Programme Area: Energy Storage and Distribution

Project: 2030 Electricity Price Time Series

Title: Future Retail Electricity Supplier Costs

Abstract:

The methodology underpinning this study, and the study results are detailed in a slide deck accompanying this report. This report focuses on the interpretation of those results, and is intended to be read in conjunction with that slide deck.

Context:

This knowledge building project aims to outline a number of price scenarios for the retail price of electricity across a number of different energy vectors in 2030. This project, delivered by Baringa, builds on their existing time series of hourly supplier electricity costs for 2030. They delivered an hourly electricity price series for 2030 based on traceable assumptions for three different 2030 supply-demand scenarios. The key objectives were:

- To investigate the costs that domestic electricity suppliers in Great Britain might face in 2030.
- To make projections on the assumption that, unless formally announced, no changes are made to the electricity market arrangements in place today
- To focus in particular on the hourly variation and seasonal shape of supplier costs

GB Future Retail Electricity Supplier Costs - Interpretation

CLIENT: ETI

DATE: 22/11/2018

Introduction

ETI commissioned Baringa Partners to carry out a study of future retail electricity supplier costs. The study's objectives were:

- To investigate the costs that domestic electricity suppliers in Great Britain might face in 2030.
- To make projections on the assumption that, unless formally announced, no changes are made to the electricity market arrangements in place today
- To focus in particular on the hourly variation and seasonal shape of supplier costs

The methodology underpinning this study, and the study results are detailed in a slide deck accompanying this report[1]. This report focuses on the interpretation of those results, and is intended to be read in conjunction with that slide deck.

Annual generation and costs

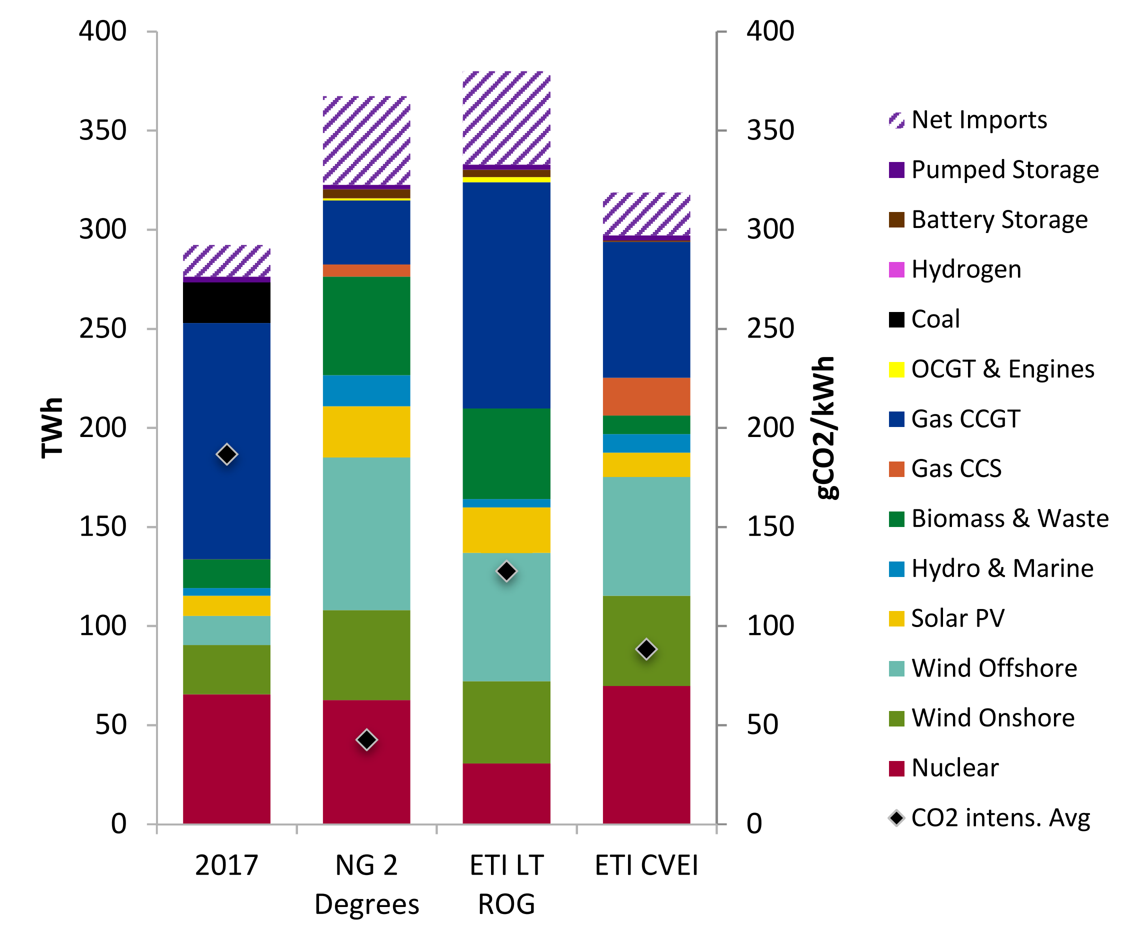
Modelling was carried out under three scenarios:

- **National Grid Two Degrees (NG 2 Degrees):** A relatively high demand scenario, with relatively high renewables, nuclear and imports, but reduced levels of CCGT
- **ETI Long-Term Role of Gas (ETI LT ROG):** The highest-demand scenario modelled, with high levels of renewables, CCGT and storage, but reduced nuclear capacity
- **ETI Consumers, Vehicles and Energy Integration (ETI EVEI):** With demand the lowest of the three, this scenario has the highest levels of nuclear, but the lowest levels of renewables and storage

These scenarios were drawn from public sources, and were chosen to represent a range of carbon intensities and levels of renewable generation, as well as different levels of electrification (e.g. of transport) and flexible demand. The resulting generation profiles are shown in Figure 1.

[1] Baringa (2018) GB Future Retail Electricity Supply Costs: Project of hourly retail cost stacks in 2030 under three scenarios

Figure 1 Annual generation by technology type and modelled scenario

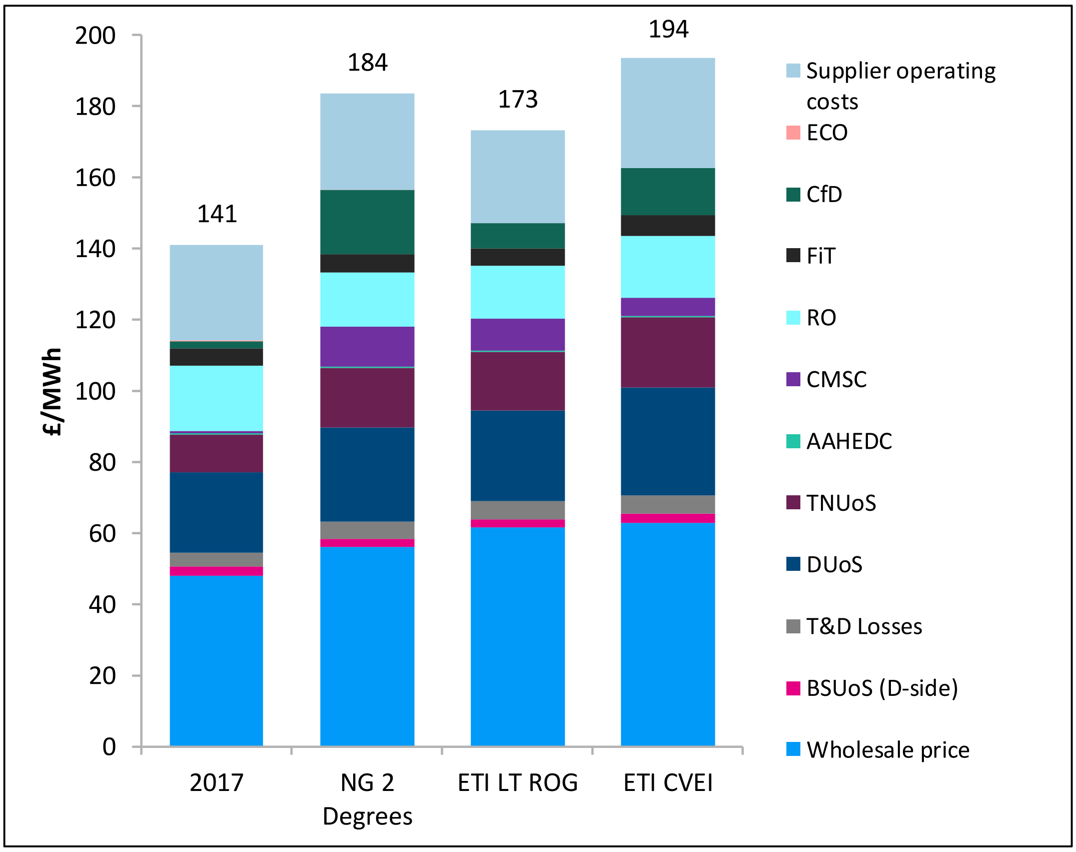


The scenarios show significant variation in the total electricity demand, the generation mix, and hence the carbon intensity. NG 2 Degrees has high levels of renewables, nuclear and imports, which results in low carbon intensity. Note that imported electricity is treated as zero carbon because it is assumed that the carbon cost has been accounted for under the exporting country's carbon budget. This does however depend on policy decisions being taken outside our national borders.

ETI LT ROG has the highest carbon intensity, arising primarily from the high levels of CCGT use. ETI CVEI has a similar share of CCGT capacity to ETI LT ROG, but its load factor is lower since baseload power is met more through nuclear generation.

The cost to suppliers under each of these scenarios is summarised in Figure 2.

Figure 2 **Load-weighted average retail cost stack**



Focusing first on the wholesale price, the trend from today to 2030 is upwards. Despite the increased uptake of forms of generation with low marginal costs of generation such as wind and solar (which would be expected to drive the wholesale price downwards), the underlying commodity prices (in particular natural gas) keep wholesale prices high.

There is, however, a degree of variation between scenarios. The lowest wholesale price can be seen under the NG 2 Degrees scenario, which is consistent with the high share of electricity coming from sources with low marginal costs (nuclear, wind, solar). ETI LT ROG and ETI CVEI have similarly high wholesale prices associated with them, which is consistent with the relatively high reliance on natural gas (either CCGT or gas with Carbon Capture and Storage).

However, the overall cost to suppliers seen between scenarios does not match the pattern observed for the wholesale price. ETI LT ROG, is less reliant on low carbon subsidies than ETI CVEI or, in particular, NG 2 Degrees. Those scenarios have high levels of both renewables and nuclear generation, both of which are assumed to require some form of subsidy.

Furthermore, the low overall demand under ETI CVEI results in relatively high per-unit network charges (TNUoS and DUoS). This is because most of those network costs are not directly linked to demand (load-related expenditure is not proportional to consumption levels, and is also a relatively small share of overall network costs). The same fixed costs therefore need to be covered by a smaller number of consumed units of electricity.

Hourly and seasonal profiles

The detailed generation and supplier costs are described in detail in the accompanying slide deck.

The purpose of the hourly analysis is to understand the extent to which suppliers are exposed to cost signals that should lead to efficient consumption behaviour. As seen above, administrative costs in 2030 represent a larger share of the overall supplier cost base than they do in 2017. If those costs are not recovered in an efficient way, there is a risk that the overall system planning and operation is suboptimal, resulting in more generation capacity than would otherwise be needed, and more utilisation of generation with high marginal costs and high levels of carbon emissions.

The results suggest the following:

- The increased contribution of administrative charges seen annually is replicated in the hourly analysis, but the effect is more marked at this more granular level. During the evenings, and in particular the winter evenings, the recovery of TNUoS and the CM charge represent a large part of the supplier cost stack.
- At the same time that the administrative prices are creating a larger evening cost peak than seen in 2017, the within-day shape of the wholesale price appears to be weakening, suggesting that the marginal cost during the evenings is less predictably high.
- By design, this modelling has assumed that the recovery of DUoS charges is carried out in the same way as today (i.e. relatively flat for domestic customers). However, as flows on the distribution network become more complex, and distribution networks are run with more constraints, it is expected that more time-dependent or dynamic price signalling will be required.

By 2030 there is a good chance that wholesale and network-related price signals will not be aligned at all times. It is also expected that administrative charges, if not updated accordingly, could undermine the effectiveness of those price signals. There is a need, therefore, to reform all these various mechanisms in a coordinated and coherent way to ensure that the electricity system is used efficiently whilst the necessary administrative costs can still be recovered.

Key findings

This analysis has highlighted a number of potential issues that could arise if electricity regulations today were left unchanged by 2030:

- **Administered charges will become more significant:** Whilst it may make sense today to levy administered charges during peak periods, by 2030 the timing of those peaks is likely to be less predictable. Administered charges, rather than mirroring periods of network or system stress, would drive demand away from predetermined periods regardless of the actual system need, potentially exacerbating stress events at different times of the day.
- **Dynamic charges may be needed:** With the deployment of domestic smart meters, and the likely move to Half Hourly settlement, there is a case to be made for recovering a

larger proportion of administered charges on a more dynamic basis. However, this would need to be done in a way that did not introduce undue uncertainty for suppliers and consumers, and in a way that still delivered predictable revenues for the network companies and generators.

- **Efficiency and self-supply creates social equity issues:** The scenario with the lowest overall demand has the highest per-MWh charges. This is because non-variable underlying costs (e.g. legacy FIT, residual network charges, and supplier operating costs) still need to be recovered even in a world of higher consumption efficiency or an increase in domestic self-supply. This raises an issue of societal fairness, since customers least able to reduce or flex their demand (e.g. renters, or those without sufficient capital to invest in flexible technologies) may incur an increasing share of these fixed costs.
- **Transmission charges expected to grow significantly:** TNUoS charges are expected to outstrip DUoS charges, largely since this will be the mechanism by which Offshore Transmission Owner (OFTO) charges are recovered. This may further challenge the notion that TNUoS should be recovered during evening peaks.
- **Local and global price signals will need to be aligned:** As flows on the network become more complex, there is likely to be an increasing mismatch between overall national energy balancing needs and local network needs. Unless the network charges faced by customers reflect the true cost of network usage with sufficient locational and temporal granularity, the wrong demand behaviours could be incentivised.

We do not anticipate that the policies and regulations in place today will remain unchanged by 2030. Indeed, a number of possible modifications have been mooted, and may be implemented in the coming years. What this analysis shows is that these changes cannot be made on a component-by-component basis. The overall effect of these supplier costs on the behaviour of end consumers will depend on the combined effect of these charges.

Version History

Version	Date	Description	Prepared by	Approved by
1.0	22/11/18	FINAL	C. Collins	O. Rix

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