CHARGING SEMINAR SUMMARY

This document summarises the output from the charging seminars held by National Grid in London and Glasgow Summer 2016

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Contents

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1. Introduction

Over the last few months National Grid (NGET) has met with a large number of stakeholders with varying roles within the Electricity Industry to discuss network charging arrangements. Following on from these discussions there was broad consensus that charging regimes are in need of change to ensure they remain appropriate in an increasingly changing energy landscape, and that this change needs to be progressed through a holistic review.

We asked stakeholders how they would like us to progress this initial thinking and they strongly supported a need for dedicated charging seminars to allow full discussion of the need for change. We therefore took the opportunity to host two seminars in July, held in London and Glasgow to discuss the above and how to address the need for change. Mindful of other ongoing industry work in this area, we invited a number of guest speakers to present their considered thoughts on the need for change in charging. In the afternoon we led interactive sessions considering in more detail the scope and approach to be taken in a holistic review.

The purpose of this document is to give an overview of the seminars and to provide a summary of industry thoughts given in the interactive sessions undertaken. These sessions looked for industry views of what a charging review should look like in terms of scope, duration and how it should be managed. This document will provide an overview of the National Grid presentations but focused on summarising the interactive sessions. When summarising we note that there will always be difference of opinions across industry parties. We have tried to present a broad picture of discussions in this document, highlighting areas of broad consensus where possible, and also noting where there was no clear agreement across seminar delegates.

Further detail on the analysis presented, and questions asked at the seminars can be found in appendices 1 and 2 at the end of this document.

2. Overview of the Seminars

2.1. Drivers for Change

More than 160 industry participants attended the 2 National Grid charging seminars held on 14th and 21st July, including distribution and transmission connected generators, small and large suppliers, consultants, academics, large energy users, network companies and policy makers.

In the morning session we reported back to attendees, based on our thoughts and refined through discussions with stakeholders, the main drivers for change in electricity network charging arrangements.

To complement our own findings regarding drivers for change, presentations were made from the following associations on work they had individually been undertaking considering the need for change in network charging arrangements:

- Energy UK
- Association for Decentralised Energy (ADE)
- Energy Networks Association (ENA)

The six high level drivers for change we have identified with the help of our stakeholders are shown in Figure 1 below.

Figure 1 Main Drivers for Change

These drivers are:

Market Developments: GB and EU energy policy has resulted in changes to the overall commercial framework. Network charging arrangements need to change to reflect these broader impacts.

Distributed Generation: Historically generation has flowed from the transmission system into the distribution system to the end consumer. The rapid increase in small scale generation located close to the end consumer has made distribution networks more active, changing these assumptions.

Smart & HH Metering Implications: Smart and half-hourly metering can create great opportunities for consumers to proactively manage their demand. The current network charging arrangements may need to change to reflect this changing nature of demand whilst being aware of the impact for vulnerable groups who are less able to demand manage.

Facilitating Flexibility: New advent of new technologies such as storage and smart metering is meaning that operational services can be procured from a much broader range of providers. It also means that system operators at a distribution level can also procure services. How should charging arrangements evolve to facilitate these developments?

Predictable Charges: Network charges have become increasingly volatile in recent years. Coupled with the fact that this volatility is not predictable, this has led to increased risk both in terms of investment and how costs are levied on the end consumer. This may end up with the end consumer paying more due to the risk premia industry parties are adding to prices to protect themselves from price volatility.

Reflecting Sunk Costs: Funding arrangements for network companies mean that the costs of assets are recovered over many years. In an evolving power system how do we ensure that these sunk costs are efficiently recovered?

2.2. Evidence for change: 'Do Nothing' scenario

A future model of TNUoS tariffs until 2040 under the current methodology[1] has been prepared by National Grid to illustrate the future direction of travel of these tariffs under a "*do nothing*" assumption.

The model has been prepared to illustrate some of the consequences of not changing the charging methodology in response to the changing nature of the electricity system.

The model presents national average tariffs and other information in 2016/17 prices. Appendix 1 discusses a number of important metrics for TNUoS charges looking forwards and highlights some of the key assumptions under the four Future Energy Scenarios[2].

A high level summary of the model results was presented to attendees at the seminar, with some examples drawn out for each of the identified drivers for change (see slides 3-8 of the Case for Change pack). A fuller presentation can be found in Appendix 1. Seminar attendees also had the opportunity to discuss modelling assumptions and data analysis in more detail over the lunchtime and afternoon break sessions, and to use the interactive model themselves.

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1 As defined in Section 14 of the Connection and Use of System Code. http://www2.nationalgrid.com/uk/industry-information/electricity-codes/cusc/the-cusc/

2 http://fes.nationalgrid.com/

2.3. Interactive afternoon sessions

The afternoon sessions allowed stakeholders to give their views on what a charging review could look like in terms of:

- The Long Term Vision / Ideal End State;
- Scope; and
- Principles for approaching a holistic review (including where we can learn from previous industry change initiatives and broad timelines)

2.3.1. Long Term Vision / Ideal End State

We asked seminar attendees to think about a vision / ideal end state for transmission charging and commercial arrangements in 10-15 years' time. To help with this, we had copies of the key drivers for change in commercial arrangements (introduced in the morning session), the current objectives of the CUSC and some example vision statements available.

In collating the vision statements from both seminars, we recognised that there was a primary group of themes emerging in almost every vision – namely:

- No distortions, a consistency of approach to charging across networks, a whole system view (where behaviour incentivised by the charging regime does not distort other markets).
- Lowest long term cost to the consumer, an efficient network.
- Key theme of stability and predictability – in both the charging framework and charges themselves – underpinned by ideas of simplicity, transparency and sustainability.

As well as a number of second order themes – which were:

- Cost reflectivity – including time of use signals, locational signals, signalling SO requirements – but in a way that customers can react.
- Users rewarded or charged based on value (in Glasgow this discussion was broadened to discuss whether users should be charged based on use of the network or the amount of benefit they derive from a network).
- Technology neutral.
- Market driven, with market access for all .
- Flexibility to customer needs.

Based on this collation of themes, we would suggest using the following as a 'working draft' vision statement for the charging review:

'A transparent charging regime that provides consistent and predictable signals across networks, time periods and locations, and that recovers the costs of efficient network development at lowest long term cost to the consumer, through the appropriate reflection of costs and benefits to network users.'

This regime will:

- Promote cost reflectivity, but not beyond the point that users can meaningfully respond or to the detriment of beneficial competition
- Facilitate wider energy policy, but not drive policy outcomes
- Promote a stable investment environment by being based on sound principles, but be responsive to changing customer needs through appropriate governance arrangements

2.3.2. Scope and timing of a charging review

Following the creation of the overall vision, each table was then asked to consider the scope of a charging review in terms of what it should review and address, and how this should then be done (i.e. incrementally or holistically, short term or long term)?

In advance, National Grid created a list of scope modules from discussions with stakeholders. These are listed in Figure 2 on page 10. For the purpose of this exercise we classed a scope module as a topic area within the current charging arrangements which may require change.

We were conscious that this may not be a definitive list so participants as part of the exercise were also asked to consider whether any scope modules should be added, and whether or not any on our list should be considered out of scope of the charging review. From this two further scope items were added as indicated in Figure 2.

Where appropriate, we have included current CUSC Modifications which are seeking to address that particular module. Current modifications can be found at the following link.

http://www2.nationalgrid.com/uk/industry-information/electricity-codes/cusc/modifications/Current/

Next participants were asked to consider the following questions:

- Whether any of the items should be out of scope
- Should Industry address the module within 1-2 years, or should it considered from over a longer period?
- Can it be addressed as an incremental change by itself or would it better be looked at holistically (i.e. taking into account distribution and other modules – see figure 2 on page 10)?

Out of Scope?

Market Splitting/Locational Marginal Pricing (LMP) and Single Network Charge were noted by the majority of participants as being out of scope.

LMP is a way for wholesale energy prices to reflect the value of energy at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. Although very cost reflective, stakeholders believed that LMP would increase complexity, decrease predictability and be a negative change for the electricity industry at this time of increased change.

There was significant support for the need to consider transmission and distribution charging holistically. Many participants saw the merit in harmonisation between Transmission and Distribution charges. In their view, if the review was done correctly from a holistic point of view, then there would be no need to aim for a specific single network charge.

All other modules were regarded as being in scope by the majority of stakeholders either as incremental changes or part of a holistic review.

Incremental or Holistic?

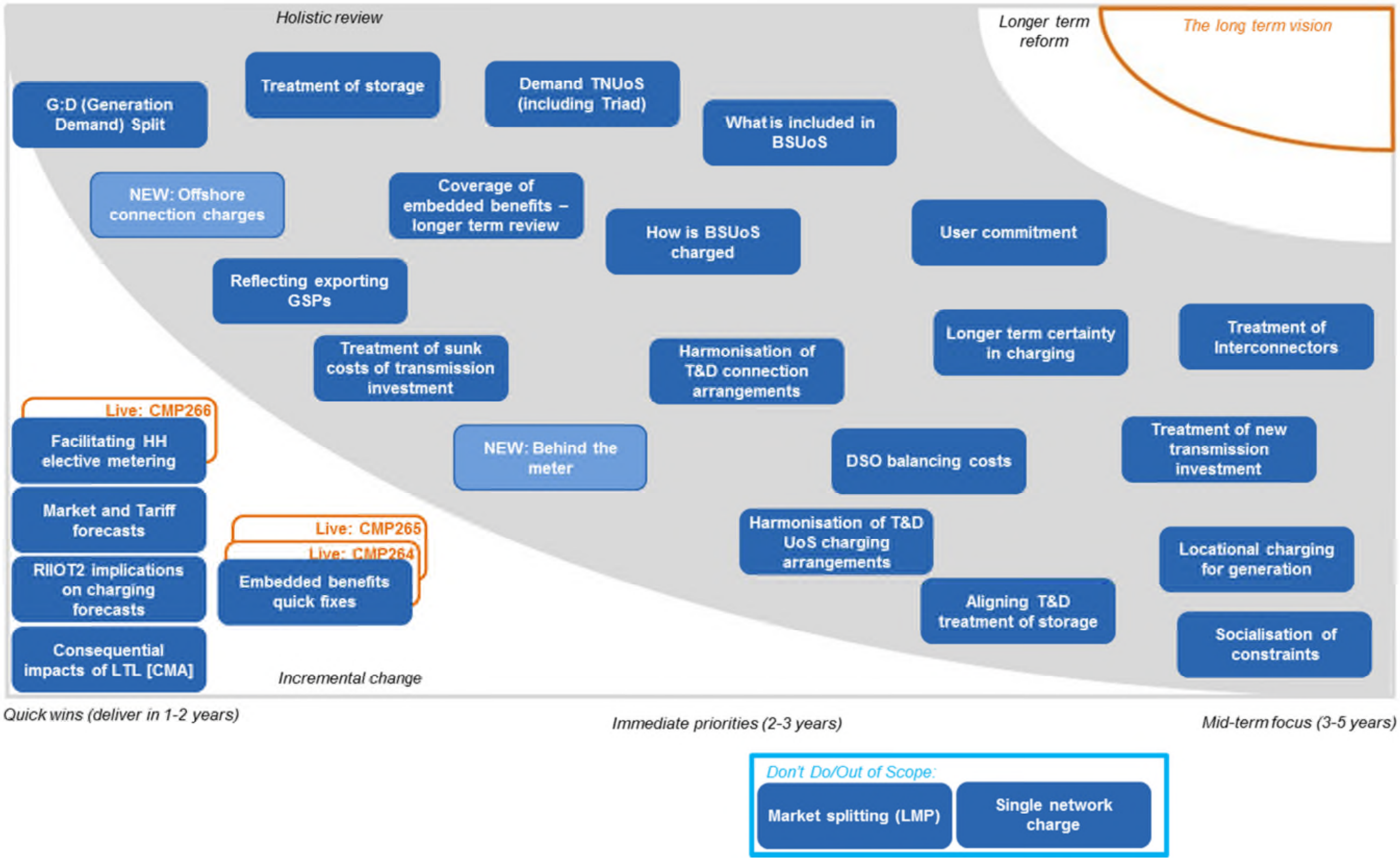
Figure 3 on page 11 shows our interpretation of a representative industry view across both seminars. There was a high degree of consensus across the tables on certain scope modules, particularly those that could be considered out of scope or quick wins, but there was greater divergence of opinion on what should be in our out of a holistic review, or indeed whether a holistic review is necessary.

Whilst some stakeholders considered some other scope modules could be considered as incremental changes, others viewed them as best progressed using a holistic approach. In some cases, for example embedded benefits, there may be a need to undertake an immediate proposal as a temporary fix pending a broader review. This is the approach we have already taken to the TNUoS charging of HH metered customers (CMP266) and the approach Scottish Power have taken in relation to embedded benefits (CMP264).

Figure 2 Levelling the Playing Field – Scope Module Descriptions

Aligning T&D treatment of storage	Considering how T&D can/should be aligned specifically for storage (includes connection and UoS)	**How is BSUoS charged**	Principles of how BSUoS is charged, and to whom it is charged	**Single network charge**	End to end review of all charging methodologies – T&D, demand and generation
Consequential impacts of LTL (CMA)	Consequential changes to network charging from the CMA locational transmission losses recommendation	**Locational charging for generation**	Definition of the locational element of generation TNUoS	**Socialisation of constraints**	Creating location specific BSUoS, reflecting, for example the cost of transmission constraints
Demand TNUoS (including Triad)	Review of Triad methodologies and definition of peak network usage	**Longer term certainty in charging**	Considering how to create longer term price certainty in terms of lead time and duration	**Treatment of Interconnectors**	Consideration of how interconnectors, and the flows on interconnectors are charged
DSO balancing costs	Consideration of how DSO balancing costs are recovered	**Market and Tariff forecasts**	Improve NG forecasting of expected tariffs	**Treatment of new transmission investment**	Treatment of new technologies such as HVDC
Facilitating HH elective metering	Resolve the charging issue for NHH customers with smart meters who can provide HH data	**Market splitting (LMP)**	Fully nodal pricing model (Local Marginal Pricing)	**Treatment of storage**	How the connection and UoS charges are calculated for storage sites – including how these are defined
G:D (Generation Demand) Split	Principles of who pays TNUoS – and how it is split between demand and generation	**Reflecting exporting GSPs**	To account for GSPs regularly exporting onto the transmission system	**Treatment of sunk costs of transmission investment**	Reviewing whether signals should respond more dynamically where capacity is under-utilised
Harmonisation of T&D connection arrangements	Considering how T&D can/should be harmonised to give the same principles of access & 'depth' of charging	**Review coverage of embedded benefits**	Including TNUoS, losses and net charging on BSUoS	**User commitment**	Consider different levels / timings of user commitment for different users
Harmonisation of T&D UoS charging arrangements	Considering how T&D can/should be harmonised to create a level playing field and not distort siting decisions	**RIIOT2 implications on charging forecasts**	RIIO-T2 outcomes (revenue & cost data) unclear creating uncertainty in TNUoS forecasts form April 2021.	**What is included in BSUoS**	Principles of what is included in BSUoS
NEW: Behind the meter	Consideration of the charging arrangements for mixed demand and generation sites	**NEW: Offshore connection charges**	Depth of connection charging for offshore sites		

Figure 3 Levelling the Playing Field – Scope of Review



2.3.3. Principles and Approach for a Charging Review

Stakeholders were asked for their views on the principles for approaching a charging review. There was good agreement amongst the tables and we have summarised an updated set of principles to reflect this discussion as follows:

- Take a holistic approach to reviewing the charging arrangements
- Balance delivering review as soon as possible while maintaining a process including open and transparent consultation
- Clear responsibilities for parties
- Use clear objectives for the review in order to focus on proactively driving alignment between the long term vision and policy
- Use evidenced based/objective methodologies to determine the most appropriate options to progress
- Deliver an efficient change process – limiting re-work and reusing/building on previous analysis (and Modifications) wherever possible to ensure that participants' time is used effectively
- Initiate a progressive transition to the future, taking into account changing technologies/behaviour whilst recognising the journey to date and implementing changes in appropriate timescales

Stakeholders were also asked for their views on the approach required and were asked for examples of good industry change. A wide variety of views were given but the need for engagement and governance arrangements involving a broad stakeholder base were consistently highlighted as a necessity.

2.3.4. Next steps

All of the stakeholder views summarised in the above document will be used by National Grid to inform its next steps. The clear message we received from stakeholders at the seminars was that a holistic review is the most suitable approach to resolve the issues identified in the document and our proposal for how this could work will be shared later in 2016.

2.3.5. Feedback from the seminars

We collected feedback on the day via feedback cards and also 'car park areas' where attendees could give us their thoughts on future areas of analysis that could support the review.

Generally feedback on the day was positive, with average scores out of ten over 7 for both days. Participants particularly valued the analysis presented by Paul Wakeley in the case for change session, and the opportunity to discuss the scope of the review, with many participants noting that the afternoon exercises were well planned and facilitated. However some attendees expressed frustration that work was not moving at pace, and that they would like the work to have been more developed ahead of the seminar. More broadly, some participants noted that the seminars had engaged widely across industry and that this was really positive.

Appendix 1: The Case for Change – the ‘do nothing’ scenario

A future model of TNUoS tariffs until 2040 under the current methodology[3] has been prepared to illustrate the future direction of travel of these tariffs under a “*do nothing*” assumption.

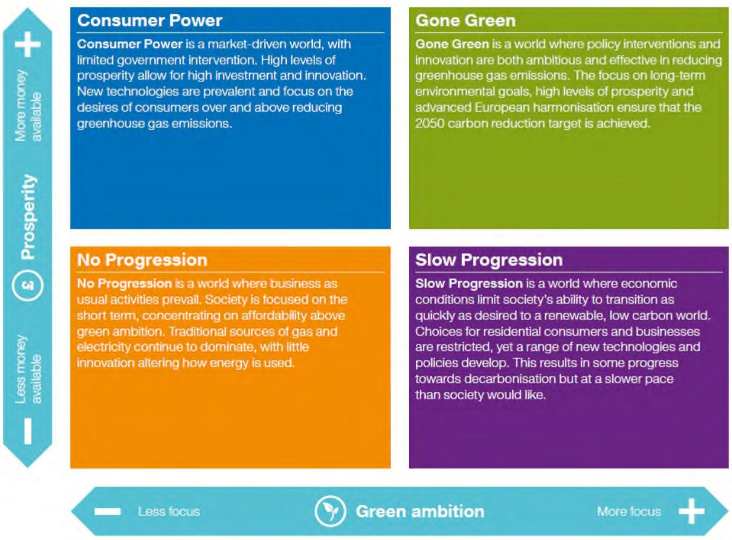
The model has been prepared to illustrate some of the consequences of not changing the charging methodology in response to the changing nature of the electricity system.

The model presents national average tariffs and other information in 2016/17 prices. This annex discusses a number of important metrics for TNUoS charges looking forwards and highlights some of the key assumptions under the four FES scenarios.

Individual locational tariffs are dependent on the precise locations and type of generation and demand, as well as location and rating of circuits, and are not forecast in this analysis. Five year forecasts of TNUoS tariffs are published annually by National Grid[4].

FES Scenarios

In order to take a view of what future scenarios are for generation and demand, the underlying data used in the modelling is taken from the four scenarios in National Grid’s Future Energy Scenarios 2016 report[5]. These four scenarios are based on differing levels of prosperity and green ambition.



3 As defined in Section 14 of the Connection and Use of System Code. http://www2.nationalgrid.com/uk/industry-information/electricity-codes/cusc/the-cusc/

4 http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=45336

5 This analysis is based on the 2016 FES document published in July 2016 http://fes.nationalgrid.com

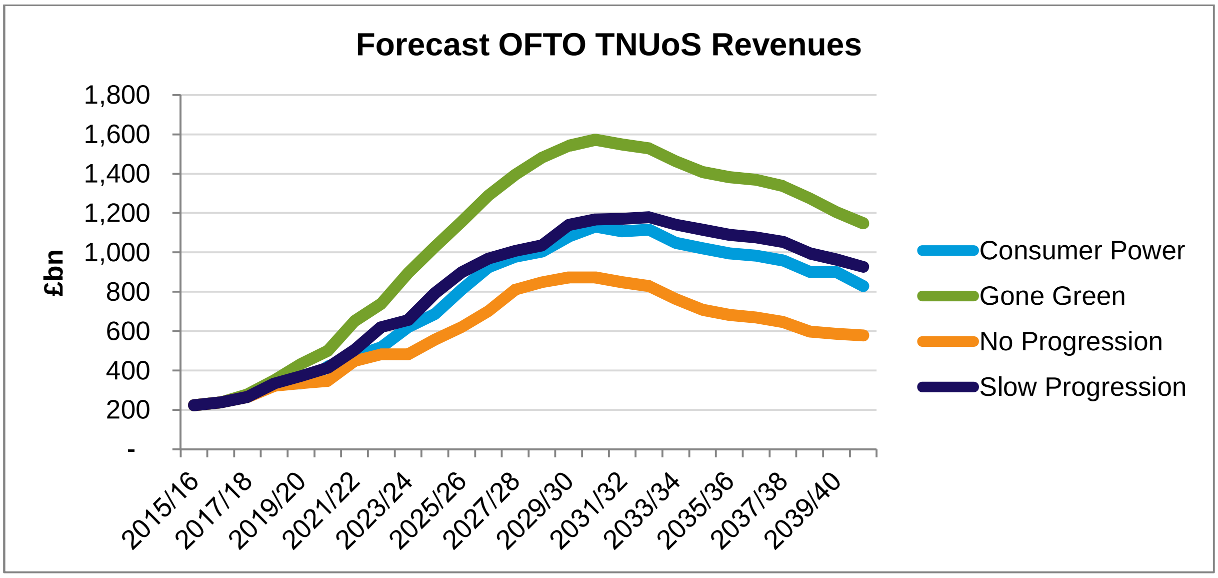
Future Allowed Revenue for TNUoS

Future allowed TNUoS revenue is the annual amount of money to be recovered through TNUoS. It comprises the allowed revenues of the onshore and offshore Transmission Owners (TOs), plus allowances for other incentives including the Network Innovation Competition.

The key future drivers of allowed revenue for TNUoS are the growth in offshore networks driven almost exclusively by offshore wind, and the growth or decline in the onshore networks under the different assumptions.

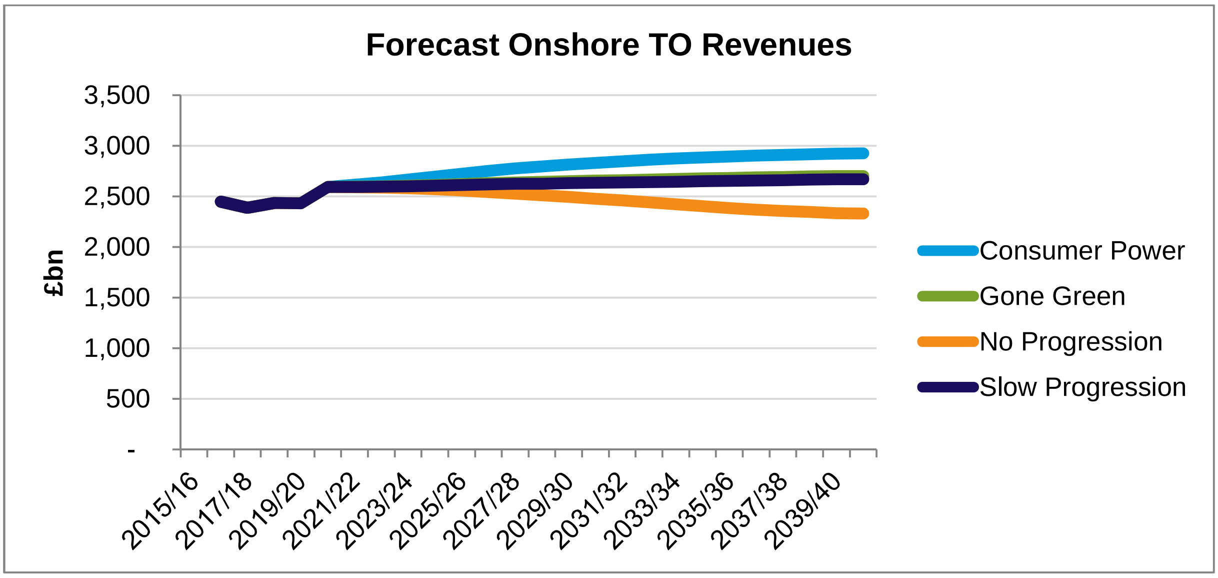
Offshore networks

It is assumed that radial networks continue to be the prevailing method for connecting offshore wind farms to the onshore network. The revenue associated with offshore TOs is assumed to scale with the volume of offshore wind connected under the different scenarios, but with two adjustments: efficiency - the more network there is, the lower the unit rate of the cables; and secondly distance - the more installed capacity the further offshore it will be, so the longer and more expensive the cables. It is not surprising that the Gone Green scenario which has the highest volume of offshore wind has the highest future OFTO revenues. The decline in OFTO revenues at the tail-end of the period is the assumption that existing assets are paid for over a 20-year period, and then require only maintenance costs.

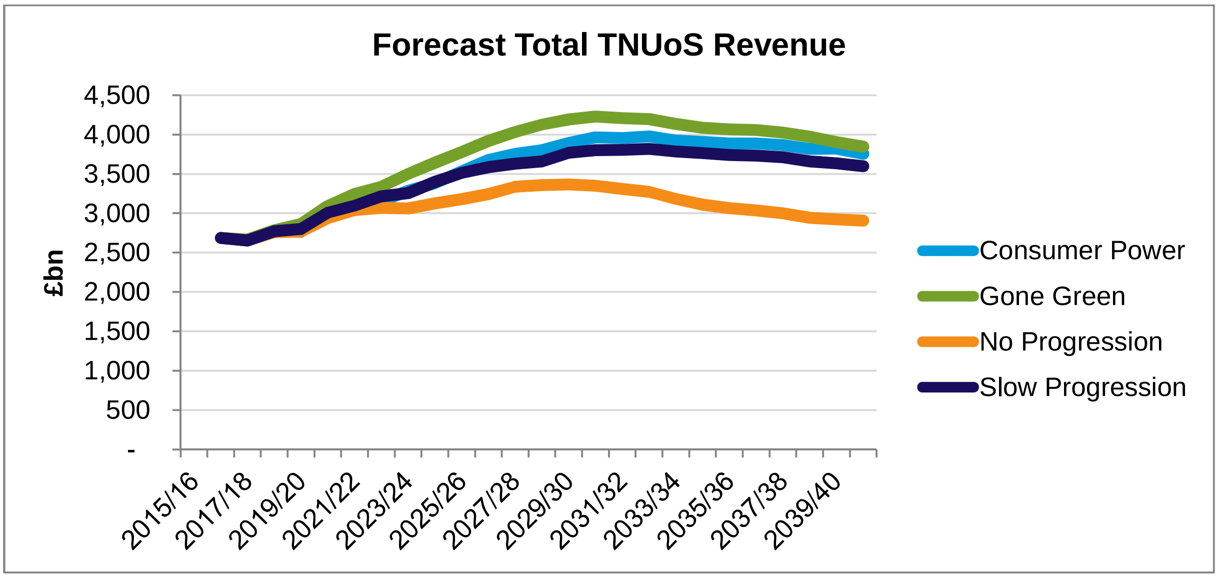


Onshore Networks

For onshore TOs the cost of the network is assumed to be driven by two things – the growth or reduction in winter peak of the transmission net demand, and the quantity of embedded generation connected. Each of these factors has a scaling factor with winter peak contributing more to a change in onshore TO revenue than embedded generation.



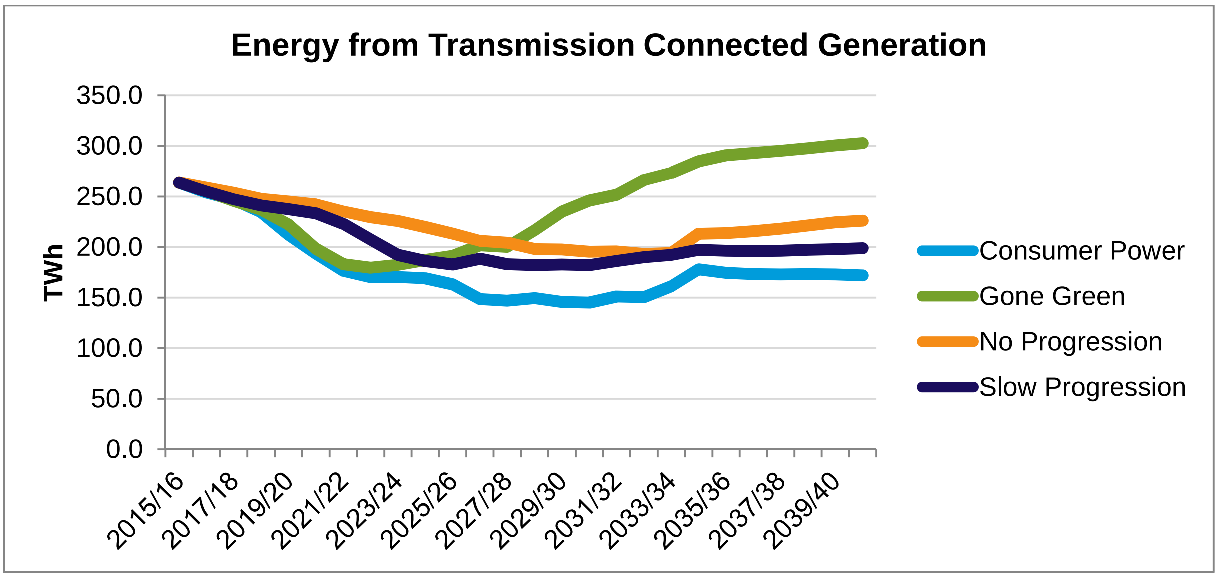
Combining the Offshore and the Onshore components of Allowed Revenues, gives a future total forecast for TNUoS allowed revenue as shown.



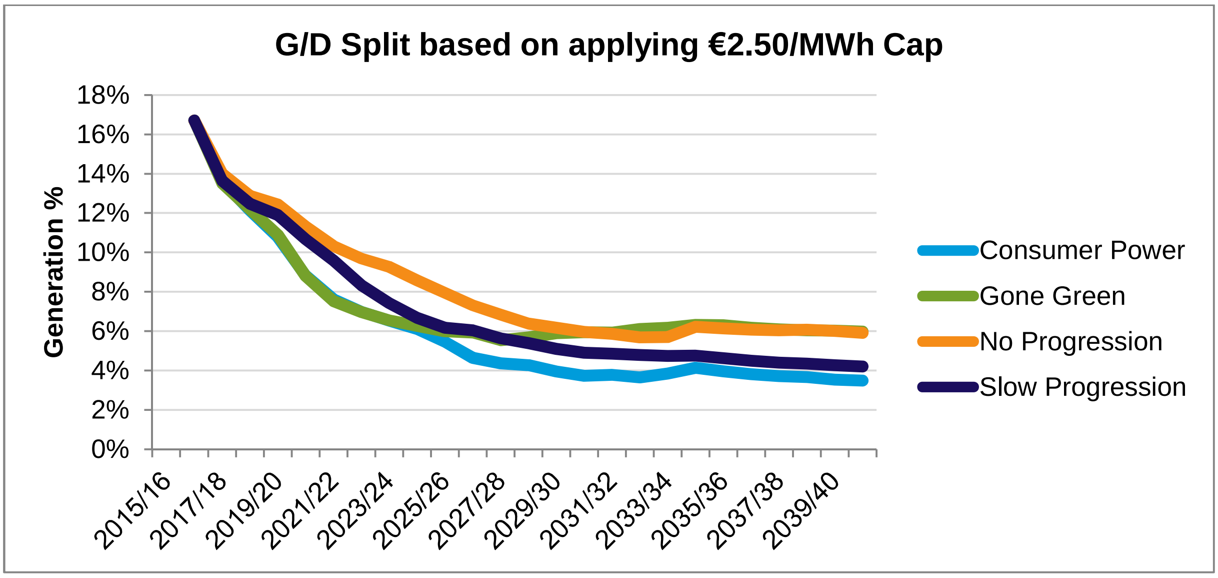
Generation / Demand Split

The first calculation in TNUoS is the split between generation and demand, which allocates sums of revenue to be recovered from Generation and from Demand. This is currently governed by a €2.50/MWh cap from Regulation (EU) No. 838/2010, which applies to the average generation tariff. Note that the €2.50/MWh is not index linked so its value will decrease in real terms over time.

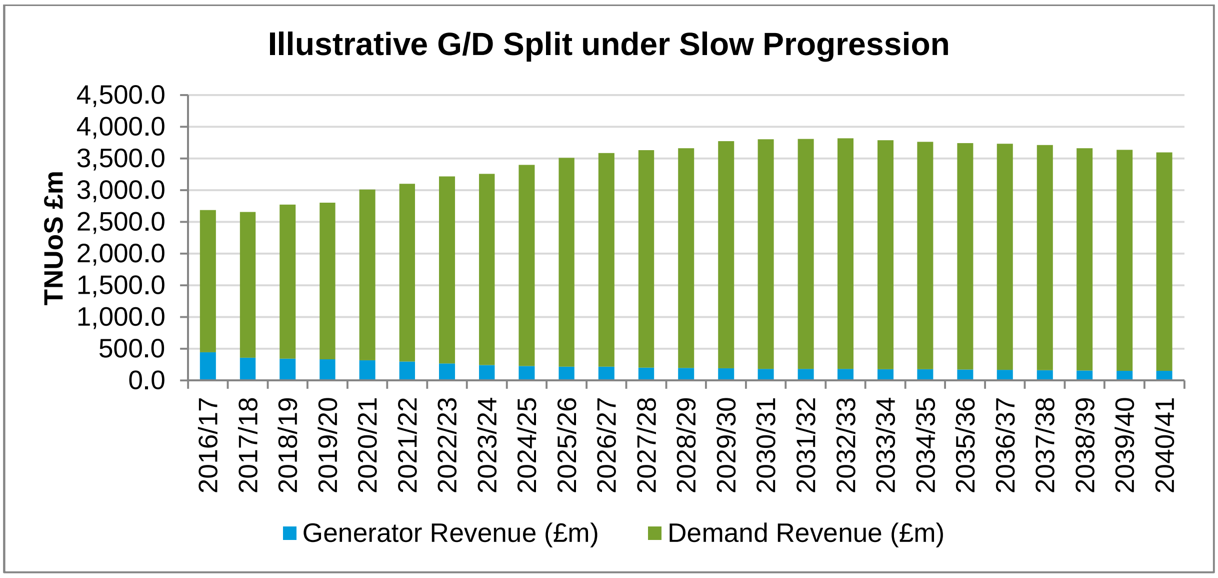
Assumptions must be made about the total energy produced by transmission connected plant that pays TNUoS, in order to convert a “per MWh” cap in to a “per MW” charge. The value of the total energy produced is taken from the FES, and does not include energy produced by interconnectors or embedded plant.



The combination of the €2.50/MWh, an exchange rate assumption (taken from the OBR), and the volume forecast above give a total value in £m that can be recovered from generation. This is typically expressed as a percentage of the total allowed revenue; prior to the European cap the split was 27% for generation, and 73% for demand. Going forward, the effect of the €2.50/MWh cap is that generation pays a reducing share of the total value of TNUoS.



As an illustrative example, under the Slow Progression scenario the following split of TNUoS allowed actual revenue between generation and demand applies.

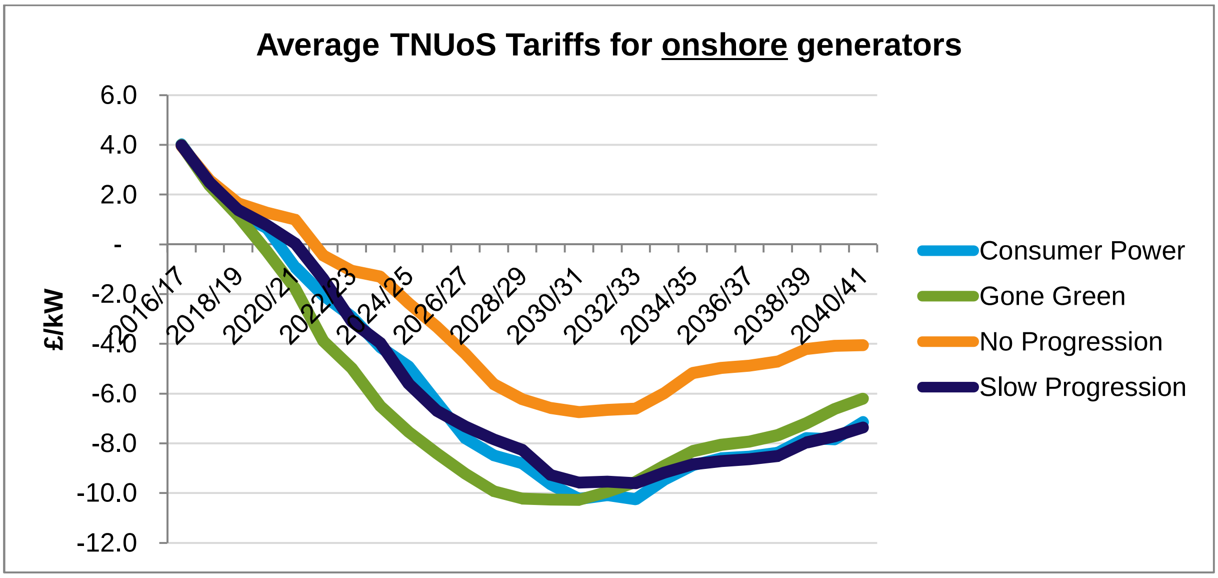


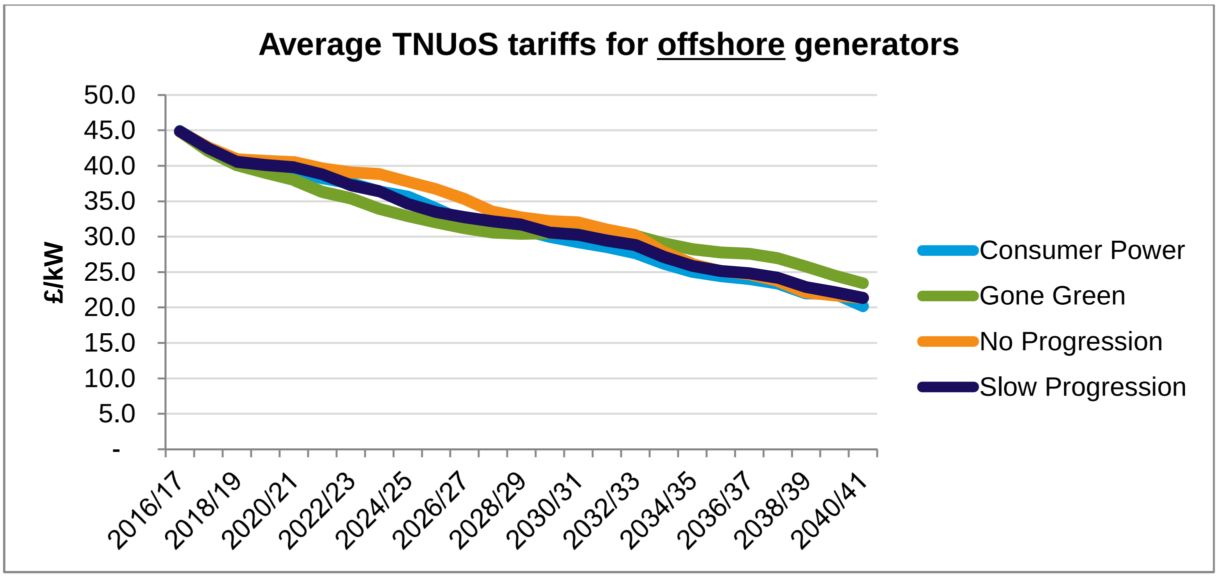
Generation tariffs

The methodology for calculating local circuit charges for offshore local tariffs means that around 75% of the offshore TO revenue is comprised of local circuit costs for offshore generators.

The total values of the onshore locational charges, onshore local circuit charges and onshore substation charges for generators are assumed to scale with the quantity of generation.

The generation residual is used to ensure the total pot of money recovered from the components of generation tariffs (locational, onshore local circuits, offshore local tariffs, local substation tariffs) does not exceed the total permitted under the €2.50/MWh cap. In future, more revenue is recovered from offshore local circuits than is permitted under the cap, which means that the generation residual becomes negative. This means that average onshore tariffs become negative. The consequence of this is that that majority of onshore transmission connected generation would expect to be paid TNUoS, and offshore generators would expect to pay TNUoS.





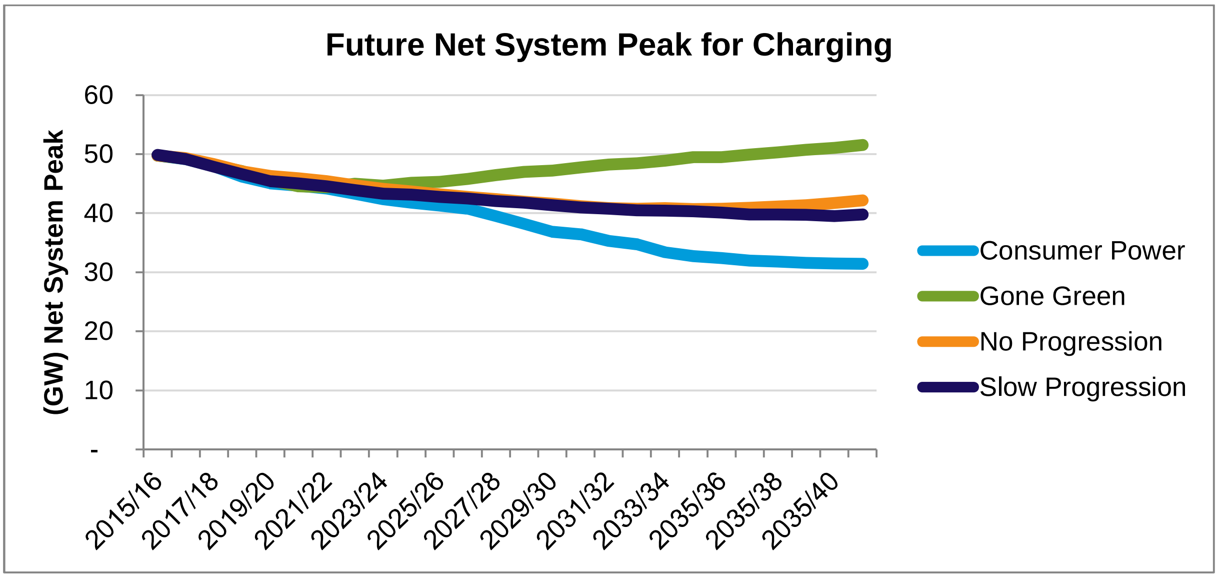
Demand Volumes

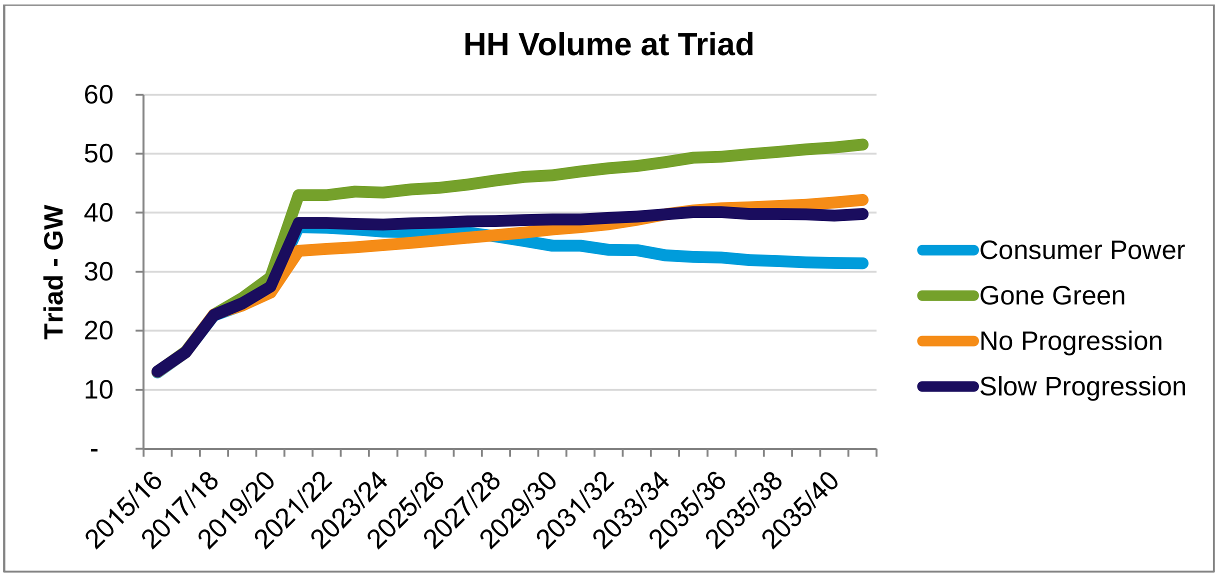
To estimate demand tariffs, there is a need to estimate the chargeable volumes for i) system peak[6], ii) HH volumes[7] and iii) NHH volumes[8]. One of the key features that feeds the split between HH and NHH volumes is the rollout of smart metering, with domestic customers expected to move from NHH charged to HH charged as some point once they have HH smart meters.

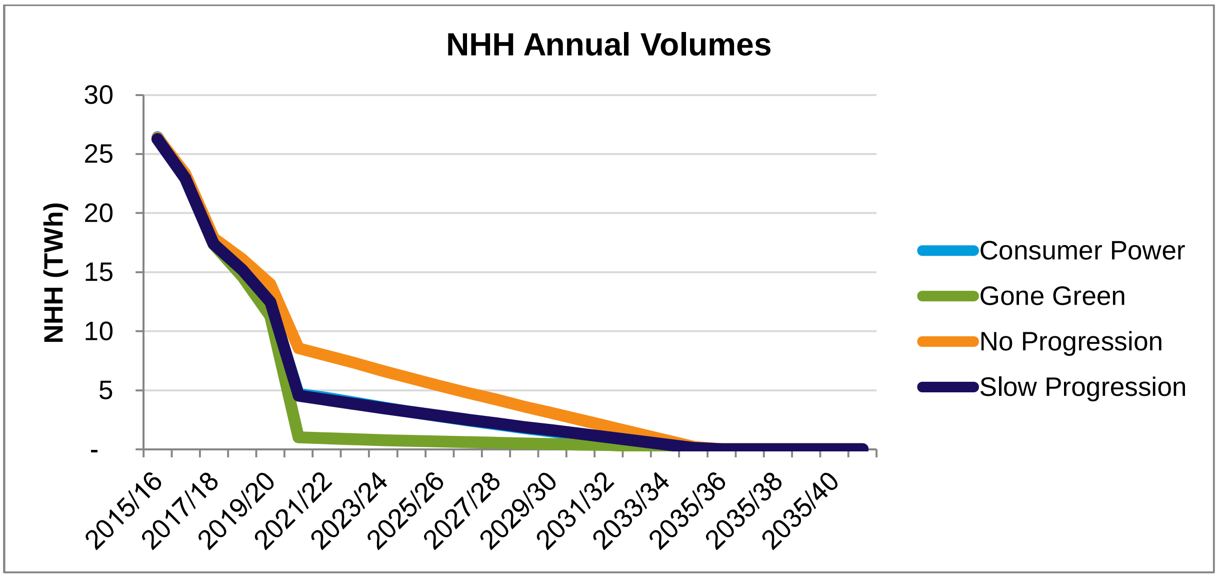
6 This is net system peak – i.e. that seen on the transmission system.

7 HH volumes are for half-hourly settled customers, who are charged a £/kW tariff on the basis of the average energy they use over the three Triad periods.

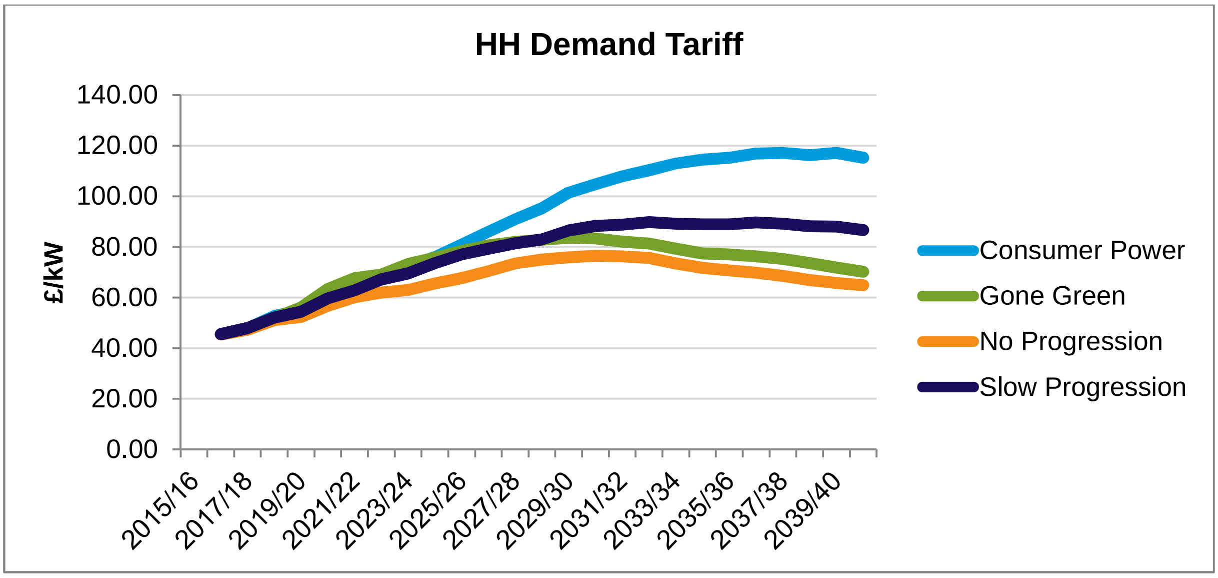
8 NHH volumes are for non-half-hourly settled customers, who are charged a p/kWh tariff on the basis of their profiled usage between 4pm and 7pm over each day of the year.

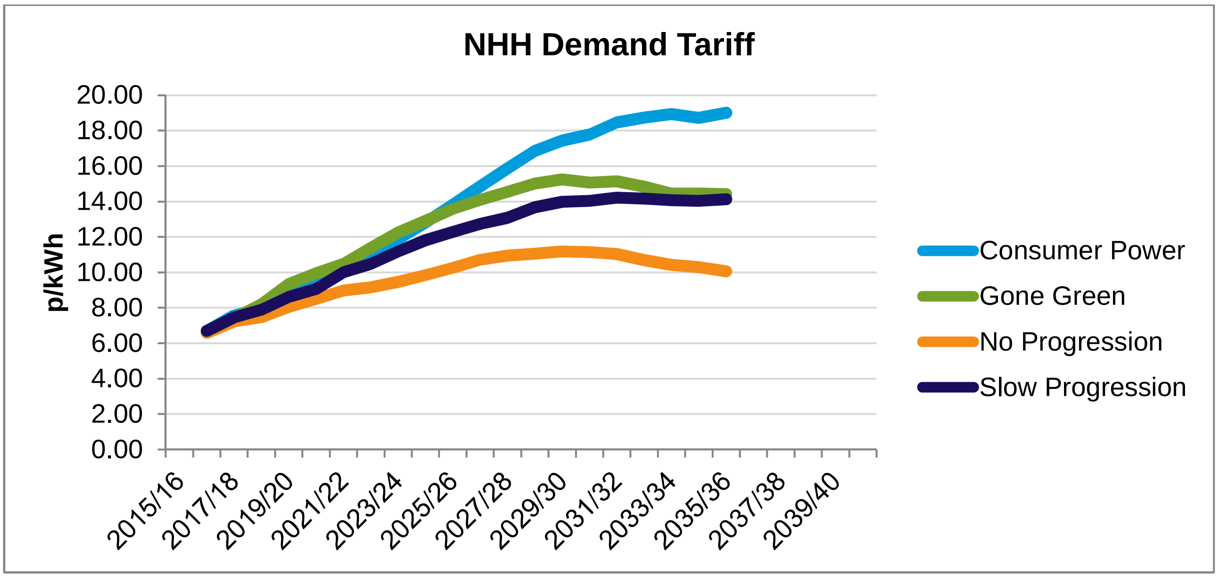

Future Net System Peak for Charging
(GW) Net System Peak
60
50
40
30
20
10
-
2015/16
2017/18
2019/20
2021/22
2023/24
2025/26
2027/28
2029/30
2031/32
2033/34
2035/36
2035/38
2035/40
Consumer Power
Gone Green
No Progression
Slow Progression


HH Volume at Triad
Triad - GW
60
50
40
30
20
10
-
2015/16
2017/18
2019/20
2021/22
2023/24
2025/26
2027/28
2029/30
2031/32
2033/34
2035/36
2035/38
2035/40
Consumer Power
Gone Green
No Progression
Slow Progression


NHH Annual Volumes
NHH (TWh)
30
25
20
15
10
5
-
2015/16
2017/18
2019/20
2021/22
2023/24
2025/26
2027/28
2029/30
2031/32
2033/34
2035/36
2035/38
2035/40
Consumer Power
Gone Green
No Progression
Slow Progression

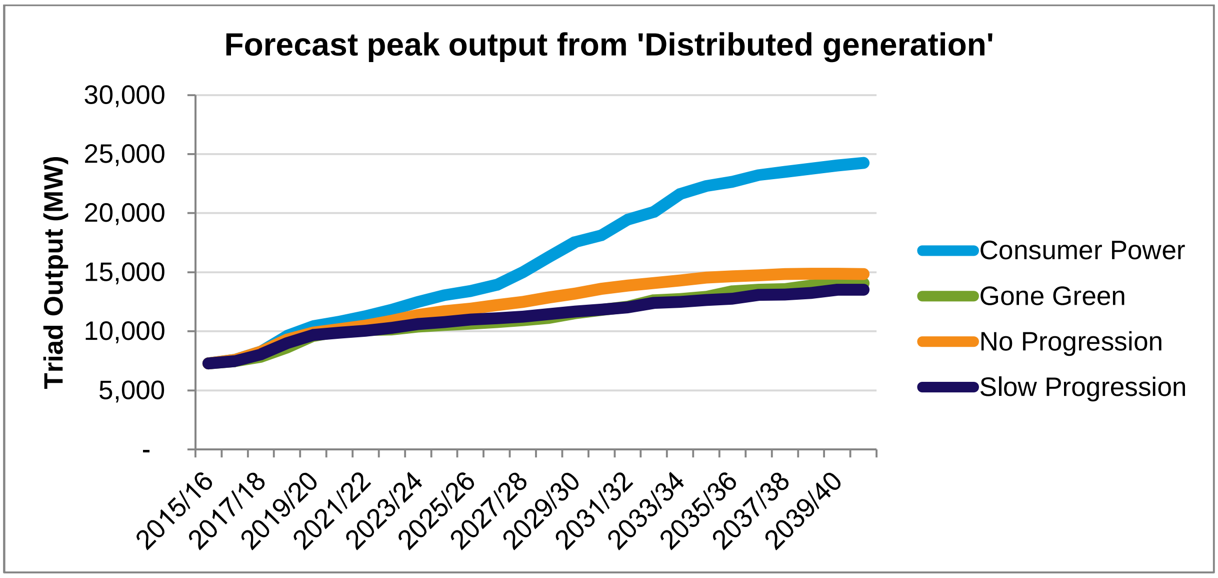
Demand tariffs are then forecast on the basis of the forecast volume of HH and NHH demand, and the total allowed revenue to be recovered from demand. The results are shown in the following graphs. Note there are no NHH tariffs beyond 2035 as it is assumed at this point all households will have been allocated a smart meter and so will be HH charged.

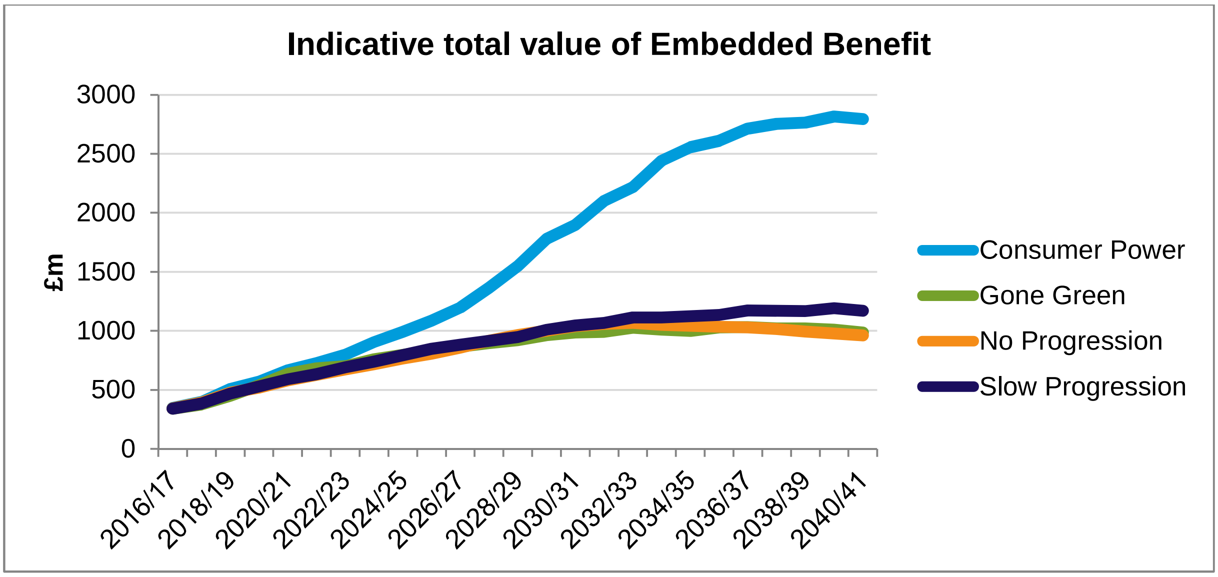




Indicative Total Value of the Embedded Benefit

Demand TNUoS embedded benefit is gained by an embedded generator by outputting at the time of Triad, thereby reducing their supplier's liability for demand TNUoS. The generator receives at most a benefit equal to their output multiplied by the HH demand tariff.





Appendix 2: Summary of Questions asked at the Seminars

Below is a summary of the questions asked at the two seminars. As we have amalgamated the questions from the two seminars, this summary does not cover every question asked.

What are National Grid's views on the other industry reports e.g. ADE/Cornwall Energy Report?

We welcome third party analysis from all stakeholders to help shape the debate. It is only by getting a wide variety of views that we can ensure the review is appropriately scoped and a clear vision can be created. At the charging seminars, we were pleased to welcome external organisations to present on the analysis they had undertaken to a broad audience. We have also tried to ensure that a variety of views are represented to create a balanced debate fully reflecting the areas that you have told us we need to consider.

Paul emphasised the G/D split and 2.50 euro cap in his analysis. Will this remain in place? And if it is removed, does it make his analysis wrong?

Paul's analysis is based on status quo and under this scenario the cap remains in place. CUSC Modification CMP255 was recently approved by the Authority, and as such even if the cap were removed the G% would remain the same. If the cap were removed, Paul's analysis would need updating but only by small amount; and typically the issue of a "negative Generation residual" would be forecast to happen a few years later, as without the €2.50/MWh cap more money can be collected from Generation overall.

How aligned are the industry views on the change needed, and where they are misaligned, how can we manage this?

Views on the overall need for change appear to be broadly aligned. However we understand that views may differ on potential solutions to these drivers. Through the charging review it is critical that all views are heard and given respect, and that any decisions are clearly explained in a timely manner.

What do you see as the impact of Brexit on this work? Will it open up new options for change (for example on the interconnectors)?

The result of the EU referendum presents no immediate driver for change to a Charging Review. This is because the UK remains a member of the Internal Energy Market (IEM), until a post-Brexit settlement is agreed. National Grid believe the IEM provides significant benefits to both UK and EU energy consumers, by way of harmonised rules facilitating energy transportation and increased interconnection, which allows buying and selling energy efficiently. This helps keeping household bills down, and also brings significant benefits in terms of security of supply and integration of low-carbon energy. The IEM also provides a stable framework for UK and European energy companies in which investments can be made.

National Grid believes it is vital that the UK to retains access to the IEM. Energy must now become a key priority area as the Government begins negotiations on how the UK's exit from the EU will be handled. We note that an exit from the European Union could cause significant uncertainty for the energy sector in the medium and long term, in particular with respect to the UK's membership of the internal energy market (IEM).

We don't yet know how storage and other technologies are going to develop (as noted in the FES scenarios), how can we set a long term review in motion when there is so little certainty?

Feedback from stakeholders has supported the need for a proactive management of the way we charge, to move away from the current 'sticking plaster' reactive approach to the charging methodologies. We recognise the future will never be certain but we believe that a long term vision can be set out which allows more clarity to our future charges.

How can we manage the interdependencies between all of these potential changes? Is it possible to understand the consequential impacts when several changes are all being considered concurrently?

We believe that the breadth of change required warrants a holistic review and stakeholders have told us that change needs to be considered in the round; looking at network charges as a whole. We agree with the challenge of managing many interdependent areas of work and believe that the right governance arrangements are critical to the success of a charging review.

How do we see charging changes interacting with the capacity market – will the timings of the CM be taken into consideration?

Stakeholders have told us that we need to consider the broader impacts of changes to charging arrangements and that includes the Capacity Mechanism.

Change causes uncertainty for developers and others making long term investments, what is the Panel's view on how we can minimise/manage the uncertainty caused by a full scale review?

Whilst stakeholders agree with the need for a broad level of change they have also told us they want the period of uncertainty to be minimised. National Grid, Ofgem and industry parties need to consider ways of delivering a process which allows for stakeholder views to be considered whilst progressing change in a timely manner. We also recognise that whilst this period of uncertainty should be minimised, an appropriate approach to implementation timescales needs to be taken to manage uncertainty.