Introductions

Rajiv Gogna  
Partner  
(0)20 7439 2266  
rajiv.gogna@lcp.uk.com

Chris Matson  
Partner  
(0)20 7432 0674  
chris.matson@lcp.uk.com

Gurpal Ruprai  
Consultant  
(0)20 3824 7425  
gurpal.ruprai@lcp.uk.com

Kyle Martin  
Head of Market Insight  
(0)20 7439 2266  
kyle.martin@lcp.uk.com
Who we are

• Financial services consultancy, based in London
• 700 staff and partners
• LCP Energy Analytics focusses on the GB and Irish electricity markets
• Combination of energy market expertise, mathematical modelling and new technological approaches
• Work closely with industry and decision makers
• Provide a range of services, from modelling support to market insight

We advise half of the FTSE100 firms
We have provided the modelling framework for a number of decision makers.

- We designed, developed and maintain BEIS’ primary forecasting tool, the Dynamic Dispatch Model, used in all long term forecasting and policy impact analysis.

- Ofgem uses our modelling to assess network charging reforms, including embedded benefits/TCR.

- National Grid uses our modelling to support the annual capacity requirement recommendation, calculate EFCs and derating factors.

- The LCCC uses our modelling to calculate the costs of the CfD framework, and to set the interim levy rate and total reserve amount.
How we help our clients

Across GB and Ireland

- Energy market forecasting and scenarios
- Transaction support and generation asset valuations
- Capacity Market & Contracts for Difference advice
- Real-time trading visualisation and analytics
- Policy impact studies
- Market insight
- Commercial and operational optimisation
- Bespoke modelling solutions
Our experience

Examples of recent projects

GB and Irish assets due diligence support

**Capacity market support**
Provided modelling projections of the GB market to evaluate potential bidding strategies in the capacity market auctions to a number of large and small scale generators.

**GB clients – Wind asset evaluations**
Provided modelling and analysis to support business case for portfolio of wind assets.
Detailed locational modelling, to capture price cannibalisation and imbalance risk.

**Impacts of COVID-19 and BSUoS**
LCP have provided clients with short and long term forecasts assessing the impacts from COVID-19, including our own BSUoS forecast.

**GB power market portfolio forecasting**
LCP provide a number of clients with regular GB power market forecasting, portfolio valuations, asset dispatch projections and associated cashflows.

**M&A**
LCP has advised clients on M&A for multiple assets including: Flexible assets (gas & batteries), wind, CCGTs, small scale renewables and nuclear.
Provided wholesale, BM, CM, embedded benefit and ancillary service projections.
LCP Enact
Real time trading analytics for the GB electricity market

Data integration
LCP Enact brings in real time and historic data from a number of data sources, to allow traders and analysts to see one integrated market view.

Cutting edge UI
This data is delivered through a web interface, using the latest technologies to allow easy visualisation of data, quick analysis and even mobile alerts.

Al-powered forecasting
Enact provides a live 6 hour view of system imbalance (NIV) and system prices, allowing traders to help balance the system and realise the profitability of their assets. Our NIV forecast delivers a £2/MWh profit on trades executed 30 minutes before delivery.

See more at lcpenact.com
Agenda

Background

Backwards looking analysis
• Comparison of BSUoS charges in 2019/2020
• Average BSUoS charges vs HH volatility
• Key drivers of BSUoS

Forward looking analysis
• Analysis of BSUoS for summer 2020 and beyond
• NGESO BSUoS forecasts and sensitivities on these
What is BSUoS?

- **Balancing Services Use of System (BSUoS)** charges recovers the cost of the day-to-day operation, balancing and securing of the transmission system.

- The BSUoS charge is a flat tariff paid by transmission connected generators and suppliers on an ex post basis.

- The charge reflects the cost of balancing actions in that period, and is charged back to the active participants in the half hour on a £/MWh basis.
What is BSUoS?

- **System Balancing**
  (All actions taken to maintain stability – SO flagged actions, locational constraints, inertia)

- **Energy Balancing**
  (All actions taken to resolve energy imbalances i.e. when a generator hasn't produced enough power or a supplier has not bought enough power)

- **Additional costs**
  Ancillary services, internal costs etc

- **Cashout**

  - Residual Cashflow Reallocation Cashflow (RCRC)
Comparing last year to this year
Lower demand

COVID-19 has resulted in a significant decrease in demand, and a flattening of the shape across the day, particularly the morning peak.
Gas prices have slumped since April 2019, particularly in the last 3-4 months.

Renewable output

- April 2020 levels are broadly similar to the same month last year
- May has shown significantly higher wind output (pre curtailment) this year
BSUoS costs have been increasing

- BSUoS has sharply increased in the last two months
- NGESO monthly forecasts have so far been quite indicative

- BSUoS is higher across the day relative to a year ago, most notably during overnight periods and over the afternoon
- Lower demand has highlighted the influence of solar generation
BSUoS has increased, but so has its volatility
And it’s becoming harder to predict

In recent months the BSUoS charge has both increased and become less predictable:

- The spread in the distribution of the half-hourly BSUoS charges has widened compared to last year
- The tail of the distribution has grown, in April and May 2020 BSUoS exceeded £10/MWh in 10% of all settlement periods
- This higher volatility is likely to be ultimately passed through to consumer bills due to higher risk premium
BSUoS has increased, but so has its volatility
And it’s becoming harder to predict

- NGESO’s half hourly BSUoS forecast has not followed their monthly forecast and has been materially different from outturns
- This makes wholesale dispatch decisions and the pricing of bids and offers in the balancing mechanism more difficult
Captured BSUoS is important

Technologies are impacted by higher BSUoS differently

BSUoS Capture Price
(7-Day Lagged Moving Average)
Why has BSUoS increased

Key drivers are lower charging base and constraints costs

BSUoS charges have risen significantly under Covid compared to the same period last year.

The key reasons for this were:

- Decrease in the **charging base**, as a direct result of decrease in overall levels of generation and demand

- An increase in **energy imbalance** costs, the cost associated with bids/offers accepted to satisfy the Net Imbalance Volume (NIV)

- An increase in **constraint** costs. This includes system actions to satisfy locational constraints and maintain system stability (e.g. inertia)
Increasing energy imbalance costs

The system is now short on average, as long system prices become more punitive

The system price is set by the most expensive turn up action in a short system, and the most expensive turn down action in a long system

2019

- Higher demand and higher gas prices meant turn ups were expensive and turn downs were cheap.
- This meant the system was on average long, to avoid facing a punitive short cashout price

2020

- Lower demand and lower gas prices have made turn ups cheaper (more CCGTs available to turn up) but bids more expensive
- It’s now the long system price that is more punitive, so the system tends to stay short
Increasing energy imbalance costs
This means a material increase in energy imbalance costs

2019
- Long system
- On average, being paid to turn units down (bids ~ £20/MWh)
- Offset by fewer but more expensive offers (offers £60+/MWh)
- Nets out to near zero

2020
- Short system
- On average, paying to turn units up (offers ~ £40/MWh)
- Bids are now closer to £0/MWh, so very little offset
- Nets out to a material cost

Note: RCRC should reimburse this cost to participants
Key drivers to BSUoS
System actions - locational constraints

- The England/Wales constraint has been the largest contributor to BSUoS (~50% of all balancing costs)
- Low demand has exacerbated effects such as: offshore wind congestion, RoCoF management, congestion around the Humber area and voltage management
- Zone 8 received 22x the volume of accepted SO bids in Apr/May 2020 compared to the same period in 2019.
- Zone 13 received 10x the volume of accepted SO offers in Apr/May 2020 compared to the same period in 2019.
Key drivers to BSUoS

Inertia

This year’s system inertia levels are **significantly** lower than the same time last year:

- This is a result of low demand, high renewable output and less synchronous generation
- While NGESO do not separate out actions taken for maintaining inertia, it is clear that certain periods will have required an increase in system inertia
All of these effects can be broadly captured by considering **residual demand**:

**Residual Demand** = **Tx Demand** – **Tx Wind**  
*(pre curtailment)*

- This shows a fairly consistent relationship with BSUoS to last year, suggesting we are not experiencing materially different costs for similar levels of residual demand.
- We are simply extending the curve further to the left to low levels of residual demand we have not seen before.
Non Market Based Tools
Non Market Based Tools

Optional Downward Flexibility Management (ODFM) and Sizewell B

- Allows the ESO to increase demand in low demand periods by turning off embedded generation or turning up embedded demand
- This flexibility is procured outside of the BM and other markets, effectively removing these actions from the BM.

ODFM is currently only set to last for summer

- Utilisation-based service fee (£/MW/hr).
- ODFM actions will not feed into cashout, with costs recovered through BSUoS.

National Grid ESO has also confirmed that it has agreed a “one off, fixed term” contract with Sizewell B instead of making daily payments to the generator via the Balancing Mechanism.
Looking forward
NGESO BSUoS forecasts

Projecting an additional £427m of balancing cost over the May-August 2020 summer period

NGESO published revised BSUoS projections on the 15th May, showing an additional £427m across the May-August summer period.

This was based on modelling of low demand periods, specifically where transmission system demand is below 18GW and hence ESO intervention is required to ensure system stability.

NGESO used a wide range of demand simulations (30,000), but static assumptions on the bid/offers and required level of actions at each low demand level.
NGESO BSUoS forecasts

NGESO have made a number of key assumptions about the costs of actions at low levels of demand

<table>
<thead>
<tr>
<th>Bids / offers, £/MWh</th>
<th>Period</th>
<th>Demand (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>13</td>
</tr>
<tr>
<td>CCGT offer</td>
<td>All</td>
<td>80</td>
</tr>
<tr>
<td>Wind bid</td>
<td>Daytime</td>
<td>-150</td>
</tr>
<tr>
<td></td>
<td>Overnight</td>
<td>-80</td>
</tr>
<tr>
<td>IC trade</td>
<td>All</td>
<td>-200</td>
</tr>
<tr>
<td>New service</td>
<td>All</td>
<td>-200</td>
</tr>
</tbody>
</table>

**Market dispatch, MW**

<table>
<thead>
<tr>
<th>CCGT dispatch</th>
<th>Period</th>
<th>Demand (GW)</th>
<th>13</th>
<th>14</th>
<th>15</th>
<th>16</th>
<th>17</th>
<th>18</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Daytime</td>
<td>913</td>
<td>1,192</td>
<td>1,490</td>
<td>1,706</td>
<td>2,759</td>
<td>3,863</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Overnight</td>
<td>187</td>
<td>187</td>
<td>357</td>
<td>1,004</td>
<td>1,674</td>
<td>1,474</td>
<td></td>
</tr>
<tr>
<td>Forecast wind</td>
<td>All</td>
<td>7,500</td>
<td>7,500</td>
<td>8,000</td>
<td>10,000</td>
<td>10,000</td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td>Forecast IC</td>
<td>All</td>
<td>500</td>
<td>500</td>
<td>500</td>
<td>1,000</td>
<td>2,000</td>
<td>2,000</td>
<td></td>
</tr>
<tr>
<td>Nuclear load</td>
<td>All</td>
<td>5,648</td>
<td>5,648</td>
<td>5,648</td>
<td>5,648</td>
<td>5,648</td>
<td>5,648</td>
<td></td>
</tr>
<tr>
<td>Pump storage</td>
<td>All</td>
<td>-556</td>
<td>-556</td>
<td>-556</td>
<td>-834</td>
<td>-834</td>
<td>-834</td>
<td></td>
</tr>
</tbody>
</table>

**System requirement, MW**

<table>
<thead>
<tr>
<th>CCGT requirement</th>
<th>Period</th>
<th>Demand (GW)</th>
<th>13</th>
<th>14</th>
<th>15</th>
<th>16</th>
<th>17</th>
<th>18</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Daytime</td>
<td>6,113</td>
<td>5,958</td>
<td>5,958</td>
<td>5,668</td>
<td>5,518</td>
<td>5,518</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Overnight</td>
<td>3,783</td>
<td>3,783</td>
<td>3,508</td>
<td>3,348</td>
<td>3,348</td>
<td>2,548</td>
<td></td>
</tr>
<tr>
<td>Max Wind</td>
<td>Daytime</td>
<td>900</td>
<td>2,187</td>
<td>3,383</td>
<td>4,579</td>
<td>6,274</td>
<td>7,470</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Overnight</td>
<td>3,093</td>
<td>3,990</td>
<td>5,286</td>
<td>6,608</td>
<td>7,505</td>
<td>8,731</td>
<td></td>
</tr>
<tr>
<td>IC requirement</td>
<td>All</td>
<td>-500</td>
<td>-500</td>
<td>-500</td>
<td>-500</td>
<td>-1,000</td>
<td>-1,000</td>
<td></td>
</tr>
</tbody>
</table>

- The assumed offer prices (the price at which a generator will either turn-on or increase its output) for CCGT across all the 13-18GW demand range seem high against a background of low gas and EU ETS prices and in comparison to recent BM activity.

- Wind bid prices (the price paid by a generator to reduce its output) seem very heavily negative, rising to the prices required by AR1 supported CfD generators to turn-down or off. This implies a significant level of turndown given the amount of wind capacity receiving lower levels of support.

- IC traded prices (price required in this instance to reverse flow across the interconnectors) seem to mirror the level of wind bids.
**Sensitivities on NGESO BSUoS forecasts**

Adjusting CCGT & wind offers/bids based on recent observations

Using data on actual bid/offers from April/May to May, have adjusted the assumptions for CCGT offer prices, down from £80/MWh to £50/MWh.

Doing same for wind (plus assumptions on the supply curve) aligns closely with NGESO assumptions.

This brings the BSUoS forecast down slightly.

---

<table>
<thead>
<tr>
<th>Bids / offers, £/MWh</th>
<th>Period</th>
<th>13</th>
<th>14</th>
<th>15</th>
<th>16</th>
<th>17</th>
<th>18</th>
</tr>
</thead>
<tbody>
<tr>
<td>CGGT offer</td>
<td>All</td>
<td>50</td>
<td>50</td>
<td>50</td>
<td>50</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>Wind bid</td>
<td>Daytime</td>
<td>-155</td>
<td>-134</td>
<td>-131</td>
<td>-129</td>
<td>-73</td>
<td>-73</td>
</tr>
<tr>
<td></td>
<td>Overnight</td>
<td>-131</td>
<td>-84</td>
<td>-73</td>
<td>-73</td>
<td>-73</td>
<td>-68</td>
</tr>
</tbody>
</table>
Sensitivities on NGESO BSUoS forecasts

Adjusting CCGT & wind market dispatch assumptions based on recent observations

We have also tested NGESO’s projections using updated assumptions for the market dispatch of CCGT and wind.

The CCGT assumptions from NGESO appear reasonable, aligning closely to the level of dispatch observed at low levels of demand in recent months.

However, the wind forecast assumption of 10GW is relatively high, with low periods of demand averaging closer to 6GW output.

Reducing assumed wind output (before curtailment) to 6GW has a material impact on BSUoS forecasts, roughly halving the additional costs due to Covid-19 effects.
Sensitivities on NGESO BSUoS forecasts

Simulated wind and market dispatch stochastically

NGESO’s modelling uses a static view of market dispatch (though is run against a very large number of demand traces).

We have used LCP’s dispatch model to also **stochastically simulate wind**, and the resulting market dispatch of other generation.

We have maintained NGESO’s assumptions for the level of synchronous generation required at different demand levels.

This shows reasonably close alignment to the results using our updated dispatch and bid assumptions on the previous slide.
Sense check Grid numbers using relationship

Residual demand relationship established in backwards looking analysis

In the backwards looking analysis, we saw a strong relationship between residual demand and BSUoS.

Applying this relationship against our simulations of wind & demand for May-Aug 2020 provides a useful sense check on the more detailed modelling.
The new normal?
Low residual demand levels will become commonplace in future years

The lower levels of residual demand under Covid-19 have led to increased BSUoS charges in 2020 relative to 2019.

However, these residual demand levels are likely to become normal in coming years.

Looking at the April-May period in 2025 (based on LCP modelling), residual demand levels are expected to be even lower than those seen in 2020. This is a result of higher levels of renewable generation rather than lower demand, so will not result in the same reduction of charging base. Nevertheless this will lead to high BSUoS charges.

In addition, higher commodity prices will increase the cost of system actions (as CCGTs are typically turned up) and increase BSUoS charges (all else remaining equal).
Conclusions

Under Covid-19, BSUoS charges have increased and become more volatile
- This is primarily due to increased constraint costs (for locational and system stability actions) and a smaller charging base – both of which are driven by lower levels of demand
- There is a particularly strong relationship observed between BSUoS charges and residual demand (transmission system demand net of wind)

NGESO’s forecasts predict an additional ~£500m of costs this summer. However, these projections use some cautious assumptions, such as high CCGT prices, static market dispatch and one wind level over all simulations. Based on our analysis of recent market behaviour, stochastic analysis of summer and using NGESO’s current expectations of the requirement for balancing actions at different demand levels, we expect a lower additional cost than is currently forecast.

- These forecasts are very uncertain due to high level of volatility in key inputs, uncertainty in market behaviour and new services being implemented by NGESO
- To truly capture the costs of summer, a more detailed fundamentals-based approach is required, due to a lack of historic data for the low levels of demand we expect to see and to fully capture locational impacts.

High, volatile BSUoS charges are expected to be a feature in the future
- Increased renewable penetration will drive low residual demand levels similar to those seen this summer
- A return to higher commodity prices would increased costs of system actions and could lead to higher BSUoS charges (all else remaining equal)
- An issue we have not covered is the increase in Scottish constraints. Though not a major driver for this summer’s high costs, they are expected to become a significant cost in future years and drive high BSUoS charges outside of summer
Appendix: Future impacts of constraint management on BSUoS
Impacts of constraint management on BSUoS

Analysis of constraint management between 2023 - 2030

We analysed the 2023 – 2030 period, which spans the period from the start of the constraint management service being procured by National Grid ESO until the end of the Network Options Assessment (NOA) period.

The graph shows LCP’s constraint forecasts across just the B6 boundary between 2023 and 2030. Currently the ESO is spending about £450m a year on constraints across all of GB but **LCP forecast that by 2025 the ESO will be spending almost £1bn a year across just the B6 transmission boundary.**

40% of the time, the power transfer limit of this boundary will be exceeded. In other words, **40% of the time renewable generation will have to be constrained off** and almost certainly replaced with carbon emitting generation sources south of this boundary.
Impacts of constraint management on BSUoS

Analysis of constraint management between 2023 - 2030

We see significant drops in the cost of managing thermal constraints in 2027 and 2029 this is due to major transmission builds being completed. These are E2DC (a 2GW HVDC cable from Torness to Hawthorne Pit) and E4D3 (a 2GW HVDC cable from Peterhead to Drax).

Originally this transmission infrastructure was estimated for delivery in 2023 but despite the ESO recommending the construction of these links, the Transmission Operators (TO's) were not able to proceed with any preliminary work due to Ofgem not guaranteeing funding through the network price controls.

East Anglia and the South East coast also have constraint issues arising in the future.
Use of our work

This generic presentation should not be relied upon for detailed advice or taken as an authoritative statement of the law. If you would like any assistance or further information, please contact the partner who normally advises you. While this document does not represent our advice, nevertheless it should not be passed to any third party without our formal written agreement.

This work has been produced by Lane Clark & Peacock LLP
This work is only appropriate for the purposes described and should not be used for anything else. It is subject to any stated limitations (eg regarding accuracy or completeness). Unless otherwise stated, it is confidential and is for your sole use. You may not provide this work, in whole or in part, to anyone else without first obtaining our permission in writing. We accept no liability to anyone who is not Our Client.

If the purpose of this work is to assist you in supplying information to someone else and you acknowledge our assistance in your communication to that person, please make it clear that we accept no liability towards them.

Our experts work in pensions, investment, insurance, energy and employee benefits.

- Join us at our next event: [www.lcp.uk.com/events](http://www.lcp.uk.com/events)
- Share our insights and opinions on our viewpoint: [www.lcp.uk.com/our-viewpoint](http://www.lcp.uk.com/our-viewpoint)
- Watch and listen to our comments on topical issues: [Our YouTube channel](http://www.lcp.uk.com/emails-important-information)
- Connect with us for updates: @LCP_actuaries
- LinkedIn

Lane Clark & Peacock LLP is a limited liability partnership registered in England and Wales with registered number OC301436. LCP is a registered trademark in the UK (Regd. TM No 2315442) and in the EU (Regd. TM No 002935583). All partners are members of Lane Clark & Peacock LLP. A list of members’ names is available for inspection at 95 Wigmore Street, London, W1U 1DQ, the firm’s principal place of business and registered office. The firm is regulated by the Institute and Faculty of Actuaries in respect of a range of investment business activities. Locations in London, Winchester, Ireland and - operating under licence - the Netherlands. © Lane Clark & Peacock LLP 2020 http://www.lcp.uk.com/emails-important-information contains important information about this communication from LCP, including limitations as to its use.