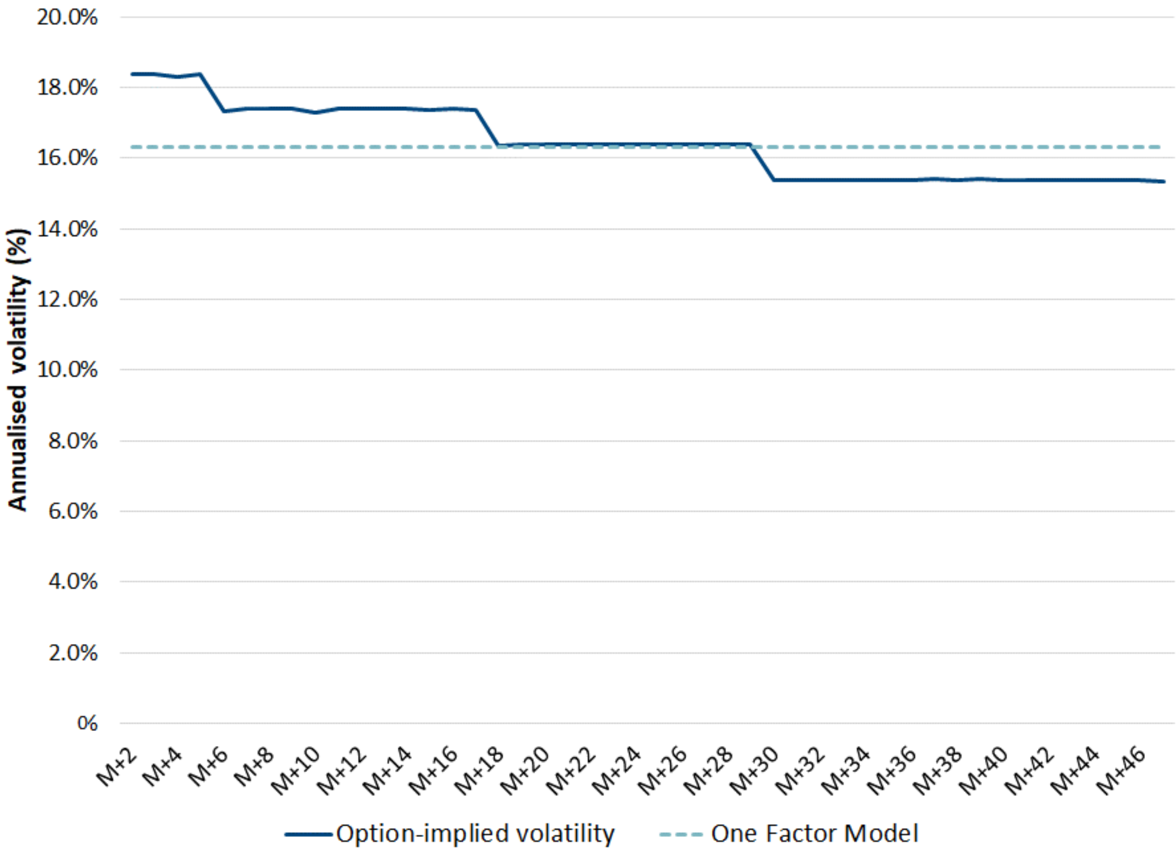
[254] **Exhibit BR-34**, Hull J.C., Options, Futures and Other Derivatives, 9th edition, pp. 392-394.

futures contract. Knowing the final result of the model (the price of the option) and all the inputs except for the implied volatility, we calculate the implied volatility by "inverting" the calculation formula.

288. To safeguard against outliers, we calculate average implied volatilities for different maturities across 30 trading days. We then construct a term structure of implied volatilities based on how the average implied volatility varies with time to maturity.

289. As is evident from Figure 25, the volatility of coal prices does not significantly decline with time to maturity. Accordingly, we assessed how a one-factor model, which is a model where volatility is constant across all maturities, compares to the two-factor model. We found that a one-factor model (the dotted line in Figure 25) provides only a marginally worse fit than a two-factor model and so, to reduce the computational burden, we have adopted a one-factor model.

FIGURE 25: ARA COAL VOLATILITY TERM STRUCTURE[255]



B.2.ii.b Volatility of gas prices

290. We estimate volatility of gas prices from data on forward contracts published by ICIS Heren for gas traded at the Dutch Title Transfer Facility ("TTF"). Gas prices generally show seasonal variations reflecting the significantly higher demand for gas for heating during the winter months. To account for the seasonality in prices we estimate two separate two-factor models, one for winter and one for summer.

291. To compute the historical volatility of gas prices, we first construct a "relative term structure" of monthly delivery periods from standard forward contracts traded at the TTF. Products are traded with reference to a specific delivery period, for example September 2017 in case of monthly contracts or Q3 2018 in case of quarterly contracts.[256] To obtain a relative term structure, we measure the time difference between the assessment date (trading date) and the delivery period in order to trace prices across the term structure over

[255] Harris-Hesmondhalgh Workpapers, Tables C.2.2 – Black Model, Tab 'Vol term structure'.

[256] For a given delivery month, we take the most granular product available as at the assessment date, meaning that if we have monthly, quarterly and yearly contracts we consider the monthly contract. Purchases of standard gas forward contracts entitle to flat hourly deliveries over a pre-defined delivery period.

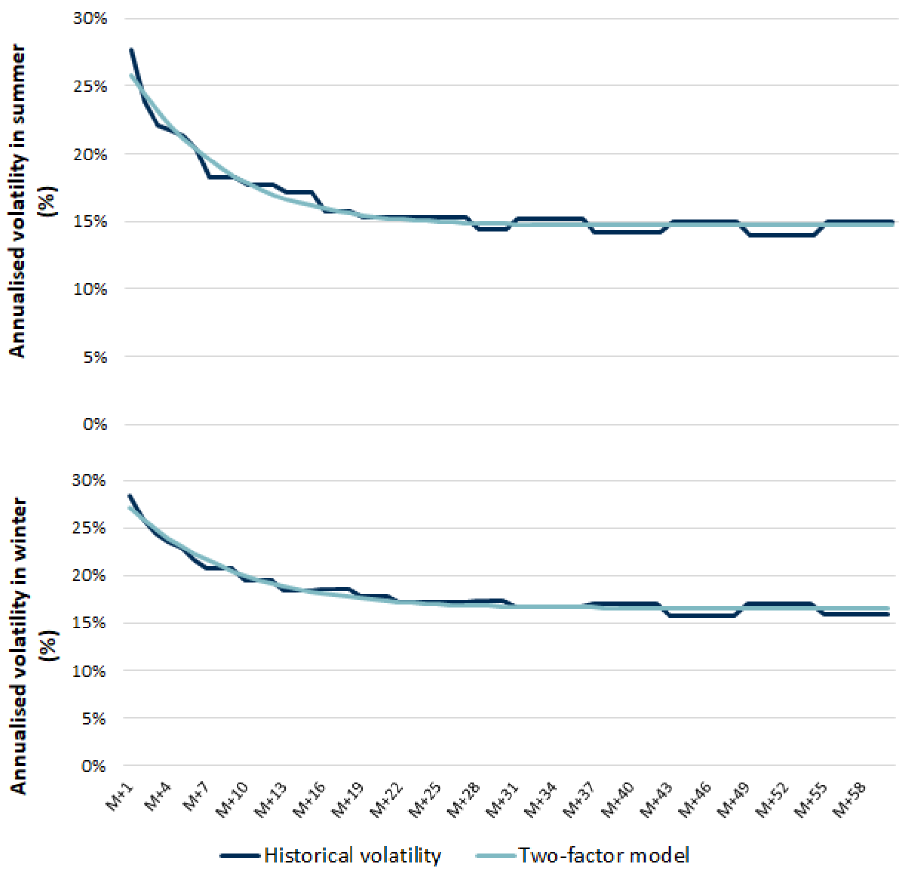
time. For example, on a trading date in July 2017, the September 2017 product would be the two months-ahead (“M+2”) product. Similarly for quarterly contracts, on a trading date in January 2018, the Q3 2018 product would be a Q+2 product.

292. To determine the historical volatility of gas prices, we calculate the daily “returns” for each (relative) contract; a daily return is the change in price from one day to the next and determine the natural logarithm of these returns (daily log returns).[257] Standard theory states that the standard deviation of daily log returns for a product measures its volatility.[258] Finally, we determine what parameters for each two factor model best replicate the historical volatility term structure that we have found. Figure 26: plots the modelled TTF volatility term structures against the historically observed one.

[257] Following standard practice in finance, the Clewlow and Strickland (2000) model we impose for coal and gas prices assumes that forward prices are log-normally distributed. This implies that log returns are normally distributed which has several desirable properties.

[258] Calculation of standard deviation is based on a sample of trading days between 2013 and 2017.

FIGURE 26: TTF TWO-FACTOR MODEL FIT[259]



B.2.iii Correlation

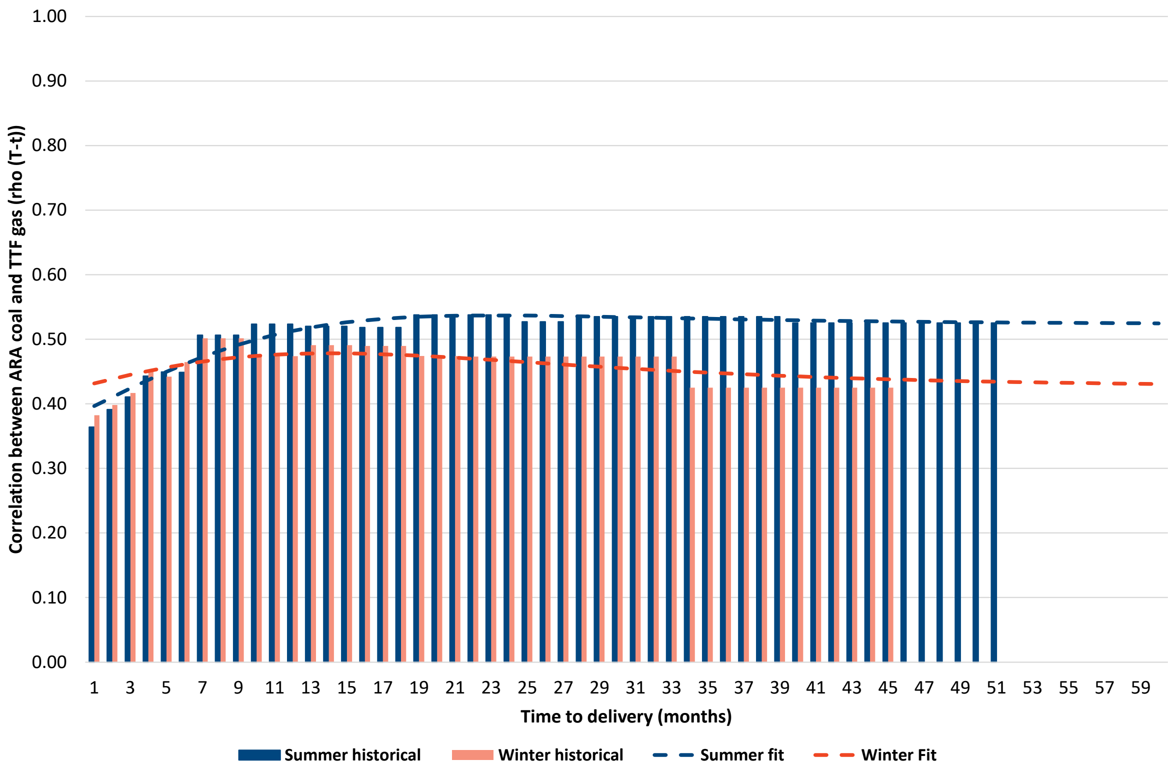
293. The final issue that we need to take into account when creating our price paths is how coal and gas prices relate to each other i.e. what correlation there is between the movements of coal and gas prices. We need, therefore, to estimate their correlation based on data that would have been available as of the valuation date.

294. Intuitively we would expect coal prices to increase when gas prices increase because to some extent they are “competing fuels”, meaning that there are uses – the main one being electricity generation – where gas-fired power plants can be used as a substitute for coal-fired power plants and vice versa. For example, whenever the price of coal is such that the use of coal becomes less competitive than the use of gas, gas will replace coal, gas demand will increase and gas prices can be expected to increase. A change in the price of coal, therefore, leads to a change in the price of gas. In other words, coal and gas prices are “correlated”.

259 Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

295. As the coal and gas prices do not move entirely independently of each other, we need to account for their correlation when simulating spot prices. To obtain correlated spot prices, we build a term structure of correlation using the same methodology we used to build the volatility term structure of gas prices. We build daily log returns for coal and gas forward products of different maturities over the period 2013-2017 and then compute the correlation of the returns.[260] The bars in Figure 27 represent the historical correlation term structure. As with the volatility term structures that we calculate for gas, we create separate correlation term structures for winter and summer to reflect the seasonality in gas prices.

FIGURE 27: CORRELATION TERM STRUCTURE AND MODEL FIT[261]



296. After calculating the historical correlation term structure, we fit a two-factor model to the two historical term structures. The dashed lines in Figure 27 represent the modelled correlation term structures and Table 9 shows the resulting correlation factors on which we rely.

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[260] Correlation is a statistical measure of the relationship of two random variables. A high positive correlation (with values close to 1) implies that the two variables move almost identically, i.e. if the price for coal goes up by 5% from one period to the next, the price for gas will also go up by roughly 5%. Conversely, a high negative correlation (close to -1) implies that if the price of coal goes up by 5%, the price for gas will go down by roughly 5%. If the correlation is zero, the price series move independently of each other.

[261] Harris-Hesmondhalgh Workpapers, Tables C.3, Commodity Correlation, Tab 'Coal_Gas_chart'.

TABLE 9: CORRELATION FACTORS[262]

	Short-term correlation			Long-term correlation		
	Coal	Gas-Winter	Gas-Summer	Coal	Gas-Winter	Gas-Summer
	[A]	[B]	[C]	[D]	[E]	[F]
	Table C.3.2	Table C.3.2	Table C.3.2	Table C.3.2	Table C.3.2	Table C.3.2
Coal	1	0.22	0.12	1	0.43	0.52
Gas-Winter	0.22	1	*0*	0.43	1	0
Gas-Summer	0.12	*0*	1	0.52	0	1

297. Each time we build a coal price path, we build a gas price path that reflects the correlation between coal and gas prices that we have estimated. To do this, we use the standard technique of "Cholesky decomposition" to derive a set of coefficients that transform uncorrelated draws into correlated draws with pre-specified correlation coefficients. This technique turns the correlation matrix in Table 9 into factors with which we then multiply our price draw for a coal price to derive a consistent gas price. The distribution of the adjusted price draws will then exhibit the correlations we calculated.

B.2.iv Intra-month variation

298. The model just described generates *monthly* prices for ARA coal and TTF gas. While coal is mostly traded in monthly contracts and so the monthly coal price is the spot coal price, gas is frequently traded for shorter periods and, in particular, for delivery on the next day, so-called day-ahead products. It is the day-ahead price that corresponds to the spot price for gas. [263] Hence, we need to turn our monthly gas price paths into daily gas price paths but do not need to do this for coal prices.

299. In order create daily gas price paths, we first make an adjustment to reflect the average historical deviation of day-ahead prices from month-ahead prices. In a second step, we include day-to-day variations in prices based on the historical volatility of day-ahead prices. We estimate both parameters from historical return data in our 2013-2017 sample of gas prices.[264]

[262] Harris-Hesmondhalgh Workpapers, Tables C.3, Commodity Correlation, Table C.3.1

[263] There is an increasing amount of intra-day trading in many European markets. Nonetheless, day-ahead prices are generally considered to be spot.

[264] Harris-Hesmondhalgh Workpapers, Tables C.1.

B.3 CO_2 price model

300. Just as we need a model of coal and gas prices so we need one for CO_2 prices. However, it would not be appropriate to adopt the same model for CO_2 prices that we use for coal and gas prices for the reasons we explain below.

301. CO_2 prices are formed within the EU Emissions Trading System (ETS) established in 2005. Over 11,000 installations including power plants and industrial plants have to submit sufficient permits (each permit covers the emission of one tonne of CO_2) to cover their emissions. The ETS regulates the total number of permits that are available and allows participants to trade these permits with each other, which establishes a market price for CO_2 permits. [265] Unused permits remain valid for future years.[266]

302. The market price heavily depends on the number of permits that the ETS allocates to participants every year,[267] and the number of permits is governed by policy decisions, unlike other commodities whose supply is driven by economic factors.

303. These features of the ETS mean that the stochastic model described in Appendix B.2 is not appropriate for CO_2 prices for two reasons:

    a. While there are forward products available for emission permits, the trading is heavily affected by the necessity to surrender permits by April of each year. Market participants generally hedge their expected emissions for a given calendar year by buying year-ahead products. A surge in trading of shorter-term products in December and January suggests that market participants trade to balance any discrepancies between their expected and actual emissions at the end of the calendar year. Furthermore, as noted above, market participants do not have to surrender all their permits in April but can keep them to use in a subsequent year. This makes it impossible to build a volatility term structure as for we did for coal and gas prices , as some products are not traded at all whereas others are only traded in specific periods of the year and it is not clear when permits are used as it is costless to store them.

    b. Secondly, market prices are heavily dependent on discrete policy choices that change the overall supply of permits. A random walk model is not able to capture these discrete policy changes and we would end up with a biased stochastic model.

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[265] **Exhibit BR-66**, European Commission, EU Emissions Trading System (EU ETS), dated 23 November 2016.

[266] **Exhibit BR-66**, European Commission, EU Emissions Trading System (EU ETS), dated 23 November 2016.

[267] Permits are allocated through auctions and free allocations, with auctions being the default mechanism since the start of Phase 3 of the ETS in 2013.

304. Instead, we choose a different approach to creating 100 possible CO_2 price paths, which allows for different policy paths. We start from the three IEA forecasts of European CO_2 prices included in the World Economic Outlook in 2016: the Current Policies scenario, the New Policies scenario and the 450 scenario.[268]

305. Table 10 shows the forecast prices for each scenario in 2020, 2030 and 2040. We use the New Policies scenario and the 450 scenario to determine an appropriate range of possible prices in each of these years assuming that the initial distribution of CO_2 prices, like the prices for coal and gas, follows a log-normal distribution.[269] We therefore construct a log-normal distribution such that 97.5% of all draws from this distribution lie below the 450 scenario value and the mean of the distribution is equal to New Policies scenario value. We do not explicitly rely on the Current Policies scenario but its prices fall within the distribution that we create and it is not possible to create a log-normal distribution that results in only 2.5% of all the draws lying below the New Policies values.

TABLE 10: IEA CO_2 PRICE FORECASTS[270]

2015 $/€ exchange rate		[1]	1.11		
Scenario			2020 [A]	2030 [B]	2040 [C]
Current Policies	2015$/t	[2]	[redacted]		
New Policies	2015$/t	[3]	[redacted]		
450 Scenario	2015$/t	[4]	[redacted]		
Inflation		[5]	[redacted]		
Current Policies	€/tonne	[6]	[redacted]		
New Policies	€/tonne	[7]	[redacted]		
450 Scenario	€/tonne	[8]	[redacted]		

Notes and sources:
[1]-[5] See Harris-Hesmondhalgh Workpapers, Tables D.3 - CO2 Price Ratchet, Table D.3.10.
[6]=[2]*[5]/[1]
[7]=[3]*[5]/[1]
[8]=[4]*[5]/[1]

306. Figure 28: shows the resulting distributions of prices in 2030, 2040 and 2050. For 2050 we have assumed that the New Policies scenario prices would increase by inflation and that the width remains the same as for 2040, which implicitly means we assume the 450 scenario

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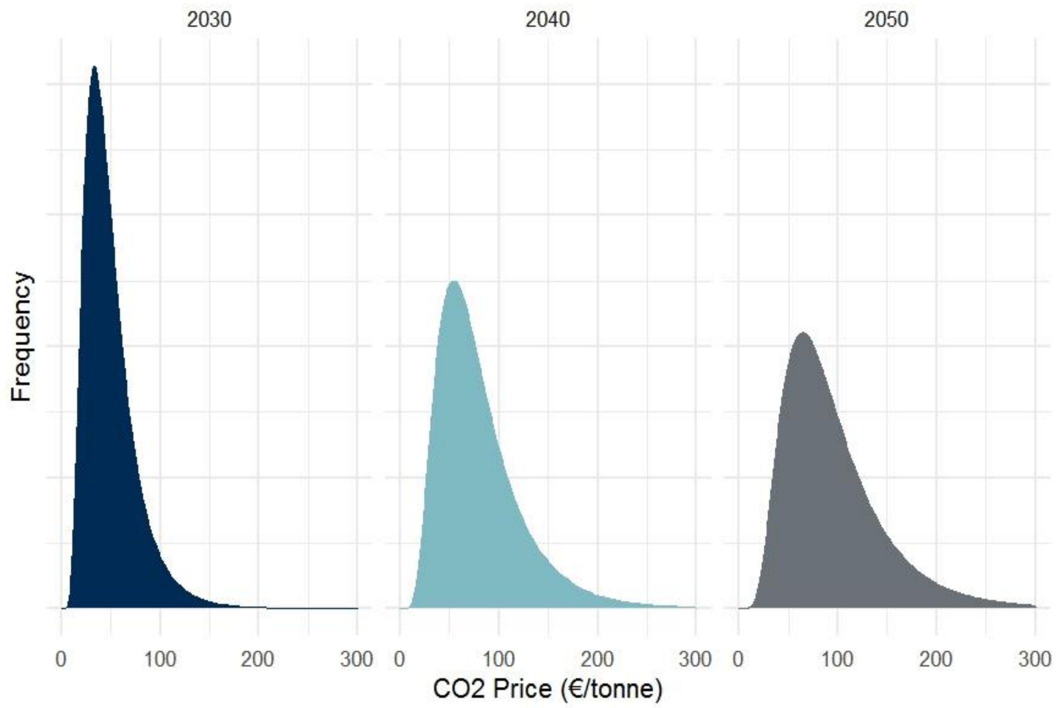
268 **Exhibit BR-32**, International Energy Agency, World Energy Outlook, 2016, Table 1.1, p. 39.

269 The standard assumption is that commodity prices follow a log-normal distribution.

270 Harris-Hesmondhalgh Workpapers, Tables D.3 - CO2 Price Ratchet.

prices also increase by inflation. Note that for 2020, the IEA does not forecast different prices in the New Policies and 450 scenarios. Hence, we simply use the price of [redacted] €/MWh shown in lines [7] and [8] of Table 10 above, and do not impose a distribution. On the horizontal axis we plot prices and on the vertical axis the frequency with which a given price level occurs – its probability of occurring. The price that we assume will occur most frequently is the New Policies scenario price. The frequency with which prices below this level occur drops sharply but there is a more gradual reduction in the frequency with which prices higher than the New Policies price are assumed to occur. By construction, 97.5% of prices remaining below the 450 scenario level. We let the computer draw 100 different prices from each distribution. These are the basis for our price paths.

FIGURE 28: CO_2 PRICE DISTRIBUTIONS[271]



307. We assume that each of the 100 draws represents one simulation of CO_2 prices in June 2030, June 2040 and June 2050. In order to determine how each price path develops from one simulation to the next, we apply a mechanism that we call the *policy ratchet*. It involves the following steps:

a. We rank the 100 price draws for each of the three years from highest to lowest (we also do that for 2020, even though the starting price in all the simulations is [redacted] €/MWh[272]);

b. Starting in 2020, we pick a particular rank number;

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[271] Harris-Hesmondhalgh Workpapers, Tables I - Other Supporting Analysis.

[272] The 2020 price for all the IEA 2016 World Energy Outlook scenarios.

c. We randomly draw a number between 1 and 100, where the occurrence of each number is equally likely;

d. This number determines the rank of the 2030 draws which we assume belongs to the same state of the world as our particular draw in 2020;

e. If the drawn rank is lower than that of the current 2020 scenario or the nominal price level associated with the drawn rank is lower than the 2020 price we have drawn, we override the draw and assume that the 2030 price for this path will be the higher of (i) the 2030 price with the same rank as the path's 2020 rank or (ii) the path's 2020 price;[273]

f. If the drawn rank is higher than the rank of the current 2020 scenario, we adopt this price as the 2030 price so long as it as least as high as the path's 2020 price, otherwise we adopt the 2020 price;

g. Having chosen a 2030 price for the path, we then linearly interpolate to find the path prices for the month between July 2020 and May 2030.

h. We then repeat this process starting from the adopted 2030 rank to find the 2040 price, and repeat it again starting from the adopted 2040 rank to find the 2050 price.

308. We repeat this sequence of steps 100 times to create 100 price paths.

309. By way of example, assume that we pick the rank 48 in 2020. As in all price paths, this means the price is [redacted] €/tonne. We then draw a random number to determine the rank for this price path in 2030 and pick 65. The price draw with rank 65 in 2030 is 34.33 €/tonne. In contrast the price draw 48 in 2030 is 45.22 €/tonne. Hence, we adopt rank 48 to determine the 2030 price for this path and linearly interpolate between [redacted] €/tonne in June 2020 and 45.22 €/tonne in 2030.

310. In an alternative example, assume we are at rank 91 in 2020 and our 2030 draw is rank 24. The price draw with rank 24 in 2030 is 62.35 €/tonne. We linearly interpolate between [redacted] and 62.35 €/tonne to obtain the CO_2 price path between June 2020 and June 2030.

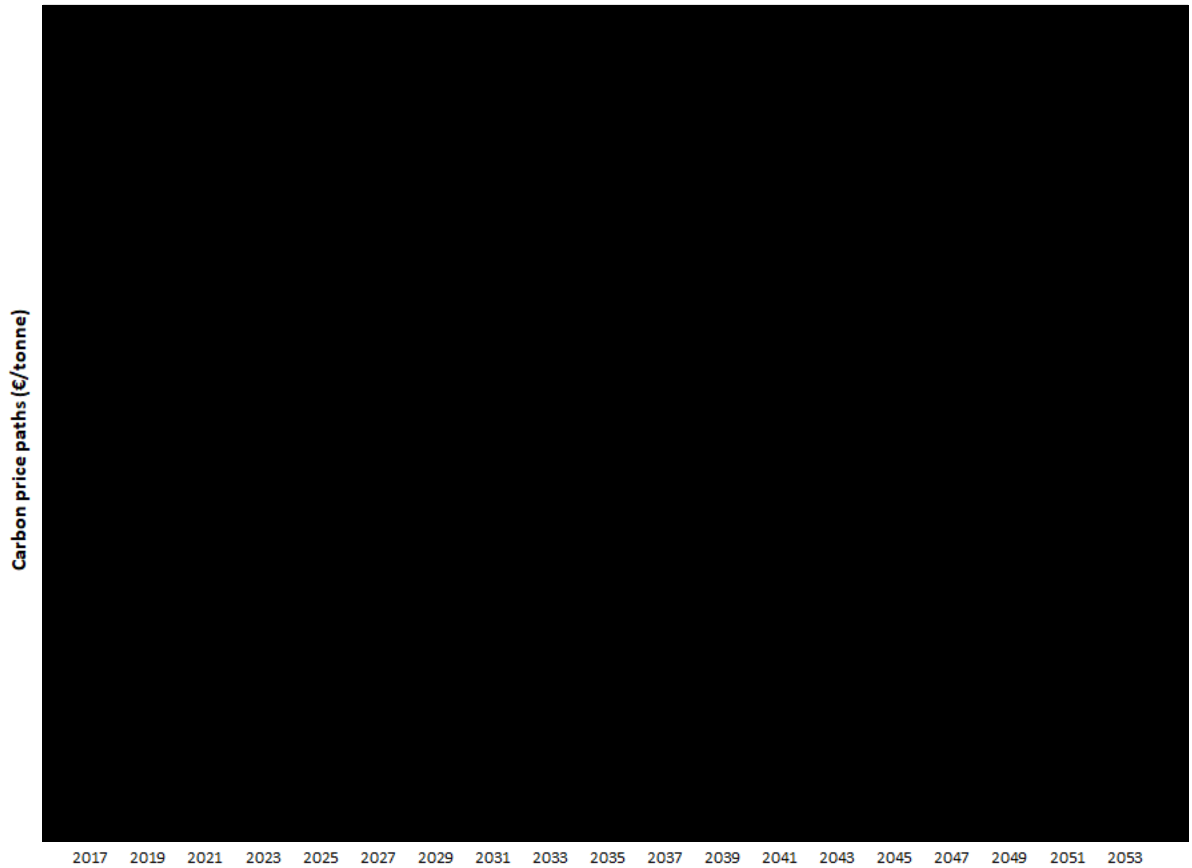
311. This mechanism thus allows for rapid increases in CO_2 prices within a decade reflecting the uncertainty around what EU climate policy will look like over the forecast period. It also allows for slower price increases, but, like any ratchet, we assume that CO_2 prices cannot decrease over time, as we deem it reasonable to assume that EU policymakers would take measures to prevent a price slump by shortening supply of permits in an effort to meet climate targets.

[273] This last contingency is only relevant for very few extreme price paths in which the same rank ten years later actually results in a lower nominal price.

312. We extend the price series to include the time from the Valuation Date to June 2020 and from June 2050 to December 2054. For the earlier period, we linearly interpolate between spot prices as of the Valuation Date and the price of [redacted] €/tonne in June 2020. For the latter period, we assume prices increase by long-term inflation.

313. Finally, we add day-to-day variations using the methodology described in Appendix B.2.iv for gas prices.[274] Figure 29 shows the resulting prices paths from 2017 to 2054.[275]

FIGURE 29: 100 DRAWS OF CO_2 PRICES BETWEEN 2017 AND 2054[276]



[274] Note that we only need to implement the second step described in Section B.2.iv, as we do not start from month-ahead prices but rather average daily prices.

[275] Note that we linearly interpolate between spot prices in 2017 and our modelled price from 2020 to create monthly prices and then take account of intra-month volatility to create daily prices.

[276] Harris-Hesmondhalgh Workpapers – Tables I - Other Supporting Analysis.

Appendix C : Electricity market modelling

314. In this Appendix we summarise the electricity market modelling that Baringa carried out, based on the input assumptions on which we asked it to rely. Appendix C.1 sets out our approach to modelling the electricity market whilst the key assumptions that are used in the modelling are described in Appendix C.2. We set out the main results of the modelling in Appendix C.3.

C.1 Approach

315. To calculate the electricity prices that are consistent with our commodity price paths, we have made use of a computer model of the entire European electricity market and used this to estimate electricity prices for each of the 100 commodity price paths from 2020 to 2054 under the but-for case and from 2020-2030 under the actual case. In addition to commodity prices, such a model also needs assumptions on:

    a. Demand - peak demand, which is the highest demand expected in the year, and annual demand.

    b. Installed generating capacity – data at an individual plant level on capacity and operational characteristics (for both fossil-fuelled and renewable capacity).

    c. Interconnector capacity - how much electricity can be transferred between countries.

316. The next sub-appendix explains the sources that we have used for these assumptions.

317. We engaged Baringa to provide the electricity price projections using a well-known and well-developed power market model, PLEXOS®. PLEXOS® uses least-cost optimisation to dispatch plants to meet demand for the minimum cost, and provides projections of power prices, generation volumes, operating margins and emissions. Baringa regularly uses PLEXOS® to provide pan-European forecasts and PLEXOS® is also used by many transmission system operators.

318. Typically, Baringa runs PLEXOS® using hourly demand data. However, in this case, it has relied on 4 hourly demand periods, with demand averaged over 4 hour steps and supply dispatched in 4 hour periods to meet it. This is a pragmatic step to reduce to reasonable levels the running time required to complete 100 price paths for 34 years. For the purposes of assessing the fair market value of coal-fired power plant, we consider that the 4-hourly granularity is sufficient to reflect appropriately dispatch behaviour given that the ramping rate and start-up costs for such plants generally make it very inefficient and physically challenging to operate in shorter cycles than four hours.

C.2 Key assumptions

319. As outlined in Section V above, in addition to our commodity price paths, the key sources used in building the stochastic electricity price paths were:

a. The European Commission "EU Reference Scenario 2016",[277] which provides forecasts for installed generation capacity and annual demand for the Netherlands, Belgium, Germany, Spain, Finland, France, Great Britain, Italy and Poland.

b. The Baringa Reference Case[278] (Q2 2017 update) for capacity and annual demand for Denmark West, Norway and Sweden, interconnector capacities and peak/annual demand ratios for the key markets.

320. It is easier for Baringa to model the whole European market than to model just the countries that are likely to have an effect on the Dutch electricity market. However, the development of these distant markets, such as Greece and Romania, has essentially no impact on the Dutch market. Baringa and we took the pragmatic view that relying on the Q2 2019 Baringa Reference Case for such countries, which was already loaded into PLEXOS®, would not affect the resulting Dutch electricity prices and would significantly speed up the time required to complete the electricity modelling analysis. Table 11 summarises the sources that Baringa relied upon for all the key assumptions.

[277] **Exhibit BR-37**, European Commission, EU Reference Scenario, dated 15 July 2016.

[278] Baringa Reference Cases are the central in-house view of Baringa on how the European power market will evolve.

TABLE 11: SOURCES OF KEY ASSUMPTIONS[279]

Parameter	Markets	Source	Impact on NL prices
Capacity and annual demand	NL, BE, DE, ES, FI, FR, GB, IT, PL DKW, NO, SE All other European markets	IEA EU Reference Scenario 2016 Baringa Reference Q2 2017 scenario Baringa Reference Q4 2019 scenario	High High Low
Hourly demand profile	All	Baringa Reference Q2 2017 scenario	High
Plant characteristics	All	Baringa Reference Q2 2017/Q4 2019 scenarios (the two sets of characteristics are essentially identical)	High
Heat pump & EV demand	NL, BE, DE, DKW, ES, FI, FR, GB, IT, NO, PL, SE All other European markets	Baringa Reference Q2 2017 scenario Baringa Reference Q4 2019 scenario	High Low
Interconnector capacities	To/from NL To/from BE, DE, DKW, FR, GB, IT All other European markets	Baringa Reference Q2 2017 scenario Baringa Reference Q2 2017 scenario Baringa Reference Q4 2019 scenario	High High Low

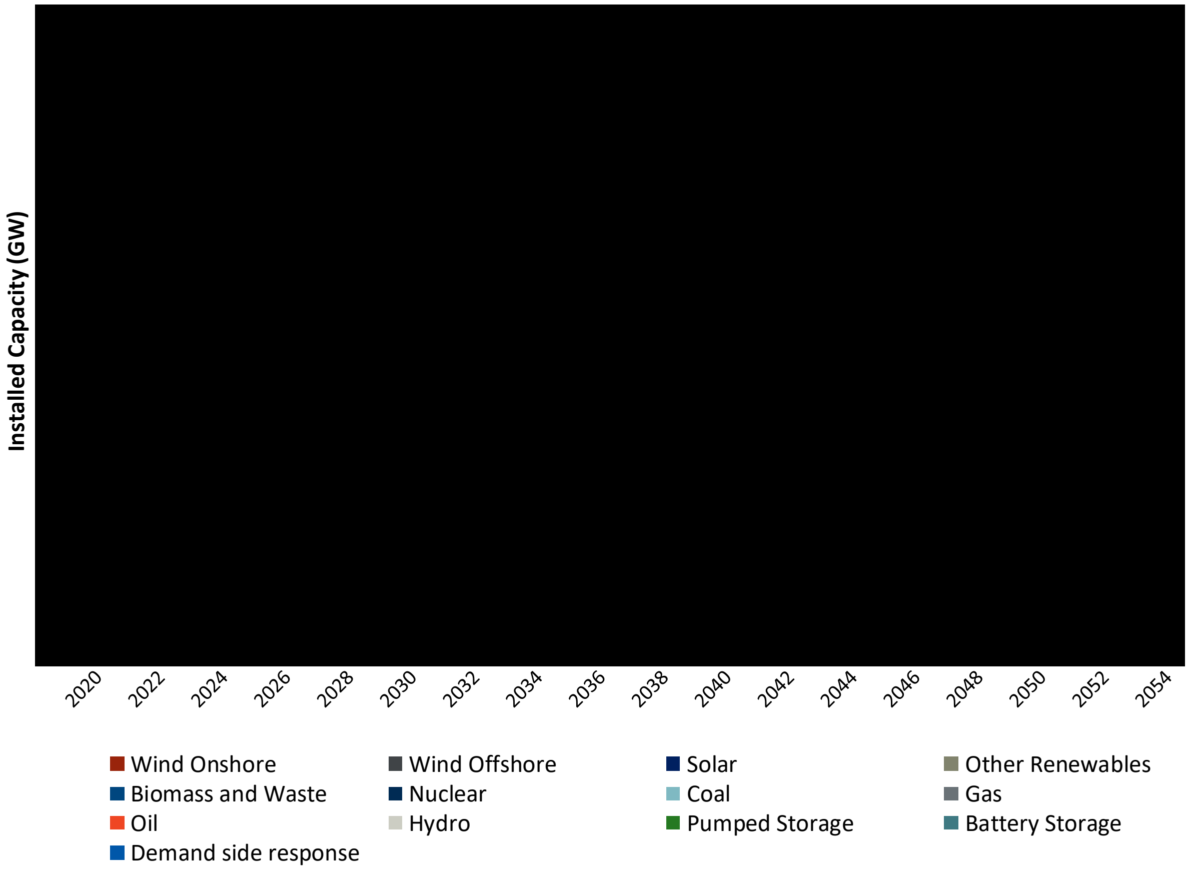
C.2.i Capacity mix

C.2.i.a Reference Scenario capacity mix

321. The EU Reference Scenario only provides generation capacity assumptions in 5 year steps so Baringa has linearly interpolated between each of the 5 year steps to obtain yearly capacity data. After 2045, Baringa kept the assumptions on capacity (and demand) constant. The resulting initial capacity mix in the Netherlands for the but-for case is shown in Figure 30. Note that demand side response or “DSR” corresponds to electricity consumers who are able to adjust their consumption in response to market signals. The capacity mixes in 2020 and 2050 for the countries neighbouring the Netherlands are shown in Figure 31. Baringa made adjustments to these assumptions to “flex” the renewable capacity assumptions in line with changing commodity price assumptions, as discussed further below, see Appendix C.2.i.b.

[279] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

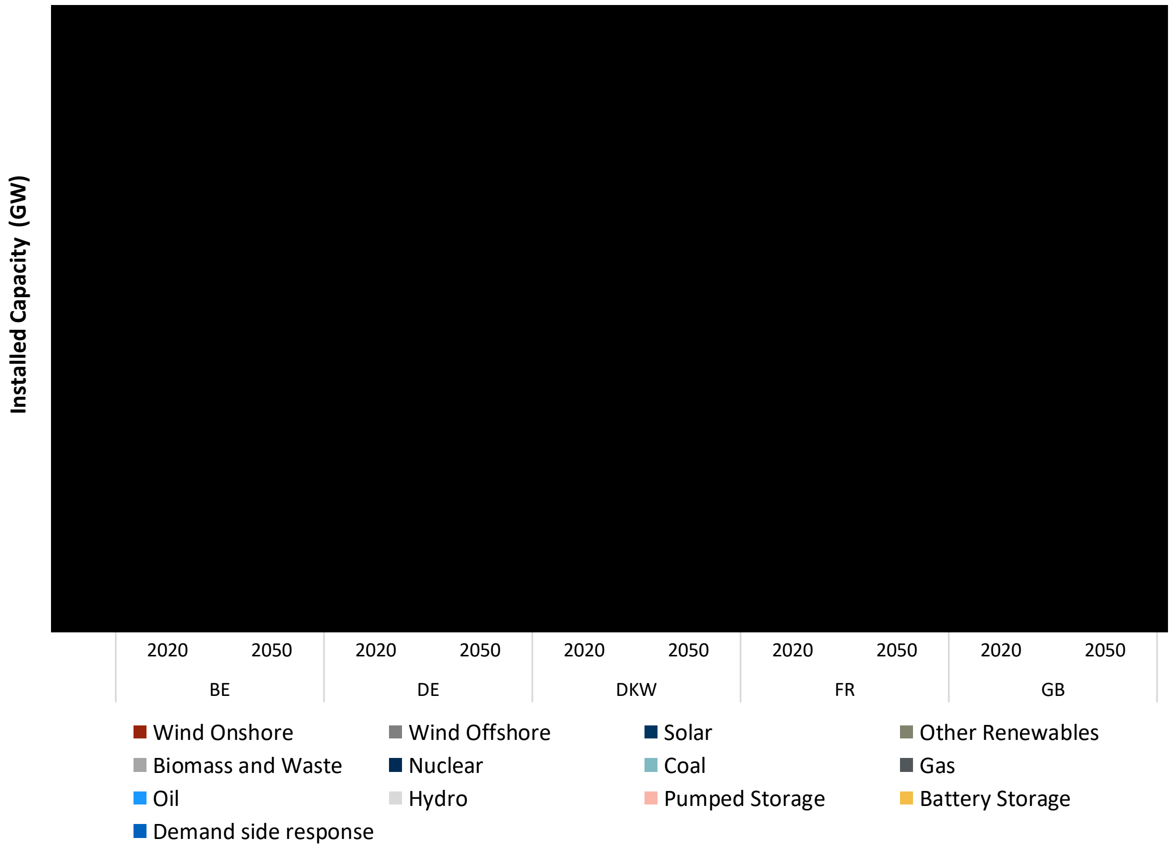
FIGURE 30: DUTCH CENTRAL CAPACITY MIX[280]



280 Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

FIGURE 31: CENTRAL CAPACITY MIX, KEY INTERCONNECTED MARKETS[281]

[redacted]



C.2.i.b Flexing generation capacity in response to commodity prices

322. The range of commodity prices included in the electricity modelling is wide, see Figure 5, Figure 6 and Figure 7 above. As we briefly discussed in Section IV.C, this price variation can be expected to drive variations in the economic competitiveness of renewable capacity compared to thermal capacity, and hence variations in the investment in renewable capacity.

323. To account for this, we "flex" the share of renewable capacity from the EU Reference Scenario capacity mix for each commodity price path. For each path, the share of renewable capacity in 2018 and from 2050 onwards is assumed to be equal to the share in the EU Reference Scenario capacity mix for those years but is allowed to diverge from that capacity mix in the intervening years with the maximum divergence occurring in the middle of the modelling horizon, i.e. in 2034. The general idea is illustrated in Figure 32. The rationale behind this approach is that in the near term there is lower uncertainty around commodity prices and the profitability of renewable capacity and the generation mix remains close to its current state, but uncertainty in commodity prices increases in the medium term and so the

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[281] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

outlook for renewables becomes more uncertain. In the long term, the capacity mix will mainly be driven by the decarbonisation agenda rather than by commodity prices.[282] Therefore, although the uncertainty in CO_2 prices increases, uncertainty around the level of renewable generation reduces. To reflect this idea, over the medium term the share of renewable capacity is increased for high commodity price paths whereas it is decreased in low commodity price paths.

324. Figure 30 and Figure 31 above show that a large share of the renewable capacity is provided by solar and wind plants. Such plants have "intermittent output", meaning that they can only generate when sun and wind are available. To balance supply and demand when faced with plants with intermittent output, network operators have to provide flexibility through resources such as batteries, which store excess electricity, or DSR, which leads to lower demand. Accordingly, Baringa has assumed that battery storage capacity and DSR will increase/decrease at the same rate as renewable capacity. In order to ensure that the capacity margin – the margin between installed capacity adjusted for availability ("de-rated") and peak demand – remains consistent with the assumptions in the EU Reference Scenario, Baringa also flexes the capacity of fossil-fired plants in the opposite direction to renewable capacity – so it reduces fossil-fired capacity in high commodity price paths that have increased renewable capacity and increases it in low commodity price paths that have reduced renewable capacity.[283] This ensures that overall capacity margins remain comparable across the different price paths, so that capacity margin fluctuations do not drive differences in prices from the different commodity price paths.

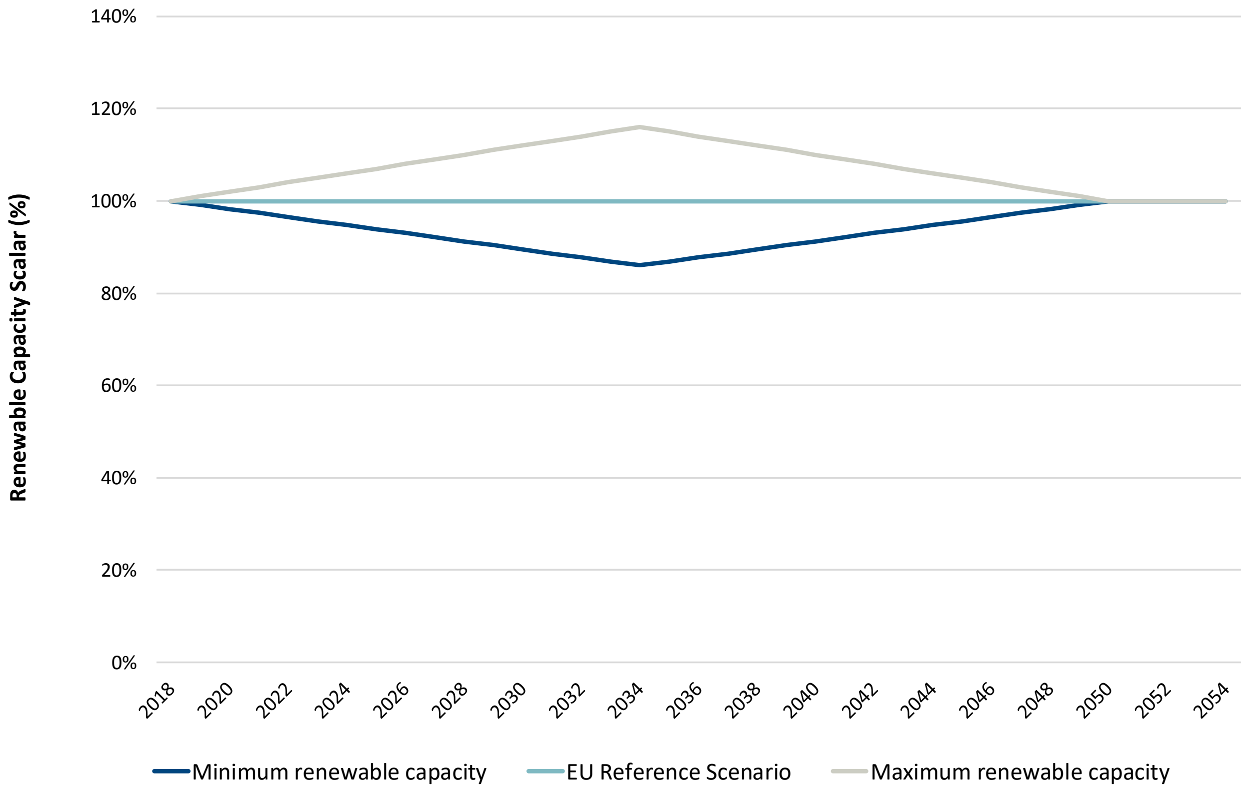
325. We flex the share of renewable output by a maximum of approximately 5 percentage points relative to the EU Reference Scenario level. To increase the share of renewable capacity in the overall capacity mix by 5 percentage points, the change in total renewable capacity may have to be much higher.[284]

[282] Whilst it is obvious that governments' are likely to intervene if insufficient renewable capacity is built, the same is likely to be true if too much renewable capacity is built because of the adverse effect this can have on security of electricity supplies.

[283] The capacity margin is the margin of available capacity over demand, generally calculated as (CAP-D/D) where D is expected peak demand and CAP is expected available generation capacity at peak, adjusted for expected outages and variation in generation from intermittent power producers.

[284] For example, suppose a market has an installed capacity of 100 GW of which 20 GW or 20% is renewable capacity. To increase the share of renewable capacity by 5 percentage points to 25%, an extra 5 GW of renewable capacity have to be added, which corresponds to a 25% increase in renewable capacity.

FIGURE 32: RENEWABLE CAPACITY ADJUSTMENT LIMITS[285]



326. To differentiate the capacity mix between the commodity price paths we calculate the extent to which commodity prices from a particular price path vary from those in the median price path. In more detail, for every price path and every year between 2020 and 2054, we first calculate the log of the annual average price of every commodity,[286] $P(t,c,n)$ and the median of those logs, $\bar{P}(t,c)$, where *t* denotes the year, *c* denotes the commodity and *n* denotes the price path. Next, we calculate the deviation from the median as:

$$\Delta P(t,c,n) = P(t,c,n) - \bar{P}(t,c)$$

327. For each price path we then measure by how much each of the three commodity prices deviate from their respective median price on average across all the years we analyse. We then average the individual commodity price deviations together to create a single "aggregate deviation" , $\Delta\bar{P}(n)$ - Formally, this is the average price deviation from the median across all modelled years (T) and all commodities (C):

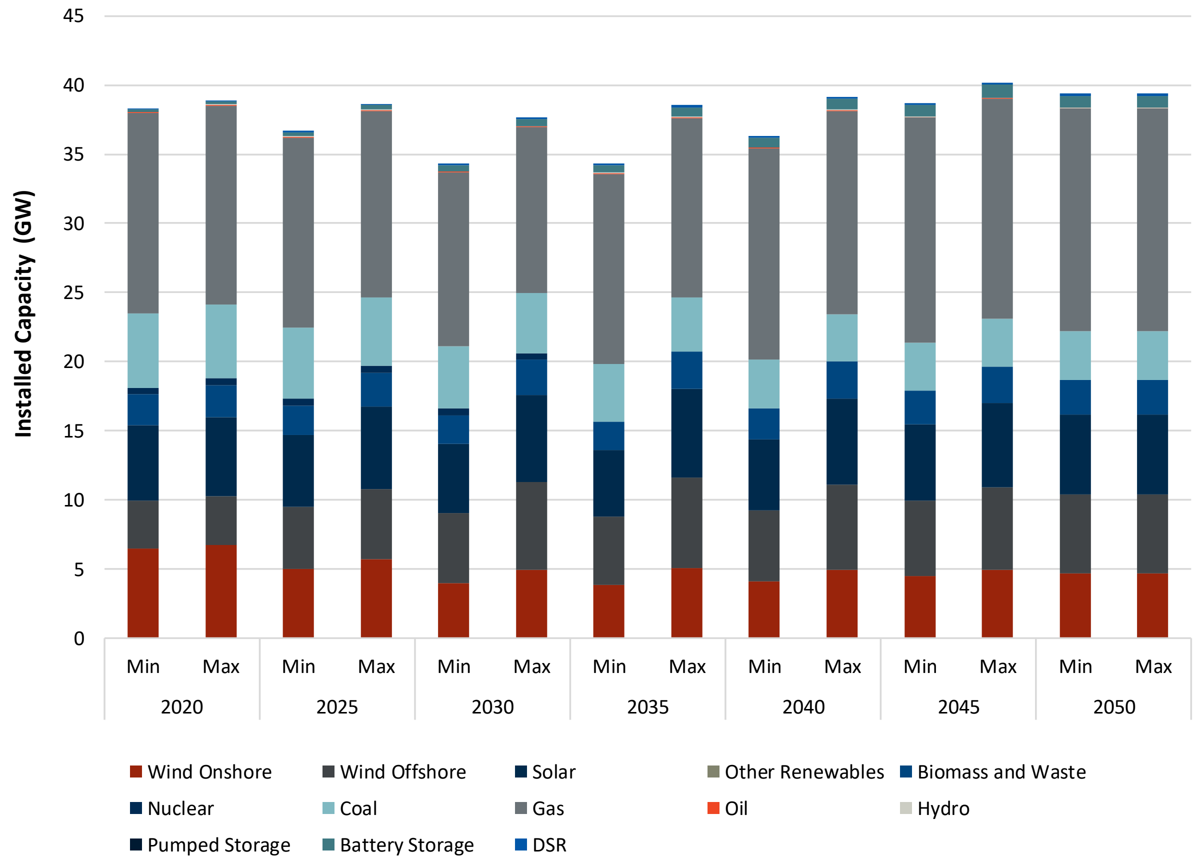
[285] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

[286] We look at logarithm values because of our assumption that commodity prices follow a log normal distribution, as discussed above.

$$\Delta\bar{P}(n) = (\sum_{t=1}^{T}\sum_{c=1}^{C}\Delta P(t,c,n))/(T \times C)$$

328. We rank these aggregate deviations from highest to lowest value. We assume that the price path with the median (50th highest) aggregate deviation corresponds to the case where the renewable capacity exactly matches the EU Reference Scenario values. We apply the maximum upward adjustment to renewable capacity share to the price paths with the 10 highest aggregate deviations and the maximum downward adjustment to the price paths with the 10 lowest aggregate deviations. The extreme outcomes from this process are shown in Figure 33 below.

FIGURE 33: RANGE OF RENEWABLE CAPACITY ASSUMPTIONS IN THE NETHERLANDS[287]



329. For the other price paths, the upward/downward adjustment is determined pro-rata from the average of the renewable capacity in the median aggregate deviation price path i.e. the EU Reference Scenario values, and the capacity in the price paths that have the greatest upward/downward deviation in renewable capacity, depending on how far away the aggregate deviation for a price path lies from the median towards the upper or lower

[287] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

aggregate deviation boundary. If, for example, the aggregate deviation lies two thirds of the way from the median to the upper bound aggregate deviation value, then its renewable capacity will be set equal to the EU Reference Scenario value plus two thirds of the additional capacity included in the maximum renewable capacity case.

330. This process is applied not only in the Netherlands, but also in all the key markets that interconnect with the Netherlands (Belgium, Denmark West, France, Germany, Great Britain).

C.2.ii Efficiency

331. The efficiencies that Baringa assigns to individual plants are based on Baringa's best estimates of reasonable values both at minimum stable load (the lowest sustainable output) and full output. For some power plants, Baringa uses specific technical data but for the majority of plants, it uses generic assumptions based of the type of the plant and its age.

332. Table 12 shows Baringa's assumptions on the average full output efficiency of plants in the Netherlands and Germany in 2020, on a capacity weighted basis.[288]

[288] By "capacity-weighted", we mean that we multiply the efficiency for a particular plant by its capacity and then sum up all these values and divide them by the total capacity. In this way, the average efficiency figures that we present are influenced more by the efficiency of larger plants than smaller plants.

TABLE 12: AVERAGE EFFICIENCY BY PLANT TYPE IN 2020 FOR THE NETHERLANDS AND GERMANY[289]

Plant Type	Full load efficiency (capacity weighted, LHV)
CHP Coal	[redacted]
CHP Gas	[redacted]
CHP Lignite	[redacted]
Coal	[redacted]
Gas OCGT	[redacted]
Gas CCGT	[redacted]
Lignite	[redacted]

Source: Baringa Partners.

C.2.iii Demand

333. We keep the assumptions on demand (peak and annual volumes) constant across the commodity price paths, thus implicitly assuming that long-term electricity demand is inelastic to price. We start from EU Reference Scenario assumptions on annual demand levels (except for Denmark-West, Norway and Finland which come from the Baringa Reference case Q2 2017), and then linearly interpolate between the 5 year steps to create yearly assumptions.

334. Baringa has used its Reference Case Q2 2017, which incorporates peak demand assumptions as well as annual demand figures, to determine peak demand levels consistent with the annual demand assumptions, by applying the ratio between peak and annual demand incorporated in its Reference Case.

335. As we do not make any capacity adjustments after 2050, we assume that demand remains flat from 2050 onwards. Based on these assumption, Figure 34 shows the assumed development of demand in the Netherlands.

[289] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

FIGURE 34: ANNUAL AND PEAK DEMAND ASSUMPTIONS, NETHERLANDS[290]

C.3 Results

C.3.i Output by plant type

336. Figure 35 shows the output by plant type in the Netherlands under the but-for case that results from Baringa's power market modelling for selected price paths and years. We show the results for the price paths with the highest, lowest and central aggregate deviations in renewable capacity, at the start (2020) and middle (2035) of the modelled horizon.

337. In 2020 there are only small differences in the capacity mix between different price paths. Differences in generation are primarily the result of commodity price differences in this year, and in particular due to gas to coal competition. In the price path with the highest aggregate deviation, and so the highest commodity prices and renewable capacity, gas-fired generation is particularly competitive; and so has high gas fired generation and lower coal-fired generation, both in the Netherlands and the markets that are directly connected to it.

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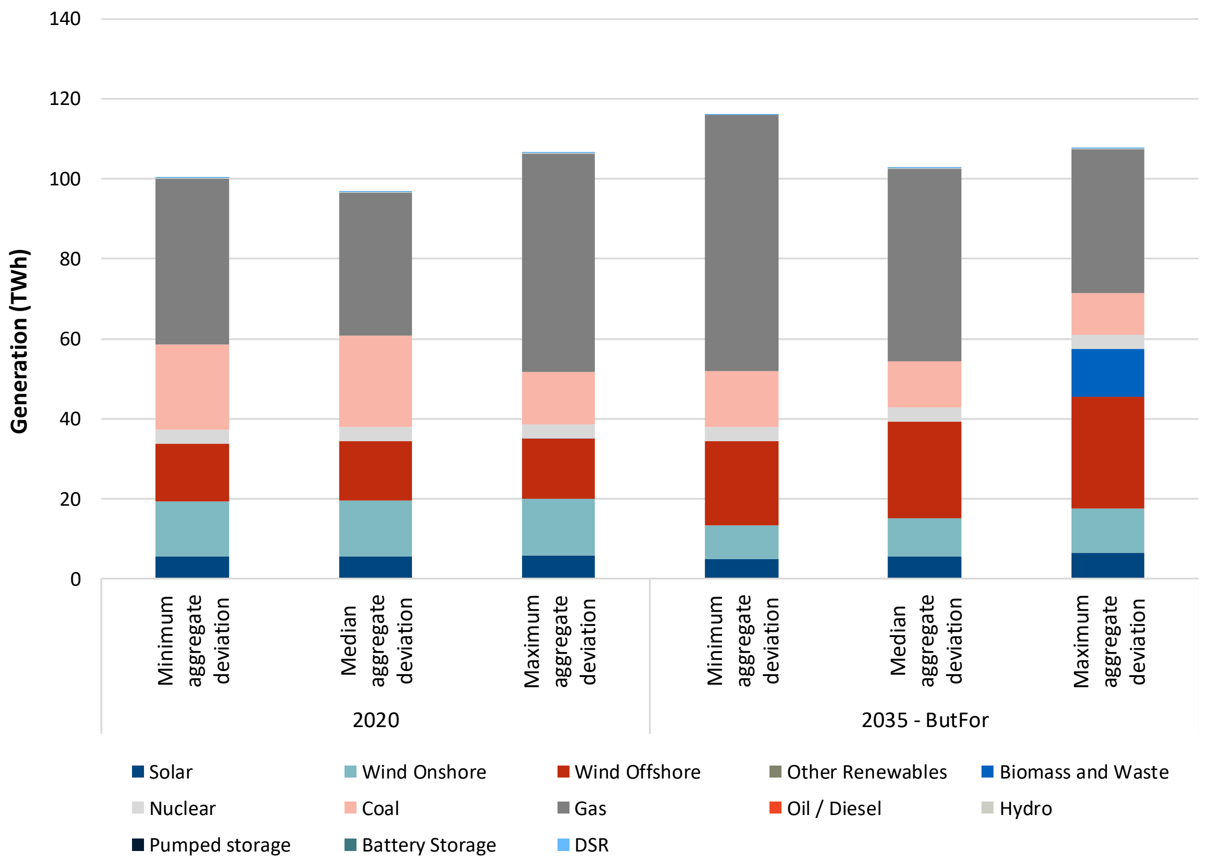
290 Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

338. By 2035 the different price paths also involve significantly different capacity mixes. For example, the generation from wind, solar and biomass varies from 34 TWh to 45 TWh. Thermal generation decreases as renewable generation increases across the price paths. There are also variations in the total Dutch generation across the price paths, driven largely by the relative competitiveness of NL thermal plants versus those in interconnected markets.

FIGURE 35: GENERATION FOR SELECTED PRICE PATHS, NETHERLANDS[291]



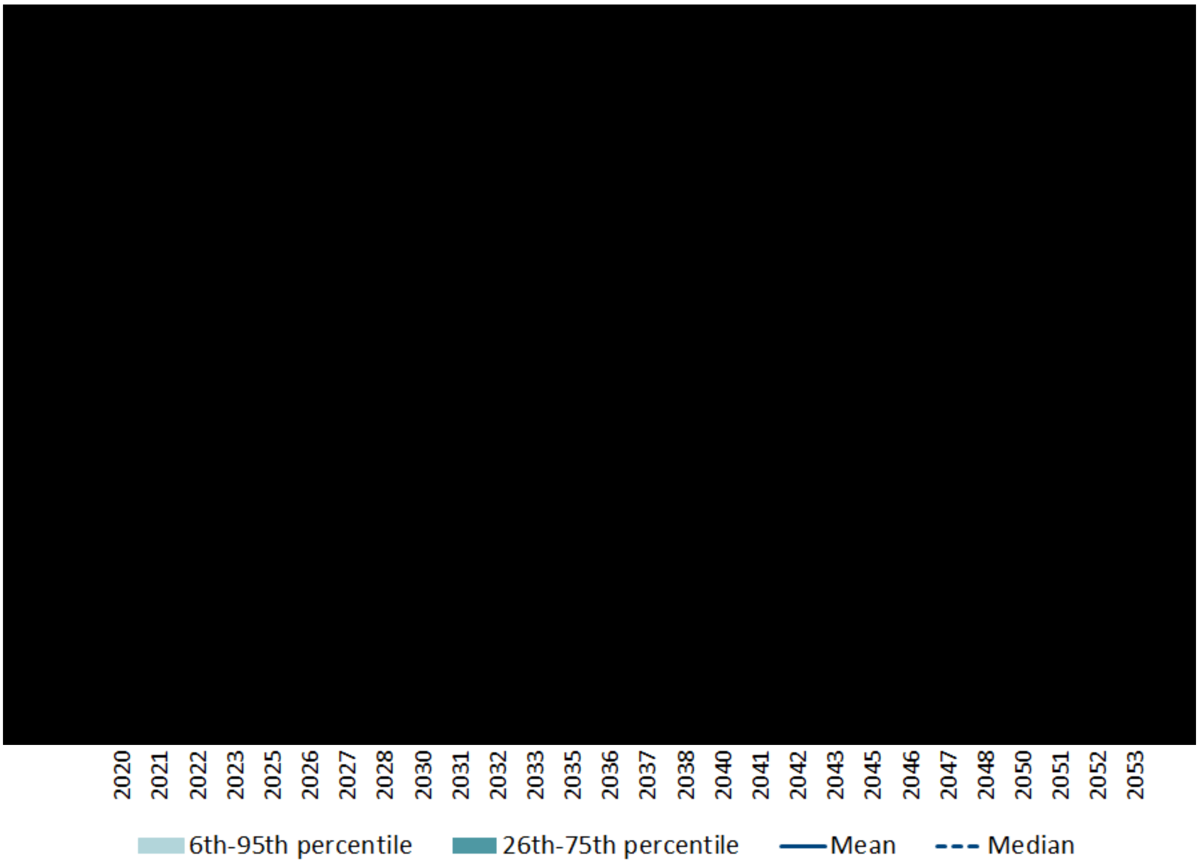
C.3.ii Electricity prices

339. The key output from the dispatch model is the wholesale market electricity price for the Netherlands for each year and price path. These results can be collated to provide a distribution of average electricity prices[292] for each month, as shown in Figure 36, which is the same as Figure 8.

[291] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

[292] What are known in the industry as "baseload prices" because the average is across all the hours in a month and hence represents the price that a plant that ran continuously throughout the month would receive. Plants that run continuously are referred to as running at baseload.

FIGURE 36: DISTRIBUTION OF MONTHLY ELECTRICITY PRICES[293]



340. As the figure shows, the range of electricity prices across different commodity price paths is large, driven primarily by the wide range of commodity prices considered particularly in the later years. The range of electricity prices would be even wider but for the fact that the impact of high commodity prices, which increase electricity prices, are to some extent offset by the higher levels of renewable capacity in these price paths for the period before 2050. Increasing the volume of low marginal cost renewable means that there are more periods when these plants are on the margin and so create very low (or negative) electricity prices and so this reduces the impact of the high electricity prices in other period.

341. There is very little difference between the monthly baseload electricity prices in the actual and but-for cases (as can be seen from Figure 37 which is the same as Figure 9 above) and essentially [redacted] before [redacted]. This is to be expected given the relatively modest change in the overall capacity mix in the Netherlands between these cases, and the fact that the capacity mix in all the other modelled countries does not vary between the cases.

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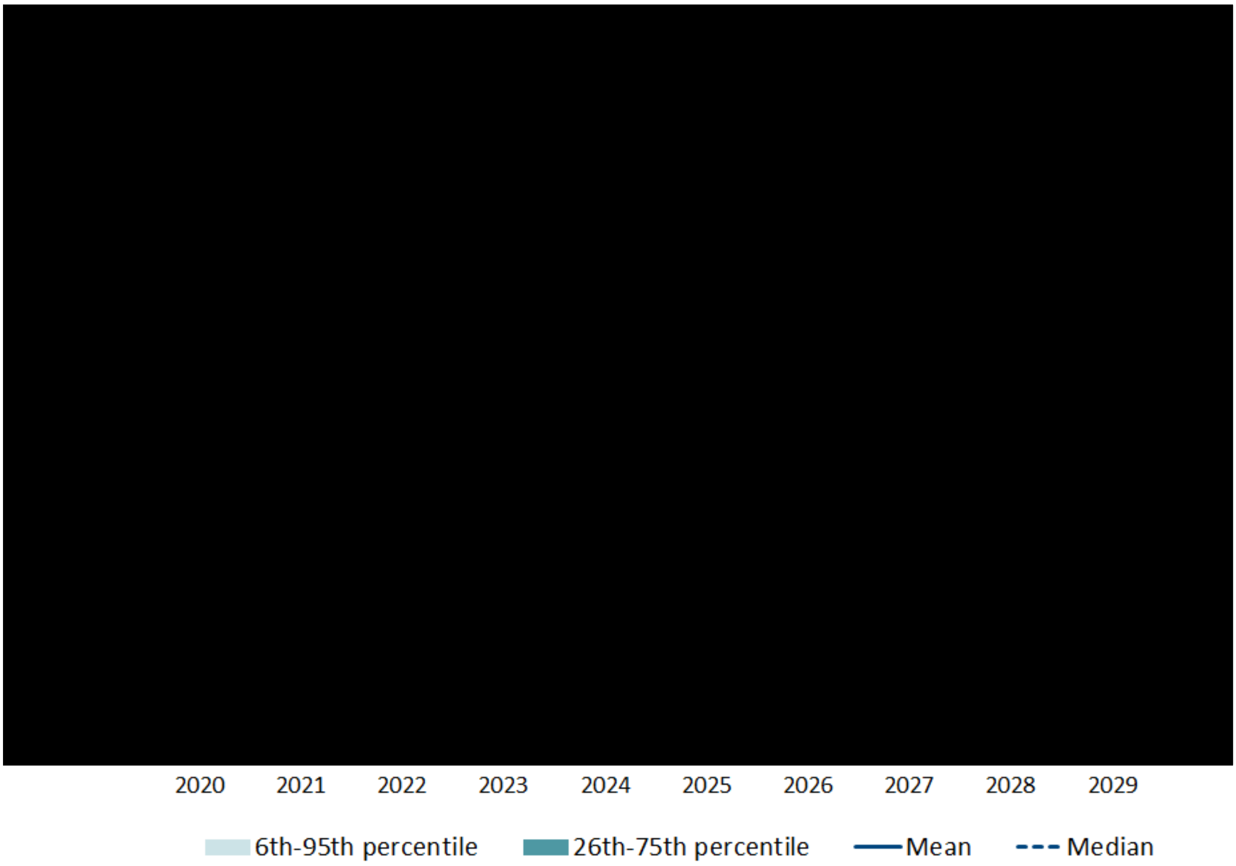
[293] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

FIGURE 37: DIFFERENCES BETWEEN ELECTRICITY PRICES UNDER THE BUT-FOR AND ACTUAL CASES[294]



342. Figure 38, Figure 39 and Figure 40 show the electricity prices for a year sorted from highest to lowest, for the but-for case for 2020, 2035, and 2054 respectively. Such figures are known as "price duration curves" because they depict the percentage of the year for which prices exceed any given value. Each figure contains the price duration curves for the price paths with the 6th highest annual average price, the median annual average price and the 96th highest average annual price across all price paths. If a price duration curve drops sharply towards or below zero (at the right hand side of the price duration curve), it indicates that renewable capacity is setting prices.

343. In 2020, there is little difference across the selected price duration curves as commodity price and renewable variation is limited, see Figure 38.

344. In 2035 there is a significant difference in renewable energy capacity between the commodity price paths whose electricity prices are shown. This mitigates the variation related to commodity prices, and brings down prices towards the right hand end of the price duration curve, see Figure 39.

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[294] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

345. In 2054, there is significant variation in electricity prices between the paths shown, which is driven largely by differences in commodity prices because there is very little difference in the capacity mix across the price paths. Accordingly, the point at which prices drop sharply downwards towards or below zero is the same for all three price paths, see Figure 40.

FIGURE 38: PRICE DURATION CURVE, 2020, SELECTED PRICE PATHS, NL[295]

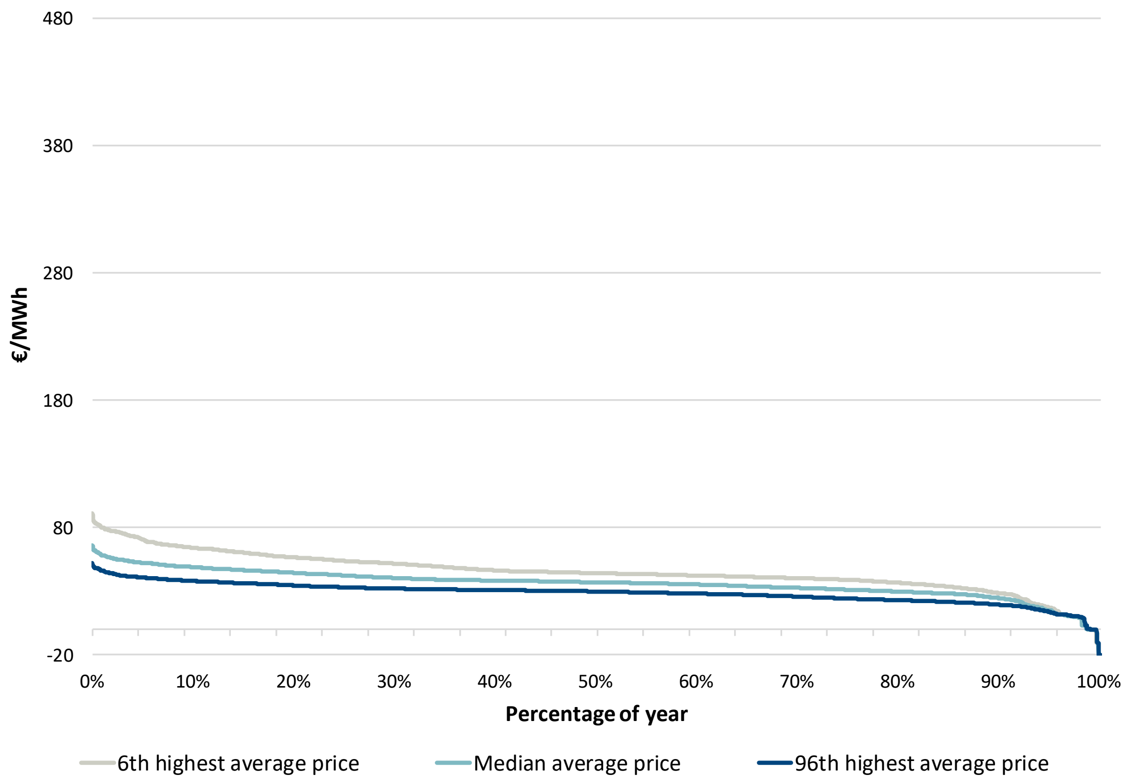


FIGURE 39: PRICE DURATION CURVE, 2035, SELECTED PRICE PATHS, NL[296]

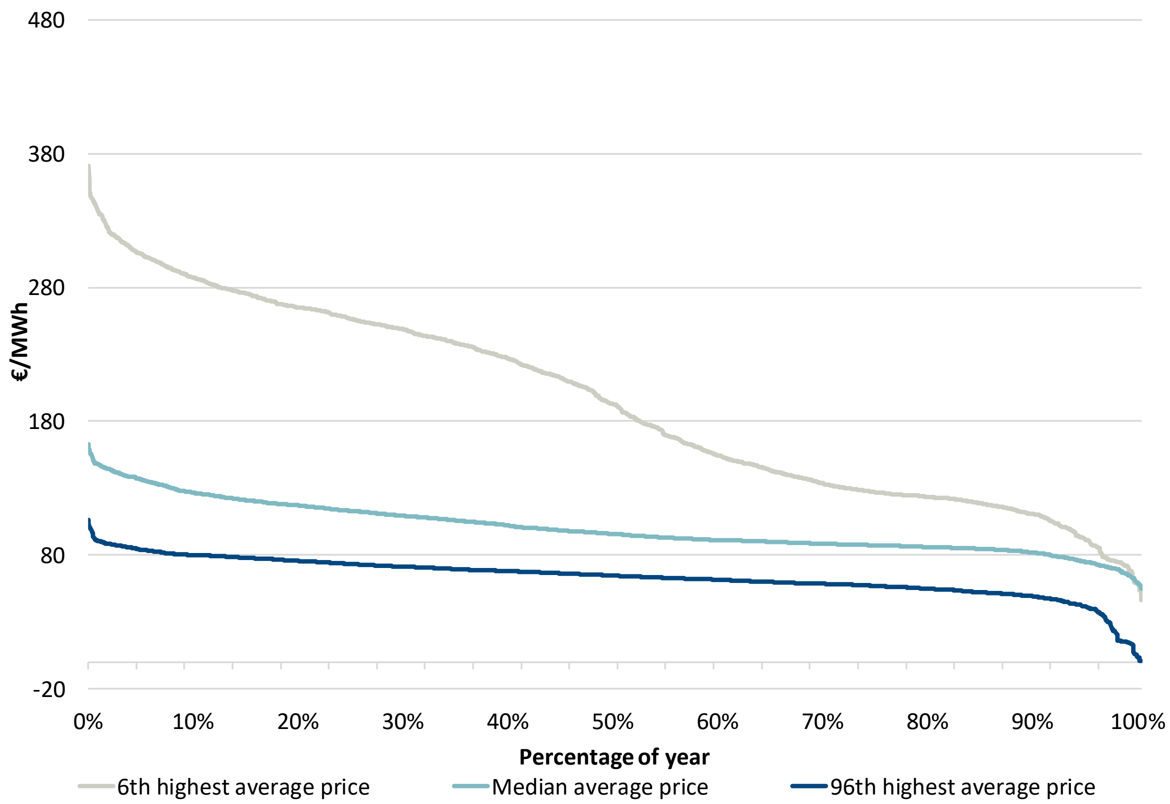
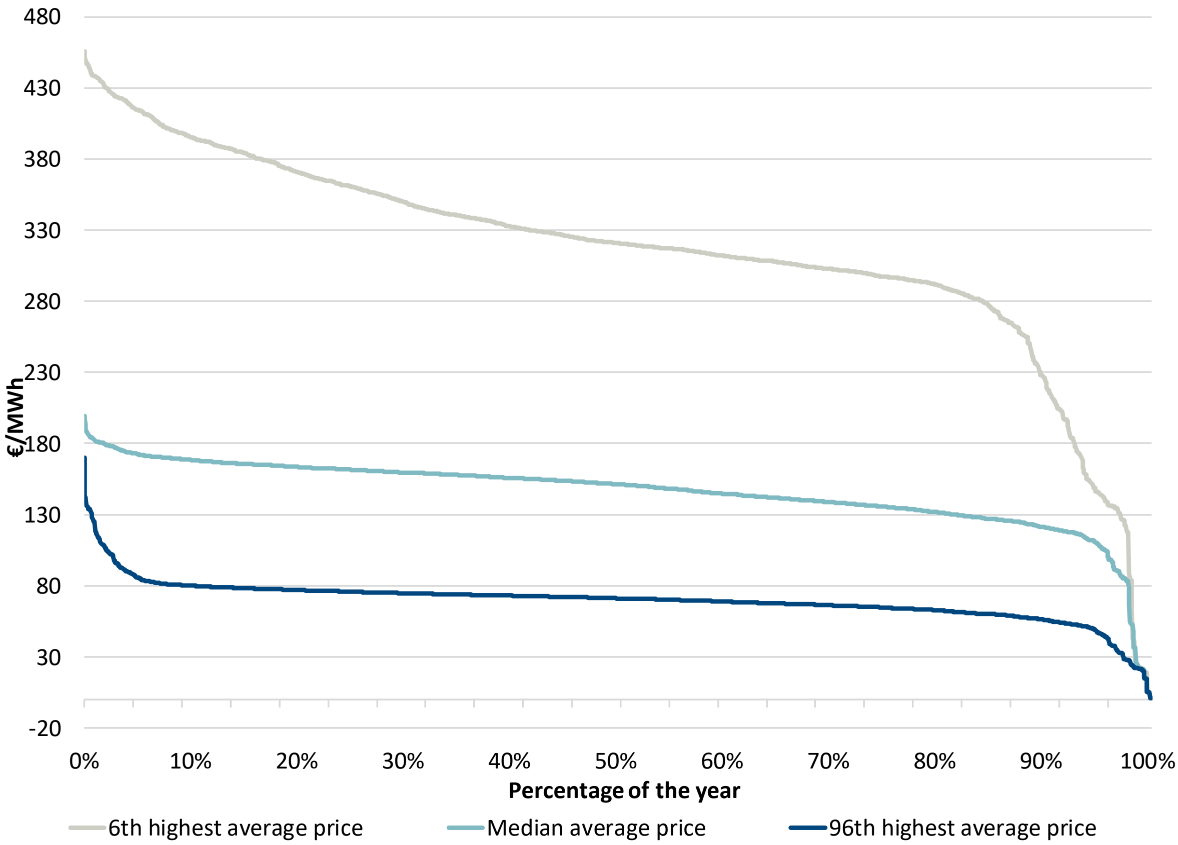


FIGURE 40: PRICE DURATION CURVE, 2054, SELECTED PRICE PATHS, NL[297]



295 Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

296 Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

297 Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

Appendix D : Technical details of the dispatch model

346. In this appendix, we describe the technical implementation of the dispatch model we referred to in Section V.C. We rely on two separate mixed integer programs,[298] a simpler one for the period from 2030 to 2054 when Eemshaven runs exclusively on coal and a more complex model for the period 2020-2029 when Eemshaven can burn a mixture of coal and biomass.

347. While we could have used the more complex model for the entire modelling period, the simpler model reduces the computational time and produces the same results as the more complex model because the plant is assumed only to burn coal.

348. Eemshaven consists of two identical units and so we focus on optimising the dispatch of just one of the units and assume that the other unit would be dispatched in an identical manner. This is also the approach that RWE takes in its long-term modelling.

349. Table 13 lists all variables that we use in the models.

TABLE 13: DISPATCH MODEL NOMENCLATURE

Variable	Description
Globals and market inputs	
$\boldsymbol{s} \in \{\mathbf{1}, \dots, \mathbf{100}\}$	Simulation index
$\boldsymbol{t}$	A four-hourly period between 2020 and 2054
$\boldsymbol{T}$	Final period
$\mathbf{N_y}$	Number of periods in year y
$\boldsymbol{y(t)}$	Discrete function mapping four-hourly period to years between 2020 and 2054
$\boldsymbol{C_t^{Elec}}$	Electricity price from Electricity market model in period t in $€/MWh_{el}$[299]

[298] A mixed integer program is one that combines linear equations, such as “a=b+c”, with requirements that a variable can for example only take the value zero or one i.e. an integer, in this case even binary, value.

[299] We refer to two different energy units, megawatt hours thermal and megawatt hours electric. A thermal power plant converts thermal energy into electric energy. However, with an efficiency below 100%, it

C_t^{Var}	Plant-specific variable costs not directly related to fuel, e.g. limestone and ammonia water in period t in €$/MWh_{el}$
C_t^{Coal}	Coal price including transport, stocking and local handling costs in period t in €$/MWh_{th}$[300]
$C_t^{CO_2}$	Emission allowance price per ton of CO_2.
C_t^{Gasoil}	Low-sulphur gas oil price in €$/MWh_{th}$
E^{Coal}	Carbon content factor of coal in $t\ CO_2/MWh_{th}$
E^{Gasoil}	Carbon content factor of low-sulpure gasoil in $t\ CO_2/MWh_{th}$
	Plant specific inputs
$\mathrm{H}_t(P_t)$	Plant efficiency in period t at generation level P_t
$\overline{P_t}$	Full output capacity in period t in MWh_{el}
$\underline{P_t}$	Minimum output capacity in period t in MWh_{el}
$SUC_t(C_t^{SUC,cash}, C_t^{Coal}, C_t^{CO_2}, C_t^{Gasoil})$	Start-up costs in period t depending on coal, carbon and gasoil prices
$C_t^{SUC,cash}$	Cash component of start-up costs
RFO_t	Margin loss due to ramping between $\underline{P}$ and $\overline{P}$
RL_t	Margin loss due to ramping upon start-up
A_t	Binary indicator taking the value of 1 if plant is available in period t and 0 else.
FO	Forced outage rate (%)
HC_A	Fuel input curve intercept
HC_B	Fuel input curve slope
$y'(t)$	Discrete function mapping four-hourly period to subsidy periods between [redacted] and April 2027[301]

cannot convert every MWh of thermal energy into electric energy but some of it becomes "waste" heat. This necessitates the distinction between the two types of energy.

300 Coal prices are usually quoted in €/ton. The standard benchmark price applicable to the Netherlands is *ARA* (Amsterdam-Rotterdam-Antwerp), which is standardised at an energy content of 6,000 kilocalories per ton. This allows us to convert prices in €/ton to prices in €$/MWh_{th}$. See Harris-Hesmondhalgh Workpapers, Tables E.1 and E.2 – Dispatch Model, Tab 'Constants and Inputs'.

301 This reformulation is necessary as subsidy periods and calendar years are not always congruent. The last subsidy period spans only January and February 2027. The corresponding set of periods for a given subsidy period is given by $\boldsymbol{y}' = \{t \in \mathbb{N} | y'(t) = y'\}$.

$\boldsymbol{N_{y'}}$	Number of periods in subsidy period y'
$\boldsymbol{ToP_{y'}}$	Maximum biomass input in a given subsidy period y' in MWh_{th}
$\boldsymbol{CoFi}$	Maximum biomass co-firing level in a given period t
$\boldsymbol{SL}$	Station load in % of net output
$\boldsymbol{C_{y'}^{Strike}}$	Strike price in subsidy period y'
$\boldsymbol{C^{Floor}}$	Floor price for subsidy
$\boldsymbol{C_t^{biomass}}$	Biomass price including transport, stocking and local handling costs in period t in $€/MWh_{th}$
Decision variables	
$\boldsymbol{u_t} \in \{\boldsymbol{0},\boldsymbol{1}\}$	Binary unit commitment variable indicating whether the plant is running or not in period t
$\boldsymbol{v_t} \in \{\boldsymbol{0},\boldsymbol{1}\}$	Binary variable indicating a start-up in period t
$\boldsymbol{w_t} \in \{\boldsymbol{0},\boldsymbol{1}\}$	Binary variable indicating a shut-down in period t
$\boldsymbol{p_t} \in \left[\boldsymbol{0}, (\overline{\boldsymbol{P_t}} - \underline{\boldsymbol{P_t}})\right]$	Generation above $\underline{\boldsymbol{P_t}}$
$\boldsymbol{f_t^{coal}}$	Coal input in period t in MWh_{th}
$\boldsymbol{f_t^{biomass}}$	Biomass input in period t in MWh_{th}

D.1 Dispatch for 2030-2054

D.1.i Defining the unit's output level

350. As explained in Section V.C, we optimise the unit's dispatch against the clean dark spread, or CDS. If the CDS is positive, it is optimal for the unit to run and earn profits. If the CDS is negative, it will be optimal in many instances to shut the unit down and wait for the next positive CDS period. We calculate the CDS in period t (CDS_t) according to the following expression:

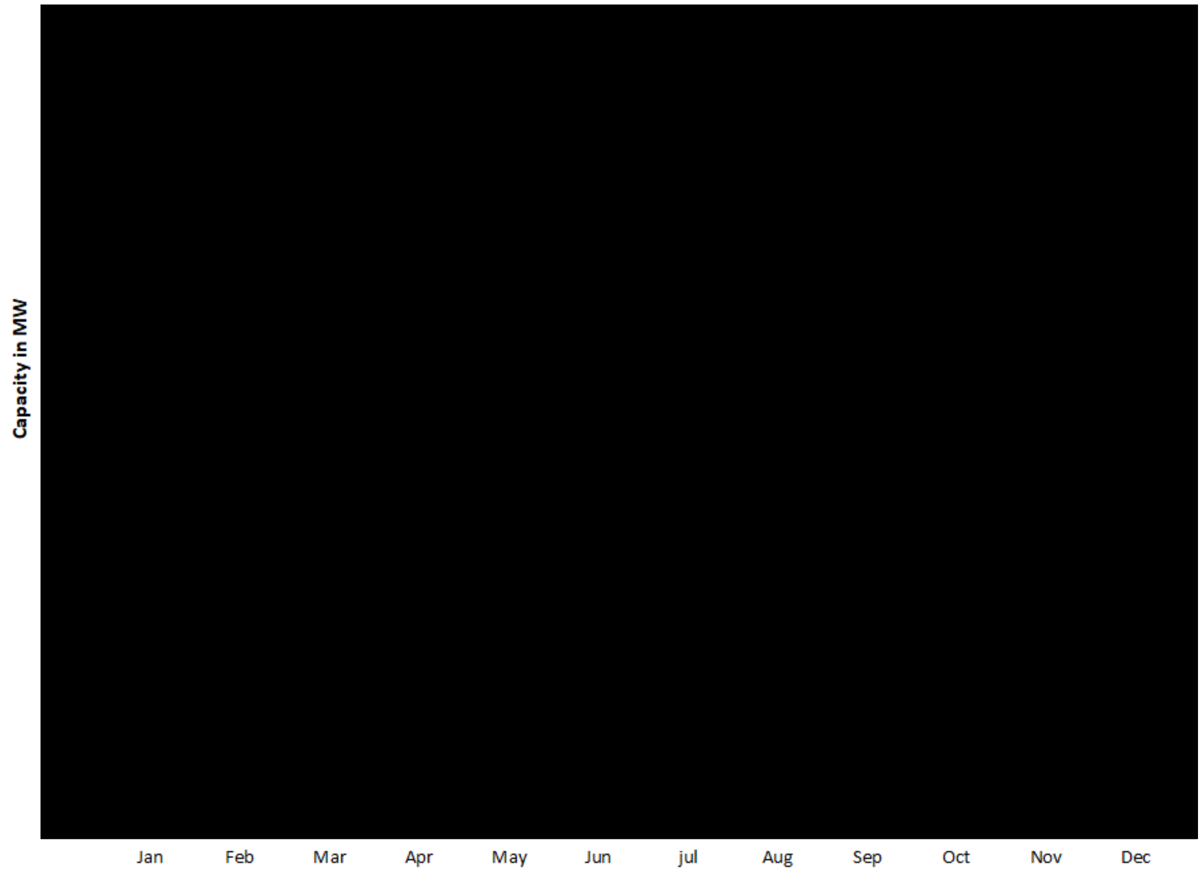
$$CDS_t = \left(C_t^{Elec} - C_t^{Var}\right) - \frac{\left(C_t^{Coal} + C_t^{CO_2} \times E^{coal}\right)}{\mathrm{H_t}(P_t)} \qquad (I)$$

351. Ideally, the unit would run in all periods t when $CDS_t > 0$ and would be shut down whenever $CDS_t \leq 0$. However, the unit faces a number of physical and technical

constraints.[302] Starting up is costly and it takes a while for the unit to reach its full output level.

352. Due to these technical constraints, it may sometimes be favourable to keep the unit running even when $CDS_t < 0$ as it would be more costly to start-up again later. While it is optimal to run at the unit's maximum capacity, $\overline{P}$, when $CDS_t > 0$, the unit's losses from operating when $CDS_t < 0$ can be minimised by reducing its output to the minimum stable generation level, $\underline{P}$. The maximum generation capacity varies slightly with the average temperature in a given month, as shown in Figure 41, but the minimum stable generation level is constant.

FIGURE 41: MAXIMUM AND MINIMUM CAPACITY[303]



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[302] As described above, Eemshaven consists of two units EEM A and EEM B. As these units are technically identical, we model them identically and therefore use the terms unit and plant interchangeably.

[303] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

353. The unit is less efficient ($\mathrm{H_t}$ is higher) if it runs on minimum generation output $\underline{P}$ and thus the clean dark spread is lower than it would be if the plant ran on full output.[304]

$$CDS_t\left(\underline{P_t}\right) < CDS_t(\overline{P}_t) \qquad (II)$$

354. In any given period, t, we can therefore determine whether it is better to run at full output or minimum output. The optimal generation level, provided the unit is running, is given by:

$$P^*_{t|u_t=1} = max\left(\overline{P}_t \times CDS_t(\overline{P}_t), \underline{P_t} \times CDS_t\left(\underline{P_t}\right)\right), P_t \in \{\underline{P_t}, \overline{P}_t\} \qquad (III)$$

355. Where $u_t \in \{0,1\}$ is a binary variable that is equal to 1 when the unit is running in period t and 0 if it is not. The corresponding optimal margin when the unit is running is given by:[305]

$$M^*_{t|u_t=1} = CDS_t\left(P^*_{t|u_t=1}\right) \times \ P^*_{t|u_t=1} \qquad (IV)$$

356. Therefore the optimal production level is independent of the choice of whether to run at all and the optimisation problem reduces to a *unit commitment problem* that optimises when to set u_t equal to one and when to set it to zero, subject to the technical constraints mentioned above and described in greater detail below.

D.1.ii Start-ups and shut-downs

357. Given that starting up a unit incurs additional costs, we have to be able to take these into account in deciding when the unit should run and to do so, we need to be able to identify periods in which the unit starts up or shuts down.

358. We define two more binary variables: $v_t \in \{0,1\}$ that indicates a start-up in period t and $w_t \in \{0,1\}$ which signals a shut-down in period t. Given the choice of u_t, the values of v_t and w_t follow directly from the relationship:

$$u_t - u_{t-1} = v_t - w_t \qquad \forall t \qquad (V)$$

359. $\forall t$ indicates that this relationship holds for all periods, in case of the 2030-2054 dispatch model that corresponds to the period from the first four hours of 2030 (1 January 2030 00:00 – 03:59 $\equiv period\ 0$) until the last four hours of 2054 (31 December 2054 20:00-23:59 $\equiv period\ T$). The relationship in (V) implicitly gives the values for v_t and w_t depending on the choice of u_t and u_{t-1}. This allows us to formulate a simple objective function as shown below in (VI).

$$J = \sum_{t=0}^{T} (M^*_t - RFO_t) \times A_t \times u_t - (SUC_t + RL_t) \times v_t \qquad (VI)$$

---

304 The efficiency of a coal-fired power plant determines how much coal is necessary to produce 1 MWh of electricity. Assuming the efficiency at full output is at [redacted]% it takes ca. [redacted] MWh of coal (which corresponds to roughly [redacted] tons).

305 Note that, for notational simplicity we proceed to denote $M^*_{t|u_t=1}$ by M^*_t.

360. SUC_t indicates the start-up cost the unit would incur if it starts up in period t (i.e. $v_t = 1$). To start up a unit must burn [redacted] MWh_{th} of coal and [redacted] MWh_{th} of gasoil. Additionally, there is a fixed cost, $C_t^{SUC,cash}$, of €[redacted]/start (as of 2020).[306] Hence, the total start-up costs are given by:

$$SUC_t = C_t^{SUC,cash} + [\text{redacted}]\ MWh_{th} \times \left(C_t^{Coal} + E^{Coal} \times C_t^{CO_2}\right) + [\text{redacted}]\ MWh_{th} \times \left(C_t^{Gasoil} + E^{Gasoil} \times C_t^{CO_2}\right) \qquad (VII)$$

D.1.iii Taking into account ramping constraints

361. A unit is unable instantaneously to go from zero output to full output but takes some time to do so. This limit on the rate at which the output of the plant can increases is known as a "ramping constraint" and we need to include it in our model because, as explained above, the commodity margin that the unit can earn depends on the output level at which it is operating.

362. We use two variables: RFO_t, "ramp to full output" from minimum stable generation, and RL_t, "ramp to lowest" i.e. minimum stable generation, to account for the lost margins associated with ramping up the output of a plant. RWE's dispatch model,[307] which underpins the results shown in the SCOut reports[308], assumes that upon start-up, a unit would need to run at its minimum stable generation capacity for one hour and that it would take two hours to get from minimum stable generation to full output.[309] The orange area in Figure 42 represents the lost generation that RWE models. The financial ramping loss is defined by the difference between $M^*_{t|v_t=1}$ and the actual margin achieved when the ramping constraints are respected.

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[306] Information received from RWE.

[307] Information received from RWE.

[308] **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017, pp. 47-48.

[309] Information received from RWE.

FIGURE 42: RAMPING LOSS IN GENERATION UPON START-UP[310]

[redacted]

363. Likewise, the orange area in Figure 43 shows the loss in generation that occurs if the unit goes from its minimum stable generation to full output. The margin loss with this ramping constraint is defined as shown in (VIII), where $M_t\ (P_t)$ gives the margin at generation level P_t.

$$RFO_t = \begin{cases} \frac{0.5}{4} \times \left(M_t\left(\underline{P_t}\right) - M_t\left(\overline{P_t}\right)\right) & if\ M_t^* = M_t(\overline{P}_t)\ AND\ M_{t-1}^* = M_{t-1}\left(\underline{P_{t-1}}\right) \\ 0 & else \end{cases} \quad \forall t \qquad (VIII)$$

[310] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

FIGURE 43: RAMPING LOSS FROM $\underline{P}$ TO $\overline{P}$[311]

[redacted]

364. The loss shown in Figure 42 is 3 times as large as the loss shown in Figure 43. If (i) the optimal margin, would be $M_{t-1}^{*} = M_{t-1}(\underline{P_{t-1}})$ if the unit was running in $t-1$, and (ii) the optimal generation level in the start-up period t is $\overline{P_t}$, then (VII) defines the conditions under which $RFO_t > 0$. Consistent with this formulation, we set $RL_t = 2 \times RFO_t$. While this definition of RL_t works in almost all cases, there can be situations (when the CDS is close to zero) when $M_{t-1}^{*} = M_{t-1}(\overline{P_{t-1}})$ but $u_{t-1}^{*} = 0$.[312] In those cases, $RFO_t = 0$ and, as shown in (IX), it is necessary for $RL_t = \frac{1.5}{4} \times \left(M_t\left(\underline{P_t}\right) - M_t(\overline{P_t})\right)$.

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[311] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

[312] It tends to be optimal to run at minimum output $\underline{P_t}$ when $CDS_t(P_t) < 0 \quad \forall P_t \in \{\underline{P_t}, \overline{P_t}\}$. However, if $\lim_{\epsilon \to 0} CDS_t + \epsilon = 0$ where $CDS_t \leq 0 \; for \;\; \epsilon \geq 0$, the relatively higher efficiency $\mathrm{H}_t(\overline{P_t})$ (vs $\mathrm{H}_t(\underline{P_t})$) can lead to situations in which full output is better than minimum output despite both resulting margins being less than zero. As an example, assume that $C_t^{Elec} - C_t^{Var} =$ [redacted] $€/MWh_{el}$ and $\left(C_t^{Coal} + C_t^{CO_2} \times E^{coal}\right) =$ [redacted] $€/MWh_{th}$. Further assume that the efficiency of full output of [redacted] is equal to [redacted] and the output at minimum generation of [redacted] is [redacted]%. The resulting margins are given by $M_t(\overline{P_t}) =$ ([redacted] $/MWh_{el} -$ [redacted] MWh_{th} / [redacted]) $\times \overline{\mathrm{P}}_t =$ [redacted] and correspondingly $M_t\left(\underline{P_t}\right) =$ [redacted]

$$RL_t = \begin{cases} 2/4 \times RFO_t \ \ iff\ M_t^* = M_t(\overline{P}_t)\ AND\ \ M_{t-1}^* = M_{t-1}\left(\underline{P_{t-1}}\right) \\ 1.5/4 \times \left(M_t\left(\underline{P_t}\right) - M_t(\overline{P_t})\right)\ iff\ M_t^* = M_t(\overline{P}_t)\ AND\ \ M_{t-1}^* = M_{t-1}(\overline{P_{t-1}}) \\ 0 \qquad\qquad else \end{cases} \quad \forall t \qquad (IX)$$

365. Finally, we impose binary constraints on the decision variables in expression (X).

$$u_t, v_t, w_t \in \{0,1\} \qquad (X)$$

366. We compute M_t^*, SUC_t, RFO_t and RL_t and pass these exogenous values on to a commercial solver[313] to solve the mixed-integer program in (XI).[314]

$$\max_{\{u_t\}_{t=0}^T} J \ subject\ to\ (V),(X) \qquad (XI)$$

367. The commercial solver returns a vector $\{u_t^*\}_{t=0}^T$ that maximises J. This vector implicitly also contains the optimal values $\{v_t^*\}_{t=0}^T$ (and $\{w_t^*\}_{t=0}^T$) . We determine the optimised output in period t according to:

$$g_t^* \coloneqq u_t^* \times (P_{t|u_t=1}^* - ramploss_t) \qquad (XII)$$

368. Note that, to avoid unnecessary definitions, we do not include the equations defining $ramploss_t$, the lost generation, because it should be clear from Figure 42 and Figure 43 what is involved in defining them.

D.1.iv Commodity margin

369. One of the key results from the dispatch model is the commodity margin that each unit earns i.e. its revenues minus the costs directly associated with operating the unit. The commodity margin in period t is determined by:

$$m_t^* \coloneqq (M_t^* - RFO_t) \times u_t^* - (SUC_t + RL_t) \times v_t^* \qquad (XIII)$$

D.1.v Results passed to the financial model

370. We compute the annual commodity margin, the annual total generation and the total running hours for a unit according to:[315]

$$\begin{aligned} cm_y^* &\coloneqq (1 - FO) \times \sum\nolimits_{t \in \boldsymbol{y}} m_t^* \quad \forall y \in \{2030, \dots, 2054\} \\ gen_y^* &\coloneqq (1 - FO) \times \sum\nolimits_{t \in \boldsymbol{y}} g_t^* \ \ \forall y \in \{2030, \dots, 2054\} \end{aligned} \qquad (XIV)$$

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313 FICO's Xpress MP.

314 See Harris-Hesmondhalgh Workpapers - Tables E.2 for details.

315 Where $\boldsymbol{y} = \{t \in \mathbb{N} | y(t) = y\}$.

$$run_y^* \coloneqq (1 - FO) \times \sum_{t \in y} u_t^* \quad \forall y \in \{2030, \dots, 2054\}$$

371. The forced outage rate (FO) adjusts the commodity margin and generation for unexpected outages when the plant *trips.* As opposed to scheduled outages, which are reflected in A_t, the forced outage rate represents probability of an outage occurring at any point throughout a year, and we therefore apply it to the aggregate margins and generation figures.

372. To simplify the explanations, we have omitted the subscript indicating that the equations apply to a particular simulation, s. But we repeat the optimization described in equations (I) to (XIV) for all simulations $s \in \{1, \dots, 100\}$ and pass on the year-simulation combinations of cm_{ys}^* and run_{ys}^* to the financial model.

D.2 Dispatch for 2020-2029

373. The dispatch model described above for 2030-2054 condenses to the optimisation problem shown in (XI) because (1) there is only one choice to be made: how much to generate in each period, and (2) we are able to specify this choice in binary terms as a decision in each period of whether not to generate electricity (*unit commitment problem*).

374. However, as described in Section V.C.2, RWE will receive subsidies for burning biomass under the SDE+ scheme until April 2027. In principle, from January 2020 to April 2027 the optimal dispatch decision should not only take into account when, and how much, to generate but also *how much* and *when* to generate *sustainably* (i.e. by burning biomass). Ideally, the dispatch decision would compare the subsidised biomass margin with the clean coal margin in period t and pick whichever option is cheaper. However, such a simple formulation of the optimisation problem is not feasible for several reasons:

    a. As discussed in Section V.C.2, the extent to which biomass is subsidised depends on the average annual electricity price of a given year. At the time a dispatch decision needs to be made, this average price is unknown;

    b. The scheme only subsidises a fixed amount of biomass-based generation. As Table 1 above shows, Eemshaven's SDE+ subsidy allows sustainable generation of up to 1,788,889 MWh;[316]

    c. Eemshaven has an environmental permit that limits its use of biomass to 800,000 tonnes per calendar year.[317] [redacted]

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[316] This corresponds to roughly [redacted]% of the total generation assuming that the plant runs [redacted] hours at maximum output in a given year.

[317] **Exhibit BR-11**, KEMA Consulting, Application for Incorporation Permit, dated 20 December 2006, pp. 48-49.

[redacted]

d. Technical constraints mean that biomass and coal are not freely interchangeable as fuels. Biomass always needs to be burnt in conjunction with coal and in any given hour the plant can burn a maximum of [redacted] of biomass.[318]

375. These features impose additional constraints that have to be taken into account.

376. As we cannot *internalise* the trade-off between the subsidised biomass margin and the coal margin, because the former is unknown at the time of the decision, we formulate the optimisation to burn as much biomass as possible subject to constraints on co-firing described above.

D.2.i Problem setup

377. As the unit margin changes with the chosen fuel mix, we cannot determine it exogenously (as a fixed input to the optimisation) as we did in the longer term optimisation problem. Instead, we have to define an additional variable for inclusion in the optimisation:

$$\begin{aligned} m_t &:= (C_t^{Elec} - C_t^{Var}) \times \left(u_t \times \underline{P_t} + p_t - \overbrace{(v_t + \frac{1}{2} rfo_t)/4 \times \left[\overline{P_t} - \underline{P_t}\right]}^{ramping\ loss} \right) \\ &- v_t \times SUC_t - \left(C_t^{Coal} + C_t^{CO_2} \times E^{coal}\right) \times f_t^{Coal} - C_t^{biomass} \times f_t^{biomass}\ \forall t \end{aligned} \qquad (XV)$$

378. The term on the first line represents the unit's revenues (adjusted for C_t^{Var}) in period t depending on the choice of u_t, p_t and rfo_t.[319] The second line represents the plant's costs in period t depending on the choice of fuel inputs f_t^{Coal} and $f_t^{biomass}$.

379. Again, we formulate the objective function, for which we find the maximum value, as the sum of all margins between $t = 0$ (1 January 2020 0:00-3:59) and $t = T$ (31 December 2029 20:00-23:59). $S_{y-1}^{biomass}$ is last year's biomass subsidy amount, which we assume to be the best estimate of the current year's biomass subsidy. The objective function J in (XVI) ensures that the optimisation decision considers the impact of the subsidy by adjusting the effective costs of biomass by the subsidy estimate.

$$J = \sum_{t=0}^{T} m_t + S_{y-1}^{biomass} \times f_t^{biomass} \qquad (XVI)$$

[318] This reflects RWE's technical expectation around the time of the valuation date.

[319] v_t is implicitly given by the relationship in (V) which also holds for this version of the model.

D.2.i.a Output level

380. As discussed above, we need to account for losses that arise due to the plant's ramping constraints. However, in this optimisation it is not possible endogenously to determine the optimal generation level if the unit is running because of the biomass mixing constraints. Therefore, as we describe, we need additional equations to adjust the generation directly as it feeds into the margin calculation in (XV). Just as before, we define two ramping components, a ramping loss upon start-up (reflecting the need to run an hour at the minimum stable generation level, $\underline{P_t}$) and a ramping loss going from minimum stable generation to full output.

381. The ramping loss upon start-up is once again governed by v_t. The ramp loss resulting from a switch in generation level requires the introduction of an additional binary variable $rfo_t \in \{0,1\}$. From (XV) follows that the ramp loss applies when $rfo_t = 1$. (Note RFO_t in the 2030-2054 optimisation is *not* a decision variable but an exogenous parameter.) The first two constraints in $(XVII)$ determine the value of rfo_t in period t. $(XVII.1)$ states that rfo_t must to be equal to 1 if $p_t - p_{t-1}$, i.e. the generation in t exceeds the generation in $t - 1$.[320] $(XVII.2)$ ensures that the ramping loss only applies when $p_t = \left[\overline{P_t} - \underline{P_t}\right]$.

382. In principle, the unit can start-up and remain at $\underline{P_t}$. In that case, there would be no ramping loss. $(XVII.3)$ covers this eventuality by specifying that the ramp loss must be less than or equal to p_t. If the optimal choice, in the absence of ramping, for a given period implied $v_t = 1$ and $p_t = 0$, $(XVII.3)$ sets $p_t = \frac{1}{4} v_t \times \left[\overline{P_t} - \underline{P_t}\right]$, such that $u_t \times \underline{P_t} + p_t - (v_t + \frac{1}{2} rfo_t)/4 \times \left[\overline{P_t} - \underline{P_t}\right] = u_t \times \underline{P_t}$.

$$rfo_t \times \left[\overline{P_t} - \underline{P_t}\right] \geq p_t - p_{t-1} \quad \forall t \qquad (XVII.1)$$

$$rfo_t \times \left[\overline{P_t} - \underline{P_t}\right] \leq p_t \quad \forall t \qquad (XVII.2)$$

$$\frac{1}{4} v_t \times \left[\overline{P_t} - \underline{P_t}\right] \leq p_t \quad \forall t \qquad (XVII.3)$$

383. Following a similar logic, $(XVIII)$ requires that $p_t = 0$ if u_t and that it takes a maximum value of $\left[\overline{P_t} - \underline{P_t}\right]$.

$$p_t \leq u_t \times \left[\overline{P_t} - \underline{P_t}\right] \quad \forall t \qquad (XVIII)$$

[320] Note that, while the model would allow values for p_t between 0 and $(\overline{P_t} - \underline{P_t})$, its linear structure leads to the choice of $p_t \in \{0, (\overline{P_t} - \underline{P_t})\}$.

D.2.i.b Fuel input

384. The burning of biomass is subject to two restrictions: (i) how much biomass can be burnt in any period, and (2) an annual limit on how much biomass can be burnt. We also have to ensure that the assumed output of the plant is consistent with the amount of biomass and coal that is being burnt. Below we describe the constraints that we use to implement these restrictions.

385. (XIX) ensures that the fuel input $\left(f_t^{Coal}, f_t^{biomass}\right)$ in the second line of (XV) suffices to generate $u_t \times \underline{P_t} + p_t - (v_t + \frac{1}{2} rfo_t)/4 \times \left[\overline{P}_t - \underline{P_t}\right]$. we compute the required fuel input by means of a linearised fuel input curve, shown as the dark blue line in Figure 44. The fuel input curve determines how much fuel the plant needs to generate at a given output level from which we can calculate the efficiency of the unit, generation level divided by fuel input, as shown by the light blue line.

FIGURE 44: FUEL INPUT CURVE AND EFFICIENCY[321]

[redacted]

[321] Harris-Hesmondhalgh Workpapers, Tables I – Other Supporting Analysis.

$$4 \times HC_A \times u_t + \ HC_B \times \left(u_t \times \underline{P_t} + p_t - \overbrace{(v_t + \frac{1}{2} rfo_t)/4 \ \times \left[\overline{P_t} - \underline{P_t}\right]}^{ramping\ loss} \right) - f_t^{Coal} - f_t^{biomass} = 0 \ \forall t \qquad (XIX)$$

386. (XIX) ensures that the sum $f_t^{Coal} + f_t^{biomass}$ equals the required fuel input for the chosen generation level in period t.

387. (XX) imposes a constraint on the maximum use of biomass in a given subsidy period y' in line with the plant's environmental permit.[322]

$$\sum_{t \in y'} f_t^{biomass} - ToP_{y'} \leq 0 \quad \forall y' \qquad (XX)$$

388. (XXI) ensures that we maintain a technically possible fuel mix by limiting the maximum use of biomass to [redacted].

$$f_t^{biomass} \leq CoFi \quad \forall t \qquad (XXI)$$

389. The formulations above require that some of the variables are restricted to taking values of either 0 or 1. We impose this restriction in $(XXII)$.

$$u_t, v_t, w_t, rfo_t \in \{0,1\} \ \ \forall t \qquad (XXII)$$

390. Lastly, we make sure that the plant observes scheduled outages by imposing:

$$u_t \leq A_t \ \forall t \qquad (XXIII)$$

391. Once again, we resort to the commercial solver to find the optimal values of $\left\{u_t^*, p_t^*, rfo_t^*, v_t^*, w_t^* \ , (f^{coal})^*, \left(f^{biomass}\right)^*\right\}_{t=0}^{T}$ to the problem:

$$\max J \ subject\ to\ (V), (XVII), (XVIII), (XIX), (XX), (XXI), (XXII), (XXIII) \qquad (XXIV)$$

392. We define the optimal generation in period t by:

$$g_t^* \coloneqq u_t^* \times \underline{P_t} + p_t^* - \frac{v_t^* + \frac{1}{2} rfo_t^*}{4} \times \left[\overline{P_t} - \underline{P_t}\right] \quad \forall t \qquad (XXV)$$

393. And the optimal margin in period t corresponds to:

$$m_t^* \coloneqq (C_t^{Elec} - C_t^{Var}) \times g_t^* \\ -v_t^* \times SUC_t - \left(C_t^{Coal} + C_t^{CO_2} \times E^{coal}\right) \times (f_t^{Coal})^* - C_t^{biomass} \times \left(f_t^{biomass}\right)^* \forall t \qquad (XXVI)$$

394. As for the 2030-2054 optimisation, we compute annual figures according to (XIV).

[322] Note that $ToP_{y'} = 0$ for periods after the subsidy end in April 2027.

D.2.ii Subsidy calculation

395. Once we know the amount of biomass that the plant has burnt in a year, we can compute the subsidies the plant will earn.

396. The SDE+ scheme awards subsidies to the gross sustainable generation.[323] We compute the share of biomass fuel input to obtain the share of sustainable generation in each subsidy period y'. The sustainable generation is given by:

$$sgen_{y'} := \frac{\sum_{t\in y'} f_t^{biomass}}{\sum_{t\in y'} f_t^{biomass} + \sum_{t\in y'} f_t^{coal}} \times (1+SL) \times (1-FO) \times \sum_{t\in y'} g_t^* \qquad (XXVII)$$

397. The subsidy margin then amounts to:

$$sm_{y'} := \min(C_{y'}^{Strike} - \frac{1}{N_y} \sum_{t\in y} C_t^{Elec}, C_{y'}^{Strike} - C^{Floor}) \times sgen_{y'} \qquad (XXVIII)$$

398. Where y is the year for which holds $\boldsymbol{y'} \subseteq \boldsymbol{y}$**.**

D.3 Harbour fees

399. Eemshaven's lease contract includes a harbour fee.[324] The contract specifies that Eemshaven has to pay a fee for each ship arriving at its dock. [redacted].[325] The last annual fee is payable in [redacted]. [redacted] Based on this information, we compute a variable harbour fee per tonne of coal/biomass used, C_t^{HF}.[326]

400. We impose the Harbour Fee Floor in two steps. First, we run the models described in the preceding sections with adjusted variable costs according to:[327]

$$C_t^{Var'} = C_t^{Var} - C_t^{HF} \qquad (XXIX)$$

401. [redacted]

[323] **Exhibit BR-12**, National Enterprise Agency of The Netherlands, Eemshaven: Decision to Grant a Subsidy, dated 30 November 2016.

[324] See ¶128.

[325] **Exhibit BR-38.A**, RWE, Schedule 22, dated 17 February 2009.

[326] The variable fee is equal to the [redacted].

[327] RWE have provided us with variable costs that include the harbour fee.

402. [redacted]

Appendix E : CAO revenues

403. CAO revenues are the income RWE generates by trading electricity, coal, gas, and CO_2 emission rights. CAO revenues are generation by typical trading activities which try to make use of arbitrage benefits, in particular 'time arbitrage'.

404. In a 'time arbitrage', the trader exploits the differences between the current spot price of a commodity and its future price. Where the spot price of a commodity is lower than its future price, it can buy a commodity now and enter into a forward agreement to sell the commodity in the future for a higher price.

405. For example, suppose on a particular day the clean dark spread[328] for power to be delivered in three months' time is positive. That is, the electricity price RWE could obtain under a forward agreement would be higher than the forward prices for commodities needed to produce this electricity. RWE could enter into a forward agreement, committing itself to deliver a certain amount of electricity in exchange for a fixed price in three months' time. At the same time, RWE could enter into other forward agreements where it purchases the coal and CO_2 permits that Eemshaven will need to generate that power in three months' time, thereby locking in its costs. By locking in the price of electricity and the relevant input costs in three months' time (together, the "three months' forward CDS"), RWE can thereby lock in a margin.

406. When the time to deliver the power arrives, RWE has two options: (i) It can produce the electricity and use it to fulfil the forward contract, or (ii) it can buy electricity at the spot CDS to fulfil its forward agreement and sell the commodities bought forward to produce this electricity. Irrespective of what the spot CDS is, RWE will be able to at least realise the fixed margin under the CDS. Whenever the spot CDS at the time of delivery is positive, RWE can produce the electricity and deliver it for the agreed margin. It can also sell the production at the spot CDS and buy the required electricity to fulfil the forward contract at the spot CDS. The choice will not have any impact on RWE's margins. However, if the spot CDS at the delivery date is negative, RWE can even make an additional profit by using option (ii) above, i.e. by "unwinding" the hedge.

407. We illustrate these trading operations in Table 4 below, which assumes a forward CDS for Eemshaven of 3 €/MWh (see line [1]). First, we will consider different possibilities for RWE if the spot CDS is positive:

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328 As explained in ¶ 125, the clean dark spread is the difference between the electricity price for a period and the marginal generation costs of the plant.

a. If the spot CDS is higher than the forward CDS (see first column), RWE can make a profit by producing electricity and selling it at the higher spot CDS (5 €/MWh instead of 3 €/MWh) ('Option 1'). However, since it will still need to fulfil the existing forward CDS agreement it entered into, RWE will be required to buy electricity at expensive spot CDS (5 €/MWh) in order to deliver it for receiving the lower forward CDS (3 €/MWh). The initial excess profit (2 €/MWh) of selling its generation at the spot CDS cancels out with the excess costs of buying a spot CDS (2 €/MWh). The net impact is equivalent to simply producing to fulfil the forward CDS and locking in a margin of €3/MWh ('Option 2').

b. The second column and third columns show an identical result. By producing to fulfil the forward agreement, RWE locks in a margin of €3/MWh ('Option 2'). The alternative, where RWE first sells the production at the spot CDS for a gain and then trades a Spot CDS to fulfil the forward CDS leads to equivalent result ('Option 1').

408. Despite the existence of different strategies to exploit price differences for a profit, they all lead to the same margin of €3/MWh, a trait that economists call a "no arbitrage opportunity".

409. However, an arbitrage opportunity arises when the Spot CDS is negative (see fourth column). In this case, RWE would not produce. RWE can make €1/MWh by selling the commodities secured under the forward agreements and, instead, buy the energy required to fulfil the forward contract at the spot CDS. For this delivery, it will get €3/MWh, i.e. the net result is a profit of €4/MWh.

TABLE 14: ILLUSTRATION OF ASSET BACKED TRADING[329]

				Spot CDS > 0			Spot CDS < 0
				Spot CDS > Forward CDS	Spot CDS = Forward CDS	Spot CDS < Forward CDS	Spot CDS < Forward CDS
				[A]	[B]	[C]	[D]
Forward CDS	€ / MWh	[1]	Assumed	3	3	3	3
Spot CDS	€ / MWh	[2]	Assumed	5	3	1	-1
Decision to produce		[3]		Yes	Yes	Yes	No
Option 1: Fulfill forward agreement by "unwinding hedge"							
Produce at spot CDS terms	€ / MWh	[4]	[2] when [3] = Yes	5	3	1	n.a.
Trading spot and forward CDS terms	€ / MWh	[5]	[1]-[2]	-2	0	2	4
Net result	€ / MWh	[6]	[4]+[5]	3	3	3	**4**
Option 2: Fulfill forward agreement with own production							
Produce at forward CDS terms	€ / MWh	[7]	=[1]	3	3	3	3
Choice		[8]	[6] or [7]	Indifferent	Indifferent	Indifferent	Unwind hedge

410. Other forms of asset-backed trading include geographic arbitrage, where traders exploit price differences in a commodity at different locations, technical arbitrage, where a trader can take advantage of price differentials for different qualities of a commodity and production arbitrage, where firms can vary physical production to exploit price differences in the underlying commodities. These forms of arbitrage are relevant to the commodities used to produce electricity from the Eemshaven plant.

Appendix F : Adjustments to Eemshaven's data for tax reporting

411. As explained in the main body of the report, we model capital expenses, depreciation, and property taxes based on Eemshaven accounting data[330] and SCOut forecasts.[331]

412. For the purposes of modelling taxes, we are interested in the capital expenses and the depreciation expenses that are reported to Dutch tax authorities. These may differ from the accounting figures since country-specific legislation allows companies to make adjustments on financial reporting for tax purposes. We discuss the adjustments we make to the financial statements to model financial reporting for tax purposes below.

[329] Harris-Hesmondhalgh Workpapers, Tables H – Financial Model.

[330] Harris-Hesmondhalgh Workpapers, Tables G - Investment and Depreciation Model, Tabs 'Blad 1' and '173 10 to 17'.

[331] **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017, pp. 47-48. RWE provided detailed datasets of Eemshaven's capital expenses and depreciation. The datasets include information by type of investment, investment value, year, and depreciation tenors. The detailed datasets are consistent with the values reported in Eemshaven's financial statements.

F.1 Adjustments corporate income tax purposes

413. We make four adjustments to the financial statements to model financial reporting for tax purposes.

414. The first difference relates to the timing of RWE Eemshaven's impairments. Accountants record impairments when current market conditions indicate that the value of an asset has fallen below its book value. When an impairment takes place, accountants reduce the book value of the asset, which reduces the stream of future depreciation.

415. RWE recorded an impairment of [redacted] for tax purposes in [redacted].[332] We include this impairment when modelling depreciation.[333]

416. Second, RWE provided us with a document demonstrating that adjustments to the total capital expenses and depreciation in the financial statements match the filings RWE made to the Dutch Tax authority. The document reallocates certain operating expenses under the financial statements as capital expenses for tax purposes. Up until [redacted], the reallocated amounts total [redacted].[334] We take into account the reallocated capital expenses, and depreciate them over five years.[335]

417. The third difference relates to the likely dismantling costs that Eemshaven will need to incur after ending operations. Dismantling expenses relate to the costs that the plant operator need to incur to return the site to its initial conditions after the plant's closure. Under standard accounting rules, companies are allowed to record large foreseeable future expenses in their accounts, and depreciate them over time.[336] However, prior to dismantling, these expenses do not represent a cash outlay. They are simply a way for the business to offset the dismantling costs against taxes while the business is still operating. [redacted]

[332] Harris-Hesmondhalgh Workpapers, Tables G - Investment and Depreciation Model, Tab 'Blad 1', TAX VIEW section.

[333] We model depreciation and impairments jointly. To model the [redacted] impairment, we model two scenarios. First, we model the likely depreciation expense of [redacted] in the absence of the impairment. Then, we model the depreciation profile in [redacted] after taking into account the [redacted] impairment. The [redacted] impairment that Eemshaven reported to Dutch tax authorities totals [redacted]. We then back-out the percentage reduction in the value of the assets in place in 2016 consistent with a total impairment of [redacted] impairment.

[334] Harris-Hesmondhalgh Workpapers, Tables G - Investment and Depreciation Model, Tab 'Blad 1'.

[335] We assume 5 years to reflect the likely short-lived nature of these expenses.

[336] For more information see **Exhibit BR-67**, IAS Plus, IAS 16 Property Plant and Equipment.

[redacted] Our analysis removes the dismantling provisions from the CAPEX and depreciation analysis, which account for roughly [redacted].[337]

418. Finally, RWE has made other minor adjustments to the CAPEX that total [redacted] between 2010 and 2017.[338] We take into account these differences in our tax calculations.

419. To assess the accuracy of our depreciation forecast from 2017 onwards, in Table 15 we compare the depreciation based on RWE's tax returns and our financial model, for the period 2010 to 2017. Our financial model reports total depreciation in the period 2010-2017 of [redacted]. Eemshaven tax returns indicate a reported depreciation of [redacted], a difference of only [redacted]. Hence, we conclude that our depreciation modelling is accurate. After taking into account the four adjustments mentioned above, we project depreciation for tax purposes over time.

TABLE 15: TAX RETURNS COMPARISON[339]

				2010 [A]	2011 [B]	2012 [C]	2013 [D]	2014 [E]	2015 [F]	2016 [G]	2017 [H]	Total [I]
Tax depreciation	€ mln	[1]	See note	[redacted]								
Impairment	€ mln	[2]	See note	[redacted]								
Sum of depreciation and impairment	€ mln	[3]	[1]+[2]	[redacted]								
Modelled depreciation	€ mln	[4]	Table G7	[redacted]								
Difference	€ mln	[5]	See note									[redacted]
Difference over modelled depreciation	%	[6]	[5]/[4]									[redacted]

Notes and sources:
[1], [2]: Inputs from RWE, tab 'Blad1'
[5]= [3][I]-[4][I]

420. For the post-2017 forecast period, we rely on data from the October 2017 SCOut report. SCOut provides detailed investment projections over the [redacted] year period [redacted] inclusive. We record those expenses in our model.

421. We project Eemshaven's CAPEX after [redacted] based on SCOut, after removing one-off investments in the forecasted period[340] and distinguishing between cyclical major

337 Harris-Hesmondhalgh Workpapers, Tables G - Investment and Depreciation Model, Tab 'Blad1'.

338 Harris-Hesmondhalgh Workpapers, Tables G - Investment and Depreciation Model, Table G8.

339 Harris-Hesmondhalgh Workpapers, Tables G - Investment and Depreciation Model, Table G13.

340 SCOut describes the main drivers of CAPEX for every year. To project expenses over time, we exclude from the analysis the years 2018 and 2019, [redacted]. See **Exhibit BR-40**, RWE, SCOut Q3 2017, Station Contribution Outlook, dated 10 October 2017, pp. 47-48

overhauls[341] and ongoing CAPEX[342]. We project ongoing CAPEX and overhaul years over time with inflation. The resulting investment profile follows a cyclical shape, combining years with smaller ongoing CAPEX and years that additionally carry out overhauls.

422. Our model also takes into account that Eemshaven is unlikely to incur planned investment in years close to the plant's closure, as we explain in Section VI.A.6 above. Figure 45 below illustrates the CAPEX over the entire period of operations through 2054.

FIGURE 45: EEMSHAVEN CAPEX 2010-2054[343]

[redacted]

423. We assume that all the investments the SCOut report forecasts for [redacted] depreciate over a [redacted] year period.[344] Figure 46 below shows the resulting depreciation profile. The original plant investments, which took place largely between 2010 and 2015, are fully

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[341] We understand that RWE carries out scheduled overhauls for Eemshaven every [redacted] years. [redacted]. We infer the cost of these overhauls from the large CAPEX recorded in SCOut [redacted]

[342] We calculate yearly smaller ongoing capital expenses by excluding one-off investments and scheduled overhauls.

[343] Harris-Hesmondhalgh Workpapers, Tables G - Investment and Depreciation Model.

[344] We assume [redacted] years to overhauls and other small ongoing investments.

depreciated by [redacted]. Hence, the only deprecation after [redacted] relates to relatively minor depreciation of maintenance-related capital expenditures.

FIGURE 46: DEPRECIATION AND IMPAIRMENT ASSUMING FULL OPERATIONS 2010-2054[345]

[redacted]

424. Our analysis also takes into account differences between the actual case and the but-for case. In the actual case, where Eemshaven is set to stop operations at the end of 2029, the plant would be allowed to apply 'accelerated' deprecation and fully depreciate its assets by the end of 2029. After closure, the plant makes no additional investments. Figure 47 and Figure 48 below illustrate the CAPEX and depreciation profiles under an assumed closure date of 2029.

[345] Harris-Hesmondhalgh Workpapers, Tables G - Investment and Depreciation Model.

FIGURE 47: CAPEX ASSUMING FULL OPERATIONS 2010-2029[346]

[redacted]

FIGURE 48: DEPRECIATION AND IMPAIRMENT ASSUMING FULL OPERATIONS 2010-2029[347]

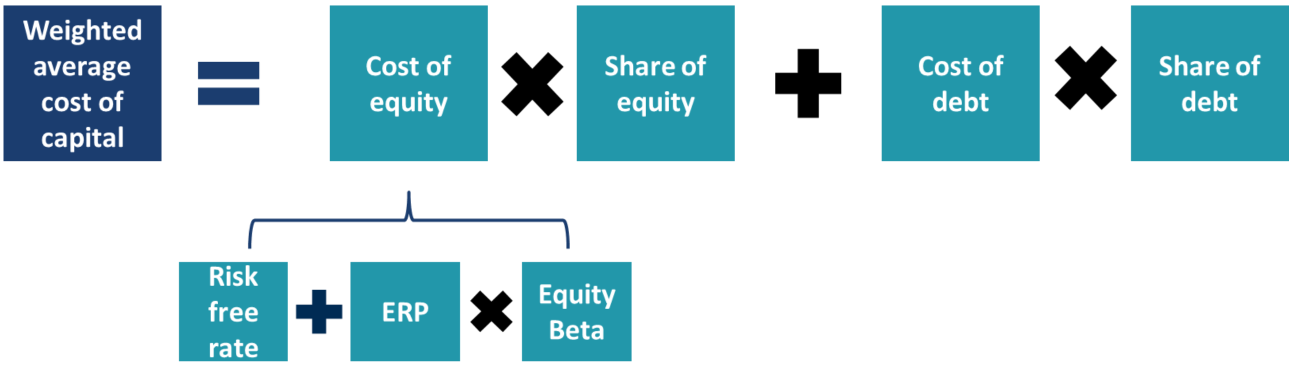
[redacted]

Appendix G : Discount rate

425. We apply the weighted average cost of capital, or WACC, as the discount rate. The WACC reflects that energy companies routinely use a combination of debt and equity to finance a project. The WACC recognises that debt and equity are subject to different risks and costs, and discounts the cash flows of the project by taking into account the proportion of debt and equity used to finance a project. Simply put, the WACC is the average rate a project pays to finance its assets.

426. The following figure illustrates the WACC formula:

FIGURE 49: WEIGHTED AVERAGE COST OF CAPITAL[348]



427. Mathematically, the WACC formula is expressed as:

$$Cost\ of\ capital = \left(r_f + \left(r_m - r_f\right) \times\ \beta\ \right) x\ (1-d) + r_d x\ (1-t_c)\ x\ d$$

where:

$\left(r_f + \left(r_m - r_f\right) \times\ \beta\ \right)$: is the cost of equity, and specifically

r_f is the expected returns of risk-free assets (Risk Free Rate);

$(r_m - r_f)$ is the expected market excess returns over risk-free assets, which is also called MRP ("Market Risk Premium"), or ERP ("Equity Risk Premium");

β is the equity beta, and is a measure of the market, also called systematic, risk of the investment.

r_d is the cost of debt.

t_c is the corporate tax rate.

d is the share of debt of a project and, conversely, $(1-d)$ the share of equity.

348 Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital.

G.1 Cost of Equity

428. The Capital Asset Pricing Model ("CAPM") is a widely applied model to measure the cost of shareholder equity. We have applied the CAPM to estimate the cost of equity and the cost of debt both in the context of business valuation and in the context of regulatory proceedings, where cost of capital is used as a determinant of access prices to regulated infrastructure such as gas pipelines or electricity networks.

429. In essence, the logic underlying CAPM is that, to hold equities which are not risk free, investors will require a return over and above the return that they could earn on a risk-free asset. This additional return is the MRP or ERP.

430. The contribution of the specific project or firm to the investor's systematic risk is measured by the parameter "beta". Beta reflects the risk that is correlated with the market, and that investors cannot eliminate by holding a diverse portfolio of assets. We refer to this as 'systematic risk'. A portfolio with a systematic risk equivalent to the market risk would have a beta of 1. An asset with a higher systematic risk than the market would have a beta above 1. Conversely, an asset with a systematic risk below that of the market would have a beta below 1. Thus, a beta of 0.5 means that if the market declines by 1%, we would expect the value of the investment to decline by 0.5%, so in this example it is less risky than the market. A beta of 1.5 means that if the market declines by 1%, we would expect the value of the investment to decline by 1.5%, so it is more risky than the market. By definition, the market portfolio has a beta of 1.0.

G.1.i Choice of beta

431. The capital asset pricing model states that the cost of capital for Eemshaven depends on its asset beta. This beta cannot be calculated directly. RWE AG, the parent company of Eemshaven, is publicly traded in the market, but the stock movements reflect developments in its various business areas, so we cannot infer the market movements associated to its coal generation businesses. This is a common problem in practice because investment projects are seldom organised as independent public companies. The solution to this problem is to estimate betas for a sample of companies that face the same (macro) risks as Eemshaven.

432. To calculate the asset beta one must calculate the returns for shareholders of the comparable firms, for example at weekly intervals, and calculate the correlation between these returns and the returns on the market index over the same period.[349]

433. The criteria for identifying good risk comparables are that they should:

[349] Returns include share price increases, dividend distributions, and buybacks.

a. be in the same industry or line of business. The corollary is that "pure-play" comparables are better than comparables that operate in several industries or lines of business;

b. face similar (macro) risks. In this case, the most important macro risk is alternative evolution of the commodity inputs; and

c. have similar cost structures. For example, companies with high fixed operating costs will have higher asset betas than companies with lower fixed costs. Also, growth companies that expect to make large future capital investments generally have higher asset betas than mature firms.

434. Listed companies generating electricity from coal sources are the obvious place to start a search for suitable comparables. However, note that listed companies active in the coal-fired power generation business tend to be integrated companies, combining activities of electricity generation and distribution.

435. The market movements of integrated companies will hence reflect movements of their various businesses and power plant portfolio. To address this, we have searched for publicly listed companies for which a majority of their revenues come from energy generation and trading activities, and for which coal-fired generation is the most important contributor to its production activities. These companies will be predominantly impacted by relevant developments in the coal-generation business, such as changes in market-wide electricity prices and coal prices.

436. Table 16 summarises the results of these companies. Our sample includes six companies as of October 2017. Five of them operate in Poland, while the sixth one operates in Canada. Revenues from energy generation and trading make up between 67% and 99% of total revenues. Conversely, coal and lignite generation make up at least 68% of the plant's own energy generation. We proxy coal revenues by assuming that these are proportional to the shares of coal and lignite production shares. For example, 91% of Tauron's energy production comes from coal and lignite, and hence we assume that 91% of its energy and trading revenues come from coal. We estimate a firm's share of revenues from coal-fired power generation business as the product of its share of revenues coming from generation and the share of energy and trading revenues coming from coal, as shown in row [3] below. We hence estimate that between 41% and 95% of these firms' revenues depend on coal-fired generation, with a median value of 74%.

TABLE 16: REVENUE TESTS FOR SELECTED COMPANIES[350]

		Zespol Elektrowni Patnow Adamow Konin SA [A]	Tauron Polska Energia SA [B]	PGE Polska Grupa Energetyczna SA [C]	Enea SA [D]	Energa SA [E]	TransAlta Corp [F]	Median [G]
Share of revenues from generation and trading	[1] Table F6	95%	80%	88%	67%	61%	99%	84%
Share of production from coal Generation	[2] Table F6	100%	91%	87%	93%	68%	76%	89%
Share of revenues from coal-fired power generation	[3] [1]*[2]	95%	73%	76%	63%	41%	75%	74%

Notes and sources:
[3]: Revenues proxy from the generation share

437. We calculate the betas only on a sample of companies between the end of September 2012 and the end of September 2017 with share prices continually available from the moment they were listed.[351] We also verified that the shares were sufficiently “liquid”, or traded with sufficient frequency. Stocks that are not traded frequently, or “illiquid” stocks, will in fact tend to underestimate beta. We rely on two liquidity tests that Mr. Harris has applied in other work with energy regulators. First, we check that the shares of these companies were traded every week from the moment they were listed within our sample period. All of the firms meet this criteria. Second, we look at the bid-ask spread of the traded shares. The bid ask spread is the difference between what sellers wants to sell the stock for (or ask) and what buyers are willing to pay for it (or bid) at a given point in time. Illiquid stocks reflect relatively large spreads between both figures. In other work, energy regulators have applied a maximum bid-ask spread of 1% for a stock to be included in a beta estimate. Table 17 illustrates that all of the firms meet this standard.

350 Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital, Table F4.

351 In the case of Zespol Elektrowni Patnow Adamow Konin SA and Energa SA, trading data start slightly later, in late October 2012 and early December 2013 respectively.

TABLE 17: LIQUIDITY TESTS FOR SELECTED COMPANIES[352]

		Zespol Elektrowni Patnow Adamow [A]	Tauron Polska Energia SA [B]	PGE Polska Grupa Energetyczna SA [C]	Enea SA [D]	Energa SA [E]	TransAlta Corp [F]
Bid-ask spread	[1] Table F10	0.8%	0.5%	0.3%	0.6%	0.2%	0.4%
Share of weeks with trading activity	[2] Table F7	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Notes and sources:
Information collected between September 2012 - September 2017
[A]: Traded since October 2012
[E]: Traded since December 2013

438. For the companies selected, I obtained estimates of the firms' betas from Bloomberg, a financial data provider. We use a beta calculated using a weekly return over a five-year period against a world index of share prices.[353]

439. Market data on Bloomberg shows betas on a 'levered' basis, meaning that the individual betas computed for the companies reflect each firm's combination of equity and debt. These betas are not comparable, because the debt of a firm impacts the market risk of equity holders. We therefore proceeded to 'unlever' the beta of each company to calculate the asset betas, by taking into account its share of debt and the applicable tax rate.[354] A standard mathematical formula estimates how debt affects the equity beta. The standard formula permits the conversion of 'levered' betas to the "unlevered" betas that would apply if the companies had 100% equity financing.[355] We estimate asset betas within a range of 0.32 and 0.73, as shown in row [3] of Table 18 below. We took the median of these values, at 0.47 as the asset Beta applicable to Eemshaven.

352 Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital, Table F5.

353 FTSE All World.

354 We use net debt and explain the choice in Appendix G.3 below. In addition, tax rates are relevant in the CAPM model because debt is tax deductible. Financing a project through debt, as opposed to equity, has the advantage of reducing a project's tax payments. The unlevering formula recognises the impact of the corporate income tax rate on the beta.

355 **Exhibit BR-68**, Corporate Finance Institute, Hamada's Equation. The standard formula is given by:

$$Unlevered\ Beta = Unlevered\ beta\ x\ (1 + (1 - tax)\ x\ leverage\ ratio)$$

Where,

- Tax is the applicable corporate tax rate,
- And leverage ratio reflects D/E, the ratio of net debt to equity.

TABLE 18: BETA ESTIMATES FOR COAL INTENSIVE POWER GENERATION FIRMS[356]

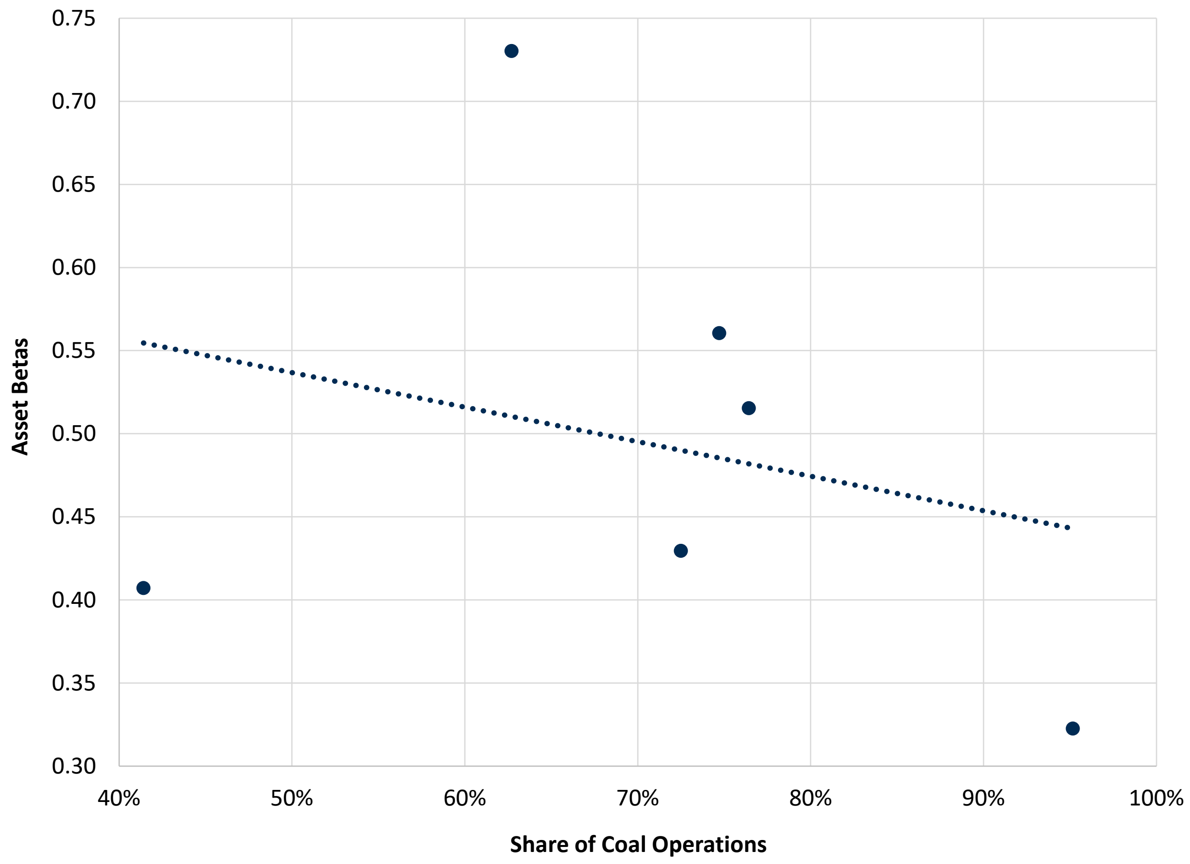
Company		Zespol Elektrowni Patnow Adamow	Tauron Polska Energia SA	PGE Polska Grupa Energetycz na SA	Enea SA	Energa SA	TransAlta Corp	Median
Country		POLAND	POLAND	POLAND	POLAND	POLAND	CANADA	
Raw Beta	[1]	0.50	0.78	0.53	0.86	0.60	1.15	
Net debt to EV	[2]	42.7%	54.7%	3.9%	18.1%	35.3%	48.7%	39%
Corporate tax rate	[3]	19.0%	19.0%	19.0%	19.0%	19.0%	26.5%	
Asset beta	[4]	0.32	0.43	0.52	0.73	0.41	0.56	0.47

440. The firms from which we derive the betas do not obtain their revenues exclusively from coal-fired electricity generation. For RWE Eemshaven coal-fired electricity generation is the only source of revenue. Hence, we have also investigated the relationship between a firm's assets beta and the proportion of its revenues from coal-fired electricity generation, to see if asset beta for a firm that derives all of its revenue from coal-fired electricity generation – like RWE Eemshaven – could have a beta that differs from the median beta we estimate above.

441. To do this, we calculated the statistical relationship between each company's asset beta and its underlying coal and lignite portfolio. We proxy the size of the coal portfolio by taking into account the share of energy produced with coal or lignite, and in turn the share of energy generation and trading activities of the total firm revenues. We find that, on average, a greater share of revenues coming from coal fired power is associated with a lower beta. In the case of a company operating at 100% in the sector of coal fired power, the statistical relationship implies that a coal fired power plant attracts a beta of 0.43, lower than, but consistent with, the median value derived above. This implies that using an asset beta of 0.47 is likely to overestimate the asset beta of RWE Eemshaven, and hence overestimate its actual cost of capital.

[356] Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital, Table F2.

FIGURE 50: RELATIONSHIP BETWEEN ASSET BETA AND SHARE OF COAL OPERATIONS[357]



G.1.ii Market risk premium

442. The CAPM calls for investors' forecast of the market risk premium (MRP). The MRP is the difference between the return obtained from investing in the average market portfolio and the return offered by risk-free investments. This MRP is the additional return which investors need or expect over and above a risk-free asset, to compensate for the risk of holding the market portfolio of investments. There is no consensus MRP, but analysts usually start with long-term historical averages. Good statistical estimates of average historical MRPs require very long periods of time. The most commonly cited averages run from 1900 to date.

443. In other work, we have based our estimates of the MRP on long-run historical averages. In a recent report for the European Commission on the cost of capital in the EU telecoms sector we stated that an MRP of 5-5.5% over bonds would be reasonable.[358] Applying the upper

[357] Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital.

[358] **Exhibit BR-69**, European Commission, Review of Approaches to Estimate a Reasonable Rate of Return For Investments in Telecoms Networks in Regulatory Proceedings and Options for EU Harmonization, 2016, pp. 9-10.**Exhibit BR-70**, Damodaran, A., Equity Risk Premium (ERP): Determinant, Estimation and Implications - A post Crisis Update, Stern School of Business, dated 1 October 2009

end of the range will attribute less value to future cash flows relative to using the lower number, and hence reduce the present value of the cash flows.

G.1.iii Risk-free rate

444. The analysis involves estimating cash flows denominated in euros out to 2054. Market risk premiums are derived as an excess return from a long-term risk-free rate. Accordingly, we use the average yield on 20-year Euribor swaps as the risk-free rate as of October 2017.[359] We use a 20-year maturity because this is consistent with the historical MRP data available. The estimated risk-free rate is [redacted]%.

G.2 Cost of debt

445. The cost of debt is the cost at which a company could obtain debt financing. These costs depend on the creditworthiness of the company. We therefore determine the creditworthiness of comparable companies, which we consider to be European utilities.[360] For these, a typical Debt imposes a cost to a project. Table 19 shows the credit ratings of a wide range of European utilities. We find that a Standard and Poor's debt credit rating of BBB was typical for Western European companies in October 2017. Our sample includes the top-four energy utilities by market capitalisation as reported by Bloomberg, as well as all companies within the top 20 of energy firms for which the majority of revenues comes from power generation activities. The total sample is comprised of nine firms, including: Iberdrola, Engie, Endesa, Verbund, Fortum, EnBW, Uniper, Enel, and EDF.

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[359] Euribor is the lending rate between banks in the European Union and is calculated on loans with very short maturity (between one week and one year). It is risk free because it widely used by major financial institutions to settle very short term obligations. A 20 year Euribor swaps reflect the market expectations of Euribor rates in 20 years, consistent with the 20-year maturity of the MRP.

[360] We look at European utility companies because they would likely be potential third party buyers.

TABLE 19: STANDARD AND POOR'S CREDIT RATINGS OF WESTERN EUROPEAN UTILITIES

Company	IBERDROLA SA	ENGIE	ENDESA SA	VERBUND AG	FORTUM OYJ	ENBW ENERGIE	UNIPER SE	ENEL SPA	EDF
Ticker	IBE SM	ENGI FP	ELE SM	VER AV	FORTUM FH	EBK GR	UN01 GR	ENEL IM	EDF FP
Country	SPAIN	FRANCE	SPAIN	GERMANY	FINLAND	GERMANY	GERMANY	ITALY	FRANCE
LT Foreign Issuer Credit	[redacted]								-

Notes and Sources:
Selected comparables are the largest companies in terms of market capitalisation operating in western Europe. Their primary industry is power generation but for Enel SPA.
Credit ratings as of valuation date.

446. Hence, the cost of debt we apply is the 20 years yield[361] of the EUR Composite Index from Bloomberg, which is a market indicator for the cost of debt issued by a set of companies with BBB rating. As of 9 October 2017, the yield associated to these firms equalled [redacted]%.

G.3 Share of debt

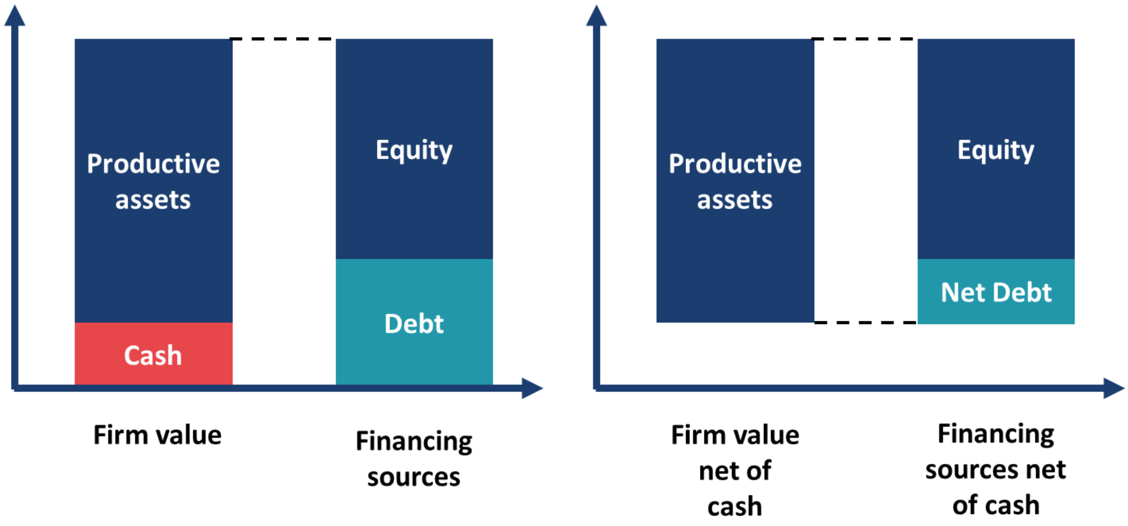
447. The WACC combines the cost of equity and the cost of debt in proportion to the amount of debt and equity used to finance an asset like Eemshaven. The best guide as to the proportion of debt and equity a buyer would apply to Eemshaven is the proportion of debt and equity that firms engaged in power generation apply to their other assets. Accordingly, we derive the share of debt and equity by looking at the share of debt and equity financing from the same firms that we used to estimate beta.

448. We compute net debt, which is the outstanding debt level after excluding a company's cash holdings. The key idea is that cash can offset the outstanding debt of a firm, and so net debt better reflects the outstanding debt obligations of a firm.[362] The use of net debt derives from the idea that the value of a firm has essentially two components. On the one hand, the value of its productive assets, and on the other hand, the value of its cash holdings, which are subject to a different class of risk than the rest of the business. Because the value of any firm is claimed by either its debt holders or its equity holders, removing cash entails also adjusting the relative shares of the financing sources of a firm. Figure 51 below illustrates this point, where the exclusion of cash leads to a commensurate reduction in the level of debt.

[361] 20-years is a typical maturity for a corporate bond.

[362] **Exhibit BR-4**, Berk, J.B., DeMarzo, P.M., Corporate Finance, Third Edition, p. 417.

FIGURE 51: FIRM VALUE AND FINANCING SOURCES, WITH AND WITHOUT CASH[363]

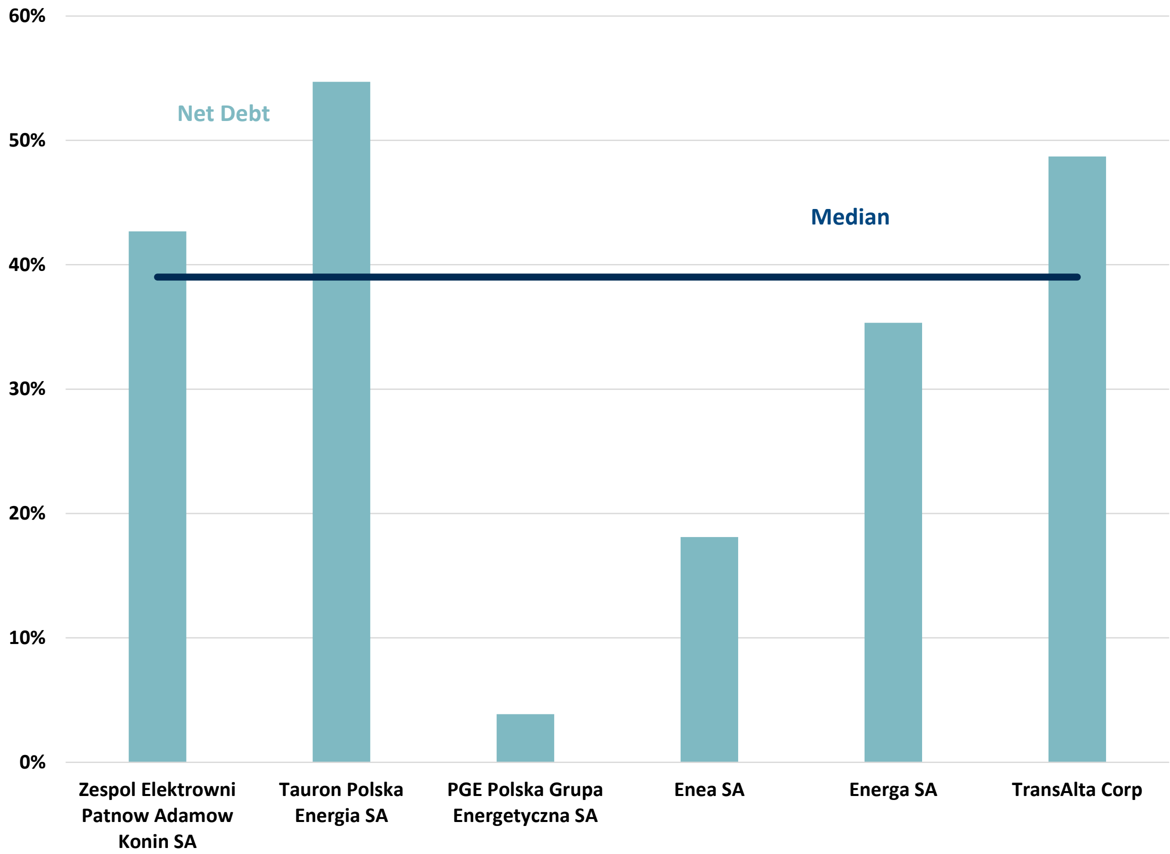


449. The exclusion of cash is fundamental to appropriately measure business risk. Cash is exposed to little market risks, since the value of cash is largely independent on the variations in market-wide returns. Regardless of the direction on which the market moves, €100 in cash are worth essentially the same over time, so the beta of cash tends to be close to 0. The exclusion of cash tends to a) decrease the equity beta of a project, and b) reduce the weight of debt in the cost of capital calculation.

450. We compute the share of net debt from the set of comparable companies over the entire analysis period between September 2012 and September 2017. Our analysis indicates that the median net debt ratio of these companies stands at 39%, which we apply as the target debt level a third-party investor would apply to a coal-fired power plant. The horizontal blue line in Figure 52 below illustrates the median net debt ratio.

[363] Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital.

FIGURE 52: NET DEBT RATIO AND MEDIAN[364]



G.4 Final cost of capital

451. In Table 14, we combine the cost of equity and the cost of debt in the Weighted-Average Cost of Capital ("WACC"). In a first step, our analysis calculated the unlevered beta from a sample of comparable companies in Bloomberg. The unlevered beta needs to be transferred again into a levered beta that reflects the debt and equity combination of a potential buyer. Moreover, we combine the elements above to derive a cost of capital that reflects the equity and debt combination for a third-party buyer of Eemshaven as of the valuation date of October 2017. We obtain a discount rate of 3.85% as of October 2017.

364 Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital.

TABLE 20: COST OF CAPITAL AS OF OCTOBER 2017[365]

Date	[1]	See note	09/10/2017
Risk-free rate	[2]	See note	[redacted]
Beta (unlevered)	[3]	Table F3	0.47
MRP over long-term bonds	[4]	Assumed	5.50%
Beta (levered)	[5]	See note	0.70
Cost of levered equity	[6]	[2]+[5]x[4]	[redacted]
Cost of debt	[7]	See note	[redacted]
Tax rate	[8]	See note	25.0%
Target debt ratio	[9]	Table F3	39%
WACC	[10]	See note	3.85%

Notes and sources:
[1]: Valuation date.
[2]: EuroSwap (20 years).
[5]=[3]*(1+(1-[8]))*[9]/(1-[9])
[7]: BVAL composite index, BBB rating 20Y maturity as of 9/10/2017.
[8]: Exhibit BR-81, KPMG, Corporate Tax Rates.
[10]: [6]x(1-[9])+[7]x[9]x(1-[8]).

365 Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital, Table F1.

Appendix H : CO_2 prices

FIGURE 53: CO_2 PRICES[366]

CO2 Prices (€/ton)

[redacted]

Appendix I : List of Workpapers

This section lists the supporting Brattle workpapers below:

a. **Harris-Hesmondhalgh Workpapers, Tables A – Commodity returns**
   i. Tables A.1 – TTF gas returns
   ii. Tables A.2 – ARA coal returns
b. **Harris-Hesmondhalgh Workpapers, Tables B – Commodity Forward Curves and Commodity Betas**
c. **Harris-Hesmondhalgh Workpapers, Tables C – Volatility and Correlation**
   i. Tables C.1 – TTF gas volatility
      (1) Tables C.1.1 – Historical volatility
      (2) Tables C.1.2 – Two-factor model
   ii. Tables C.2 – ARA coal volatility
      (1) Tables C.2.1 – ICE data preparation
      (2) Tables C.2.2 – Black model

366 Harris-Hesmondhalgh Workpapers, Tables D.3 – CO2 Price ratchet.

iii. Tables C.3 – Commodity correlation

d. **Harris-Hesmondhalgh Workpapers, Tables D – Price path simulation**
   i. Tables D.1 – Random draws and Cholesky decomposition
   ii. Tables D.2 – Coal and gas price simulation
   iii. Tables D.3 – CO_2 price ratchet

e. **Harris-Hesmondhalgh Workpapers, Tables E – Dispatch model**
   i. Tables E.1 – Dispatch model 2020-2029
   ii. Tables E.2 – Dispatch model 2030-2054
   iii. Tables E.3 – Dispatch model inputs

f. **Harris-Hesmondhalgh Workpapers, Tables F – Cost of Capital**

g. **Harris-Hesmondhalgh Workpapers, Tables G – Investment and depreciation model**

h. **Harris-Hesmondhalgh Workpapers, Tables H – Financial model**

i. **Harris-Hesmondhalgh Workpapers, Tables I – Other supporting analysis**

j. **Harris-Hesmondhalgh Workpapers, Tables J – Clean dark spread curve**

Appendix J : List of Exhibits

Exhibit No.	Description	Date
Exhibit BR-1	Minister of Economic Affairs and Climate, Electricity Production Prohibition Act	20 December 2019
Exhibit BR-2	2017-2021 Coalition Agreement, Confidence in the Future	10 October 2017
Exhibit BR-3	Levy, G., Computational Finance Using C and C#, Quantitative Finance Series, 2008	
Exhibit BR-4	Berk, J.B., DeMarzo, P.M., Corporate Finance, Third Edition	
Exhibit BR-5	Report of the Ministry of Economic Affairs, 2016	
Exhibit BR-6	Velatia Networks, Safe and Reliable, Goodbye to the Coal Power Plants in the Netherlands by 2030	21 January 2019
Exhibit BR-7	CBS, Trends in the Netherlands 2018, Economy	
Exhibit BR-8	International Energy Agency and Nuclear Energy Agency, Projected Costs of Generating Electricity, 2015 Edition	30 September 2015
Exhibit BR-9	RWE, Eemshaven Power Plant	
Exhibit BR-10	RWE, Environmental Permit Eemshaven	11 December 2007
Exhibit BR-11	KEMA Consulting, Application for Incorporation Permit	20 December 2006

Exhibit BR-12	National Enterprise Agency of The Netherlands, Eemshaven: Decision to Grant a Subsidy	30 November 2016
Exhibit BR-13	Government of The Netherlands, The Future of Fossil Fuels	
Exhibit BR-14	Final Report 2014-2019, Dutch Coal Covenant	
Exhibit BR-15	Our power plants in the Netherlands - Uniper, last accessed on the 23 December 2020	
Exhibit BR-16	Vattenfall, Vattenfall's Last Coal Power Plant in The Netherlands is Closing	20 December 2019
Exhibit BR-17	de Volkskrant, One of The Last Four Coal-Fired Power Stations in The Netherlands Wants to Close	21 October 2020
Exhibit BR-18	Phys.Org, Dutch Lawmakers Approve Plan to Close Coal Power Plants	26 November 2015
Exhibit BR-19	European Commission Press Release, State Aid: Commission Approves Compensation for Early Closure of Coal Fired Power Plant in the Netherlands, Brussels	12 May 2020
Exhibit BR-20	International Valuation Standard Council, International Valuation Standards	31 January 2020
Exhibit BR-21	Global Arbitration Review, The Guide to Damages in International Arbitration, Third Edition	1 December 2018
Exhibit BR-22	Alstom, Power Plant Economics, 2006	
Exhibit BR-23	World Bank, "Guidelines on the Treatment of Foreign Direct Investment," Foreign Investment Law Journal, Chapter IV Expropriation and unilateral alterations or termination of contracts, 1992	
Exhibit BR-24	Graham, J.R. and Campbell R.H., "The Theory and Practice of Corporate Finance: Evidence from the Field", Journal of Financial Economics	10 December 1999
Exhibit BR-25	Reilly, F., Brown, K.C., Investment Analysis & Portfolio Management, Chapter 11: An Introduction to Security Valuation, Seventh Edition, Thomson Southwestern, 2003	
Exhibit BR-26	Copeland, T., Koller, T., Murrin, J., Valuation Measuring and Managing the Value of Companies, Second Edition, John Wiley & Sons, Inc., 1994	
Exhibit BR-27	Quiborax S.A. v. Plurinational State of Bolivia, ICSID Case No. ARB/06/2, Award	16 September 2015
Exhibit BR-28	RWE, Annual Report 2017	

Exhibit BR-29	S&P Global Platts, Engie sells 2.3 GW German, Dutch Coal Plants to Riverstone Holdings	26 April 2019
Exhibit BR-30	Royal Institute of Chartered Surveyors (RICS). Depreciated Replacement Cost Method of Valuation for Financial Reporting, London: 1st Edition, November 2018	
Exhibit BR-31	European Commission, State Aid SA.54537 (2020/NN) - Netherlands Prohibition of Coal for the Production of Electricity in the Netherlands	12 May 2020
Exhibit BR-32	International Energy Agency, World Energy Outlook, 2016	
Exhibit BR-33	BP, Statistical Review of World Energy, 2020	
Exhibit BR-34	Hull J.C., Options, Futures and Other Derivatives, 9th edition	
Exhibit BR-35	Argus, UK Carbon Price Floor to Remain in Place Until 2021	26 November 2016
Exhibit BR-36	RWE, Eemshaven Cofiring Business Case	
Exhibit BR-37	European Commission, EU Reference Scenario	15 July 2016
Exhibit BR-38.A	RWE, Schedule 22	17 February 2009
Exhibit BR-38.B	RWE, Schedule 23	17 February 2009
Exhibit BR-38.C	RWE, Land Lease Akte I	16 March 2009
Exhibit BR-38.D	RWE, Land Lease Akte II	11 March 2009
Exhibit BR-39	RWE, Cluster Eemshaven, MTP 2017 (2018-2022)	8 September 2017
Exhibit BR-40	RWE, SCOut Q3 2017, Station Contribution Outlook	10 October 2017
Exhibit BR-41	Basteviken, M., Pearson-Woodd, N., Asset-Backed Trading in the Energy and Resources Sector, International Tax Review	5 March 2019
Exhibit BR-42	Corporate Finance Institute, Arbitrage	
Exhibit BR-43	Municipality of Eemsmond, Real Estate Tax	
Exhibit BR-44	RWE, Consideration of Overhead Costs When Evaluating Assets and Contracts	30 September 2015
Exhibit BR-45	Forbes - Energy Innovation: Policy and Technology, Carbon Capture And Storage: An Expensive Option For Reducing U.S. CO2 Emissions	3 May 2017
Exhibit BR-46	EIA, Assumptions to The Annual Energy Outlook: Cost and Performance Characteristics of New Central Station Electricity Generation Technology, 2015	
Exhibit BR-47	NREL, Annual Technology Baseline 2017	
Exhibit BR-48	OECD, Purchasing Power Parities (PPP) 2008-2019	

Exhibit BR-49	Deloitte, Netherlands Alert, New Policy Goals Include Corporate Income Tax Rate Reduction, Abolition of Dividend WHT	13 October 2017
Exhibit BR-50	PWC, Corporate - Group Taxation, Netherlands	6 September 2020
Exhibit BR-51	PWC, Netherlands Corporate Taxes on Corporate Income	6 July 2020
Exhibit BR-52	Myers, S.C., Determinants of Corporate Borrowing, Sloan School of Management, MIT, September 1976	
Exhibit BR-53	Guthrie, G., Real Options in Theory and Practice, Oxford University Press, 2009	
Exhibit BR-54	Overheid.nl, Decree on Basic Safety Standards for Radiation Protection	23 October 2017
Exhibit BR-55	Brealey, Myers, and Allen, Principles of Corporate Finance, 10th edition, (The McGraw-Hill Companies, 2011)	
Exhibit BR-56	Perold A.F., The Capital Asset Pricing Model, Journal of Economic Perspectives - Volume 18, Number 3, Summer 2004	
Exhibit BR-57	RWE, RWE Bonds and Credit Ratings	30 November 2020
Exhibit BR-58	EMMI, Euribor Rates	
Exhibit BR-59	United Nations Climate Change, Joint Implementation	
Exhibit BR-60	Overview of NL Issued Letters of Approval for Participation in a JI Project Activity, Last Update Nov. 2013	
Exhibit BR-61	Clewlow L., and Strickland C., Energy Derivatives: Pricing and Risks Management, Lacima Publications, 2000	
Exhibit BR-62	International Monetary Fund, World Economic Outlook Database, October 2017	
Exhibit BR-63	Pindyck, R.S., The Dynamics of Commodity Spot and Futures Markets: A Primer, The Energy Journal, 2001, Vol. 22, No. 3	
Exhibit BR-64	FTSE Russell, FTSE All-World Index	29 January 2021
Exhibit BR-65	Dimson, Risk Measurement When Shares are Subject to Infrequent Trading, Vol. 7, No. 2	1 May 1979
Exhibit BR-66	European Commission, EU Emissions Trading System (EU ETS)	23 November 2016
Exhibit BR-67	IAS Plus, IAS 16 Property Plant and Equipment	
Exhibit BR-68	Corporate Finance Institute, Hamada's Equation	

Exhibit BR-69	European Commission, Review of Approaches to Estimate a Reasonable Rate of Return For Investments in Telecoms Networks in Regulatory Proceedings and Options for EU Harmonization, 2016	
Exhibit BR-70	Damodaran, A., Equity Risk Premium (ERP): Determinant, Estimation and Implications - A post Crisis Update, Stern School of Business	1 October 2009
Exhibit BR-71	KPMG, Corporate Tax Rates	
Exhibit BR-72	Bloomberg Dataset, WACC Calculation	
Exhibit BR-73	European Central Bank (ECB), Long Term Inflation Forecast, 2017 Q3	
Exhibit BR-74	Bloomberg Dataset, Commodity Betas, Workpaper B	
Exhibit BR-75	European Central Bank (ECB), Statistical Data Warehouse, Exchange Rate US Dollar/Euro	
Exhibit BR-76.A	RWE, Eemshaven Annual Report, 2010	
Exhibit BR-76.B	RWE, Eemshaven Annual Report, 2011	
Exhibit BR-76.C	RWE, Eemshaven Annual Report, 2012	
Exhibit BR-76.D	RWE, Eemshaven Annual Report, 2013	
Exhibit BR-76.E	RWE, Eemshaven Annual Report, 2014	
Exhibit BR-76.F	RWE, Eemshaven Annual Report, 2015	
Exhibit BR-76.G	RWE, Eemshaven I Annual Report, 2016	
Exhibit BR-76.H	RWE, Eemshaven II Annual Report, 2016	
Exhibit BR-76.I	RWE, Eemshaven I Annual Report, 2017	
Exhibit BR-76.J	RWE, Eemshaven II Annual Report, 2017	
Exhibit BR-77	RWE, Book Value and Depreciation of Eemshaven, 2010-2017	
Exhibit BR-78	RWE, Eemshaven Working Capital Overview	
Exhibit BR-79	RoyalHaskoning DHV Study on Decommissioning Cost	
Exhibit BR-80	National Enterprise Agency of The Netherlands, SDE Projects Available in Autumn 2016	18 January 2017
Exhibit BR-81	International Energy Agency, Energy Statistics Manual, 2004	
Exhibit BR-82	ICE Futures Europe, API2 Rotterdam Coal Option (Future Style Margin)	8 January 2021
Exhibit BR-83	BP, Approximate Conversion Factors, Statistical Review of World Energy, 2019	
Exhibit BR-84	IEA, Unit Converter and Glossary For Common Energy Units	31 December 2016

Exhibit BR-85	Bloomberg, API21MON OECM Index Description, accessed on 15 December 2020	
Exhibit BR-86	ICIS, European Daily Electricity Markets Methodology	24 May 2017
Exhibit BR-87	IGU Natural Gas Conversion Pocketbook, 2012	
Exhibit BR-88	Energy yield calculation - Cofiring at Eemshaven	