GB Wholesale Market Summary November 2021

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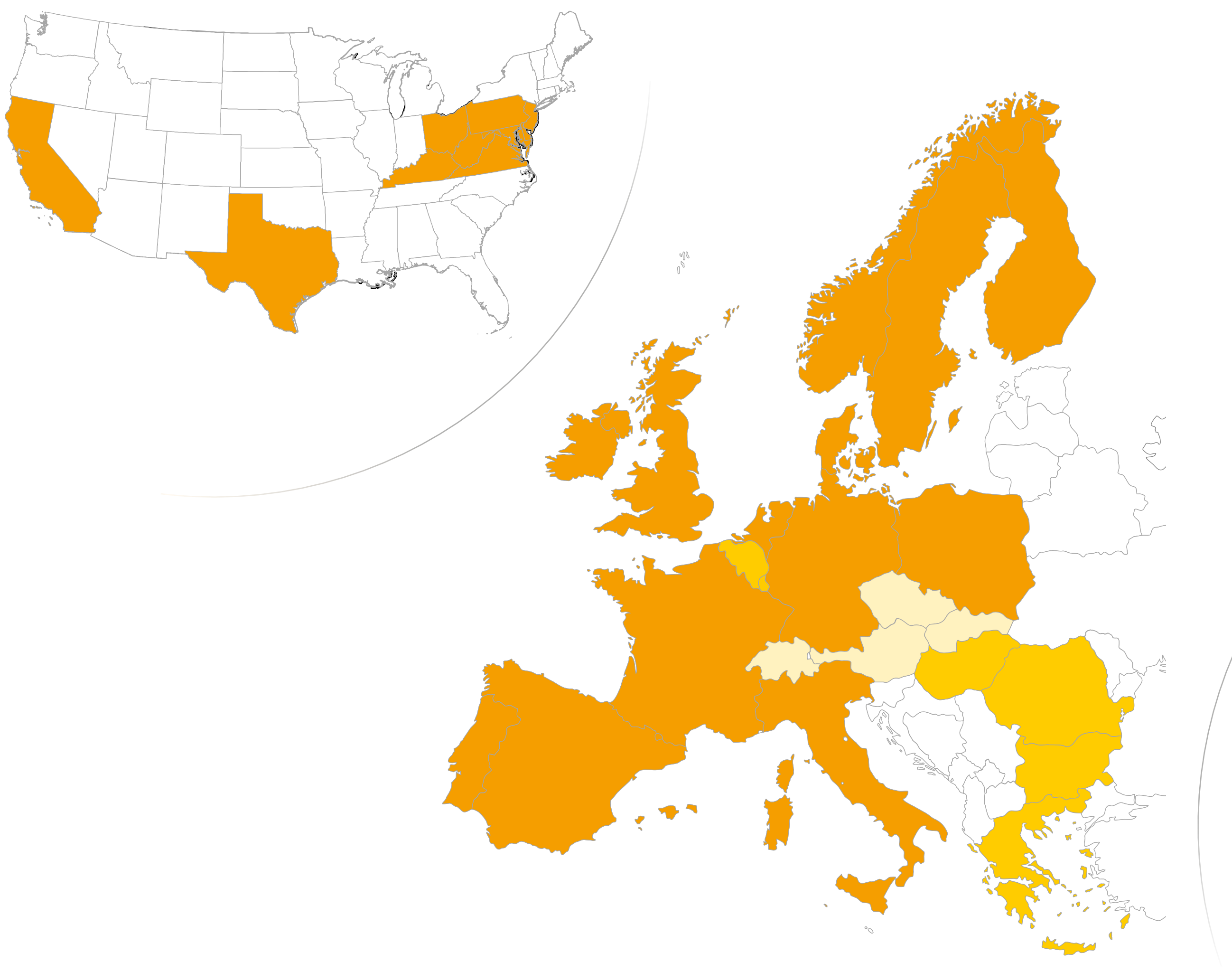

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Source: Aurora Energy Research

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Executive Summary

- The average power price in November was £183.5/MWh, a 12% increase from October
- The rise in power prices was driven by an increase in production from higher cost thermal generation to meet a 12% growth in total transmission demand, relative to the month of October
- The rise in thermal generation primarily came from CCGTs, with average load factors increasing from 28% in October to 36% in November
- Subsequently, domestic power sector emissions rose to 4.3 $MtCO_2e$, a 37% increase relative to October
- The average total GB carbon price has remained flat, with UK-ETS prices trading at an average of £61/tCO_2 in November, at similar levels to October

	Monthly value[1]	Month-on-month change	Year-on-year change	Slide reference(s)
Power prices *£/MWh*	183.5	+19.2 (11.7%)	+143.0 (352.4%)	5, 6
Gas prices *£/MWh*	68.4	-0.1 (0.2%)	+55.6 (435.1%)	7
Carbon[2] prices *£/tCO_2*	78.6	-0.6 (0.8%)	+36.9 (88.4%)	7
Transmission demand *TWh*	23.8	+2.5 (11.9%)	+1.2 (5.4%)	10
Low carbon[3] generation *TWh*	14.6	+0.7 (5.1%)	+1.0 (7.5%)	11, 12
Thermal[4] generation *TWh*	9.3	+2.3 (31.9%)	+1.2 (14.7%)	11, 12
Carbon emissions *$MtCO_2e$*	4.3	+1.2 (37.1%)	+0.6 (15.5%)	14
Grid carbon intensity *gCO_2e/kWh*	200.7	+37.4 (22.9%)	+15.9 (8.6%)	14
Wind load factors[5] *%*	45.4	+1.3 (3.0%)	+3.1 (7.5%)	25
Wind capture prices[5] *£/MWh*	172.0	+14.8 (9.4%)	+136.6 (386.4%)	27

1) Values averaged over the calendar month. 2) Includes CPS and EU-ETS, the UK-ETS auctions will commence form May 2021. 3) Includes renewables and nuclear generation 4) Includes CCGTs, coal and other fossil plants. 5) Onshore wind only

Sources: Aurora Energy Research, Thomson Reuters, National Grid, Ofgem, Elexon

Agenda

I. System performance

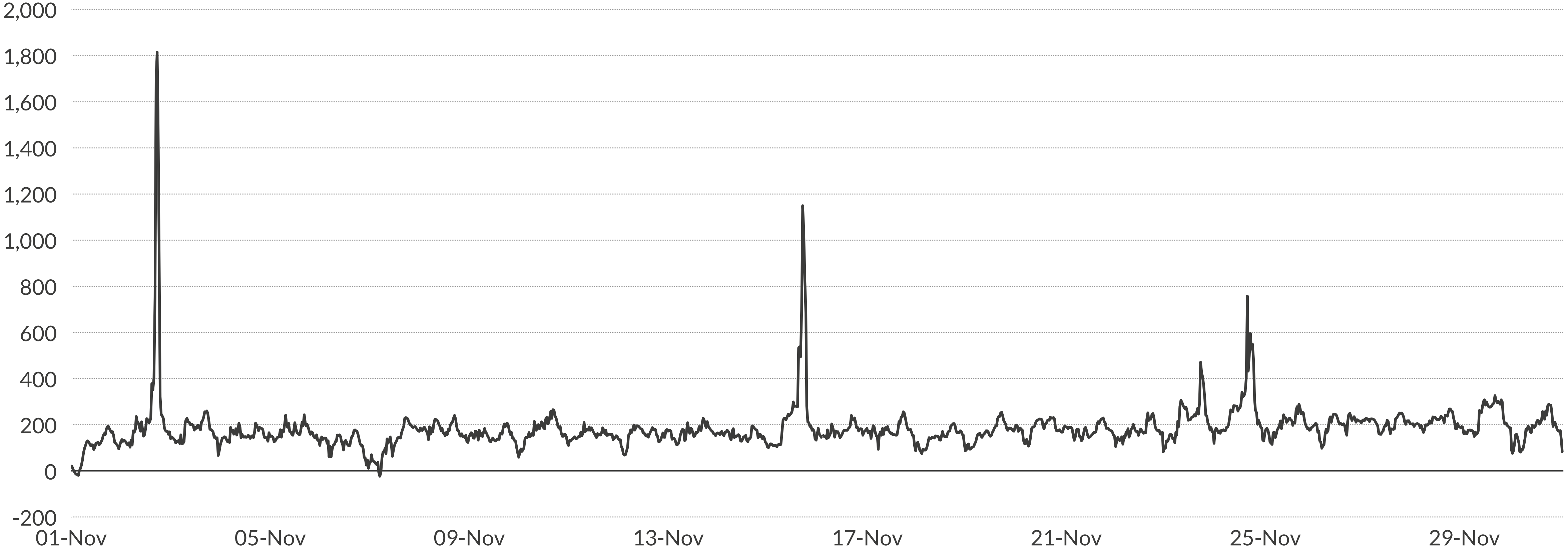
II. Company performance

III. Plant performance

Half-hourly EPEX spot price for November

EPEX spot price[1]
£/MWh

Monthly average price in November 2021: 183.53 £/MWh

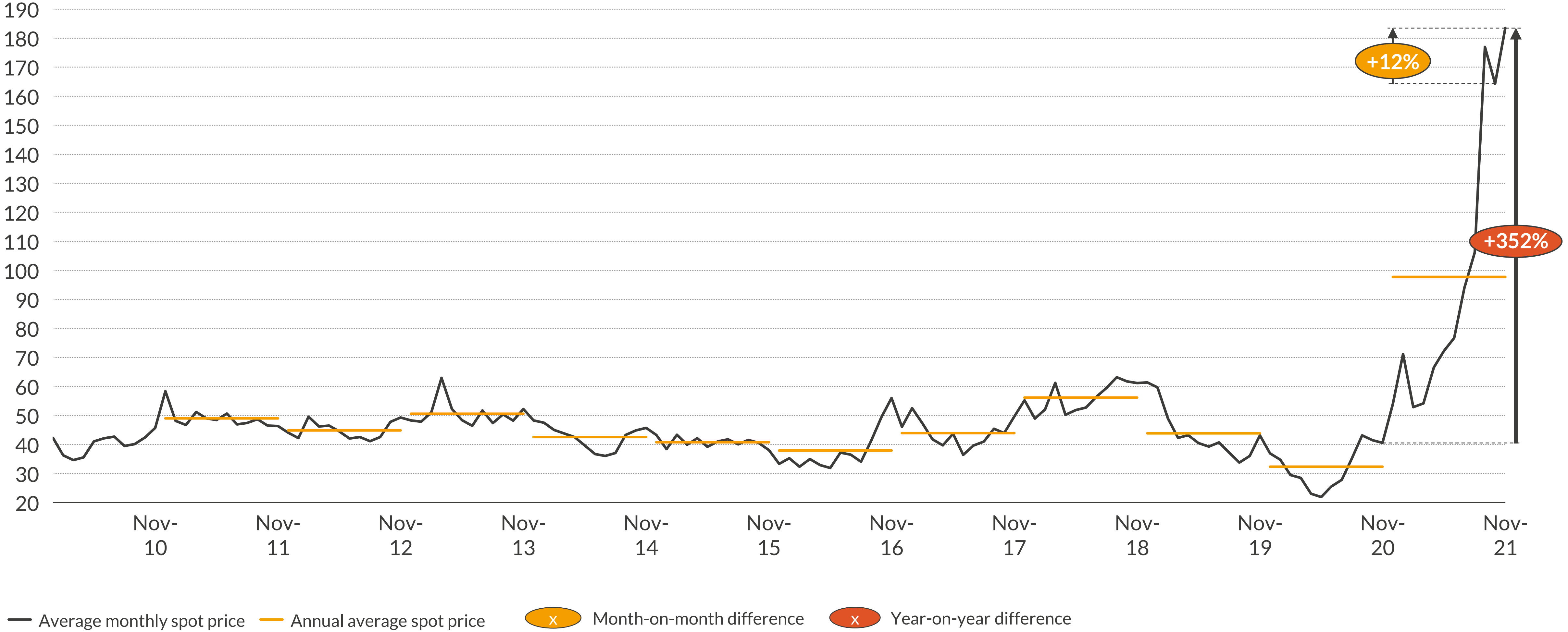


1) Half-hourly EPEX is the volume-weighted reference price over that half-hour interval, as provided by EPEX Spot

Sources: Aurora Energy Research, Thomson Reuters

Historic monthly average EPEX spot price

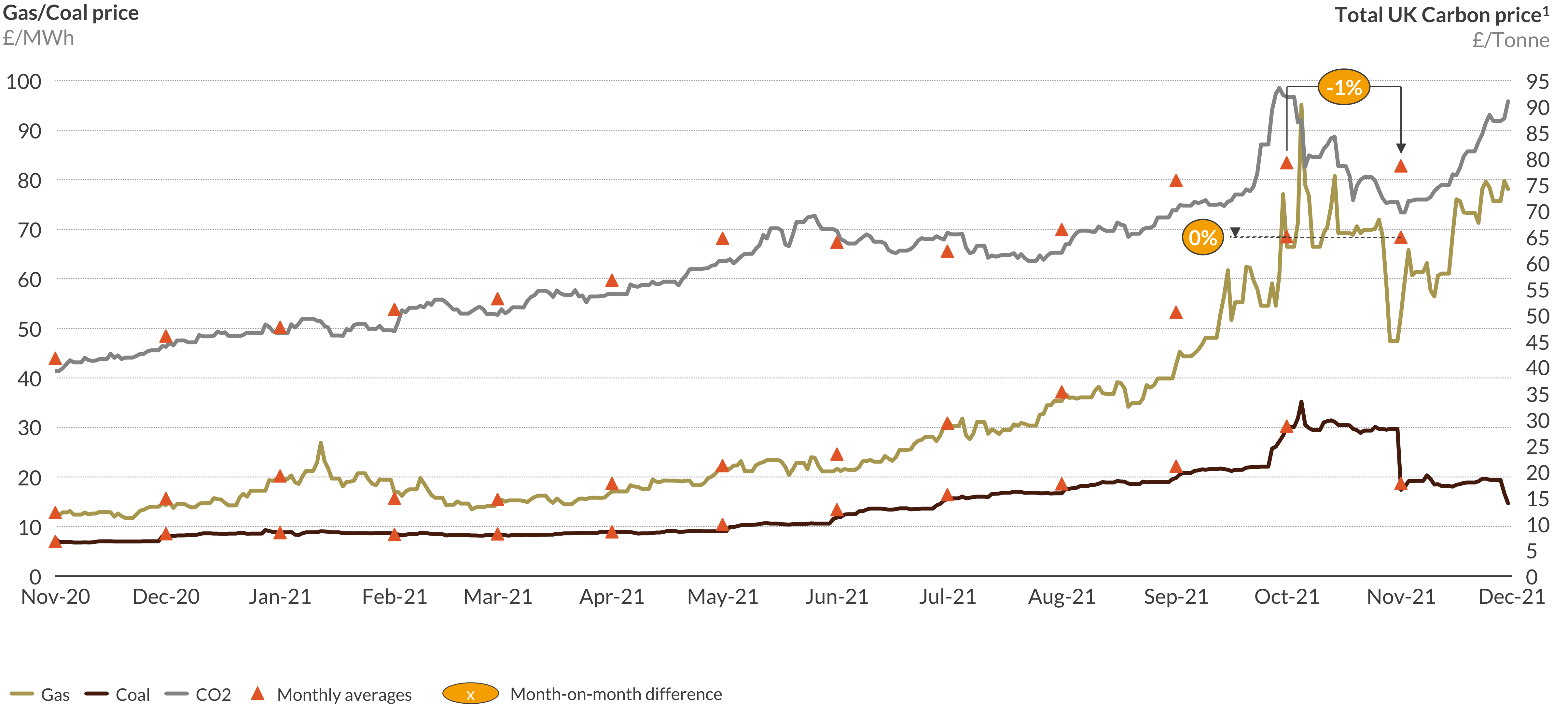
Average EPEX spot price[1]
£/MWh



1) Average monthly EPEX is the average over the month of the volume-weighted reference prices for each half-hour interval.

Sources: Aurora Energy Research, Thomson Reuters

Historic fuel prices
Gas, Coal and Carbon daily prices



1) Includes CPS and EU ETS until 18th May and UK ETS from the 19th May

Sources: Aurora Energy Research, Thomson Reuters

Historic UK ETS and EU ETS Prices

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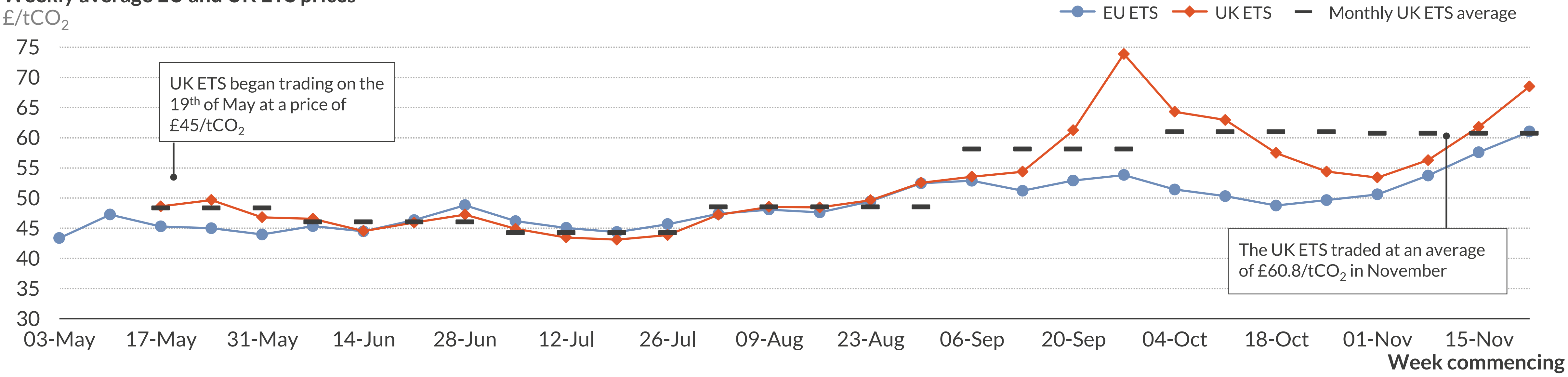
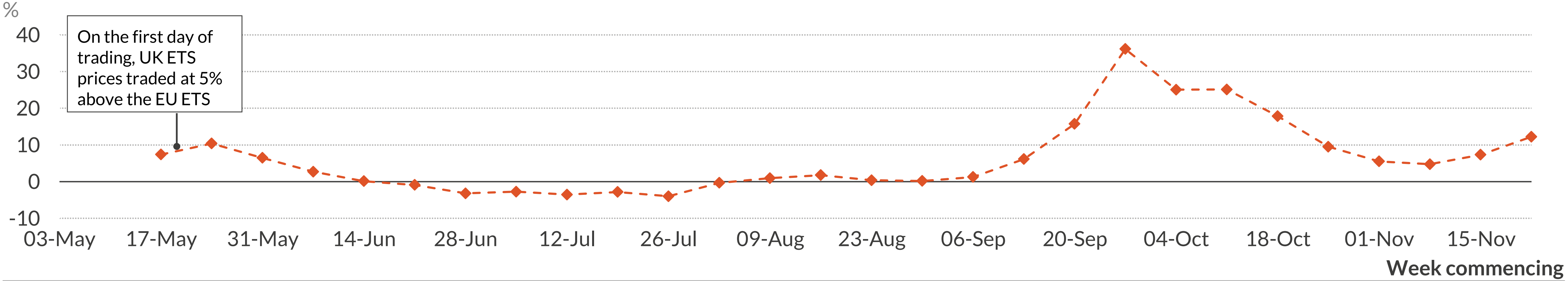
Weekly average EU and UK ETS prices

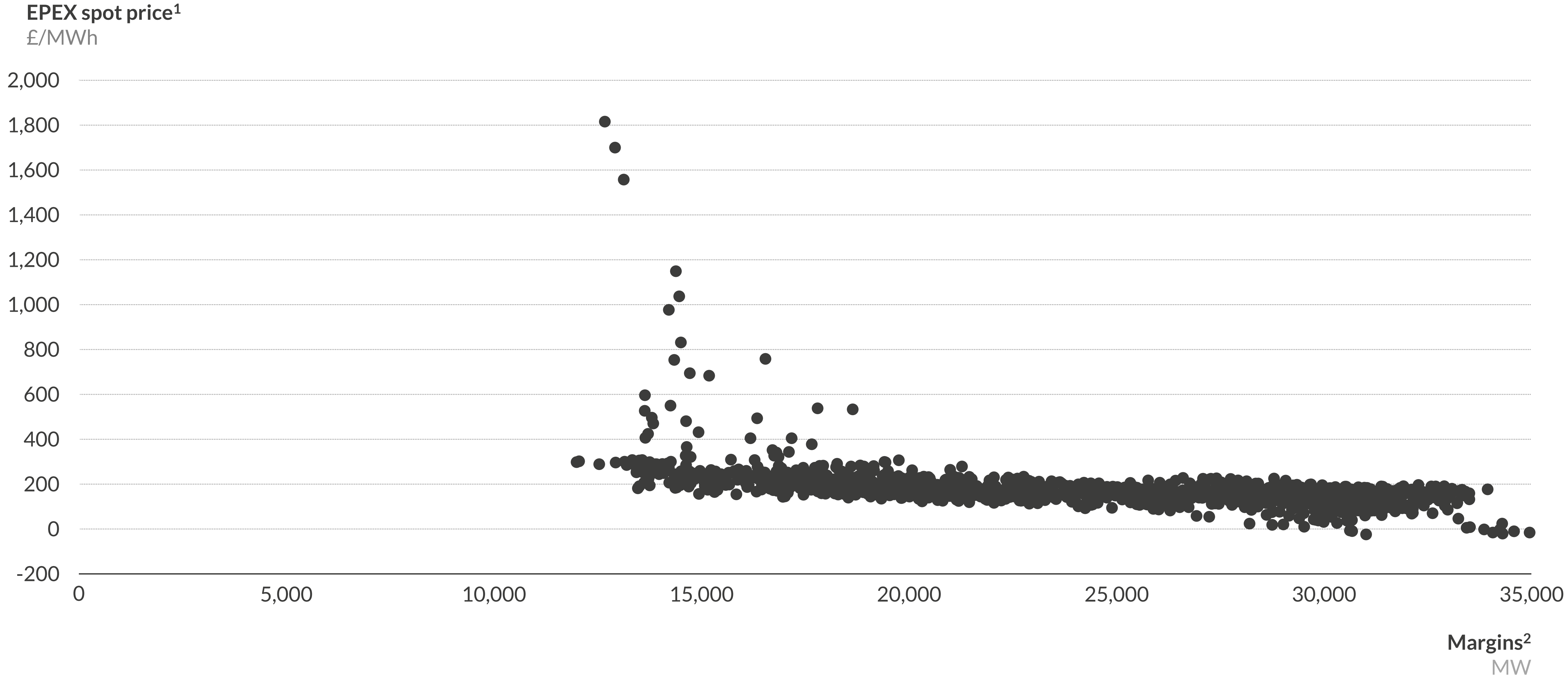


Relative difference between UK and EU ETS prices



Sources: Aurora Energy Research, ICE Futures, Bank of England

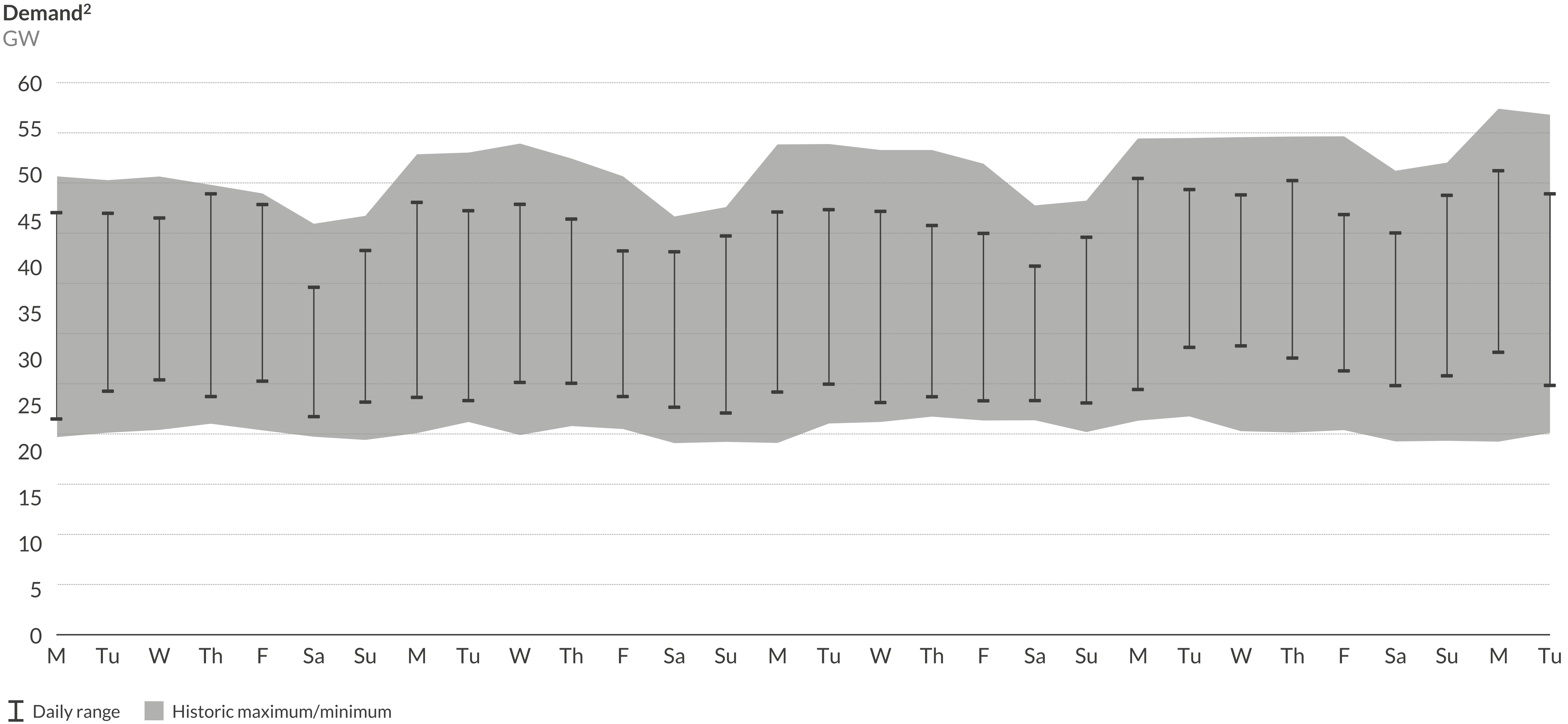
Half-hourly spot prices against half-hourly system margins for November



1) Half-hourly EPEX is the volume-weighted reference price over that half-hour interval, as provided by EPEX Spot. 2) Margins are calculated as the difference between MEL and Demand for each half-hour period. Demand data presented here is Initial Transmission System Demand Out-Turn, and does not include embedded demand. MEL is calculated as the sum of all transmission BM units reporting MEL values in each half-hour. Where a BMU gives multiple values in a half-hour, only the least is taken.
Sources: Elexon, National Grid, Thomson Reuters, Aurora Energy Research

Daily November max and min demand

Relative to historic November max and min demand since 2010[1]



1) Data from previous years is matched to the nearest weekday within the current month, to maintain the weekly demand pattern. 2) Demand data presented here is Initial Transmission System Demand Out-Turn, and does not include embedded demand.

Sources: National Grid, Aurora Energy Research

Monthly historical demand on the transmission system

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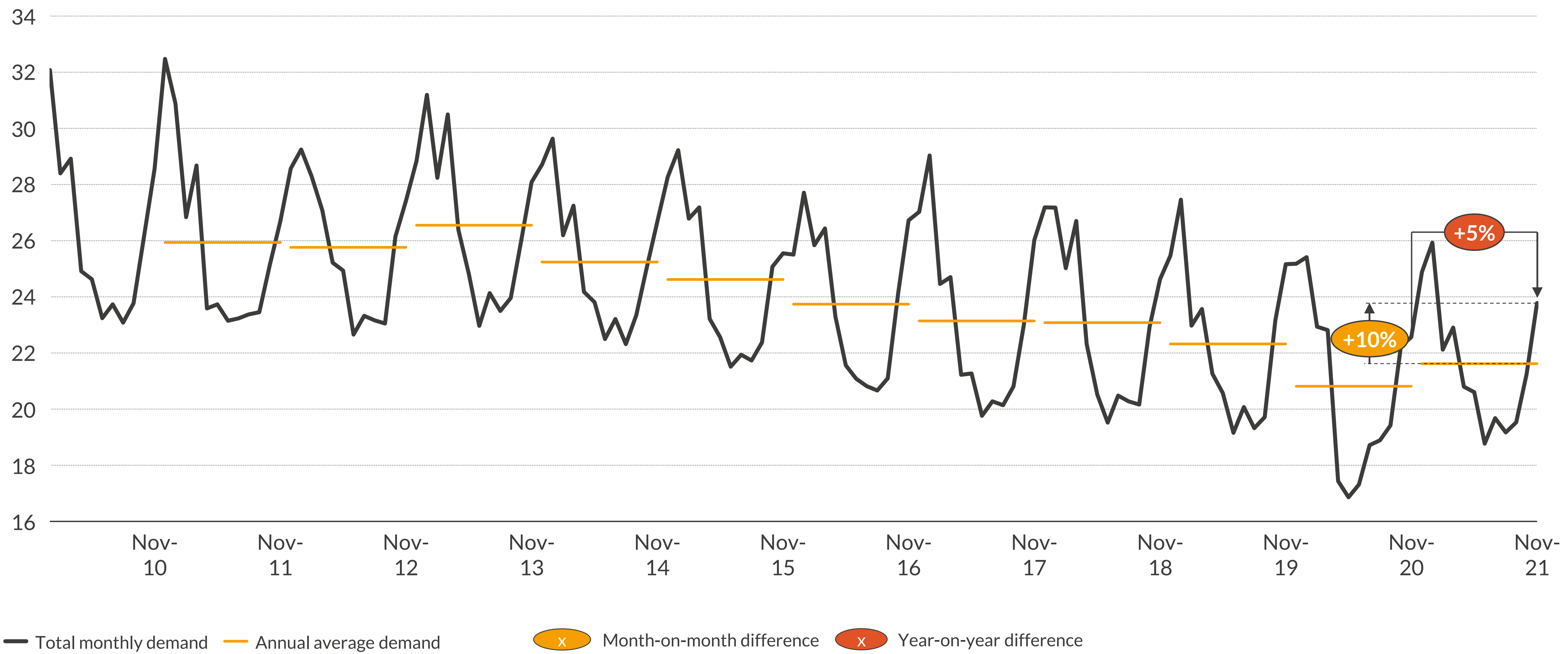
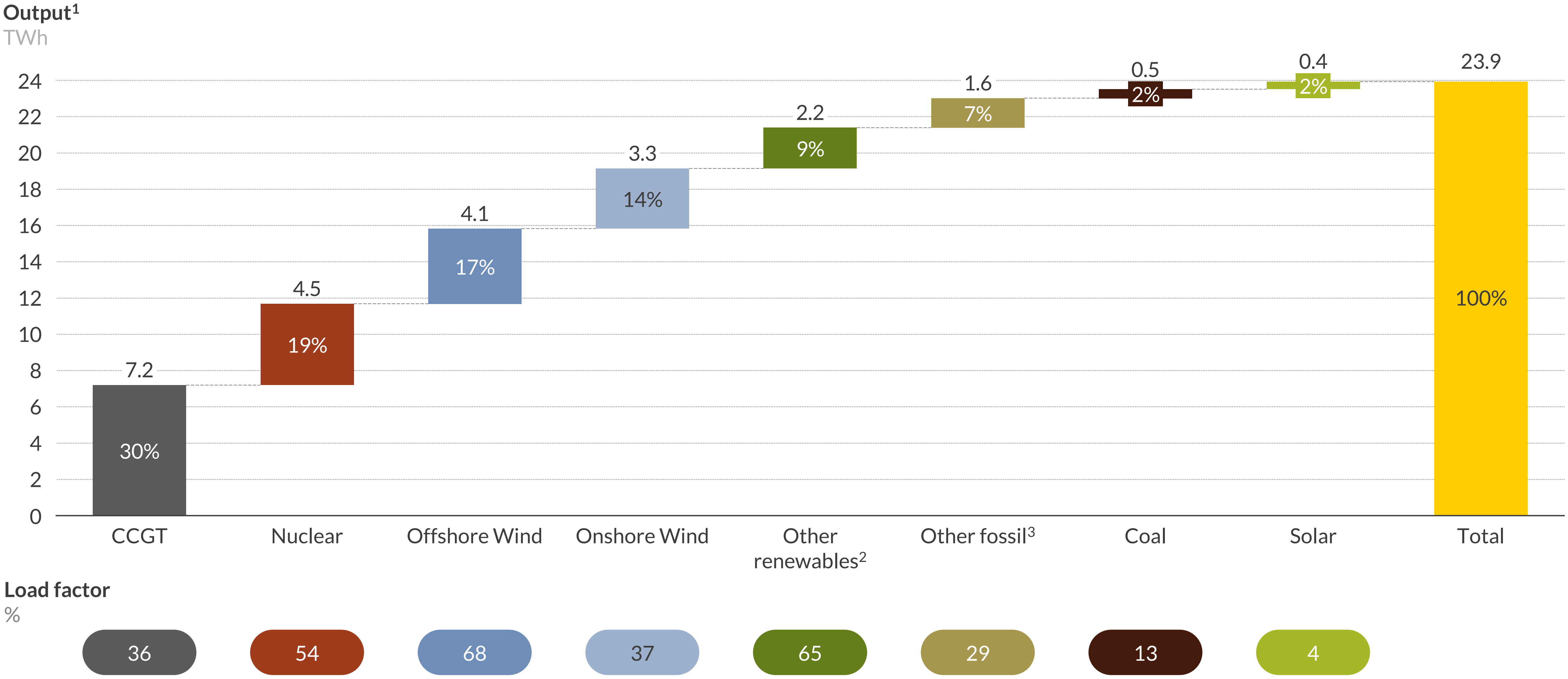
Total demand[1]
TWh



1) Demand data presented here is Initial Transmission System Demand Out-Turn, and includes station transformer load, pumped storage demand and interconnector demand, but does not include embedded demand.

Sources: National Grid, Aurora Energy Research

Monthly fuel mix breakdown

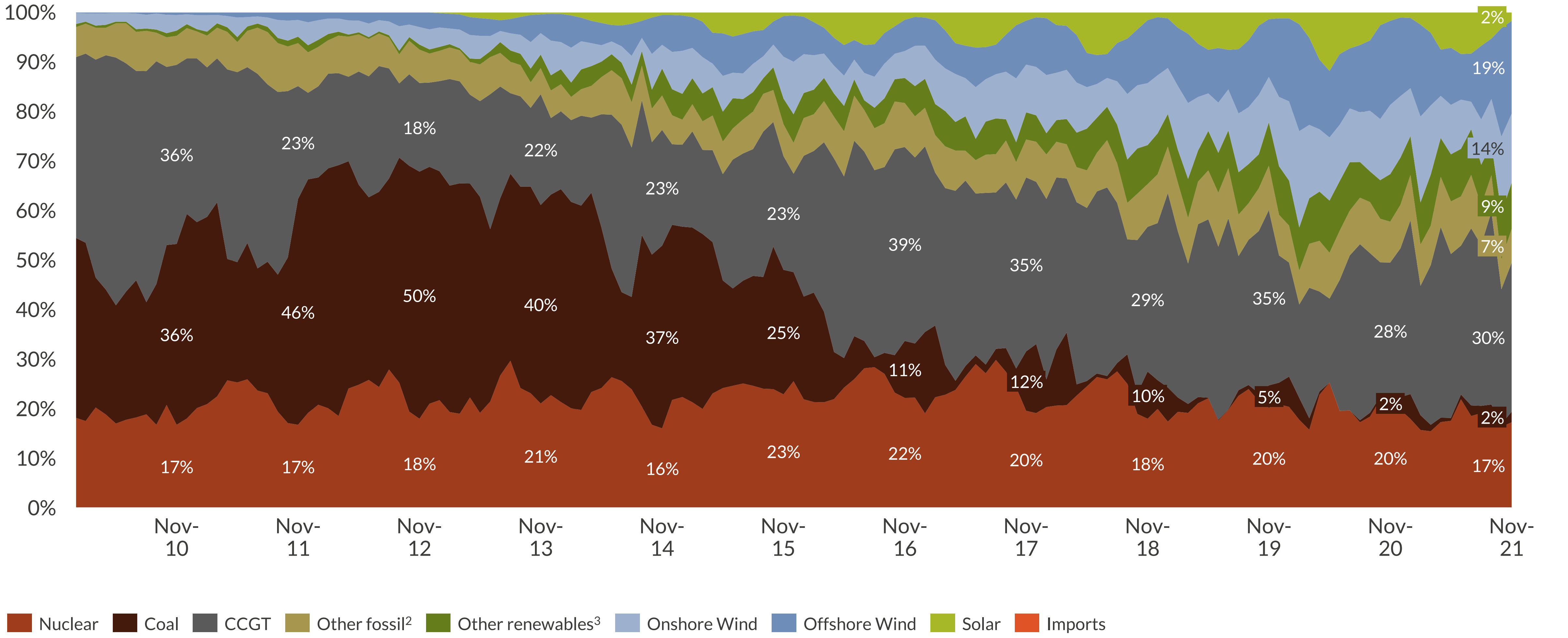


1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV assets. All numbers are rounded to 0.1 TWh which means that subtotals may not sum to total value. 2) Other fossil includes oil, CHP-CCGT and OCGT. 3) Other renewables includes biomass and hydro.

Sources: Elexon, Sheffield Solar, National Grid, Aurora Energy Research

Historical fuel mix breakdown

Output[1]
% of total



1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV. 2) Other fossil includes oil, CHP-CCGT and OCGT. 3) Other renewables includes biomass and hydro.

Sources: Elexon, Sheffield Solar, National Grid, Aurora Energy Research

Monthly interconnector flow duration curve
Flow in each half-hour for GB interconnectors

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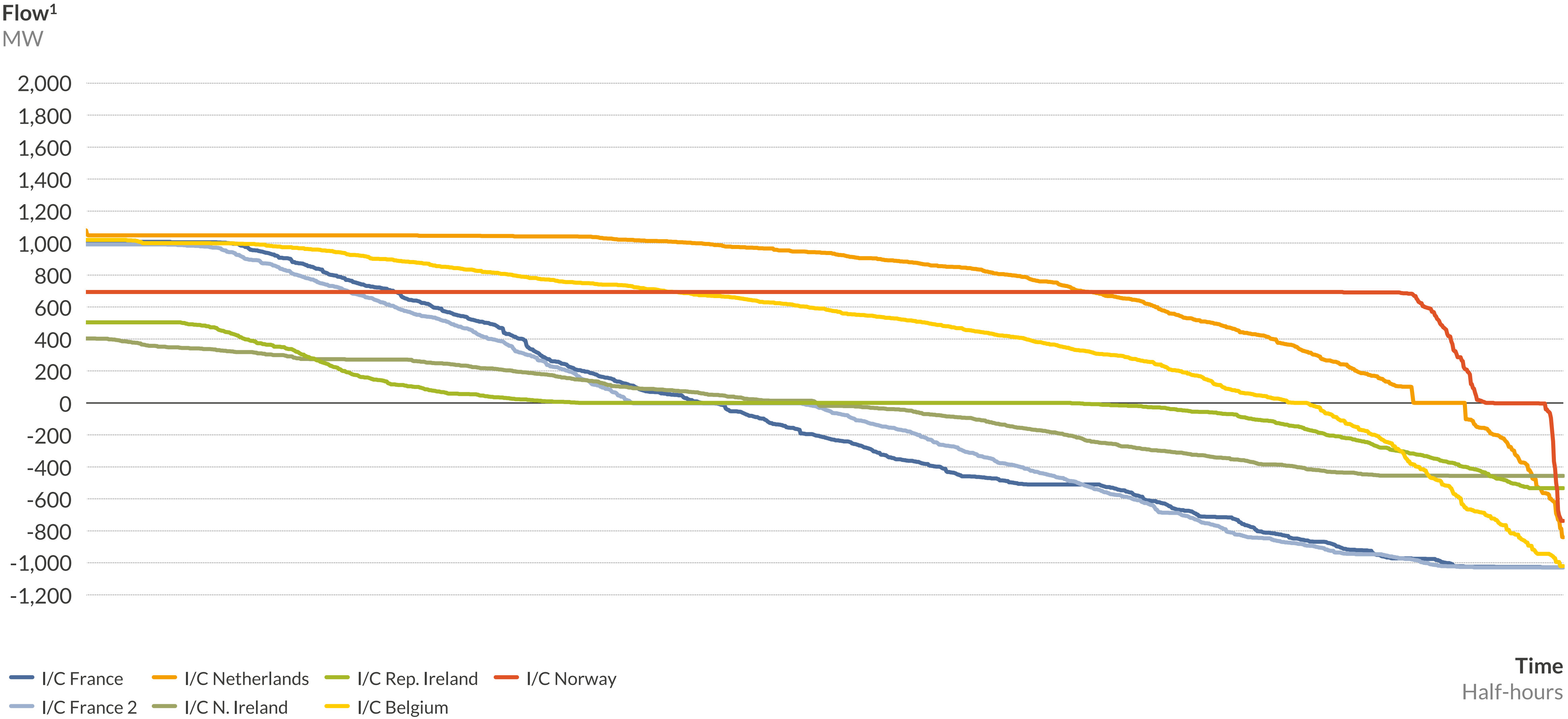
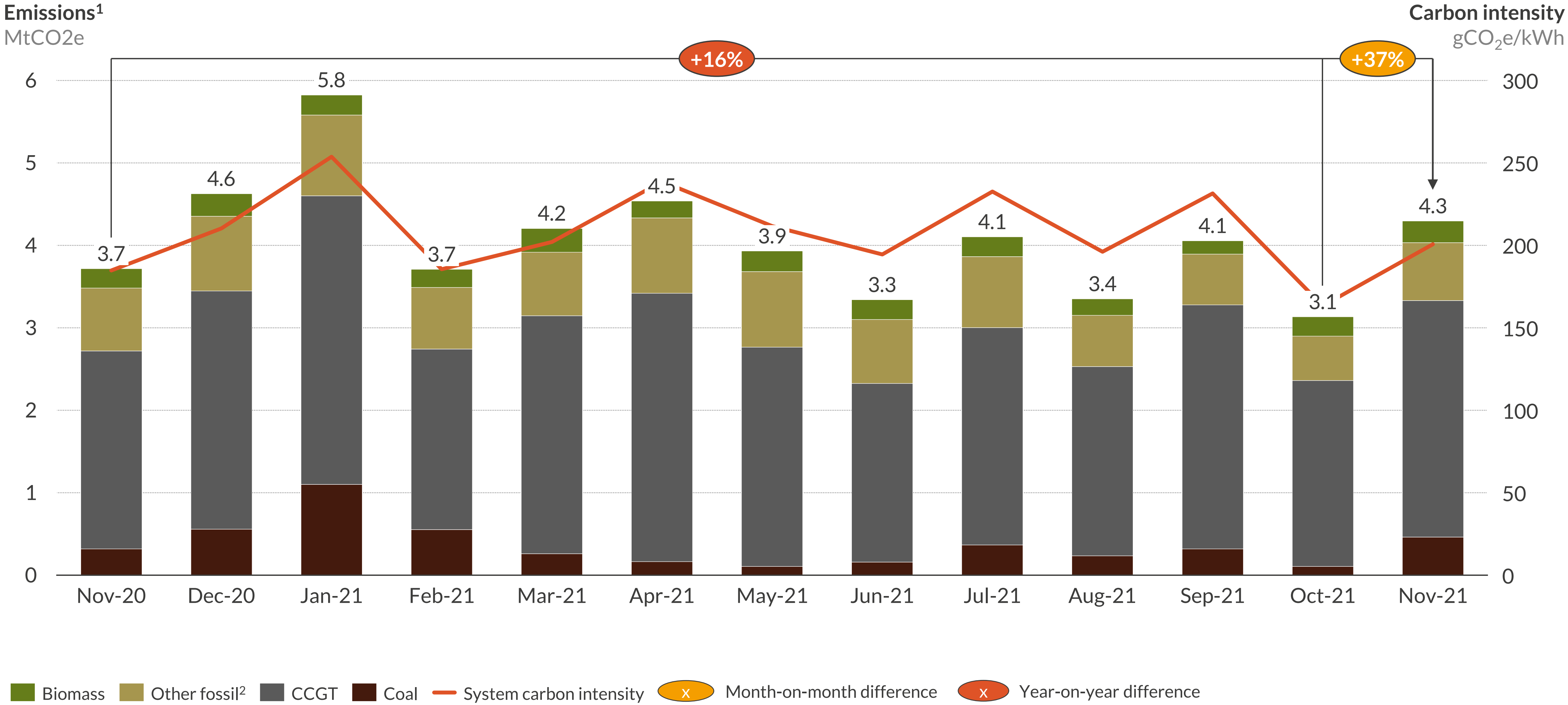


1) Positive flow is imports into GB, negative flow is exports.

Sources: Elexon, National Grid, Aurora Energy Research

Monthly emissions by technology



1) Please refer to Appendix for details of methodology employed to calculate emission amounts. Includes all Balancing Mechanism plants. 2) Other fossil includes oil, OCGT and gas CHP-CCGT.

Sources: Elexon, Ofgem, Aurora Energy Research

Agenda

I. System performance

II. Company performance (subscriber only)

III. Plant performance

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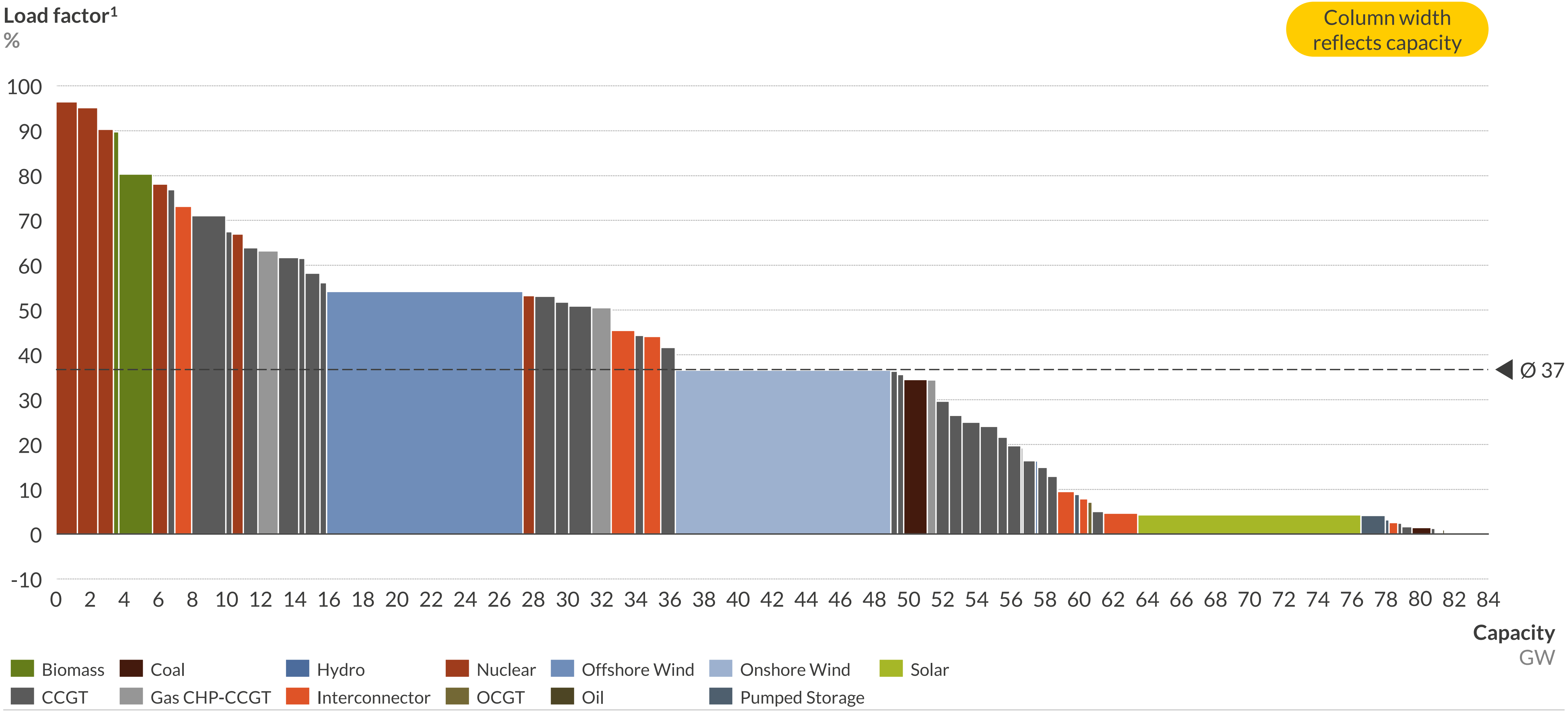
III. Plant performance

Plant utilisation – load factors by plant



1) Represents 60 plants with highest capacity according to the Balancing Mechanism (BM) database, as well as aggregated data for wind and solar. Capacity of each plant represents the sum of capacities of all its generators that have been active at least once in the last three months. Please refer to Appendix for a detailed description of the data used and categories presented

Sources: Aurora Energy Research, Elexon, BEIS

CCGT plant utilisation – by plant

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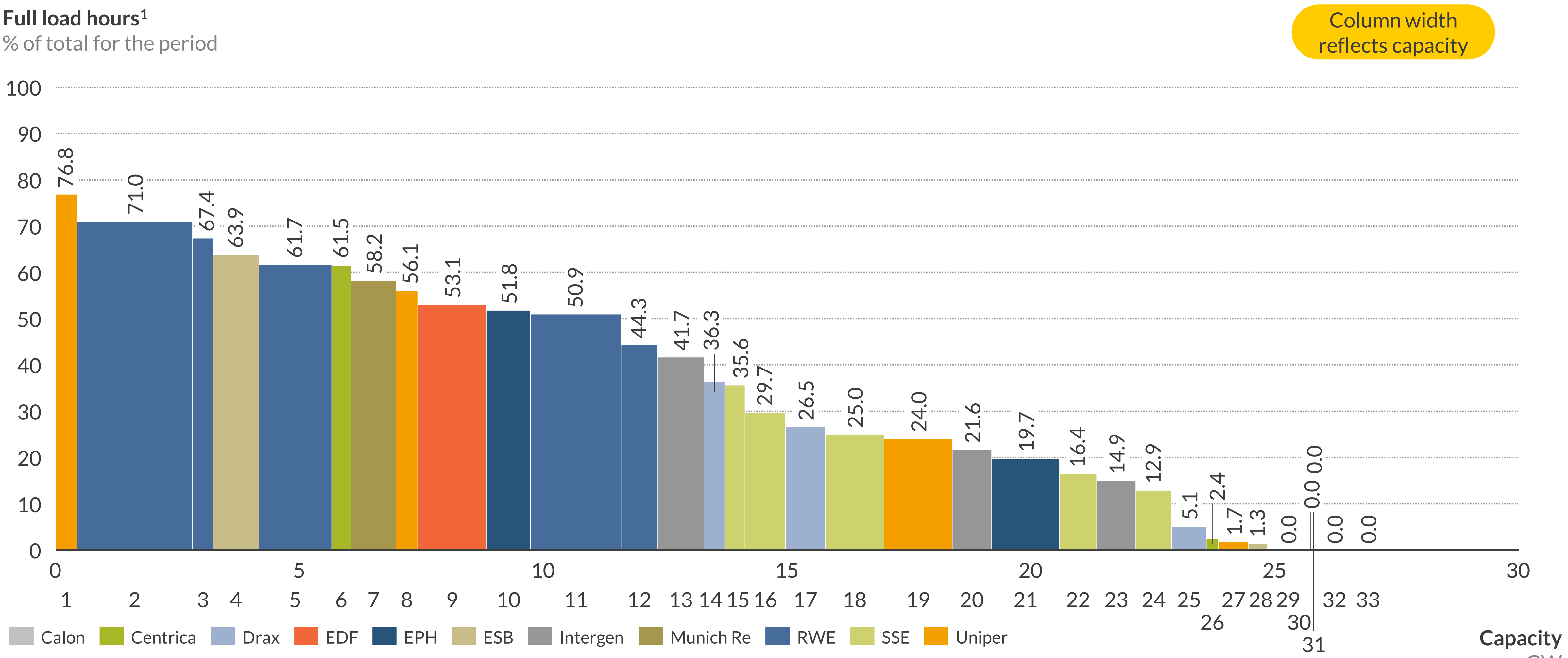
Full load hours[1]
% of total for the period



Plant Names: 1. Enfield Energy, 2. Pembroke, 3. Great Yarmouth, 4. Carrington, 5. Didcot B, 6. Kings Lynn, 7. Marchwood, 8. Cottam Dvpt Centre, 9. West Burton B, 10. Langage, 11. Staythorpe, 12. Little Barford, 13. Spalding, 14. Shoreham, 15. Seabank 2, 16. Seabank 1, 17. Damhead Creek, 18. Peterhead, 19. Connahs Quay, 20. Rocksavage, 21. South Humber Bank, 22. Keadby, 23. Coryton, 24. Medway, 25. Rye House, 26. Peterborough, 27. Killingholme 2, 28. Corby, 29. Severn, 30. Glanford Brigg, 31. Killingholme 1, 32. Sutton Bridge, 33. Baglan Bay.

1) Includes all CCGT plants of the presented companies that report to the Balancing Mechanism

Sources: Aurora Energy Research, Elexon

Coal plant utilisation – by plant

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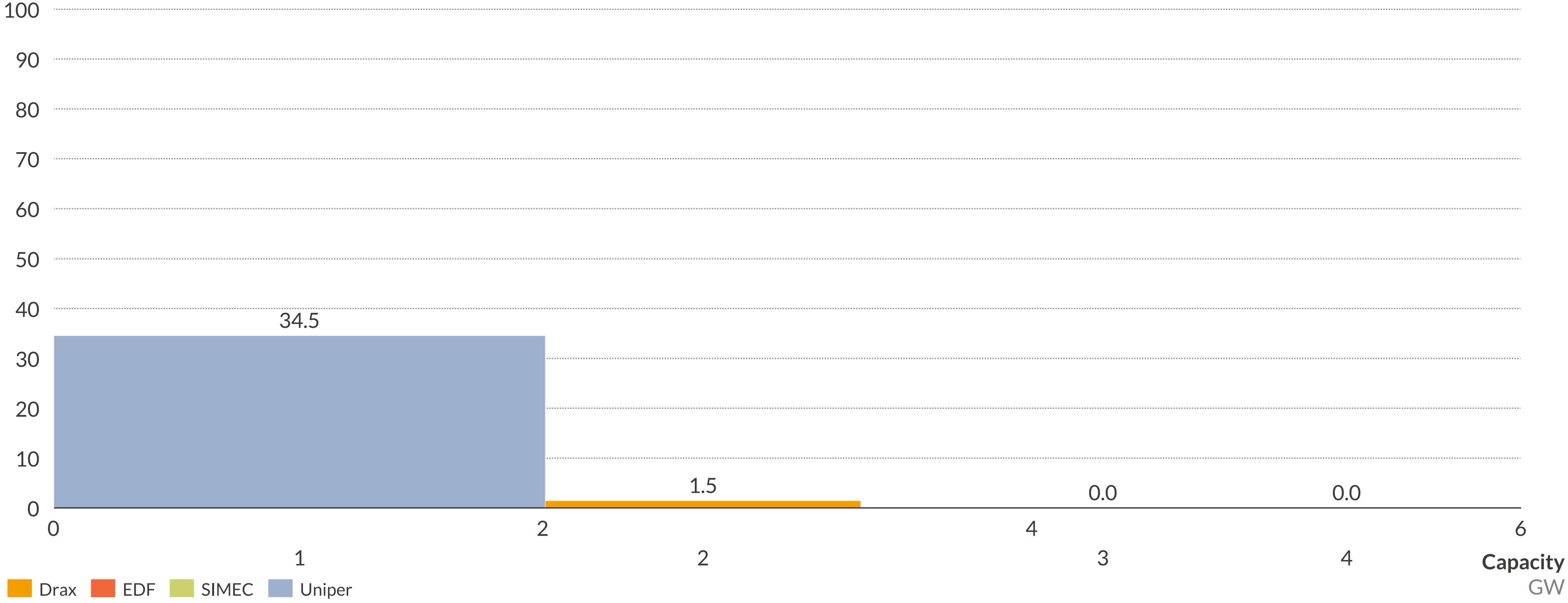
Full load hours[1]
% of total for the period

Column width reflects capacity



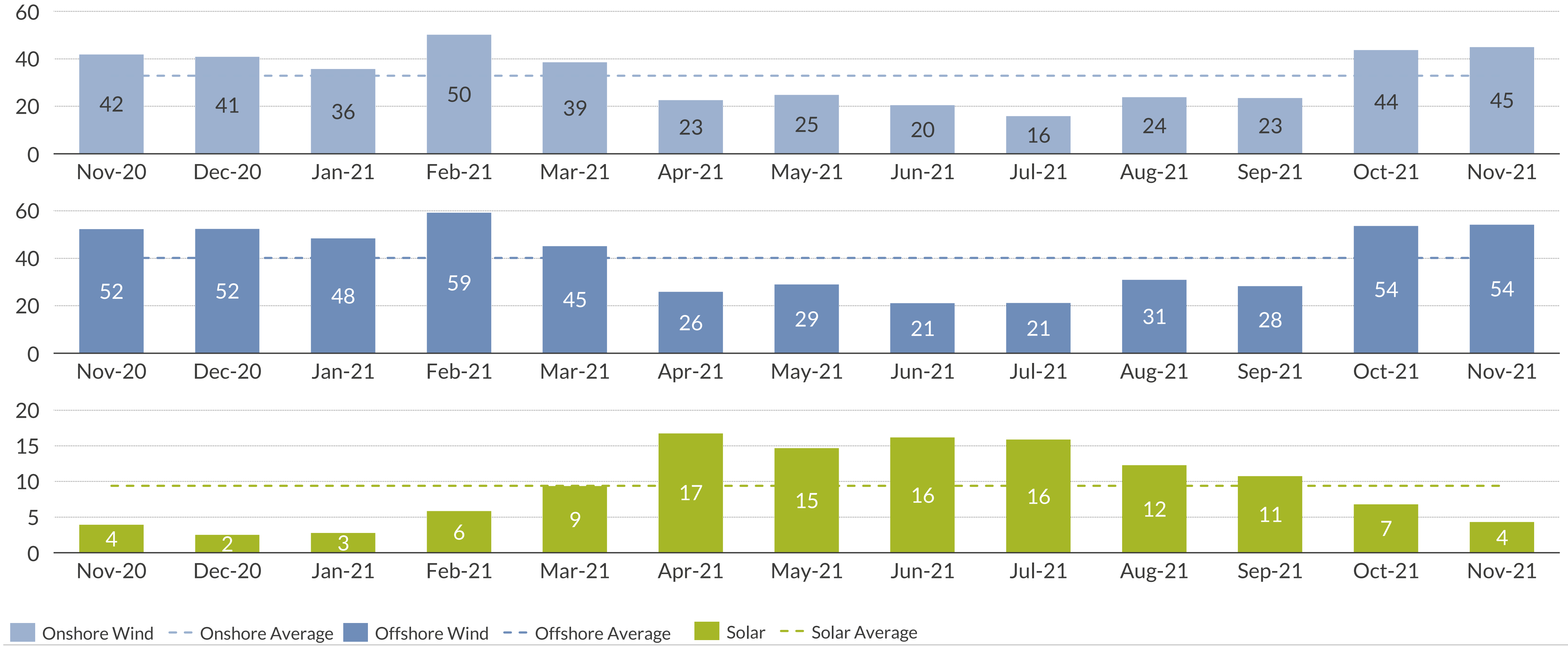
Plant Names: 1. Ratcliffe, 2. Drax Coal, 3. West Burton, 4. Uskmouth.

1) Includes all coal plants of the presented companies that report to the Balancing Mechanism

Sources: Aurora Energy Research, Elexon

Monthly load factors by technology

Average load factor[1]
%



1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV

Sources: Aurora Energy Research, Elexon, Crown Estate

Wind farm utilisation – load factor by wind farm

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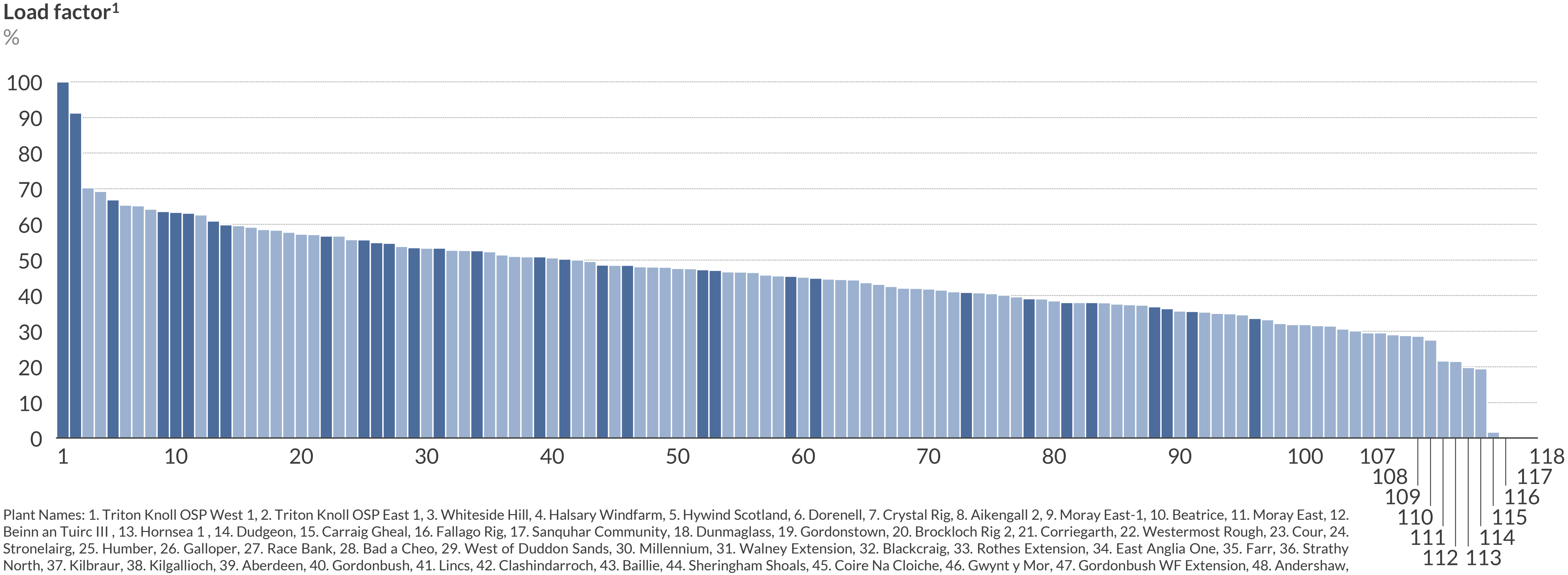

Plant Names: 1. Triton Knoll OSP West 1, 2. Triton Knoll OSP East 1, 3. Whiteside Hill, 4. Halsary Windfarm, 5. Hywind Scotland, 6. Dorenell, 7. Crystal Rig, 8. Aikengall 2, 9. Moray East-1, 10. Beatrice, 11. Moray East, 12. Beinn an Tuirc III , 13. Hornsea 1 , 14. Dudgeon, 15. Carraig Gheal, 16. Fallago Rig, 17. Sanquhar Community, 18. Dunmaglass, 19. Gordonstown, 20. Brockloch Rig 2, 21. Corriegarth, 22. Westermost Rough, 23. Cour, 24. Stronelairg, 25. Humber, 26. Galloper, 27. Race Bank, 28. Bad a Cheo, 29. West of Duddon Sands, 30. Millennium, 31. Walney Extension, 32. Blackcraig, 33. Rothes Extension, 34. East Anglia One, 35. Farr, 36. Strathy North, 37. Kilbraur, 38. Kilgallioch, 39. Aberdeen, 40. Gordonbush, 41. Lincs, 42. Clashindarroch, 43. Baillie, 44. Sheringham Shoals, 45. Coire Na Cloiche, 46. Gwynt y Mor, 47. Gordonbush WF Extension, 48. Andershaw, 49. Camster, 50. Assel Valley, 51. Mid Hill, 52. Walney, 53. Burbo Extension, 54. Bhlaraidh, 55. Beinn Tharsuinn, 56. Hill of Glaschyle, 57. Auchrobert, 58. Berry Burn, 59. London Array, 60. Griffin, 61. Greater Gabbard, 62. Glens of Foudland, 63. Freasdail, 64. Afton, 65. A Chruach, 66. Beinneun, 67. Edinbane, 68. Beinn An Tuirc , 69. Toddleburn, 70. Harburnhead, 71. Clyde, 72. Kype Muir, 73. Robin Rigg, 74. Burn of Whilk, 75. Hill of Towie, 76. Lochluichart, 77. Galawhistle, 78. Moray East-3, 79. Glen App, 80. Minsca, 81. Rampion, 82. Tullymurdoch, 83. Barrow, 84. Dersalloch, 85. Hare Hill Extension, 86. Corriemoillie, 87. Tullo, 88. Burbo Bank, 89. Thanet, 90. Dalswinton, 91. Ormonde, 92. Tullo Extension, 93. An Suidhe, 94. Minnygap, 95. Middle Muir, 96. Gunfleet Sands, 97. Crossdykes WF-2, 98. Crossdykes WF-1, 99. Dun Law Extension, 100. Whitelee, 101. Ewe Hill, 102. Moy, 103. Embedded Wind, 104. Goole Fields, 105. Braes of Doune, 106. Mark Hill, 107. Pen y Cymoedd, 108. Arecleoch, 109. Harestanes, 110. Hadyard Hill, 111. Craig, 112. Black Law, 113. Glenchamber, 114. Clachan Flats, 115. Airies, 116. Kincardine, 117. Brownieleys, 118. Keith Hill.

Offshore Wind   Onshore Wind

1) Represents UK wind farms reporting Balancing Mechanism Unit data. Figures presented reflect Final Physical Notification (FPN) expectations reported to the grid, which are not always representative of actual production

Sources: Aurora Energy Research, Elexon, Crown Estate

RES capture price versus baseload price

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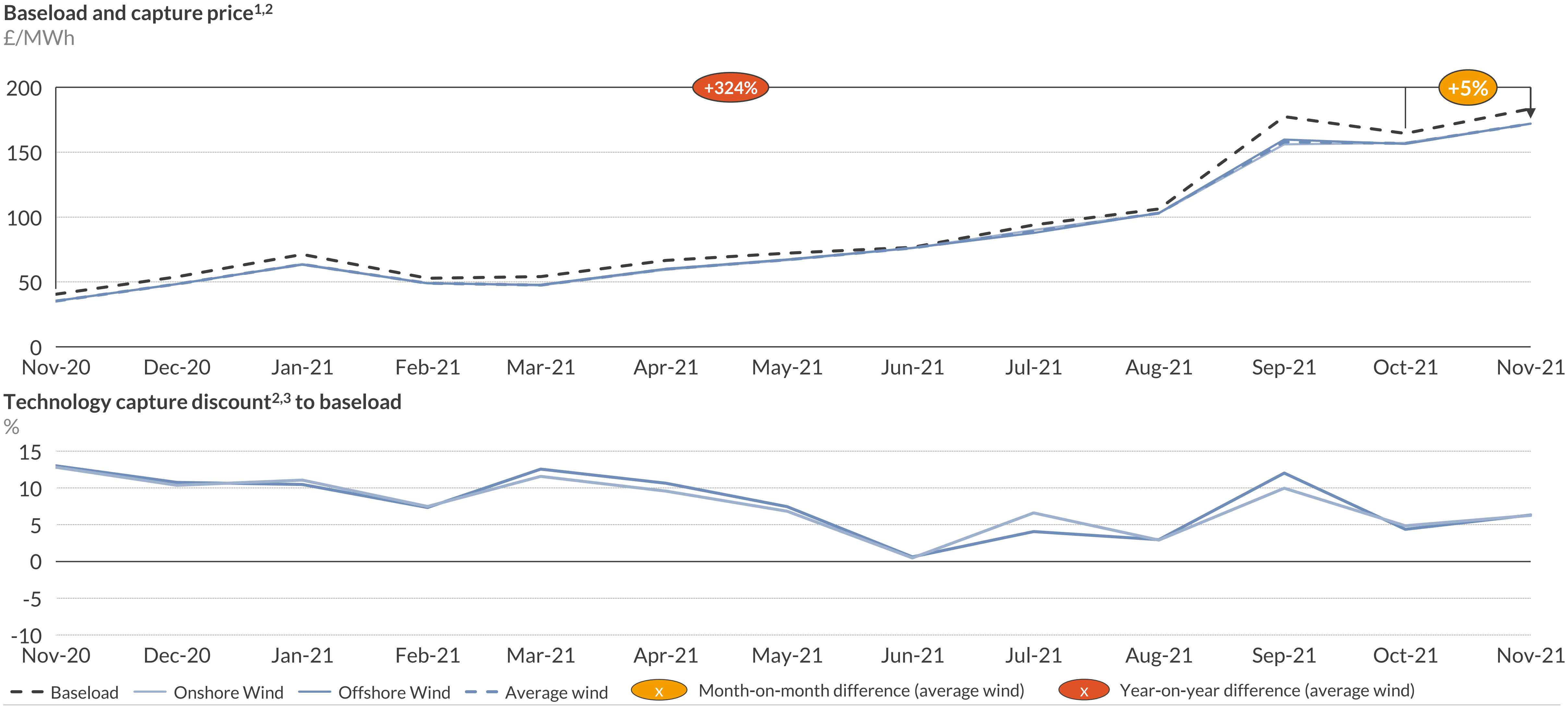

1) Baseload price is the average monthly EPEX price; 2) Wind capture price is the load-weighted monthly average EPEX price across all wind Balancing Mechanism plants for all half-hourly periods. 3) Negative values represent capture prices above the baseload price while positive values represent capture prices below the baseload price

Sources: Aurora Energy Research, Elexon, Thomson Reuters

Appendix

Data used

- Output values used in this summary reflect the sum of Final Physical Notifications (FPN) submitted by all BM Units of a given plant that have been active over the last three months.
- Capacity values used in this summary reflect the sum of capacities of individual BM Units, as reported to the Balancing Mechanism, that have been active over the last three months. They reflect long-term capacities and exclude temporary fluctuations due e.g. to plant failures or scheduled maintenance.
- Prices used in this summary are the EPEX half-hourly Reference Prices for half-hourly, two-hourly and four-hourly spot products.

Categories presented

- Full-load hours represent the plants' load factors, calculated as the ratio of the output produced in a given month to the maximum possible output given the plants' capacity.
- Running hours represent the proportion of time in a given month when a plant has been active, i.e. when at least one of its BM Units produced output greater than zero.
- Capture prices (or average output-weighted prices) are calculated as an average of EPEX half-hourly prices per MWh weighted by the plants' corresponding half-hourly outputs for all periods.
- Average gross margins are calculated as a sum of the uplift and inframarginal rent. Uplift is calculated as the difference between the EPEX price and the system marginal cost (SMC). SMC is the maximum marginal cost of all the plants with at least one generator producing above 80% of its installed capacity in a given half-hour.
- Emissions are calculated as plant output divided by electrical efficiency, multiplied by theoretical carbon content of the fuel input. The carbon content of fuel inputs is sourced from BEIS's Greenhouse gas reporting – Conversion factors 2016. System carbon intensity is calculated as the total emission divided by total electricity generated.

Source: Aurora Energy Research

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