GB Wholesale Power Market Summary January 2019

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Executive summary

1. With decreasing gas and coal prices, the average power prices in January decreased to £59.7/MWh, a £1.7/MWh fall from the previous month. However, the year on year power prices has increased by 22%. See slides 6 and 7.
2. Sustained cold temperatures in January saw the average monthly demand increase by 7.7% compared to December, leading to a rise in monthly gas generation by 2.4 TWh. See slides 7, 10 and 11.
3. Wind assets saw gross profits fall by an average of 15%, as average wind capture prices and load factors fell by 7% and 4 percentage points respectively. See slides 21 and 22.
4. Despite higher demand improving the gross margins of thermal assets, the negative performance by wind assets resulted in total monthly gross profits registering a modest increase of £6m. See slides 10, and 22.

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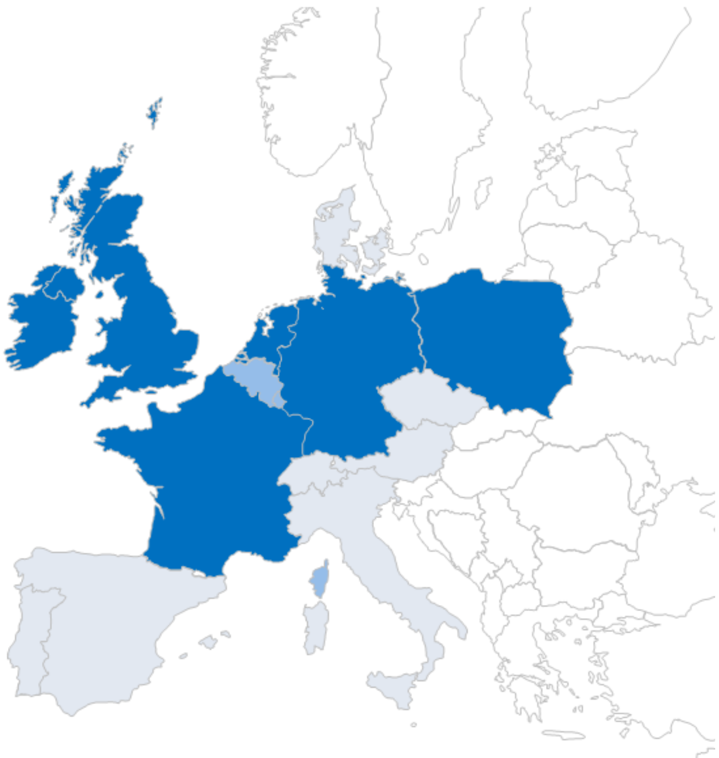

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Source: Aurora Energy Research

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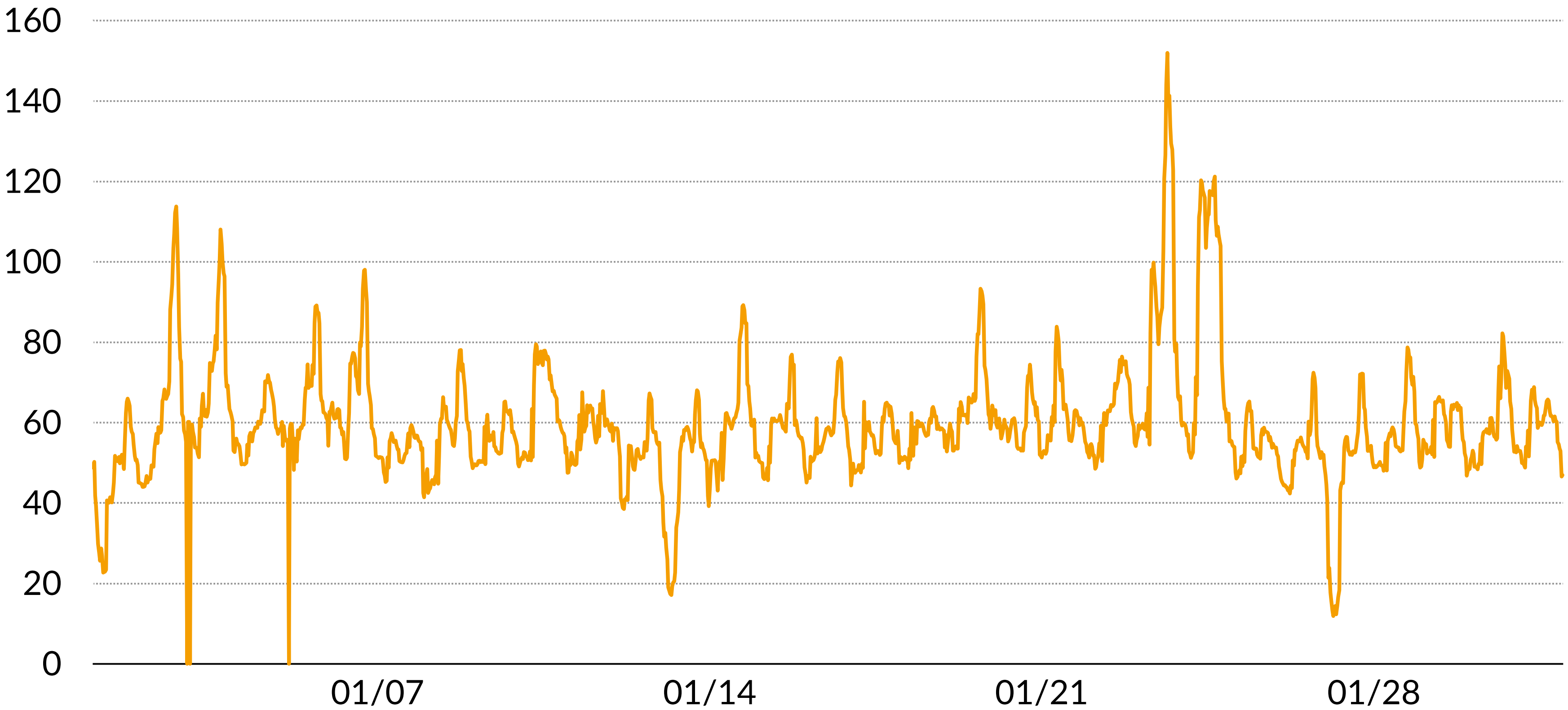
Half-hourly APX spot price for January

APX spot price[1],
£/MWh

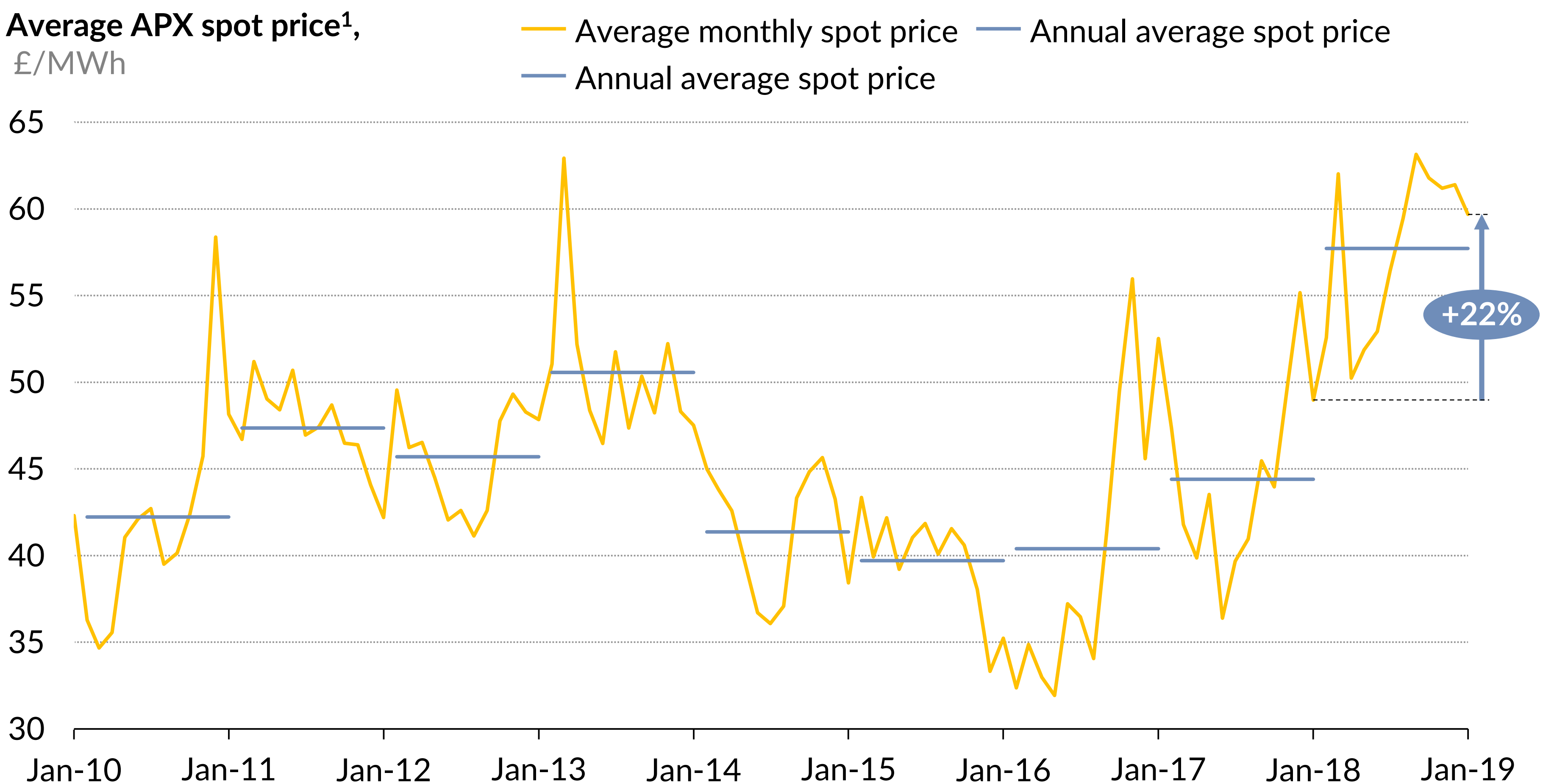
Monthly average price in January 2019: 59.7 £/MWh



1. Half-hourly APX is the volume-weighted reference price over that half-hour interval, as provided by APX Power UK.

Source: Thomson Reuters

Historic monthly average APX spot price

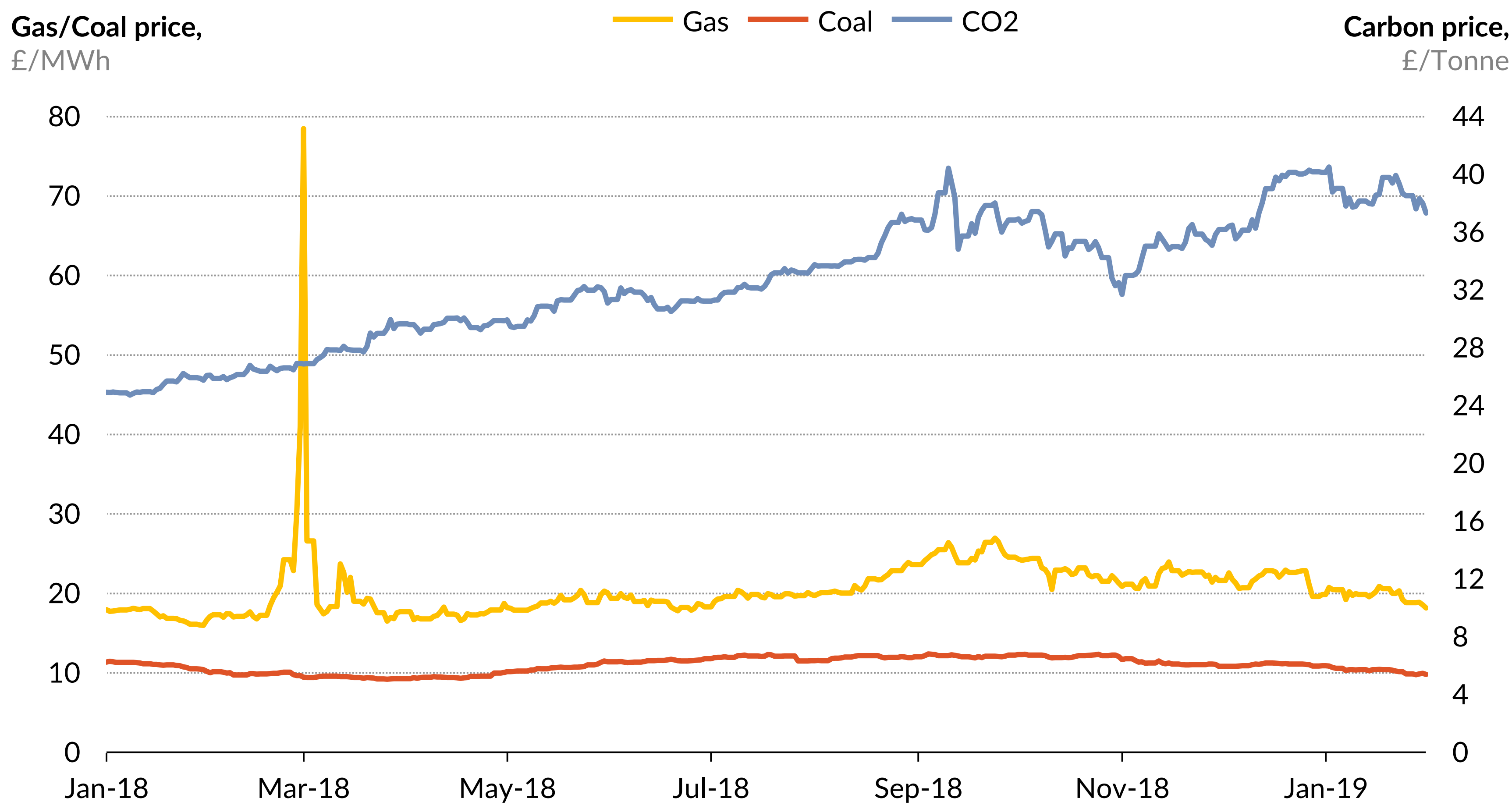


1. Average monthly APX is the average over the month of the volume-weighted reference prices for each half-hour interval.

Source: Thomson Reuters

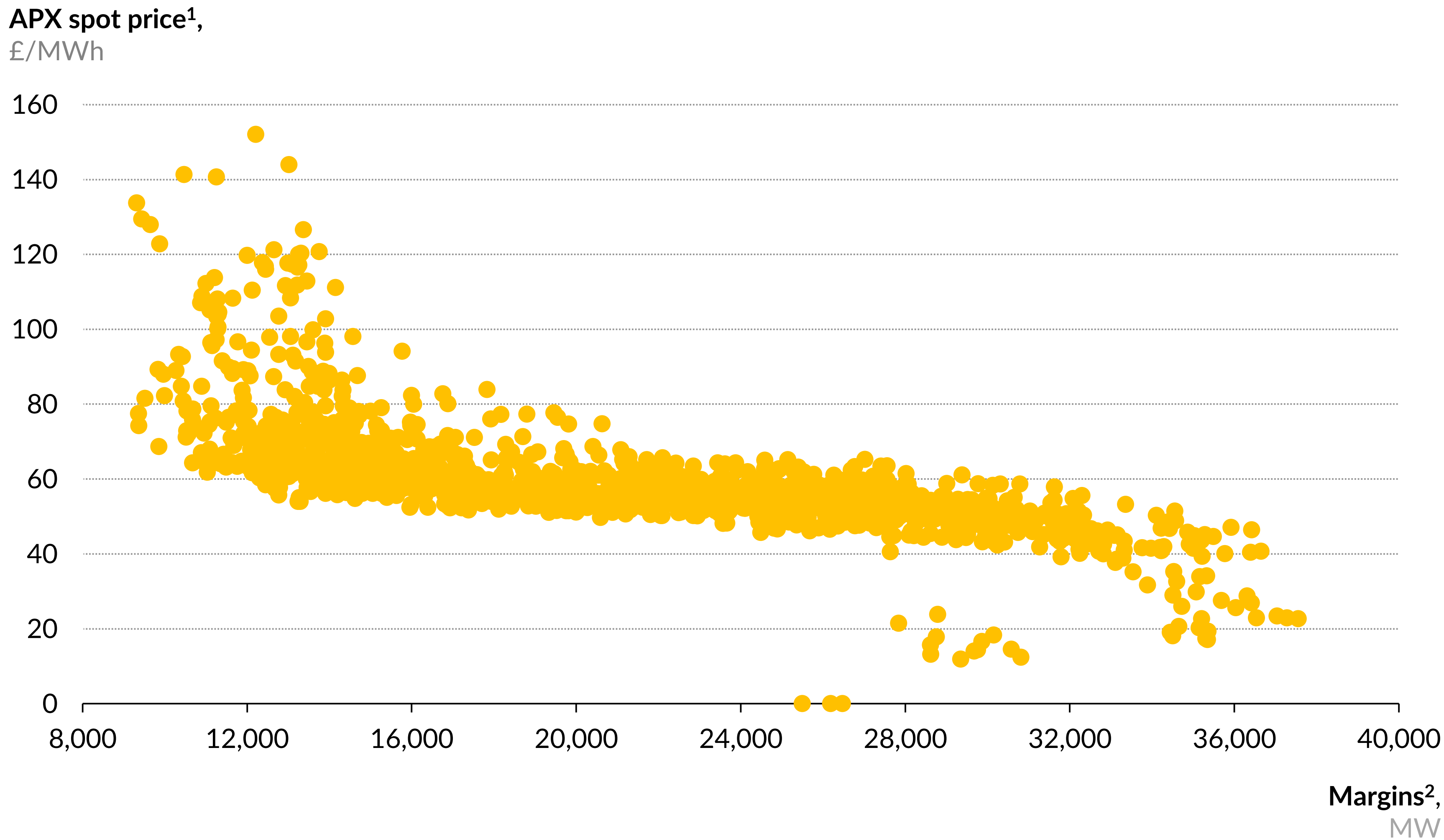
Historic fuel prices

Gas, Coal and Carbon daily prices



Source: Thomson Reuters

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

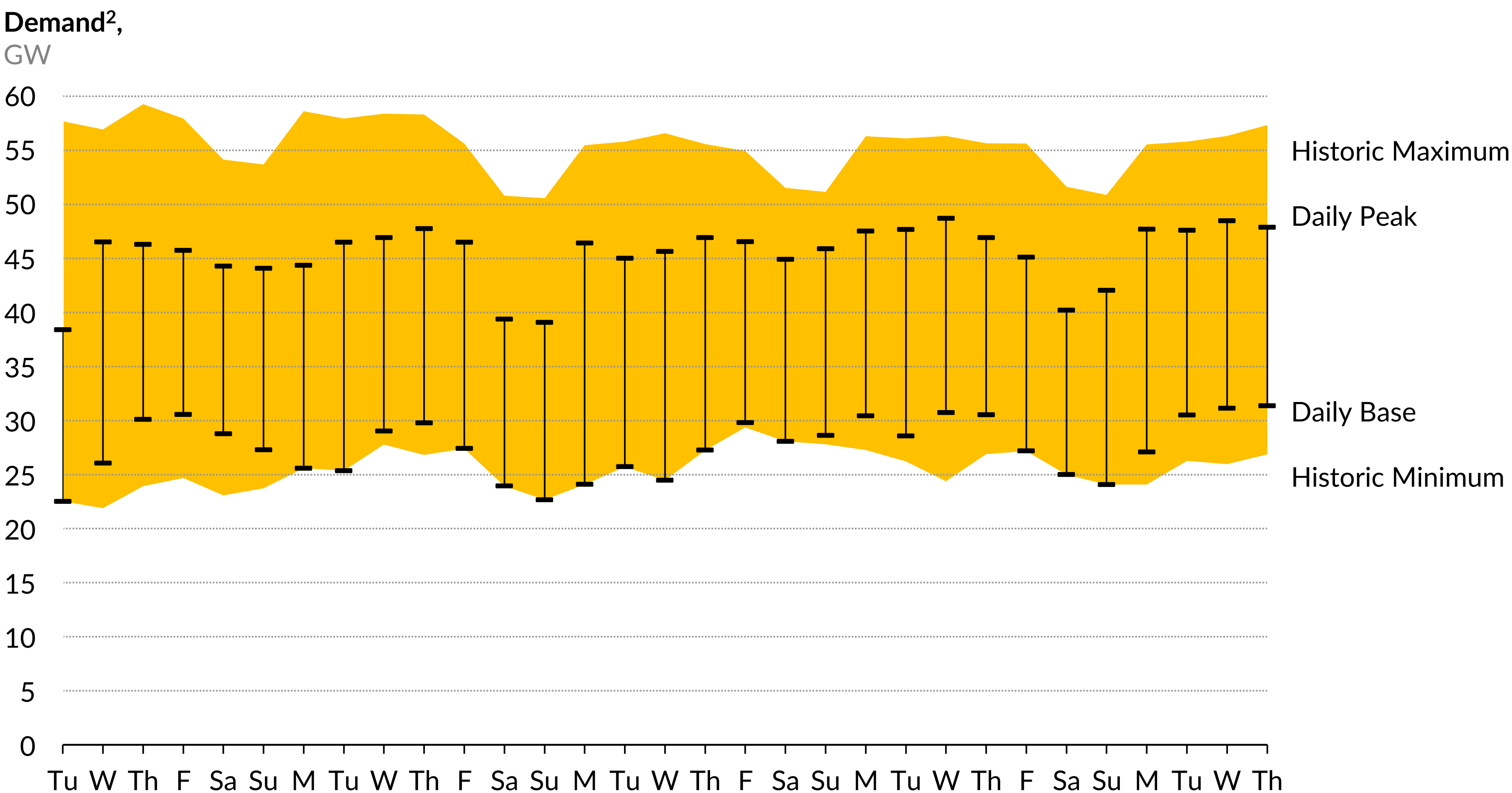


1. Half-hourly APX is the volume-weighted reference price over that half-hour interval, as provided by APX Power UK.
2. Margins are calculated as the difference between MEL and Demand for each half-hour period. Demand data presented here is Initial Transmission System Demand Out-Turn, and does not include 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

Daily April max and min demand

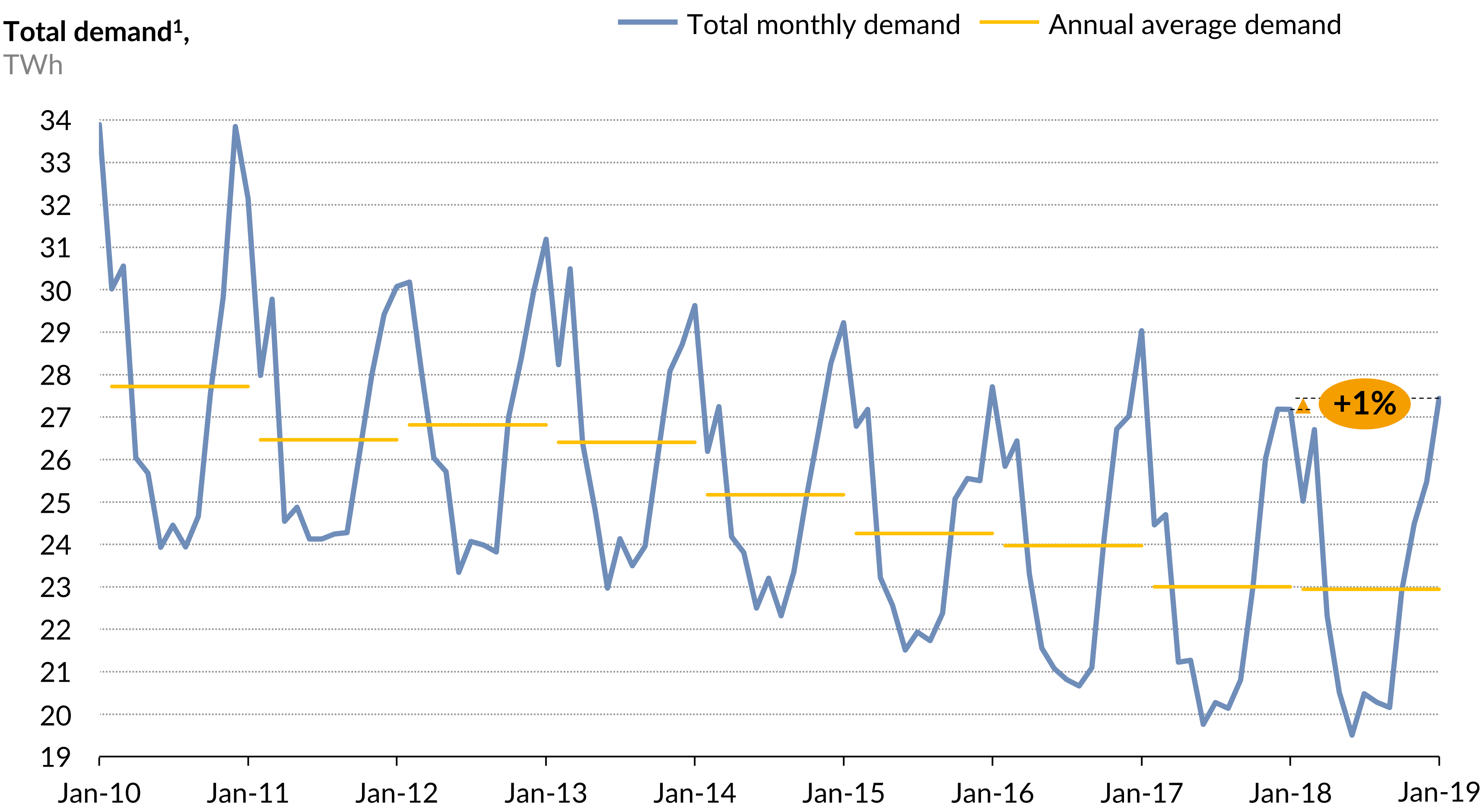
Relative to historic January max and min demand since 2010[1]



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.

Source: National Grid

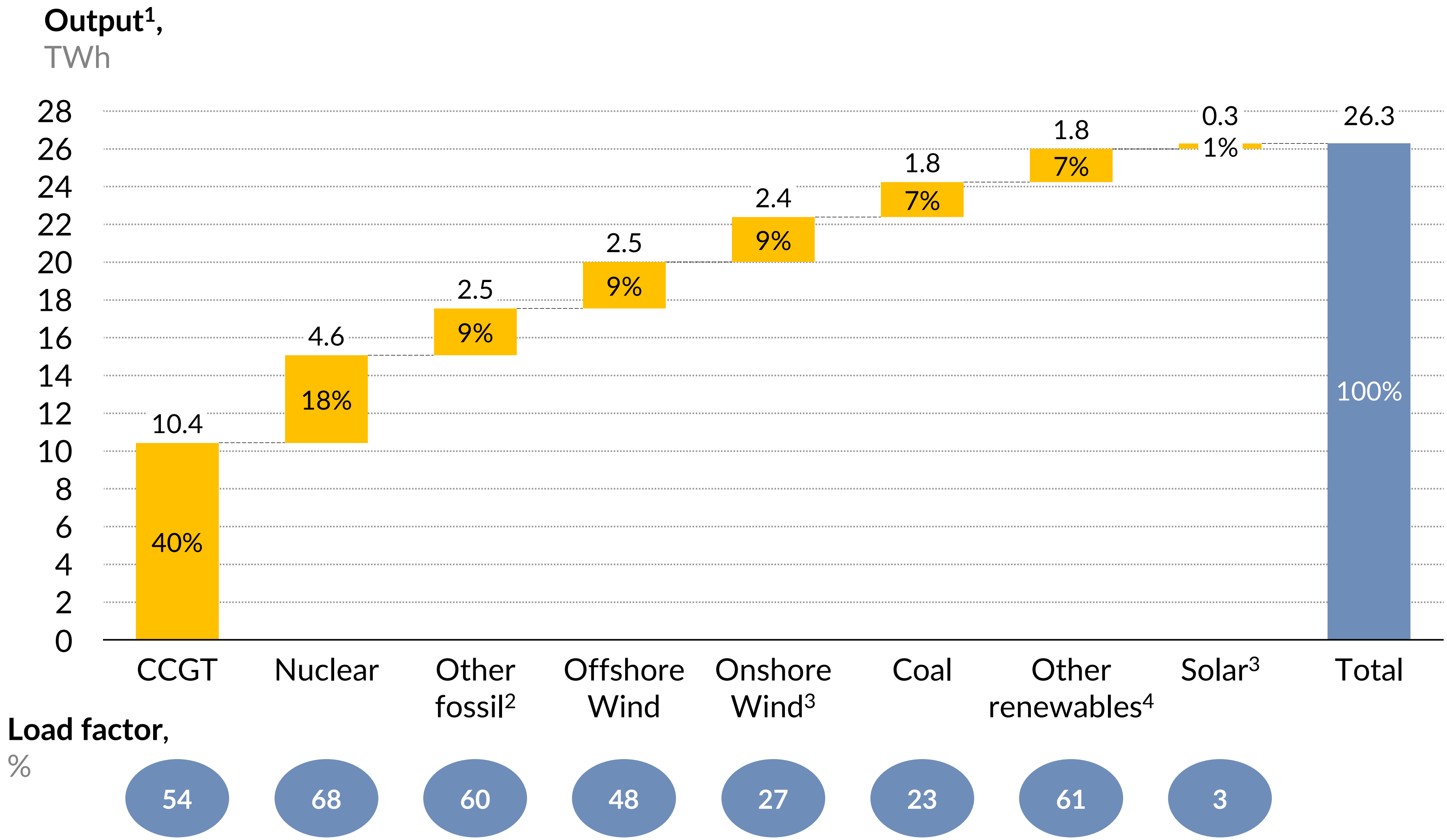
Monthly historical demand on the transmission system



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.

Source: National Grid

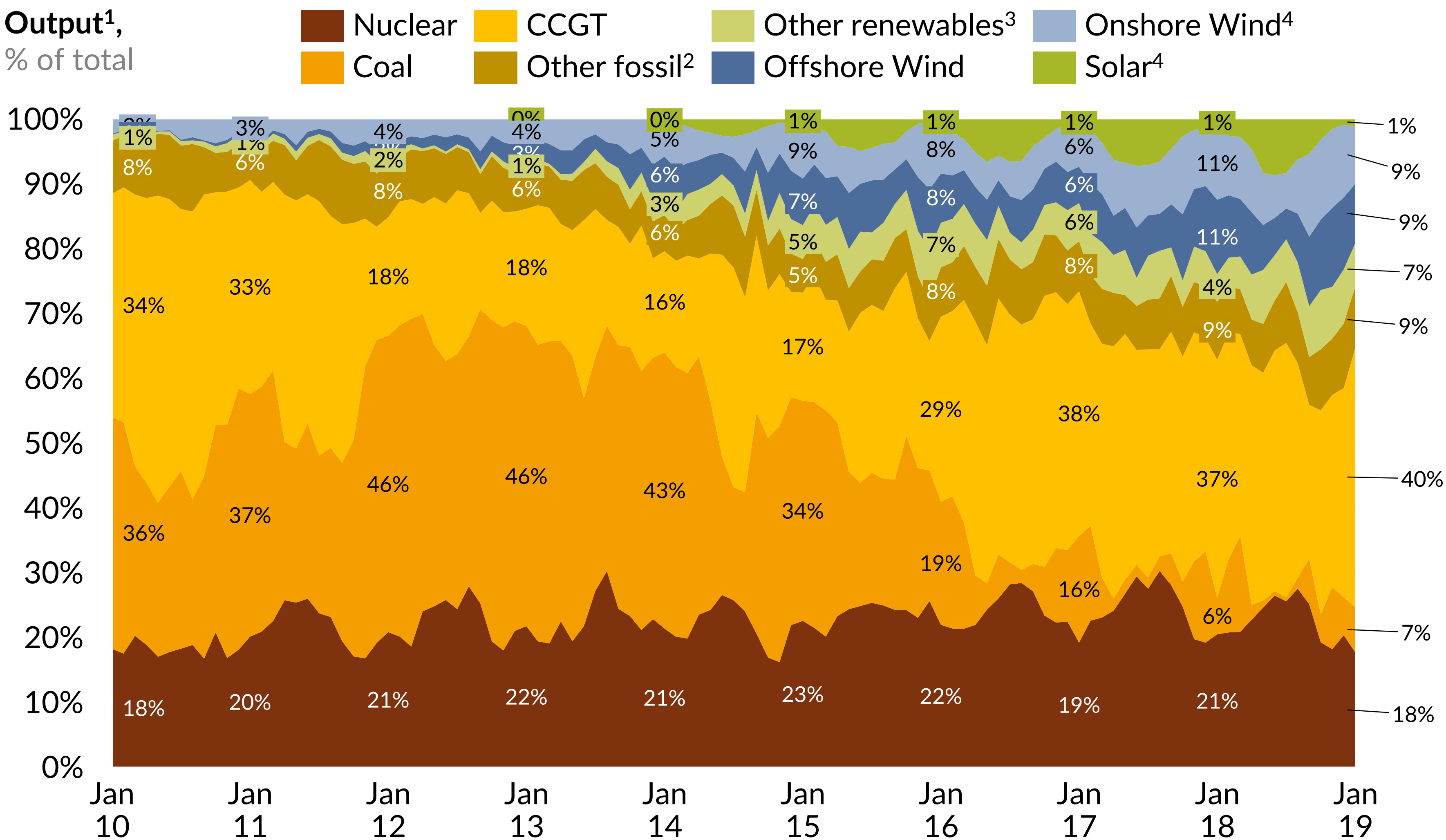
Monthly fuel mix breakdown



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) Includes embedded onshore wind and solar. 4) Other renewables includes biomass and hydro.

Source: Elexon, Sheffield Solar, National Grid

Historical fuel mix breakdown

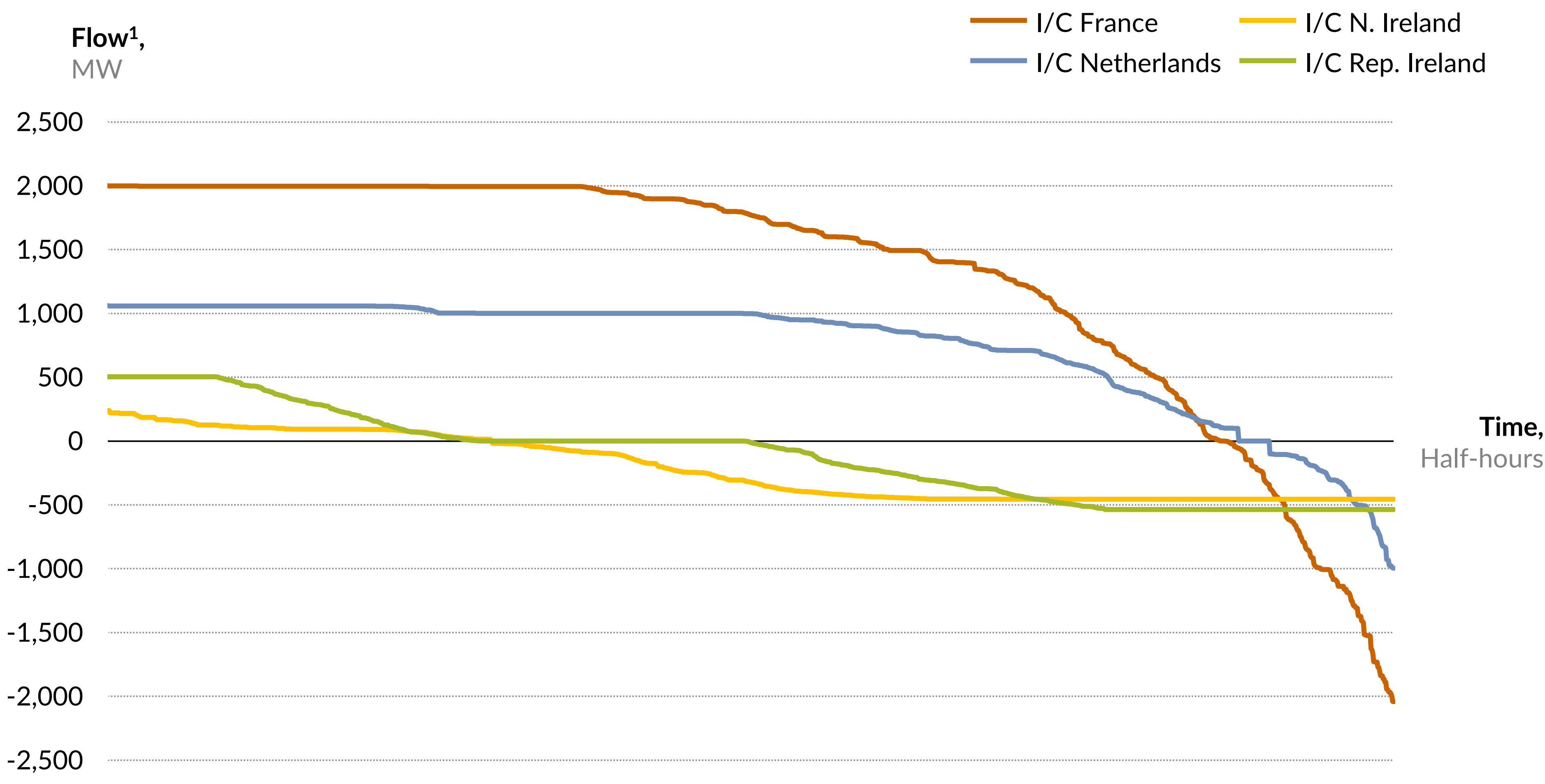


Notes: 1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV. 2) Other fossil includes oil, CHP-CCGT and OCGT. 3) Other renewables includes biomass and hydro. 4) Includes embedded onshore wind and solar.

Sources: Elexon, Sheffield Solar, National Grid

Monthly interconnector flow duration curve

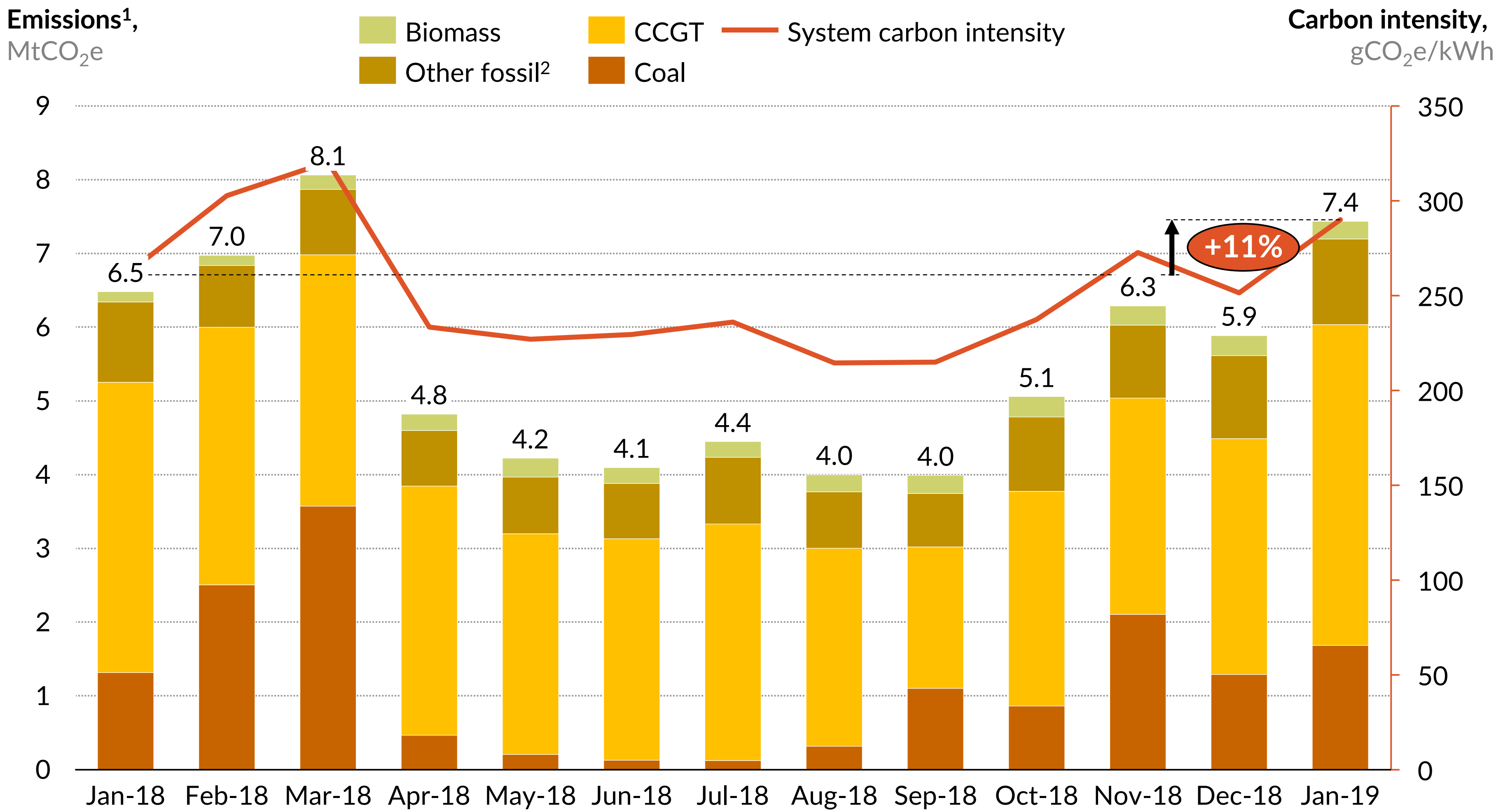
Flow in each half-hour for GB interconnectors



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

Sources: Elexon, National Grid

Monthly emissions by technology



1. Please refer to Appendix 1 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

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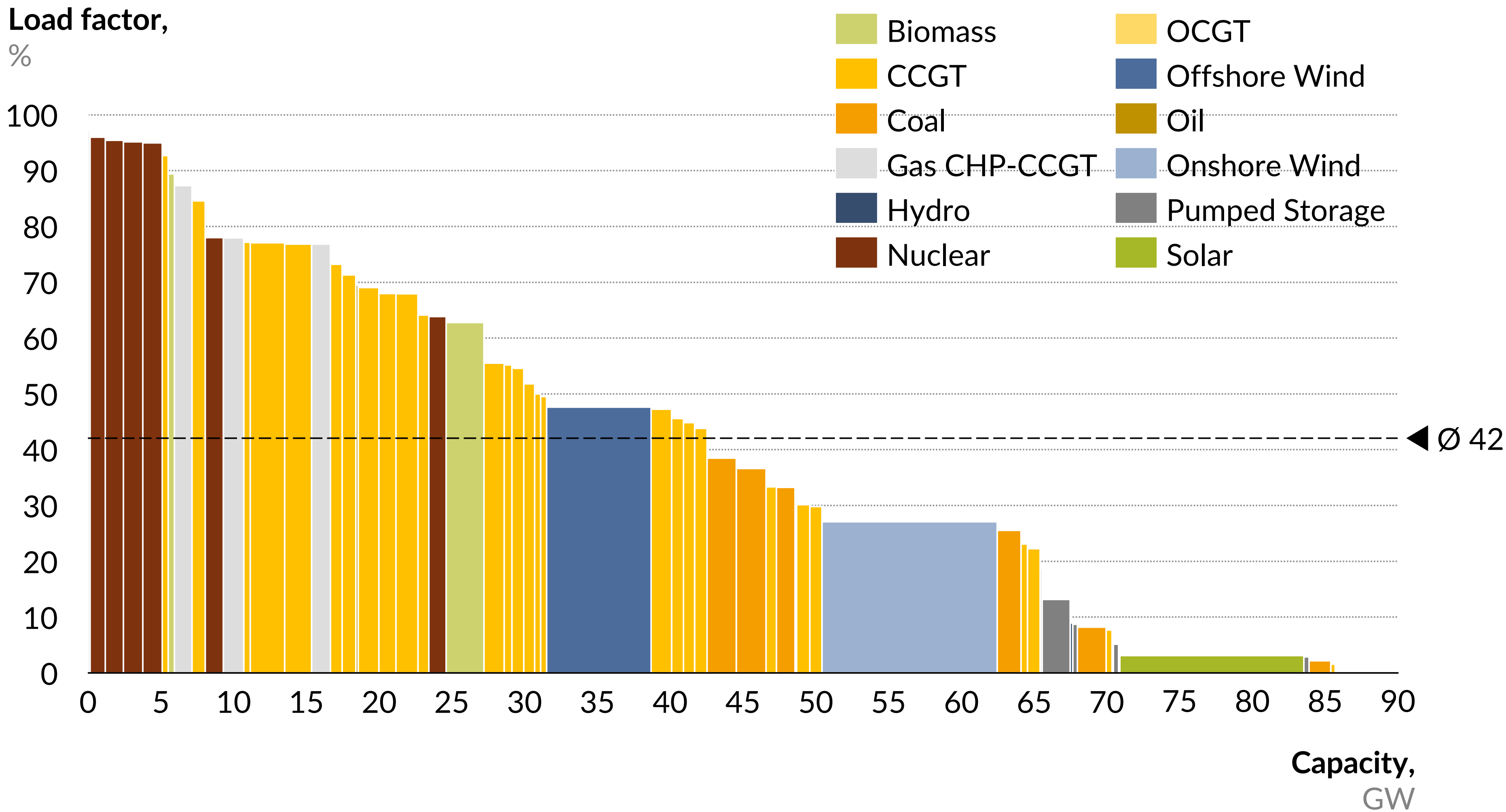
Plant utilisation – load factors by plant
(column width reflects capacity)



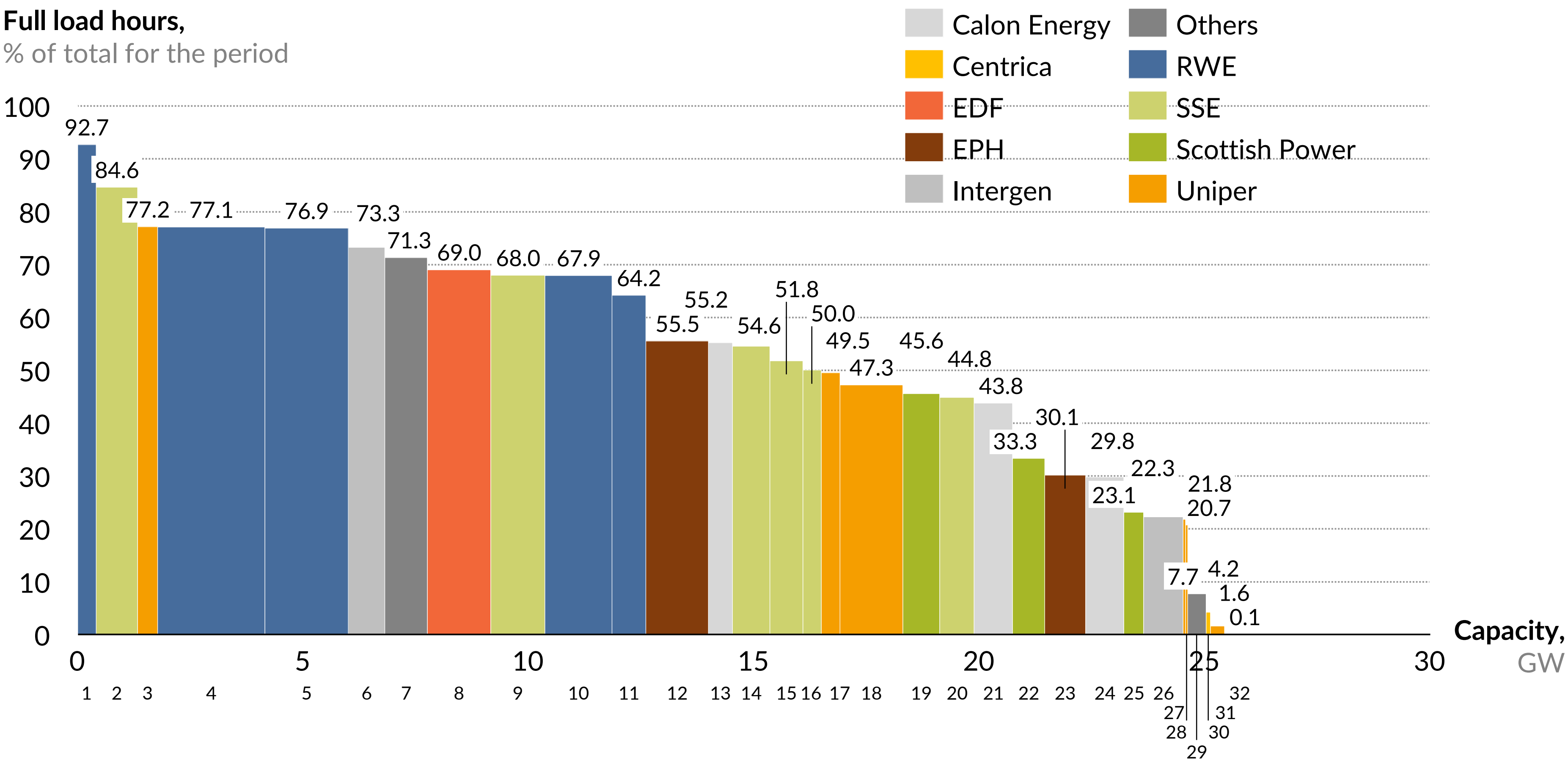
Represents 60 plants with highest capacity according to the Balancing Mechanism (BM) database, as well as aggregated data for wind and solar. Capacity of each plant represents the sum of capacities of all its generators that have been active at least once in the last three months.

Please refer to Appendix for a detailed description of the data used and categories presented.

Sources: Elexon, DECC

CCGT plant utilisation – by plant, January 2019

Column width reflects capacity



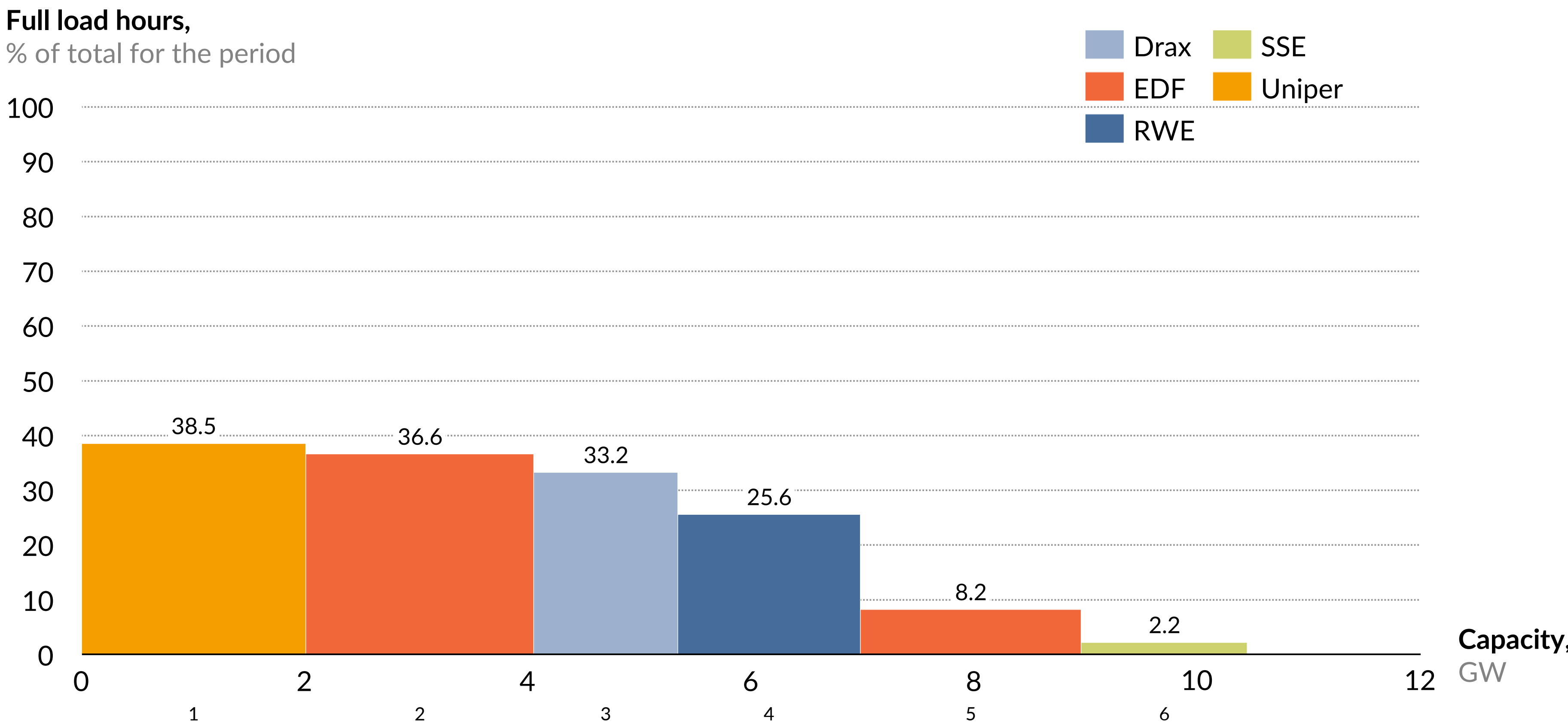
Plant Names: 1. Great Yarmouth, 2. Marchwood, 3. Cottam Dvpt Centre, 4. Pembroke, 5. Staythorpe, 6. Rocksavage, 7. Carrington, 8. West Burton B, 9. Peterhead, 10. Didcot B, 11. Little Barford, 12. South Humber Bank, 13. Baglan Bay, 14. Seabank 1, 15. Medway, 16. Seabank 2, 17. Enfield Energy, 18. Connahs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

Includes all CCGT plants of the presented companies that report to the Balancing Mechanism. Refer to Appendix B for ownerships in joint-ventured CCGT plants.

Source: Elexon

Coal plant utilisation – by plant, January 2019

Column width reflects capacity

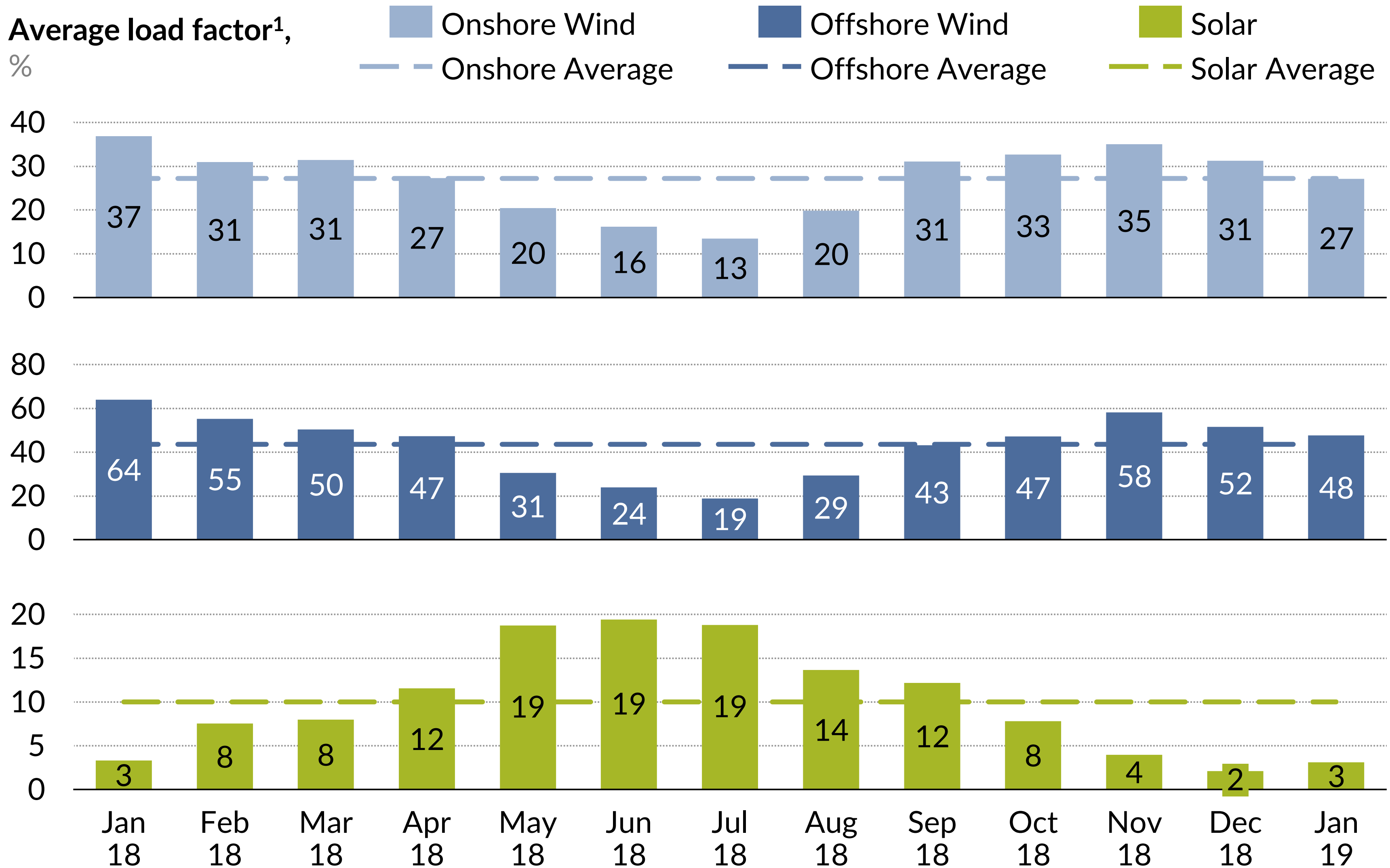


Plant Names: 1. Ratcliffe, 2. Cottam, 3. Drax Coal, 4. Aberthaw B, 5. West Burton, 6. Fiddlers Ferry.

Includes all coal plants of the presented companies that report to the Balancing Mechanism. Refer to Appendix B for ownerships in joint-ventured coal plants.

Source: Elexon

Monthly load factors by technology



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

Sources: Elexon, Crown Estate

Wind farm utilisation – load factor by wind farm

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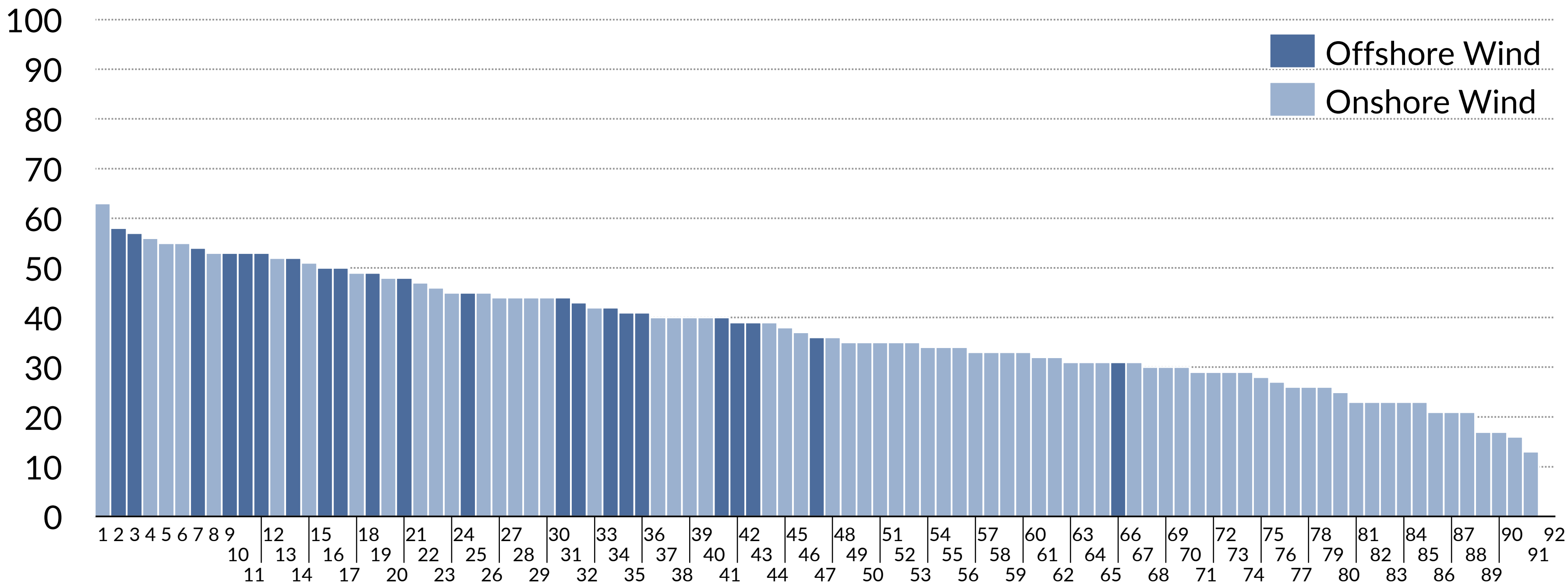
Load factor,
%

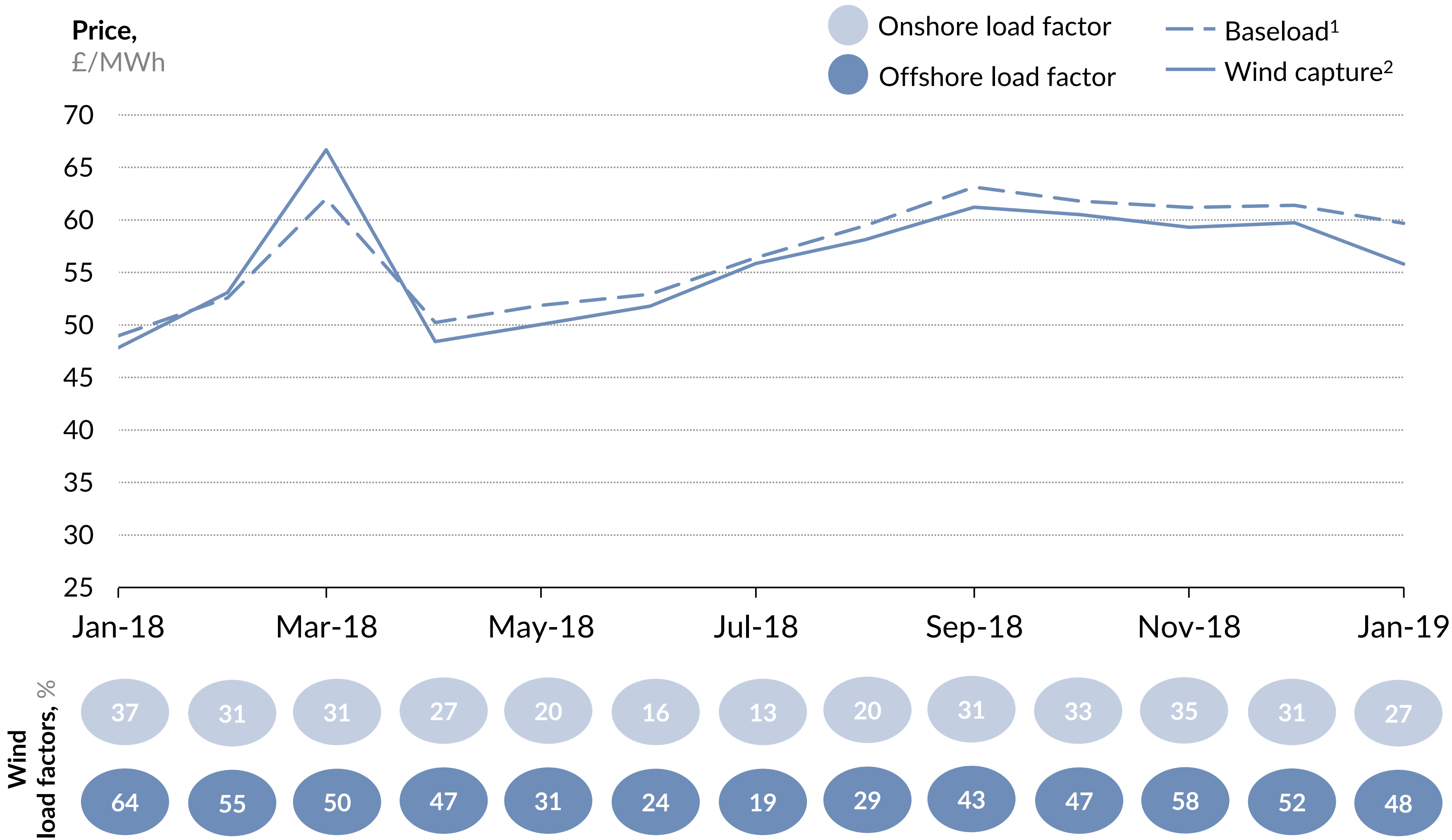


Plant Names: 1. Whiteside Hill, 2. Westermost Rough, 3. Sheringham Shoals, 4. Afton, 5. Fallago Rig, 6. Sanquhar Community Wind Farm, 7. Gwynt y Mor, 8. Cour, 9. Galloper, 10. Humber, 11. Walney Extension, 12. Brockloch Rig 2, 13. Burbo Extension, 14. Gordonstown, 15. Race Bank, 16. Walney, 17. Kilbraur, 18. West of Duddon Sands, 19. Crystal Rig, 20. Lincs, 21. Aikengall 2, 22. Carraig Gheal, 23. A Chruach, 24. Greater Gabbard, 25. Kilgallioch, 26. Assel Valley, 27. Auchrobert, 28. Blackcraig, 29. Millennium, 30. Rampion Offshore, 31. Thanet, 32. Baillie, 33. Dudgeon, 34. Gunfleet Sands, 35. Ormonde, 36. Andershaw, 37. Clashindarroch, 38. Galawhistle, 39. Glens of Foudland, 40. London Array, 41. Barrow, 42. Burbo Bank, 43. Strathy North, 44. An Suidhe, 45. Gordonbush, 46. Aberdeen Offshore, 47. Glen App, 48. Arecleoch, 49. Beinn An Tuirc , 50. Beinneun, 51. Berry Burn, 52. Harburnhead, 53. Dersalloch, 54. Freasdail, 55. Hill of Glaschyle, 56. Beinn Tharsuinn, 57. Burn of Whilk, 58. Minsca, 59. Pen y Cymoedd, 60. Corriegarth, 61. Hill of Towie, 62. Bhlaraidh, 63. Goole Fields, 64. Lochluichart, 65. Robin Rigg, 66. Tullymurdoch, 67. Clyde, 68. Dalswinton, 69. Minnygap, 70. Dun Law Extension, 71. Hare Hill Extension, 72. Mark Hill, 73. Middle Muir, 74. Edinbane, 75. Corriemoillie, 76. Ewe Hill, 77. Griffin, 78. Whitelee, 79. Tullo, 80. Black Law, 81. Dunmaglass, 82. Farr, 83. Hadyard Hill, 84. Tullo Extension, 85. Glenchamber, 86. Harestanes, 87. Moy, 88. Braes of Doune, 89. Clachan Flats, 90. Toddleburn, 91. Stronelairg, 92. Airies.

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: Elexon, Crown Estate

Wind capture price versus baseload price



1. Baseload price is the average monthly APX price.
2. Wind capture price is the load-weighted monthly average APX price across all wind Balancing Mechanism plants for all half-hourly periods.

Sources: Elexon, Thomson Reuters

Appendix A

Data used:

1. 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.
2. 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.
3. Prices used in this summary are the APX half-hourly Reference Prices for half-hourly, two-hourly and four-hourly spot products.

Categories presented:

1. 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.
2. 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.
3. Capture prices (or average output-weighted prices) are calculated as an average of APX half-hourly prices per MWh weighted by the plants' corresponding half-hourly outputs for all periods.
4. Average gross margins are calculated as a sum of the uplift and inframarginal rent. Uplift is calculated as the difference between the APX 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.
5. 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 DECC's *Greenhouse gas reporting – Conversion factors 2016*. System carbon intensity is calculated as the total emission divided by total electricity generated.

Appendix B

List of joint ventures in CCGT, coal and offshore wind:

CCGT plants:

Marchwood is co-owned by SSE (50%) and Munich Re (50%);
Deeside is co-owned by Engie (75%) and Mitsui (25%);
Seabank 1 is co-owned by SSE (50%) and Cheung Kong Infrastructure Holdings (50%).
Seabank 2 is co-owned by SSE (50%) and Cheung Kong Infrastructure Holdings (50%).

Coal plants:

Eggborough is co-owned by EPH (90%) and Engie (10%);
Rugeley is co-owned by Engie (75%) and Mitsui (25%).

Offshore wind farms:

Gwynt y Mor is co-owned by RWE (60%), Stadtwerke Muenchen (30%) and Siemens (10%);
Greater Gabbard is co-owned by SSE (50%) and RWE (50%);
London Array is co-owned by E.ON (30%), DONG (25%), the Caisse (25%) and Masdar (20%);
Gunfleet Sands is co-owned by DONG (50.1%), Marubeni (24.95%) and Development Bank of Japan (24.95%)
Walney is co-owned by DONG (50.1%), SSE (25.1%) and PGGM & Dutch Ampere Equity Fund (24.8%);
Sheringham Shoals is co-owned by Statkraft (40%), Statoil (40%) and Green Investment Bank (20%);
Lincs is co-owned by Centrica (50%), Siemens (25%) and DONG (25%);
West of Duddon Sands is co-owned by DONG (50%) and Scottish Power (50%);
Westermost Rough is co-owned by DONG (50%), Marubeni (25%) and Green Investment Bank (25%).

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