GB Electricity Market Summary

Q1-2023

January to March

Generation and Contribution by Fuel Type

Renewables:	33.61TWh (-1%)	Gas:	23.46TWh (-14%)	Nuclear:	9.21TWh (-13%)
Renewables excl. biomass:	27.52TWh (-2%)	Coal:	0.93TWh (-1%)	Net Imports:	7.25TWh (+706%)

% changes stated with respect to values in the previous quarter

Contents

1 Quarterly Review of GB Electricity Market Q4 2022 3
Demand 6
Generation 7
Prices 9
Interconnectors 10
2 Notes on the Report 13

1 Quarterly Review of GB Electricity Market Q1 2023

Despite concerns in the market during 2022 regarding the security of supply over the winter of 2022/23, prevailing GB electricity prices in Q1 2023 were generally lower than had been seen in recent previous quarters and fewer extremes were seen than was common for much of 2022. The weather was generally mild, resulting in a reduced demand which, along with high power prices despite various price caps in operation resulted in demand being generally around 10% lower. This is a significant amount of demand destruction and a record low demand for Q1.

Strong wind outturn, combined with the lower demand, caused there to be a smaller presence of conventional generation in the fuel mix than is usual for the season. Gas prices fell across the quarter, being 21% lower than in Q4 2022 and 42% lower than in Q1 2022, as European storage levels were high and saw fairly low draw-down rates. GB returned to its historically usual position of being a net importer of power, with high volumes of imports being seen from France and Norway in particular. This followed an extended period of predominantly exporting during Q3 and Q4 last year during a period French nuclear outages and a European drought.

NG ESO implemented additional measures in the system this winter in order to ensure security of supply. These were the Demand Flexibility Service (DFS) and the Winter Contingency Contracts for several coal units. Both measures were tested regularly but they were also activated for real events on one occasion for each service. DFS was activated on two days in late-January, while West Burton 1 and 2 were activated for the 7th March under their Winter Contingency Contracts.

The key takeaways from this quarter are:

- **Mild weather and low conventional generation:** Temperatures were generally higher this quarter than in recent Q1's, reducing demand beneath what is typical of the winter months. This, along with high volumes of wind generation, resulted in the lowest conventional generation (including gas-fired and coal-fired generation) of any first quarters on record since 2015. However, the occasional cold snap, particularly in mid-January and early March, resulted in spikes in pricing and demand. GB nuclear generation for Q1 was lower than previous Q1 periods reflecting recent unit closures in the fleet and some short term maintenance.
- **High levels of wind generation:** Q1 saw 23.98TWh of wind generation, only slightly below the record level of 24.82TWh seen in the previous quarter.

- **Gas storage and prices:** With the generally mild weather keeping conventional generation lower than is typical of historical Q1's, levels of gas storage were high this quarter in GB and the rest of Europe. NBP gas prices declined across the quarter, dropping from £59/MWh at the beginning of January to £39/MWh by the end of March. The average gas price over the quarter was £46/MWh, the lowest for any quarter since Q2 2022 (which itself had been notably low given the prevailing market conditions reflecting intervals of excess gas supply during periods of low electricity demand and high wind).
- **French nuclear return to service:** At the beginning of the quarter, nuclear availability in France was scheduled to increase as high as 50GW by the middle of Q1. However, the schedule was repeatedly pushed back due to a variety of factors, including the requirement for further repairs and maintenance following the appearance of stress corrosion cracking in some reactors last year, and strikes at EDF that prompted mass walkouts of employees from nuclear power stations. Nuclear availability peaked for the quarter at ~46GW in early February, but declined to be beneath 38GW for much of March.
- **Interconnector flows:** Following a period in which GB had been a net exporter of power during Q2, Q3 and Q4 of 2022, it returned to a position of being a net importer during Q1 2023 importing 7.25TWh representing a change of 706% from the exports of 1.20TWh seen last quarter. Historically, it has been usual for GB to import more power through its interconnectors than it exports in any given quarter, but the extreme market conditions of 2022 resulted in a flip in GB's position. Power imports into GB were higher than in any quarter since Q3 2021, with the largest import volumes of 2.79TWh and 2.20TWh coming from France and Norway respectively.
- **Demand Flexibility Service:** During Q1, there were twelve test activations of Demand Flexibility Service (DFS) by NG ESO and two live activations. The live activations occurred on 23rd and 24th January during the evening peak hours. System margins were beneath 8GW on both days and demand was 38-40GW. The DFS service, as of 1st April 2023, is no longer running, but NGESO have stated that they will review the potential requirement for the DFS service going into next winter.
- **Winter Contingency Contracts:** This quarter saw one period in which coal units that held winter contingency contracts were activated. During the evening of Tuesday 7th March, West Burton 1 and 2 were utilised for several hours, each reaching a peak output of 250MW. Drax had two units warmed to start too on this day but one station failed and the other was stood down before generation started. System imbalance prices peaked at £1,950/MWh at 18:00 that day, the highest system price seen in GB since January 2022. This was first time the coal plants for emergency backup were called into action; the units had previously been instructed to warm on some days during the January cold snap, but subsequently stood

down as they were not required, so the run on 7 March was the only time the units delivered energy under this service. As of 1st April, the Winter Contingency Contracts are no longer active, as per the terms of the original agreement.

- **Lower demand profile:** With consumers and industry becoming aware of the financial impact of the high power prices, domestic demand this quarter was lower than any Q1 in recent years with an average of 29.7GW. Widespread demand reduction was seen in both consumer and industrial sectors for much of 2022, and during Q1 2023, this behaviour continued.
- **Triads[1]:** The three half-hour settlement periods of peak net system demand were observed on 2nd December 2022, 15th December 2022, and 17th January 2023 with magnitudes of 39.6GW, 44.6GW, and 42.0GW respectively. The demand levels of these triads were very low with two of the three being record low numbers since the 1990s.

[1] Triads are the three settlement periods of highest system demand each separated by at least 10 days and are used as the basis for network charges

Demand

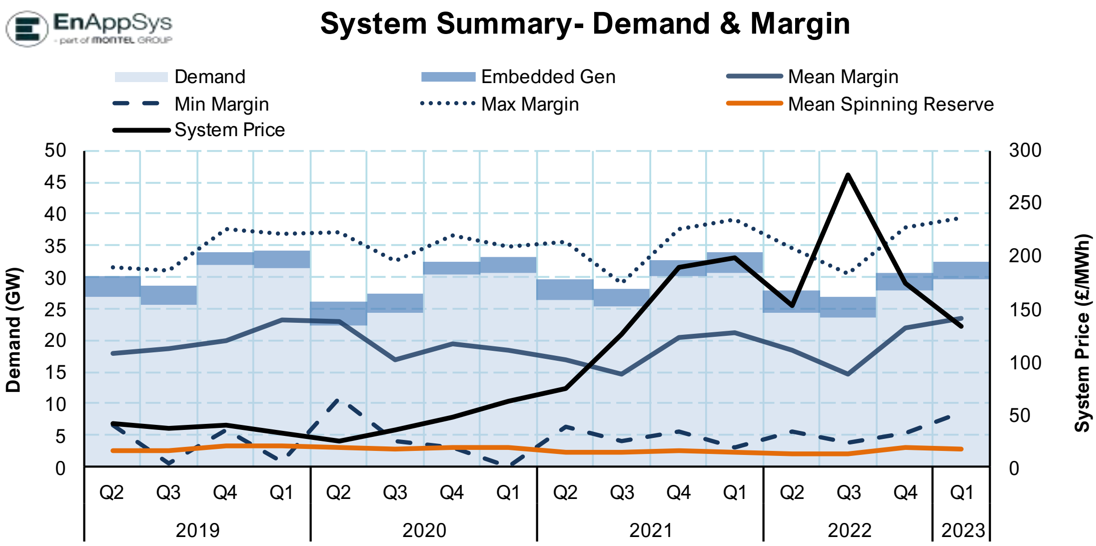

Figure 1: Total system summary – demand & margin across Q1 2019 – Q1 2023

Demand reduction in both consumer and industrial sectors had been common in 2022, as the cost-of-living crisis prompted reduced consumption because of high prices even though the full impact of the record wholesale prices was mitigated by price caps. In Q1 2023, this demand reduction continued. The introduction of a new Demand Flexibility Service by National Grid ESO provided arrangements under which consumers could be remunerated for consciously altering their consumption during activation periods. Total domestic demand was 64.1TWh this quarter, lower than the previous lowest Q1 of 2021 by 2.0TWh.

In addition to conscious efforts to keep demand low, the mild weather this winter also contributed to low demand figures. Temperatures were often warmer than is typical of the season, reducing heating load and system demand, but some cold snaps did boost demand on occasion. From 16th-29th January, cold temperatures that dropped beneath freezing resulted in increased demand. Evening demand peaks were frequently above 42GW, reaching up to 44GW at times, while overnight levels rarely dropped beneath 24GW. Pricing rose as a result, with the average day-ahead price in this period being ~20% higher than the average for the quarter.

Another cold snap was seen from 7th-16th March. Although demand did not increase to quite as high levels as in the January cold snap, it resulted in very tight margins on Tuesday 7th March and extreme pricing as margins became very tight with a combination of unexpected low temperatures and no imports from France as it faced strikes related to pension age increases.

Generation

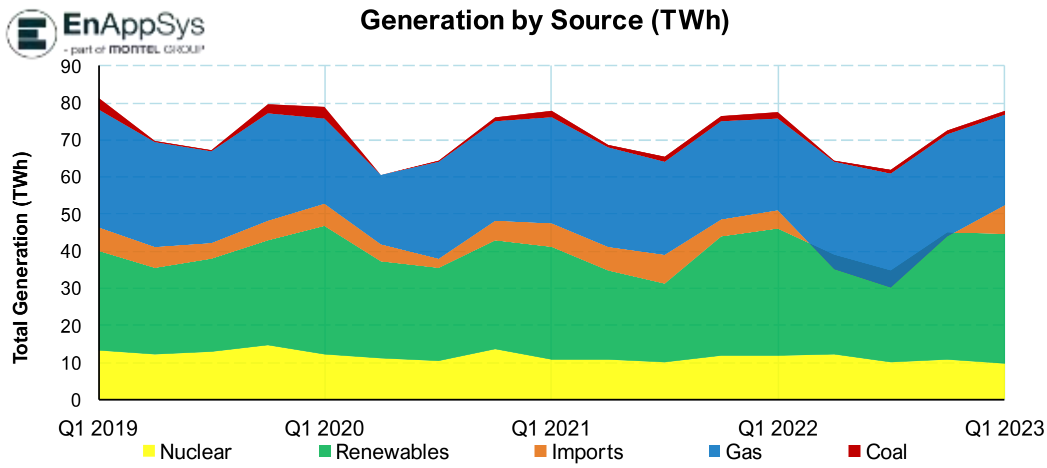

Figure 2: *Stacked total quarterly generation by the main fuel groups*

Including embedded generation[2], total wind outturn over the quarter was 23.98TWh, higher than any other Q1 on record. Due to this high level of wind generation, along with the lower demand than is typical of a Q1, conventional generation occupied a smaller share of the fuel mix than any other Q1 on record. Gas-fired and coal-fired generation had a combined share of 32.8% of total GB generation, while gas storage stocks remained at high levels throughout the quarter. Although there had been concerns surrounding security of supply this winter, activations of units that held Winter Contingency Contracts were only seen on one day, Tuesday 7th March, in response to tight margins occurring on a day in which the French system operator had indicated that emergency assistance would not be available (during a period of expected strike action in France).

[2] Embedded generation is generation that is connected to the distribution network rather than the transmission network and, as such, offsets demand thereby reducing system demand at the transmission network level

Other sources of renewable generation were relatively low this quarter, with solar generation being lower than any Q1 since Q1 2021. Hydro generation was lower than levels seen in Q1 2022, but higher than that of Q1 2021.

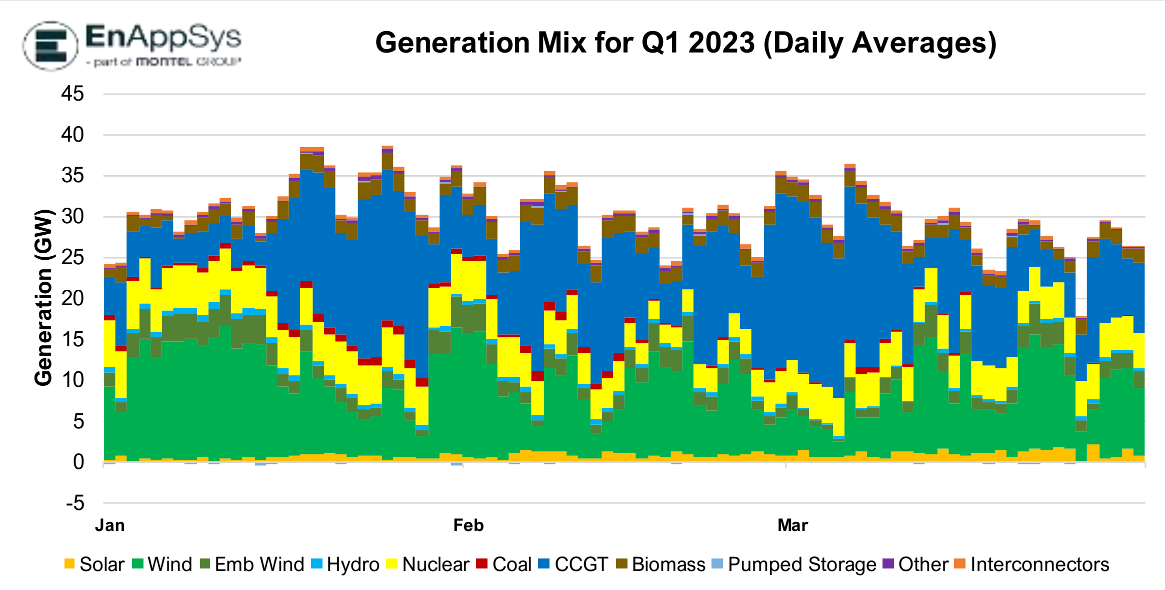

Figure 3: *Stacked total quarterly generation by generation type for Q1 2023*

Prices

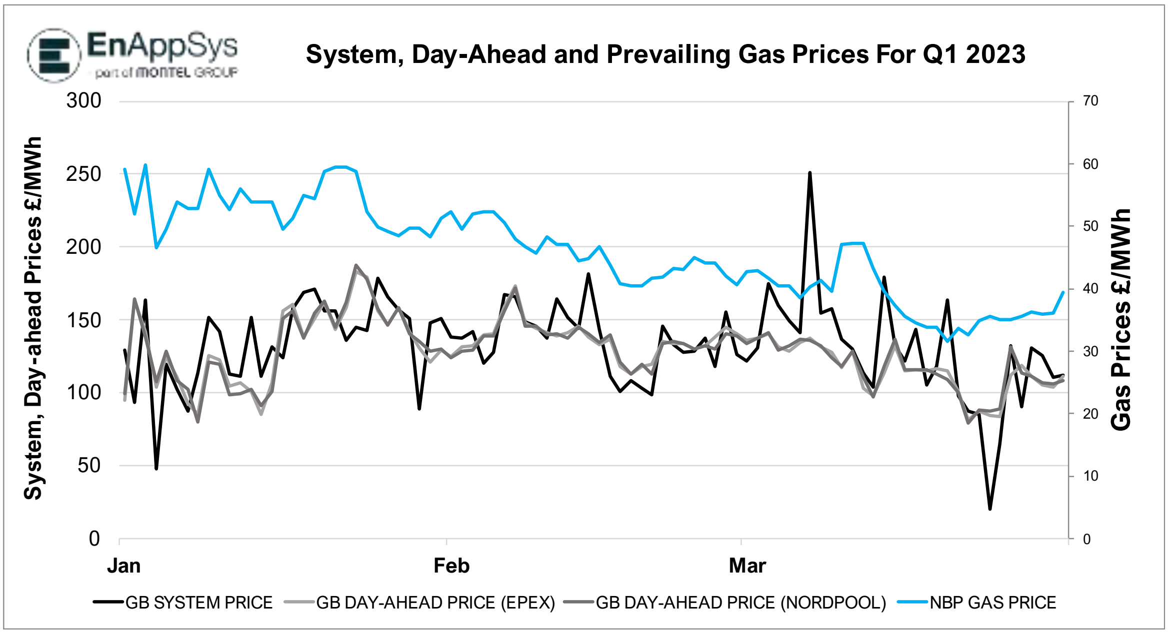

Figure 4: *GB system, day-ahead and gas prices for Q1 2023.*

Pricing remained generally low across the quarter and decreased on average. The daily average day-ahead prices peaked at ~£188/MWh during the January cold spell, while system prices peaked at an extreme high daily average of £250/MWh in March. Gas and coal prices also dropped over the quarter, as conventional generation remained generally low. Carbon prices, meanwhile, increased over the quarter, with UK ETS prices peaking at £88.65/te in late-February. The result of this was that the breakeven ranges[3] for coal and gas units both fell overall, but the range for gas units fell slightly beneath that of coal units by the end of the quarter. In Europe the same trend was observed and widespread coal-to-gas fuel switching was seen, increase the draw-down rate of gas stockpiles. In the GB coal fleet. only Ratcliffe (Uniper) operated commercially, with the other units being contracted under the Winter Contingency Contracts and kept outside the market.

[3] The breakeven range indicates the relative breakeven cost of generation for coal and gas-fired power stations based on fuel cost and efficiency factoring in the cost of carbon.

Interconnectors

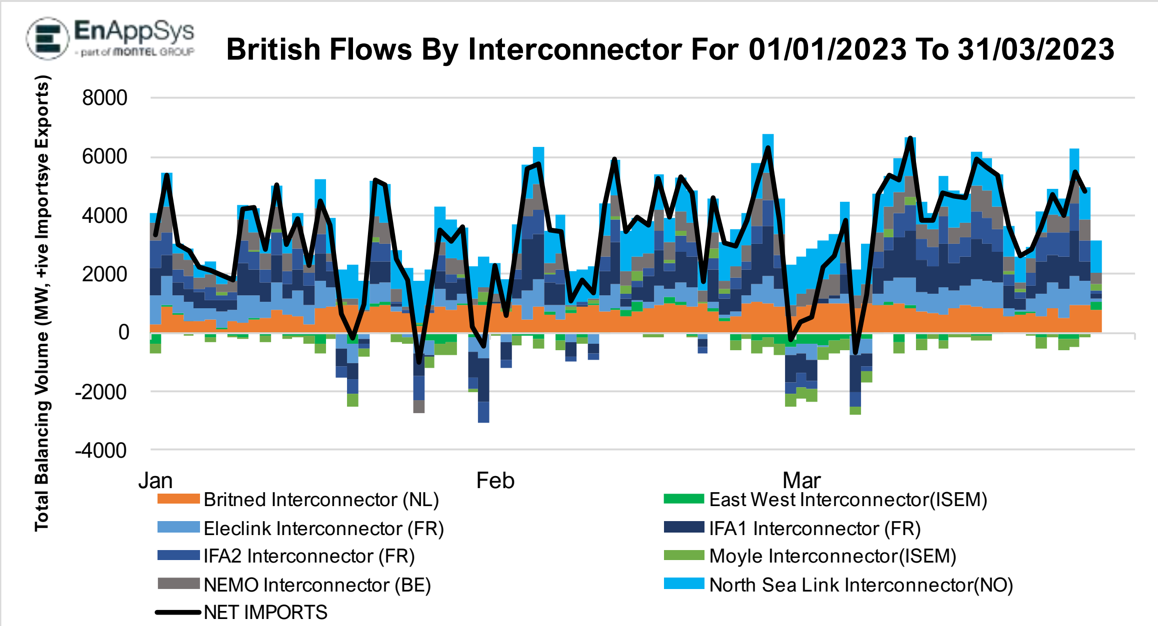

***Figure 5**: GB physical flows by country for Q1 2023*

Following three consecutive quarters in which GB had been a net exporter of power, this quarter GB returned to a more historically typical position of being a net importer. Having exported a net of 1.20TWh in Q4 2022, a net import of 7.25TWh was seen in Q1 2023. France was the biggest contributor to this flip, swinging from importing 2.45TWh in Q4 2022 from GB to exporting 2.79TWh to GB in Q1 2023. This flip occurred despite the delays in the French nuclear fleets return to service, illustrating the extent to which reduced demand has had an impact on French and other European power markets.

A total volume of 2.27TWh was exported out of the country, less than a quarter of what had been exported in the previous quarter. Over 51% of export volumes went to France. These volumes were primarily seen during periods in which nuclear availability in France dipped alongside renewable outturn, and margins dropped to levels sufficiently low to justify power imports from GB. The imports from GB on one of these days, Tuesday 7th March, resulted in very high system imbalance prices in GB that reached as high as £250/MWh on a daily average as margins dipped beneath 7GW.

Appendix: Supporting Tables

The tables below shows key statistics on generation in the quarter and all previous quarters over the last two years. Biomass and hydro values for the reporting quarter contain estimates for the embedded portion of the fleet, based on the same quarter last year as this data is published at a lag of ~3 months by BEIS[4]. Note that all percentages are given as a percentage of total generation including imports.

Table 1: Quarterly generation summary Q1 2023 (TWh)

*GB Only (Excludes Northern Ireland)	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Q1 2023
TOTAL GENERATION BY FUEL (TWh)									
Coal	2.05	0.55	1.15	1.23	1.88	0.33	1.12	0.94	0.93
Gas	28.42	27.10	25.36	26.57	24.63	28.70	30.63	27.38	23.46
Imports	6.44	6.09	7.74	4.62	5.23	-3.64	-4.59	-1.20	7.25
Nuclear	10.85	10.79	10.09	11.66	11.74	12.14	10.17	10.64	9.21
Biomass	7.65	7.04	6.32	7.71	7.02	5.39	6.32	5.73	6.08
Wind	19.25	11.48	10.41	21.29	23.27	15.91	13.46	24.82	23.98
Solar	1.69	4.53	3.75	1.25	1.98	4.46	4.25	1.43	1.69
Hydro	1.71	1.10	0.63	2.05	1.93	1.03	0.74	1.94	1.84
RENEWABLES (Biomass, Wind, Solar & Hydro)	30.30	24.16	21.11	32.30	34.20	26.79	24.77	33.92	33.61
NON-DISPATCHABLE RENEWABLES (Wind, Solar & Hydro)	22.65	17.12	14.79	24.59	27.18	21.40	18.45	28.19	27.52
FOSSIL FUELS (Gas & Coal)	30.46	27.65	26.51	27.80	26.51	29.04	31.76	28.31	24.39
TOTAL GB GENERATION (excl. Imports)	71.61	62.60	57.72	71.76	72.46	67.96	66.69	72.87	67.21
TOTAL GB CONSUMPTION (incl. Imports)	**78.05**	**68.69**	**65.45**	**76.38**	**77.69**	**64.32**	**62.10**	**71.67**	**74.46**
Fossil Fuel Percentage	39%	40%	41%	36%	34%	45%	51%	40%	33%
Clean Percentage (Renewable & Nuclear)	53%	51%	48%	58%	59%	61%	56%	62%	58%
Renewable Share of Clean Power	74%	69%	68%	73%	74%	69%	71%	76%	78%
SHARE OF GENERATION (%)									
Coal	2.6%	0.8%	1.8%	1.6%	2.4%	0.5%	1.8%	1.3%	1.2%
Gas	36.4%	39.5%	38.7%	34.8%	31.7%	44.6%	49.3%	38.2%	31.5%
Imports	8.2%	8.9%	11.8%	6.0%	6.7%	-5.7%	-7.4%	-1.7%	9.7%
Nuclear	13.9%	15.7%	15.4%	15.3%	15.1%	18.9%	16.4%	14.8%	12.4%
Renewables (Biomass, Wind, Solar & Hydro)	38.8%	35.2%	32.3%	42.3%	44.0%	41.6%	39.9%	47.3%	45.1%

Table 2: Year-on-year comparison of Q1 generation output (TWh and %)

*GB Only (Excludes Northern Ireland)	Q1 2015	Q1 2016	Q1 2017	Q1 2018	Q1 2019	Q1 2020	Q1 2021	Q1 2022	Q1 2023
TOTAL GENERATION BY FUEL (TWh)									
Coal	28.70	13.55	9.67	8.12	2.84	2.92	2.05	1.88	0.93
Gas	19.66	29.63	33.27	32.65	32.18	23.15	28.42	24.63	23.46
Imports	4.69	5.92	3.18	5.36	6.24	5.80	6.44	5.23	7.25
Nuclear	16.91	15.97	16.46	15.53	13.05	12.17	10.85	11.74	9.21
RENEWABLES (Biomass, Wind, Solar & Hydro)	15.14	14.89	18.29	24.65	26.98	34.79	30.30	34.20	33.61
FOSSIL FUELS	48.36	43.18	42.95	40.77	35.02	26.07	30.46	26.51	24.39
TOTAL GB GENERATION (excl. Imports)	80.40	74.03	77.70	80.96	75.06	73.03	71.61	72.46	67.21
TOTAL GB CONSUMPTION (incl. Imports)	**85.09**	**79.95**	**80.88**	**86.31**	**81.29**	**78.83**	**78.05**	**77.69**	**74.46**
Fossil Fuel Percentage	57%	54%	53%	47%	43%	33%	39%	34%	33%
Clean Percentage	38%	39%	43%	47%	49%	60%	53%	59%	58%
Renewable Share of Clean Power	18%	19%	23%	29%	33%	44%	39%	44%	45%
SHARE OF GENERATION (%)									
Coal	33.7%	16.9%	12.0%	9.4%	3.5%	3.7%	2.6%	2.4%	1.2%
Gas	23.1%	37.1%	41.1%	37.8%	39.6%	29.4%	36.4%	31.7%	31.5%
Imports	5.5%	7.4%	3.9%	6.2%	7.7%	7.4%	8.2%	6.7%	9.7%
Nuclear	19.9%	20.0%	20.4%	18.0%	16.1%	15.4%	13.9%	15.1%	12.4%
RENEWABLES (Biomass, Wind, Solar & Hydro)	17.8%	18.6%	22.6%	28.6%	33.2%	44.1%	38.8%	44.0%	45.1%

[4] https://www.gov.uk/government/statistics/energy-trends-section-6-renewables/Renewables obligation: certificates and generation (monthly - Excel)

Table 3 below shows key statistics on pricing in the quarter and all previous quarters over the last two years. The wholesale and within-day prices shown are averages across the quarter, whilst the system prices are given with minimum, average and maximum values[5]. Note that the values for domestic demand in Table 3 does not include interconnector demand.

Table 3 Quarterly price summary Q1 2021 to Q1 2023

*GB Only (Excludes Northern Ireland)	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Q1 2023
WHOLESALE PRICES (£/MWh)									
EPEX Day-Ahead Price	63.67	72.20	128.59	205.27	200.80	155.32	294.75	171.15	127.62
Nordpool Day-Ahead price	63.67	72.20	128.59	205.27	200.80	153.40	294.79	168.79	127.42
Within Day Price (MIDP)	59.62	71.80	125.19	191.25	194.30	149.28	282.00	165.86	128.27
WITHIN DAY PRICE BREAKDOWN (£/MWh)									
Off-Peak Hours	46.19	62.71	100.21	156.55	165.99	136.51	249.17	135.38	109.65
Peak Hours (excl Superpeak)	58.89	75.06	129.48	195.78	196.87	152.53	286.26	172.22	130.08
Superpeak Hours	93.27	81.01	166.34	254.87	249.86	166.86	334.87	207.91	160.07
SYSTEM PRICE (£/MWh)									
Maximum	4000.00	1971.59	4037.80	3916.28	4035.98	494.23	890.00	1650.00	1950.00
Average	62.04	74.85	126.14	188.62	197.64	152.31	276.40	173.31	132.61
Minimum	-61.00	-59.95	-66.73	-70.97	-90.32	-69.49	-68.53	-78.00	-91.86
Domestic Demand (MW average)	30,593	26,323	25,258	30,075	30,738	24,224	23,572	27,884	29,696
Domestic Demand incl. Embedded Gen (MW average)	33,148	29,719	28,023	32,630	33,968	27,866	26,782	30,571	32,532
Domestic Demand (TWh total)	66.1	57.5	55.8	66.4	66.4	52.9	52.0	61.6	64.1
Domestic Demand Incl. Embedded Gen. (TWh total)	71.6	64.9	61.9	72.0	73.4	60.9	59.1	67.5	70.3

Table 4: Year-on-year comparison of Q1 prices

*GB Only (Excludes Northern Ireland)	Q1 2015	Q1 2016	Q1 2017	Q1 2018	Q1 2019	Q1 2020	Q1 2021	Q1 2022	Q1 2023
WHOLESALE PRICES (£/MWh)									
EPEX Day-Ahead Price	40.84	34.63	47.96	52.72	51.83	32.70	63.67	200.80	127.62
Nordpool Day-Ahead price	40.84	34.63	47.96	52.72	51.83	32.70	63.67	200.80	127.42
Within Day Price (MIDP)	40.47	34.25	47.23	54.16	50.39	30.95	59.62	194.30	128.27
WITHIN DAY PRICE BREAKDOWN (£/MWh)									
Off-Peak Hours	33.62	28.62	40.53	47.28	44.39	24.42	46.19	165.99	109.65
Peak Hours (excl Superpeak)	41.09	33.89	47.14	54.62	50.88	32.08	58.89	196.87	130.08
Superpeak Hours	53.91	48.26	62.85	68.24	62.35	41.95	93.27	249.86	160.07
SYSTEM PRICE (£/MWh)									
Maximum	173.71	517.55	292.55	990.00	195.00	2242.31	4000.00	4035.98	1950.00
Average	46.46	36.66	46.34	57.41	50.63	32.30	62.04	197.64	132.61
Minimum	3.65	-63.02	-14.00	-150.00	-70.24	-66.25	-61.00	-90.32	-91.86
Domestic Demand (MW average)	37,109	35,335	34,613	35,203	32,936	31,343	30,593	30,738	29,696
Domestic Demand incl. Embedded Gen (MW average)	38,836	37,214	36,786	37,725	35,493	34,280	33,148	33,968	32,532
Domestic Demand (TWh total)	80.2	76.3	74.8	76.0	71.1	67.7	66.1	66.4	64.1
Domestic Demand Incl. Embedded Gen. (TWh total)	83.9	80.4	79.5	81.5	76.7	74.0	71.6	73.4	70.3

[5] Peak is 08:00 – 16:00 and 19:30 – 00:00; Super Peak is 16:00 – 19:30; Off-Peak is 00:00 – 08:00.

2 Notes on the Report

The figures used in the report refer to GB only, unlike those reported by BEIS that refer to GB and Northern Ireland. This selection has been made since the Northern Ireland electricity market is separate from the GB electricity market and is part of the Ireland all-island I-SEM market.

Generation levels by fuel from 2009 onwards are based upon National Grid fuel mix data published by Elexon as the BMRS FUELHH data, which give the operationally metered totals by fuel, down to a 5-minute resolution.

Prior to 2009, individual plant data has been aggregated from our database matching the National Grid fuel-type relationships.

To account for embedded wind and solar, the National Grid forecasts for these generators have been used as if they were output figures. Embedded hydro and biomass have been accounted for using analysis of Ofgem data on certificate awards. This embedded hydro and biomass data is published at a lag of approximately three months, so the reporting quarter will not have actual data for this section of these two fleets, instead values are estimated from the respective quarter the previous year.

Within this report, levels of offshore wind have not been separated from the wind total. This is because this can only be reliably done using metered volumes at a generating unit level. This is not a publicly available data stream and figures can only be estimated. Final Physical Notifications (FPNs) at wind farms do not correlate well with metered volumes and so cannot be used reliably.

Price and demand data primarily come from Elexon (as does the FUELHH data), with the exception of the EPEX day-ahead prices.

Availability levels are calculated by totalling levels of recorded availability at all plants in the market.

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This report has been created using our pan-European ***market data platform****, which has flexible configurable screens and automated data feeds. If you would like to gain more detailed information and insight, please contact us to arrange trial access to the platform via: sales@enappsys.com*

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