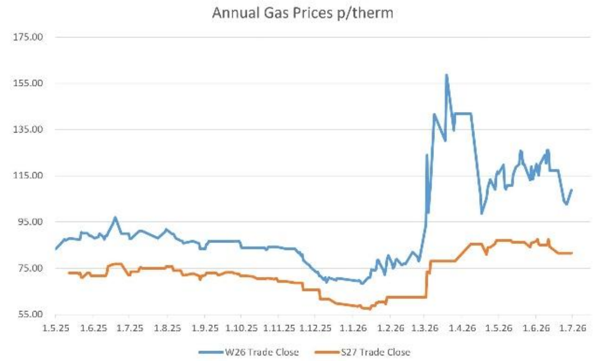
Catalyst
Digital Energy

Digital Energy Element

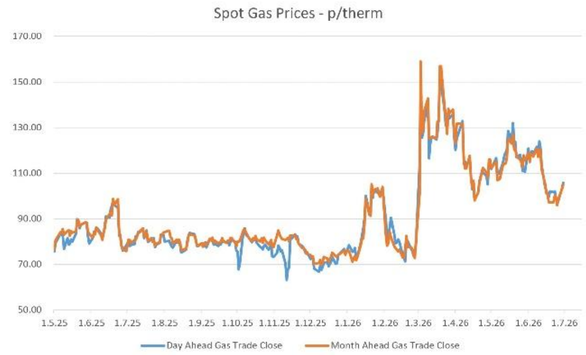
July 2026

Volatile Markets

Annual gas prices

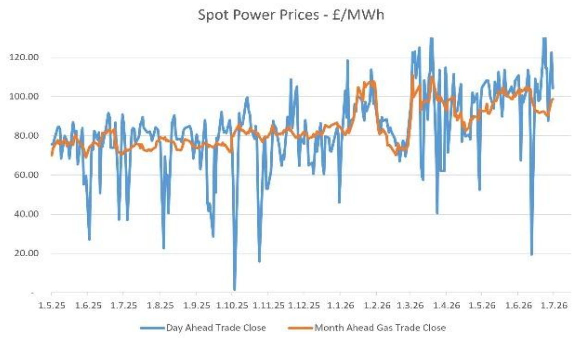


Spot gas prices



Annual power prices

Spot power prices



A month of two halves, June opened with a sharp rally on Middle East risk and Norwegian supply cuts, then handed most of it back as a ceasefire took hold, leaving wholesale gas and power lower over the month but firming again into the close.

June was, in truth, two very different markets stitched together. The first fortnight was all about risk. The second was all about relief. By the time the month closed, both gas and power sat below where they started, but anyone who only glanced at the start and end points would have missed one of the more volatile months we have seen this year.

We came into June with the near curve already carrying a heavy geopolitical premium. The escalation in the Middle East that had been building since late spring came to a head in the first week, with missile exchanges in the Gulf and strikes on Iranian infrastructure, and the market priced it accordingly. NBP day-ahead opened the month around 118p per therm and pushed up to roughly 122p by the 9th, its highest point of June. Norwegian supply made the picture worse rather than better. Planned maintenance on the Troll field, followed by unplanned outages at Aasta Hansteen and Oseberg, pulled pipeline nominations down toward 280 mcm per day at one stage, and with European storage sitting at only about 40% against a more usual 55 to 60% for early June, there was very little slack in the system. Front-month gas was up around 13% over a rolling thirty days at the peak.

The turn, when it came, was just as quick. A framework agreement between the United States and Iran from the middle of the month drained the war premium out of the curve almost as fast as it had gone in. By the 18th and 19th, the day-ahead had fallen back below 100p, down more than 12% on the week, helped along by warmer weather, healthier wind output and a wave of hedge selling. The slide carried on into the final week, with day-ahead touching the high 90s around the 26th as the Strait of Hormuz returned to normal traffic and LNG shipping confidence recovered. All told, prompt gas gave back close to a fifth of its value from the mid-month high. The month did not quite end on its lows, though. Falling wind and some nerves over how durable the ceasefire really is lifted the day-ahead back toward 105p in the last few sessions.

What stands out for buyers is how differently the back of the curve behaved. While the prompt was swinging by 20p or more, the annual contracts barely flinched. Cal-27 spent the whole month in a tight band between roughly 85p and 95p, and even at the height of the panic it traded a clear 25 to 30p below the front. That backwardation, with longer-dated gas priced well under prompt, held firm throughout and tells you the market still expects fundamentals to ease once this winter is behind us. The relief in June was very much a near-term story, not a structural reset.

Power tracked gas closely all month, which is no surprise given how much of the despatch stack gas-fired plant has been covering. Day-ahead baseload started June up around £114 per MWh and softened through the month in step with the gas sell-off. The more interesting feature came early on, when an unusual structure appeared in the curve: forward contracts for July and Winter-26 were briefly trading above the day-ahead, the opposite of the usual shape. That was down to a run of nuclear outages and stubbornly low wind generation, which left the forward market pricing in tightness that the prompt, for once, was not.

Forward power eased alongside gas as the premium unwound, but as with gas the longer-dated contracts were far stickier than the front. Summer-27 and Cal-27 power held well below prompt levels throughout, mirroring the gas backwardation and reflecting the same view that the system should be less stressed twelve months out. The month closed firmer, with power lifting again in the final sessions as wind dropped away.

Commodities

- Carbon: EU Emissions Trading Scheme carbon is quoted as over-the-counter (OTC) latest opening prices. All carbon prices are in euros per tonne (€/EUA).
- Coal: Coal is quoted as OTC latest opening prices. All coal prices are in US dollars per tonne ($/t).
- Electricity: UK power base-load and peak-load are quoted as OTC latest opening prices. All UK electricity prices are in pounds per megawatt hour (£/MWh).
- Gas: UK National Balancing Point (NBP) gas is quoted as OTC latest opening prices. All UK gas prices are in pence per therm (p/th).
- Oil: Brent crude oil is quoted as OTC latest opening prices. All Brent crude oil prices are in US dollars per barrel ($/bl).

Language/ terms

- Bearish: A bearish market shows a general decline in prices over a period of time.
- Bullish: A bullish market shows a general increase in prices over a period of time.
- Curve: A graph of forward prices over a future time period.
- Margin: The indicated UK imbalance of a given settlement period. It is the difference between the sum of the indicated generation available, and the national demand forecast made by National Grid.
- Over-the-counter (OTC): The trade of a commodity directly between two parties, often on standardised terms.
- Spark/ Dark spread: The theoretical net income of a gas/ coal-fired power plant from selling electricity having purchased the necessary fuel. The clean spark/ dark spread is this net income adjusted for the cost of carbon.

Disclaimer

Catalyst
Digital Energy

As an Award-Winning Digital Energy Consultant our job is to put you back in control of your utilities

Our Energy Spend Management platform powered by Robotic Process Automation - EaaSi® sits at the heart of our journey to transform how you manage, reduce, contract and report on your utilities.

Visit www.EaaSi.co.uk

EaaSi

EaaSi® is a registered trade marked product of Catalyst Digital Energy
www.catalyst-commercial.co.uk

Oil and gas tumble as the Strait of Hormuz crisis eases

The defining feature of June was the unwinding of the geopolitical premium that had driven energy prices higher through the spring. After months in which the conflict around the Strait of Hormuz kept oil and gas elevated, a United States brokered ceasefire between Israel and Iran took hold in the middle of the month, and the risk premium that had been built into prices began to drain out of global markets at speed.

The scale of the move was striking. Brent crude, which had crossed 100 dollars a barrel in March and peaked at around 126 dollars, fell back below 80 dollars by mid-June, its lowest level since the early days of the crisis. West Texas Intermediate followed it down. European gas prices eased in sympathy, with the continental TTF benchmark and the UK NBP both giving back a large part of the gains they had made in the first week of the month. By one measure, global oil had fallen around 20 per cent from its 2026 high.

For UK buyers, the transmission mechanism is worth keeping in mind, because none of this oil or gas actually flows through the Strait of Hormuz on its way to Britain.

The UK is affected through sentiment and through the global market for liquefied natural gas. When traders fear that shipping through the Strait could be disrupted, they price in the risk to a fifth of the world's seaborne oil and a significant share of global LNG, and that risk premium shows up in the contracts UK suppliers buy. When the fear recedes, as it did in June, the premium comes back out just as quickly.

The relief was not entirely smooth. Reports on the durability of the ceasefire were mixed, with Israeli strikes continuing in southern Lebanon and Iran at one point indicating it would close the Strait again in response.

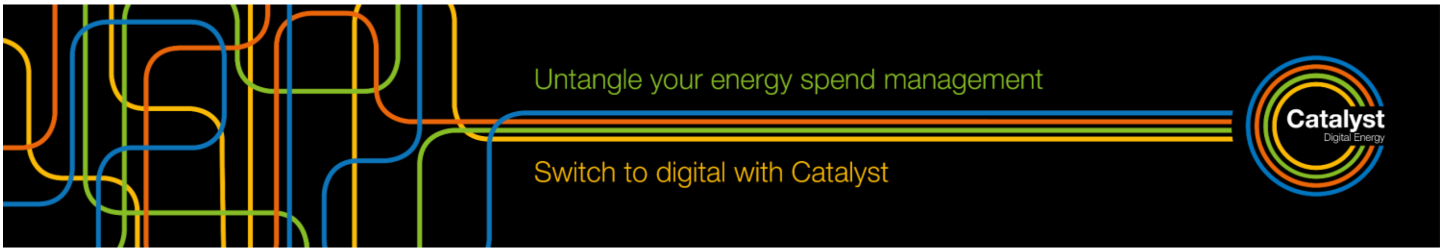
The reopening of the waterway to normal traffic, and the repair timelines for damaged regional infrastructure, remained uncertain through the month. Markets stayed nervous even as they fell, which is why the decline came in steps rather than in a straight line.

There was a supportive backdrop on the supply side as well. OPEC and its partners had been adding barrels back to the market through the spring, and the departure of the United Arab Emirates from the group earlier in the year had raised the prospect of looser production discipline. With demand growth subdued and the immediate threat to supply receding, the conditions were in place for a sharp correction once the geopolitical fear began to fade.

The effect on UK wholesale prices was clear in our daily reporting through the month. NBP day-ahead gas, which had pushed up toward 122 pence per therm in the first week of June on the combination of Middle East risk and Norwegian supply outages, fell back below 100 pence by the second half of the month as the ceasefire held and warmer weather trimmed demand.

Day-ahead power eased alongside it. The forward curve also softened, although the longer-dated contracts gave up far less ground than the prompt, a sign that the market viewed the relief as a near-term reprieve rather than a structural change in the cost of energy.

For businesses, the episode is a reminder of just how exposed UK energy prices remain to events thousands of miles away. The country has reduced its own gas production and storage over the years and leans heavily on imported LNG and Norwegian pipeline gas, which leaves wholesale prices sensitive to anything that



threatens global supply routes. The sharp fall in June was welcome, but the speed of the earlier rise is the more important lesson. For anyone approaching a renewal, it makes the case for watching the market continuously and being ready to move when a window opens, rather than assuming that calm conditions will last.

Al Jazeera

October price cap: relief in prospect, but bills stay high for winter

The household energy price cap rose by 13 per cent on 1 July, taking the typical dual-fuel bill to 1,862 pounds a year, the increase Ofgem confirmed in late May. The rise was driven almost entirely by gas, with gas bills going up by around 24 per cent while electricity rose by closer to 5 per cent, a split that reflects how much of the cost pressure has come from the wholesale gas market during the spring crisis.

It is worth remembering how the cap actually works. Ofgem sets it every quarter based on a basket of costs, the largest of which is the wholesale price of energy bought months in advance, alongside network costs, policy levies and a supplier margin. Because the wholesale element is averaged over an observation window, the cap tends to lag the live market, which is why the sharp fall in prices during June will take time to feed through fully into the figures households and businesses eventually see.

Attention has now turned to the October cap, which covers the first quarter of winter and which Ofgem will confirm by 26 August. The early signals from June are more encouraging than they were a few weeks ago. Cornwall Insight, the analyst house whose forecasts the industry watches closely, said during the month that the October cap now looks set to be broadly flat to slightly lower than the July level.

The improvement is largely down to the easing in wholesale gas prices that followed the United States and Iran ceasefire, which has taken some of the heat out of the market after a volatile spring. Under Ofgem's updated definition of typical consumption, the headline figure for October is estimated to land at around 1,654 pounds.

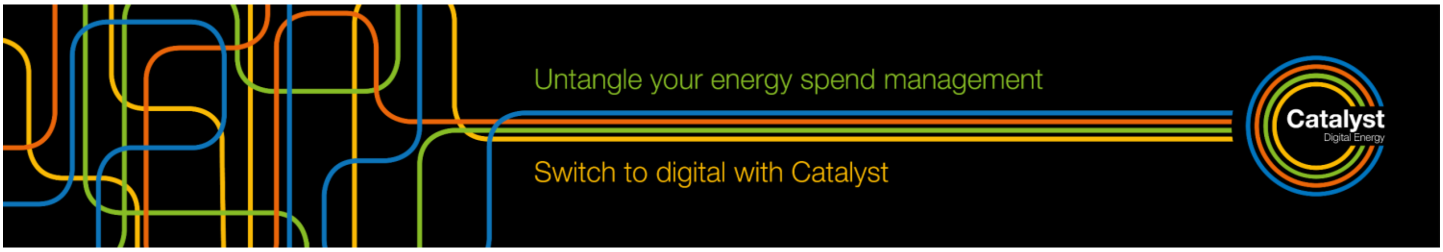
The forecasters were careful to temper the optimism. The reopening of the Strait of Hormuz to normal shipping is not yet certain, peace talks have been patchy, and the repair timelines for damaged infrastructure in the region remain unclear.

Prices are lower than they were at the height of the crisis, but they are still high by historical standards and remain vulnerable to any fresh escalation. A forecast made in June can change a great deal before the figures are locked in at the end of August.

There is also a seasonal sting in the timing. The higher prices that took effect in July will be cushioned for most households by warm weather and low heating demand. The October cap, by contrast, lands just as people turn their heating back on, which means it will have a much greater impact on what families actually pay over the coldest months of the year.

The price cap is a household instrument and does not regulate commercial contracts, so it does not set the rate any business pays. It remains, however, a useful barometer of where the wider market is heading, because it is recalculated from the same wholesale prices that feed business quotes. The fall in wholesale

---



costs through June should begin to show up in commercial renewal offers over the coming weeks, though with the usual lag and with the caveat that suppliers price in their own risk premiums. For businesses coming up to renewal, the easing market is an opportunity worth testing rather than a reason to assume prices will keep falling. The right time to fix is when the curve offers value relative to your own appetite for risk, not when a headline number happens to fall.

Cornwall Insight

Sizewell C clears its financing landmark as the nuclear programme gathers pace

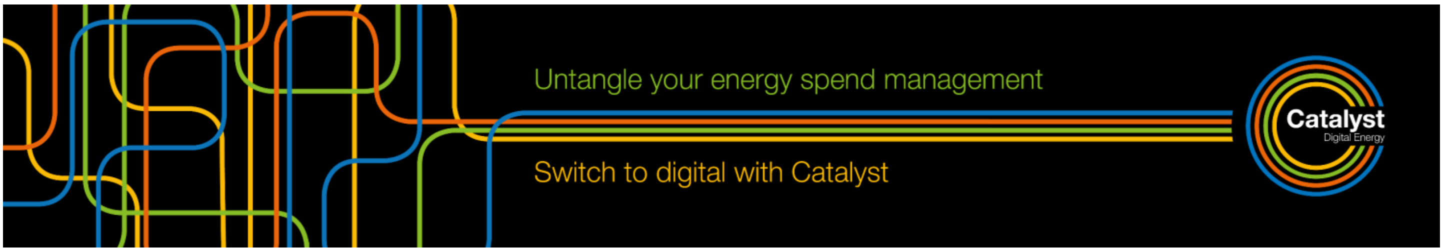
The UK's nuclear ambitions took a significant step forward in June as the Sizewell C project in Suffolk moved through a key financing milestone, clearing the way for a final investment decision on what the government has called the biggest British clean energy project in a generation. The plant is expected to cost in the region of 38 billion pounds and, once running, to generate around 3.2 gigawatts of low-carbon electricity, enough to power the equivalent of roughly six million homes for some sixty years.

The ownership structure for the project has taken shape around a government stake of 44.9 per cent, with the Canadian investor La Caisse holding 20 per cent, Centrica 15 per cent, EDF 12.5 per cent and Amber Infrastructure 7.6 per cent. The government's own commitment sits alongside the 14.2 billion pounds of capital it allocated to the project across the current spending review period, which runs from 2026 to 2030. That public backing is what has given private investors the confidence to commit.

The context for all of this is an ageing fleet. Most of the UK's existing nuclear stations are due to retire over the next decade, leaving only Sizewell B and, when it finally arrives, Hinkley Point C in operation. Without new build, the country would lose a large block of reliable, weather-independent, low-carbon generation at exactly the moment it is trying to electrify heat and transport. Sizewell C is intended to fill part of that gap, and the government has framed it as central to its energy security and net zero objectives.

Hinkley Point C also serves as a cautionary tale. That project has run years behind schedule and billions over its original budget, which has shaped both the financing model and the political handling of Sizewell C. The funding model matters for the way the plant is eventually paid for. Sizewell C is being financed through a regulated asset base arrangement, under which consumers contribute to the construction cost through a small charge on bills during the build, in exchange for lower financing costs over the life of the plant. Supporters argue this brings down the overall cost compared with the Hinkley approach. Critics point out that it asks billpayers to take on some of the construction risk before a single unit of electricity has been produced.

The Sizewell news came in the same month that the government rebranded its nuclear delivery body, with Great British Nuclear becoming Great British Energy, Nuclear, folding the nuclear programme more closely into the wider publicly owned energy company. The renamed organisation carries responsibility not only for large reactors such as Sizewell but also for the small modular reactor programme, where Rolls-Royce SMR has been selected as the preferred bidder to build the country's first fleet of factory-built reactors. The hope is that smaller, standardised reactors can be delivered faster and more cheaply than the giant projects that have defined the sector so far.



For business energy buyers, the practical implications are long term rather than immediate. None of this new capacity will be on the grid for years, and Sizewell C in particular is a project measured in decades. What it does signal is the direction of travel. The government is betting heavily on firm, low-carbon baseload to sit alongside the rapid build-out of wind and solar, in the hope of reducing the country's exposure to volatile gas prices over time. The cost of that programme will be spread across bills and taxes for many years, which is a consideration for anyone trying to understand where the non-commodity element of their energy costs is heading.

In the nearer term, the value of nuclear is best understood by looking at months like June, when low wind output pushed gas-fired plant back to the top of the despatch stack and dragged power prices up with it. A larger fleet of reliable, weather-independent generation is precisely what the system needs to reduce that sensitivity, and it is the gap that Sizewell C and the SMR programme are intended to fill.

World Nuclear News

NESO starts clearing the grid connection queue

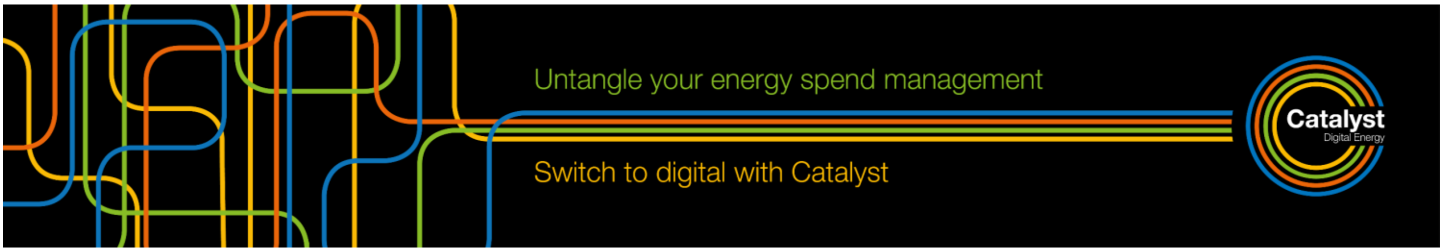
One of the quieter but more consequential developments of recent months has been the overhaul of how new projects connect to the electricity grid, led by the National Energy System Operator. For years the connections process has been a major bottleneck, with hundreds of gigawatts of proposed wind, solar, battery and demand projects stuck in a queue on a first-come, first-served basis, regardless of how ready any individual scheme actually was to be built.

At its worst the queue had stretched to hundreds of gigawatts, several times the capacity Britain will actually need to reach its 2030 goals, with some applicants quoted connection dates more than a decade into the future. That gridlock had become one of the most frequently cited barriers to investment in new clean energy.

The scale of the problem had become absurd. The connection queue had swollen to many times the capacity the country actually needs, clogged with speculative projects that had secured a place in line years earlier and a connection date sometimes well into the 2030s. Genuine, shovel-ready schemes found themselves stuck behind projects that might never be built, which slowed the entire clean power programme and deterred investment.

NESO has now begun implementing what it describes as the biggest reform of the connections process to date. The central change is a move away from the old queue toward a system that prioritises projects which are ready to proceed and which align with the strategic needs of the network. Schemes that are little more than a line on a map can no longer hold up those that are ready to build, and the connections pipeline has been re-ordered accordingly under a principle that could be summarised as first ready, first connected.

The numbers attached to the reform are substantial. NESO estimates the changes could unlock in the region of 40 billion pounds of investment a year and help clear a backlog that has been one of the single biggest obstacles to the government's Clean Power 2030 mission. The next iteration of the transitional centralised strategic network plan, which sets out where the grid needs to be reinforced, was also due from NESO during June, giving developers a clearer picture of where capacity will be available.



The reform is being delivered in gates and phases through 2026, with the first tranche of distribution-level offers expected to run from the summer into the autumn. It is a complex process and not without its critics, particularly among developers who fear their projects could be deprioritised or pushed down the revised pipeline, but the broad direction has been welcomed across the industry as a necessary step. There is also a growing strand of work on connecting large new sources of demand, such as data centres and electrified industrial sites, which place their own pressures on the network.

For businesses, the grid is easy to overlook until it gets in the way. The connection queue has been holding back not just large generation projects but also the kind of infrastructure that companies increasingly want to build, including on-site solar, battery storage, private wire arrangements and high-capacity connections for electric vehicle depots and new facilities. A faster, more rational connections process should, over time, make it easier and quicker to electrify operations and to bring on-site generation online. It also matters indirectly, because the sooner cheap renewable capacity can connect, the sooner it can start putting downward pressure on wholesale prices.

National Energy System Operator

Centrica reopens and expands Rough to shore up winter gas security

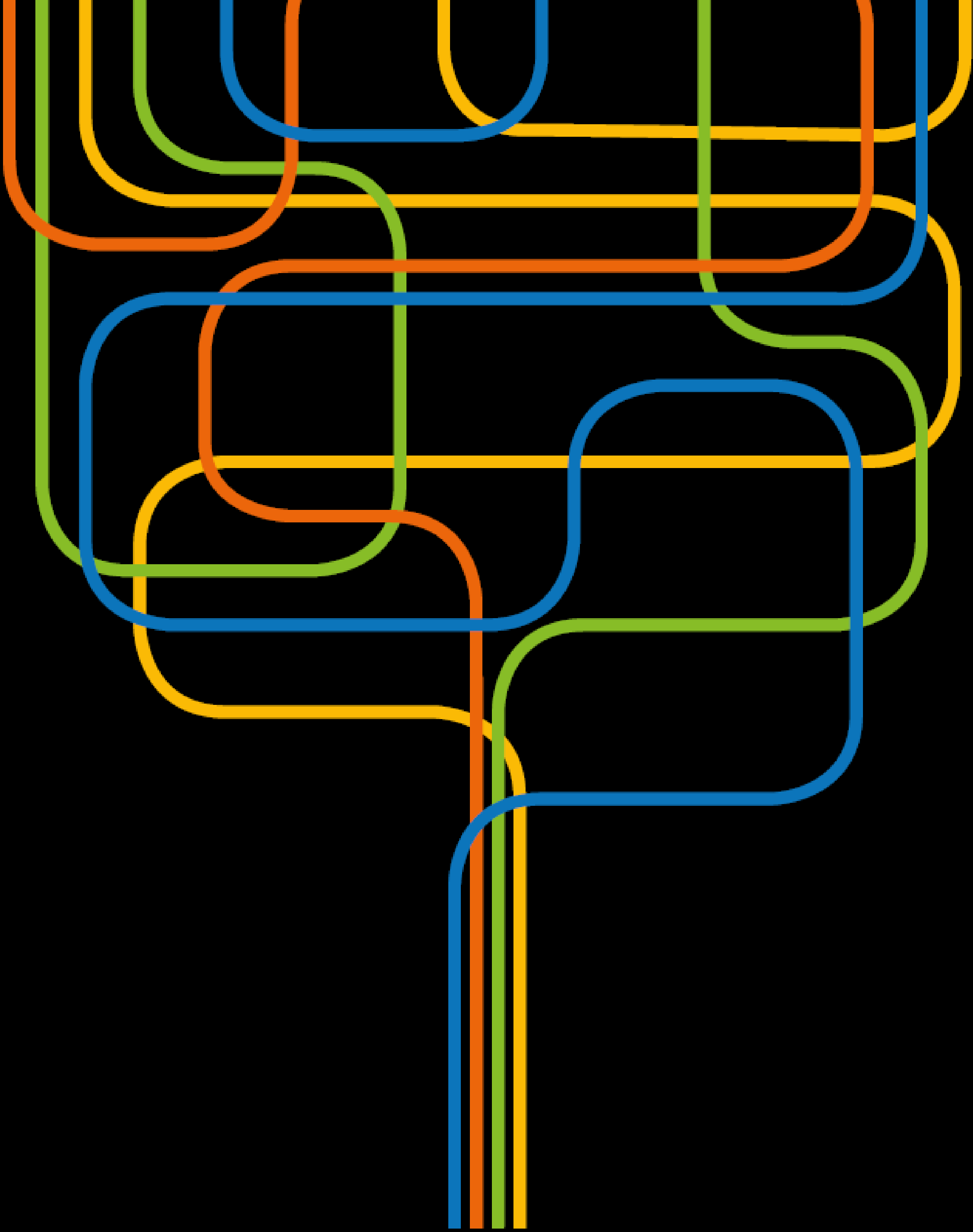
The UK's gas storage position has been a recurring theme in our market reporting, and June brought a welcome development on that front. Centrica confirmed the continued operation and expansion of the Rough facility off the Yorkshire coast, the country's largest gas store, lifting its capacity by around half ahead of next winter to roughly 54 billion cubic feet. That is enough gas to heat the equivalent of about 2.4 million homes over the winter, and it represents around half of the UK's total storage capacity on its own.

By way of comparison, large European economies typically hold enough gas in store to cover a substantial share of winter demand, whereas the UK has historically kept only a few days' worth. That structural thinness is why the live flow picture, from Norway and from the LNG terminals, matters so much to British prices, and why rebuilding storage has become a priority for policymakers worried about security of supply.

Rough has a chequered recent history. The facility was closed in 2017 on commercial grounds, a decision that drew heavy criticism when the energy crisis arrived and left Britain with strikingly little gas in store compared with its European neighbours. Centrica reopened it in a reduced form in 2022, and the latest expansion continues the rebuilding of a strategic asset that many argued should never have been mothballed in the first place.

The context makes the expansion important. Britain has historically held far less gas in store than countries such as Germany, France and the Netherlands, which leaves it more dependent on the live supply picture, including Norwegian pipeline flows and LNG arrivals, and more exposed to short-term price spikes when supply tightens. The injection season this year began with European storage running well below normal levels, a point we flagged throughout June, so any addition to UK storage capacity is a useful buffer against a cold or disrupted winter.

Centrica has also set out a longer-term vision for the site. The company has said it is prepared to invest around 2 billion pounds in redeveloping Rough as one of Europe's largest hydrogen storage facilities, although



that ambition is conditional on agreeing a new regulatory model with the government. Discussions on that framework have been described as constructive but are not yet concluded.

The economics remain challenging in the meantime. Centrica has indicated that Rough is likely to run at a loss without a new support arrangement, which underlines the wider point that storage delivers a national security benefit that is not always captured by the commercial returns available to the operator. That tension between strategic value and commercial viability is precisely what the regulatory negotiations are trying to resolve, and it is a debate that will run well beyond this winter.

For business energy users, the relevance is straightforward. More storage means a bigger cushion against the kind of winter price spikes that hit hardest when supply is tight and demand is high. It does not change the day-to-day cost of energy, but it does reduce the tail risk that worries anyone with significant gas exposure heading into the colder months, and it is one of the few structural improvements to UK supply security that can be delivered quickly.

Solar Power Portal

Ofgem to regulate energy brokers: what tighter rules mean for business buyers

A development that deserves particular attention from business energy buyers is the government's confirmation that energy brokers, known formally as third-party intermediaries, are to be brought under direct regulation for the first time, with Ofgem appointed as the regulator. It is a long-awaited reform of a part of the market that has operated with relatively little oversight despite the influential role brokers play in helping businesses buy energy.

The case for reform has been building for years. The broker market is large and fragmented, ranging from established, professional advisers to a long tail of small operators, and the standard of conduct has varied enormously. The most common complaints have concerned hidden commissions baked into unit rates without the customer's knowledge, high-pressure selling, and contracts arranged in the broker's interest rather than the client's. Because intermediaries have sat outside Ofgem's direct reach, the tools available to tackle that behaviour have been limited.

Under the plans, the government intends to legislate for a hybrid authorisation model. This combines the flexibility of a general authorisation regime with a formal registration process, so that every intermediary arranging energy contracts would need to register with Ofgem and meet a fit and proper person standard in order to operate. Ofgem would gain powers to set clear principles and rules for broker conduct, to monitor and investigate practices, to order redress where customers have been harmed, and ultimately to fine or exclude firms that fail to comply.

The timetable runs in stages. Ofgem is expected to carry out a detailed market survey through the first half of 2026 to build a clearer picture of the structure of the broker market and where the risk of harm sits. Once the legislation is in place, existing intermediaries will have a transition period, described as a sunrise period of between twelve and eighteen months, before authorisation becomes mandatory. After that point, no broker will be able to operate without Ofgem's authorisation.

Some protections are already in force. Since late 2024, suppliers have only been permitted to work with brokers that are signed up to a recognised redress scheme, and any broker dealing with a micro-business has been required to disclose its commission in writing before a contract is signed. The new framework builds on those foundations and extends meaningful oversight across the wider market, including to the larger contracts that fall outside the micro-business rules.

At Catalyst we welcome this direction of travel. The overwhelming majority of the harm in this market has come from a small number of operators who hide their margins, pressure customers into unsuitable contracts or fail to act in the client's interest. Regulation that raises the standard for everyone, requires transparency on commission, and removes bad actors is good for reputable advisers and good for the businesses they serve. Transparent, fully disclosed fees and membership of a redress scheme have long been the way we work, and a regulated market simply makes that the baseline for all.

For buyers, the practical takeaway is to expect, and to insist on, greater clarity. When you appoint a broker, you are entitled to know how they are paid, what their commission is, and what redress is available if something goes wrong. The coming regulation will make those questions standard, but there is no reason to wait for the legislation before asking them. A good intermediary will answer them happily today, and the way a broker responds to those questions tells you most of what you need to know about whether they are working for you.

GOV.UK

Battery storage pipeline tops 60GW as the National Wealth Fund steps in

Battery storage continues to be one of the fastest-growing parts of the UK energy system, and the scale of what is now in the pipeline came into sharper focus in 2026. The country has around 7 gigawatts of operational battery capacity, roughly a fivefold increase on the position in 2020, with a further 6.5 gigawatts under construction and more than 60 gigawatts holding planning consent. The volume of approvals has been running at record levels.

Co-location is increasingly part of the picture too. Pairing a battery with a solar array or a wind farm allows a developer to store output when the network is congested and release it later, making better use of a single grid connection. For businesses with their own generation, the same logic applies behind the meter, where a battery can store cheap or self-generated power for use at expensive peak times.

The sector is not without its risks. Returns depend heavily on the spread between cheap and expensive periods, which can vary from year to year, and on how the various revenue streams evolve as more storage comes online and competition increases. Even so, the weight of capital flowing into the sector suggests investors remain confident that storage will be indispensable to a renewables-led grid.

The investment picture has been strengthened by the arrival of public money alongside private capital. The National Wealth Fund has joined private investors to launch a 500 million pound platform to build, own and operate grid-scale battery assets across the country, a signal that the government sees storage as central to delivering a reliable low-carbon grid. The Clean Power 2030 plan targets between 23 and 27 gigawatts of battery capacity by the end of the decade, which implies a steady pace of new additions every year.

Batteries earn their keep in several ways at once. They buy power when it is cheap and abundant and sell it when it is scarce and expensive, they provide fast-acting balancing services that help NESO keep the grid stable second by second, and they can earn payments through the Capacity Market for being available at times of system stress. As more wind and solar come onto the system, the value of being able to shift power across hours of the day only grows, and developers are increasingly building longer-duration systems that can store several hours of output rather than just minutes.

The main constraint is no longer appetite but the grid itself. A large share of the consented pipeline is still waiting on connection dates or network upgrades, which is exactly the problem the connections reform led by NESO is trying to address. Turning today's planning approvals into operational capacity depends heavily on clearing those bottlenecks.

For businesses, the growth of storage matters in two ways. At a system level, batteries that can soak up cheap power when wind and solar are plentiful and release it when they are not should, over time, smooth out the kind of price volatility we saw in June, when a few low-wind days pushed prices sharply higher. At a site level, falling battery costs and the revenues available from grid flexibility are making on-site storage a more realistic proposition for companies with the right load profile, particularly when paired with on-site generation or used to manage expensive peak-time demand charges.

[Energy Storage News]

Britain's wind fleet breaks records as gas hits a two-year low

For all the focus on geopolitics and gas prices through June, it is worth stepping back to note how far the generation mix has shifted. The first quarter of 2026 was a record breaker for wind, which produced 29.2 terawatt hours of electricity over the three months, the most ever recorded for a single quarter. Total renewable output reached 40.3 terawatt hours over the same period, up 20 per cent on the first quarter of 2025.

Solar has become an important contributor in its own right, lifting the renewable share through the lighter half of the year and complementing wind, which tends to be strongest in winter. Britain's growing fleet of interconnectors adds further flexibility, allowing the country to import power from neighbours when domestic generation is short and to export it when there is a surplus. These links also help to keep the system balanced when the weather turns, smoothing out swings in supply that the country would otherwise have to manage on its own.

For energy buyers, the implication runs deeper than the headlines about record days. A system increasingly shaped by the weather produces prices that swing more widely between cheap, windy periods and tight, still ones. That argues for procurement strategies that can take advantage of the low-price periods rather than simply locking in a single fixed rate. Increasingly, the question is not only what you pay per unit, but whether you can shift consumption toward the hours when power is cheapest and cleanest.

The single most striking moment came in late March, when wind generation hit a new half-hourly high of 23,880 megawatts. During that record period wind provided more than half of Britain's electricity, and gas-fired generation fell to its lowest level in nearly two years, supplying just 2.3 per cent of the mix. For a country that not long ago relied on gas for the bulk of its power, that is a remarkable figure, and it shows how quickly the picture can change when conditions are right.

That progress is being driven by a steady build-out of capacity, supported by growth in solar over the lighter months and by interconnectors that allow Britain to import and export power with its neighbours. On the best days, the combination pushes fossil generation to the margins and pulls wholesale prices down with it.

June, however, was a useful reminder that the picture is not one-directional. Several days of low wind output during the month pushed gas plant back to the top of the despatch stack and dragged power prices higher, particularly toward the end of the month. The grid remains highly sensitive to the weather, and on a still day gas still sets the price.

That is the central tension in the current market. When the wind blows, electricity is increasingly cheap and clean. When it does not, the system falls back on gas and prices respond accordingly. For businesses, the lesson is that the growth of renewables is steadily lowering the floor for power prices but has not yet removed the spikes, which is why flexibility, whether through contract structure, on-site generation or demand management, is becoming a more valuable tool than ever. The destination is clear, but the journey will continue to feature sharp moves in both directions.

RenewableUK

Record AR7 auction locks in 8.4GW of offshore wind

The results of the government's seventh contracts for difference allocation round, known as AR7, continued to shape the outlook for power prices through 2026. The auction secured a record 8.4 gigawatts of offshore wind, making it the largest offshore wind auction ever held in Europe. The total was made up of 8,245 megawatts of fixed-foundation projects and a further 192.5 megawatts of floating offshore wind, enough between them to power the equivalent of more than 12 million homes.

Beyond the headline capacity, the auction matters for the supply chain. Sustained, predictable rounds give manufacturers of turbines, cables and foundations the confidence to invest in UK ports and factories, which in turn supports skilled jobs and helps to anchor more of the economic benefit of the build-out at home rather than overseas.

The result was all the more significant given how the previous round had gone. An earlier auction had failed to attract a single offshore wind bid, after the government set the maximum price too low to cover the rising cost of building turbines in a period of high inflation and stretched supply chains. AR7 corrected that, and the strong turnout was read across the industry as a sign that confidence had returned.

The strike price agreed for offshore wind was 90.91 pounds per megawatt hour. That is higher than in some earlier rounds, which reflects the rise in financing and supply chain costs the sector has faced, but it still compares favourably with the alternatives. The average wholesale power price in the UK during 2025 was above 80 pounds per megawatt hour, and the estimated cost of running a new-build gas station is in the region of 147 pounds per megawatt hour. Set against those numbers, the auction looks like reasonable value for a long-term, fixed-price, low-carbon supply.

The contracts for difference mechanism is central to how this works. Developers bid for a guaranteed price for their output over a fifteen-year term. When wholesale prices fall below that level, the generator is topped up to the strike price. When wholesale prices rise above it, the generator pays the difference back. In a period of high and volatile gas prices, that second feature means well-priced renewable contracts can actually reduce the net cost passed through to consumers.

The strategic significance is that AR7 takes the government a long way toward its Clean Power 2030 target. With this round contracted, the remaining gap to the lower end of the government's offshore wind range is around 7 gigawatts, a much more manageable figure than the industry faced a year ago. The challenge now shifts to delivery, and in particular to building the turbines and grid connections on time.

For business buyers, the auction is a marker for the medium term rather than an immediate price event. The capacity contracted in AR7 will come online over the next several years, and as it does it should help to dilute the influence of gas on power prices and provide a more stable, domestically generated supply. It is one of the clearer reasons to expect the structural cost of electricity to ease as the decade progresses, even if the path there remains bumpy.

[GOV.UK]

British Industry Supercharger: 420 million pounds a year off industrial bills

For the most energy-intensive businesses, one of the more material policy developments of 2026 has been the strengthening of the British Industry Supercharger. From 1 April 2026 the government increased the level of relief offered through the Network Charging Compensation Scheme to 90 per cent, a change it expects to save around 500 of the country's most energy-intensive firms up to 420 million pounds a year on their electricity bills.

Eligibility is the crucial detail. The relief is targeted at businesses that are both highly electricity-intensive and exposed to international trade, the combination that puts them most at risk of losing out to overseas competitors with cheaper power. Firms that believe they may qualify need to apply and provide evidence, and those already receiving the relief should make sure they are getting the full 90 per cent now available rather than an older, lower rate.

The Supercharger is aimed squarely at heavy industry. Sectors such as steel, chemicals, cement, glass and paper, which together employ around 400,000 people, are the main beneficiaries, receiving a 90 per cent discount on the network charges that make up a significant part of an industrial electricity bill. For the most electricity-intensive manufacturers, the scheme can reduce costs by as much as 8 pence per kilowatt hour, which is a substantial saving on a large load.

It helps to understand what these charges are. A business electricity bill is made up of far more than the raw cost of the energy. Network charges, which pay for the wires and pipes that carry power to site, along with policy costs that fund renewable and social schemes, can together account for a large share of the total. For an energy-intensive manufacturer running around the clock, even a small reduction in those per-unit charges translates into a large absolute saving over a year.

The policy reflects a long-running concern that British industry pays more for electricity than competitors in Europe and elsewhere, a gap that has been blamed for undermining the competitiveness of energy-intensive manufacturing and, in some cases, contributing to plant closures. The Supercharger is the government's principal tool for narrowing that gap without intervening directly in the wholesale market.

There is more to come. The government has committed to refreshing the underlying eligibility data behind the scheme during 2026, which opens the door to reassessing which manufacturing sectors qualify based on up-to-date electricity and trade intensity. For businesses on the margins of eligibility, that review is worth watching, because it could bring additional sectors into scope.

The practical message for any energy-intensive business is to check whether it qualifies, either now or under the forthcoming eligibility refresh. The savings on offer are significant enough to change the economics of a site, and the relief is not always applied automatically. For companies that fall outside the scheme, the policy is still a useful signal of where government thinking is heading on industrial energy costs, and a reminder that network and policy charges, not just the commodity, are an area where real savings can often be found through careful contract and consumption management. Energy-intensive sites may also qualify for related support such as climate change agreements, which reduce other levies, so it is worth reviewing the full picture rather than any single scheme in isolation.

GOV.UK

North Sea windfall tax stays to 2030 as Rosebank decision looms

The future of North Sea oil and gas remained a live policy question through the first half of 2026, with two strands worth tracking for their effect on domestic energy supply. The first is the Energy Profits Levy, the windfall tax on North Sea producers, which the government has confirmed will remain in place at a headline rate of 38 per cent until 31 March 2030. The levy raised around 2.9 billion pounds in the 2024 to 2025 financial year.

Set against the industry's concerns, the levy has been a meaningful source of revenue for the Exchequer during a period of strained public finances, which is part of why successive governments have been reluctant to let it go early.

The tax was introduced in 2022 as a temporary measure to capture the exceptional profits producers were making during the energy crisis, and it has been extended and increased several times since. Industry bodies have continued to warn that the combination of a high headline rate and an uncertain investment climate is accelerating the decline of the basin, with several operators scaling back their programmes and some warning of a perilous downward spiral in activity. Their argument is that a faster-than-necessary fall in domestic production simply increases the country's reliance on imported gas and oil, which in turn ties UK prices more tightly to the global LNG market, the very exposure that drove prices higher during the spring crisis.

Critics of the industry counter that the basin is in natural decline regardless of the tax, that operators have a long history of using investment threats to lobby for better terms, and that the priority should be a managed transition to clean energy rather than propping up a maturing oil and gas province. There are also genuine energy security arguments on both sides of the debate, which is part of why it has proved so difficult to resolve.

The second strand is the question of new development. The government continues to honour existing licences while declining to issue new ones for exploration, in line with its manifesto position. The closely watched decisions on the Rosebank and Jackdaw fields, both of which were licensed under the previous government but delayed after a court ruled that regulators must take account of the emissions from burning the oil and gas produced, are expected to be resolved in the coming period. In late 2025 the government also set out plans for transitional energy certificates, intended to allow limited production from or near existing fields without amounting to new licences.

The balance the government is trying to strike is a difficult one. It wants to support the transition away from fossil fuels and meet its climate commitments, while avoiding an abrupt collapse in domestic production that would leave the country more dependent on imports and put the jobs and tax revenue of the sector at risk.

For business energy buyers, the relevance is indirect but real. The faster domestic gas production falls, the more the UK depends on imported LNG and Norwegian pipeline gas, and the more sensitive wholesale prices become to global events of the kind that dominated the spring. The North Sea debate is, at root, a debate about how exposed the country wants to be, and that exposure is ultimately reflected in the prices businesses pay.

JPT

Zonal pricing rejected: the shift to reformed national pricing

After a long and often heated debate, the question of how Great Britain prices its electricity has been settled, at least in its broad direction. The government has confirmed, through its Review of Electricity Market Arrangements, that it will not introduce zonal pricing and will instead retain a single national wholesale market, supported by a package of reforms it has badged as reformed national pricing.

The reform package is about more than the headline rejection of zonal pricing. It includes work on how the Capacity Market secures the back-up generation that keeps the lights on at times of system stress, on the contracts for difference scheme that underpins new renewables, and on the dispatch arrangements that decide which power stations run and when. Taken together, these are intended to make a system built around weather-dependent generation run more efficiently.

Zonal pricing would have split the country into regions, each with its own wholesale price reflecting local supply and demand. Supporters, including some of the larger generators and technology firms, argued it would send sharper signals about where to build generation and where power is genuinely needed, and could lower prices in areas such as Scotland that are rich in wind but short of the transmission capacity to move that power south.

Opponents, including much of the wider investment community and many renewable developers, warned it would create regional disparities, add complexity, and undermine confidence at a time when the country needs to attract enormous sums of capital into new generation and networks. Their concern was that splitting the market would raise the cost of capital for new projects, ultimately pushing up bills rather than reducing them, and that consumers in some regions could find themselves paying more simply because of where they happen to live.

In choosing to keep a single national market, the government has come down on the side of simplicity and investor certainty. Rather than using regional prices to guide where assets are built, it intends to lean on improved network charging signals and on the new Strategic Spatial Energy Plan, the first iteration of which is due during 2026, to steer development to the right places. A reformed national pricing delivery plan and a separate consultation on changes to the Capacity Market are expected to follow, turning the headline decision into detailed policy.

For business energy buyers, the decision removes a significant source of uncertainty. Had zonal pricing gone ahead, the cost of electricity could in time have depended in part on where a site happened to be located, which would have complicated procurement and added a new variable to budgeting, particularly for organisations operating across multiple regions. The choice to keep a national market means buyers across the country will continue to face broadly the same wholesale reference price, with locational differences handled through network charges as they are today.

The wider significance is that one of the biggest open questions hanging over the electricity market has now been answered. With the structure of the market settled, attention turns to delivery, and to whether the package of reforms can genuinely improve the efficiency of a system that has to integrate ever larger volumes of intermittent renewable generation while keeping the lights on and costs under control.

GOV.UK

Catalyst

Digital Energy

Award Winning

Business Energy Consultants