Scottish & Southern Electricity Networks

TRANSMISSION

Transmission Charges

An overview of charges for use of the GB transmission system

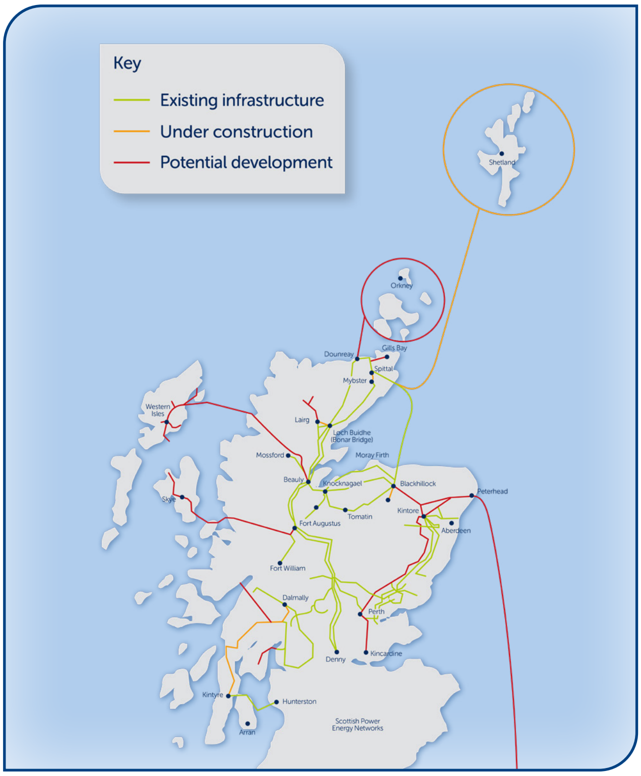
February 2021

Scottish Hydro Electric Transmission plc

www.ssen-transmission.co.uk

About this paper

Scottish Hydro Electric Transmission plc, operating under the name of Scottish and Southern Electricity Networks (SSEN) Transmission, is responsible for the electricity transmission network in the north of Scotland. As the Transmission Owner (TO) we maintain and invest in the high voltage 132kV, 275kV and 400kV network of underground cables, overhead lines on wooden poles and steel towers, and electricity substations, extending over a quarter of the UK's land mass crossing some of its most challenging terrain.



We take electricity from generators and transport it at high voltages over long distances through our transmission network for distribution to homes and businesses in villages and towns.

The north of Scotland is powered by wind and water[1]. Over 80% of the connected generation capacity is renewable energy. This energy powers all of the homes and businesses in the north of Scotland, and around two-thirds is exported onwards to the rest of GB.

An important part of our role as the TO is to provide timely and cost-effective connections for renewable generators. Renewable power from the north of Scotland is critical to the national decarbonisation effort to achieve net zero greenhouse gas (GHG) emissions.

Existing and future generation developers in the north of Scotland tell us that one of their greatest challenges is the current approach to charging for use of the transmission system. Generators express concern over the relatively high cost of these charges (compared to similar generators elsewhere in the UK), the year-on-year volatility of charges and the difficulties in being able to accurately forecast charges. Smaller generators and parties new to the energy industry also say that they find charging hard to understand and engage with. Together these factors are considered to push up the cost of renewable energy generated in the north of Scotland or, at worst, act as a barrier to such renewable generation developments ever being built.

For us, as the TO, the impact of generation developers' concerns over transmission charging has a knock-on impact on our ability to plan and undertake timely and efficient network investment. Put simply, timing and sizing uncertainty for generation developers translates to timing and sizing uncertainty for network investment. We have experienced this most recently, for example, with the Scottish islands, subsidy-free and small distribution-connected developments.

We have listened to the concerns of our generation customers and, with the support of the Electricity System Operator (ESO), undertaken our own analysis of charges for use of the transmission system. The findings of our analysis are presented in this paper.

[1]See North of Scotland Energy Trends, July 2020

Foreword

Aileen McLeod

Director of Business Planning and Commercial

We initiated this analysis of transmission charging following many conversations with our generation customers and wider stakeholders. People have been consistently telling us that charges for transmission access in the north of Scotland, as well as uncertainty about future charges, are acting as a barrier to the development of renewable energy. This, in turn, is making it difficult for us to determine system investment needs.

Our analysis supports these concerns. Transmission use of system charges are indeed many, many times higher in the north of Scotland than elsewhere in GB. The charges for a single generator can swing dramatically from year to year – and this is near impossible to predict. Volatility and unpredictability are not unique to the north of Scotland, but experienced by all generators regardless of technology or location.

Two 'big picture' factors sit uncomfortably with this analysis. First that the cost of the onshore GB transmission system has been largely stable. Ofgem's assessment of the RIIO-T2 settlement is continued stability – costs will fall by around 0.6%. Second is the strength of the national effort for decarbonisation and the energy transition. Government has put in place policies to encourage and support renewable energy. Together these factors, for us at least, raise serious questions about the approach to transmission charging.

We are publishing our analysis to widen the discussion about transmission charging. Our findings suggest there is a case for reform, but we want to hear what others think.

Claire Mack

Chief Executive Scottish Renewables

We welcome the views of wider stakeholders on this issue and are pleased to see this report from SSEN Transmission. The issue of transmission charging is significant not just for our members but also for the future development of renewables projects in Scotland. The analysis presented here shows a clear picture of current policy being out of step with future ambition and objectives. There is no doubt that the infrastructure and systems that we are going to rely upon will need to change – be that by growing or working more efficiently – to enable our path to net-zero. The evidence-base gathered in this report demonstrates that the current charging mechanism is introducing uncertainty at a time when acceleration of deployment, and the associated investment required to enable that, needs greater rather than less certainty. It is also clear that those uncertainties are falling disproportionately on offshore wind, the very technology that can bring the largest volume of low-carbon electricity on to our system and one that already bears a significant risk profile.

The current mechanism was devised for a different time and a different electricity system, and doesn't now recognise the shift in focus of both the UK and Scottish Governments to not just set ambition to meet net-zero but also to put in place legislation to ensure we do so. Transmission charges as they stand reflect neither the need for complementary technologies as part of the new low-carbon energy system, nor the additional wider socio-economic benefits which that development brings. Those benefits include the creation of jobs from developments across the whole of the UK, rather than the very tightly-defined areas where generation has happened in the past.

It's now time for the policies and regulations which underpin electricity transmission to consider not just the location of consumers of energy but also the location of the very best renewable resources in order to build out the projects that will take us further and faster towards net-zero.

The cost of the GB Transmission Network

Allowed TO Charges

The GB transmission network is a natural monopoly. That means there is only one network, with one owner, within a geographic area (Figure 1). In the north of Scotland, this is SSEN Transmission. In the south of Scotland, the network is owned by Scottish Power Energy Networks (SPEN). In England and Wales, the owner is National Grid Electricity Transmission (NGET).

As a natural monopoly, ownership of the transmission network is subject to strict regulation overseen by the national energy regulator Ofgem. Amongst other things, Ofgem sets the maximum amount that the three TOs are allowed to charge each year for use of their networks. Ofgem sets charges every five years in advance through the price control process. The next price control period, termed RIIO-2, is due to start on 1 April 2021.

In the current year 2020/21, the total charges for the GB transmission system[2] were set to recover

£2,399 million

comprising:

£374 million for SSEN Transmission (16%)
£364 million for SPEN (15%); and
£1,661 million for NGET (69%).

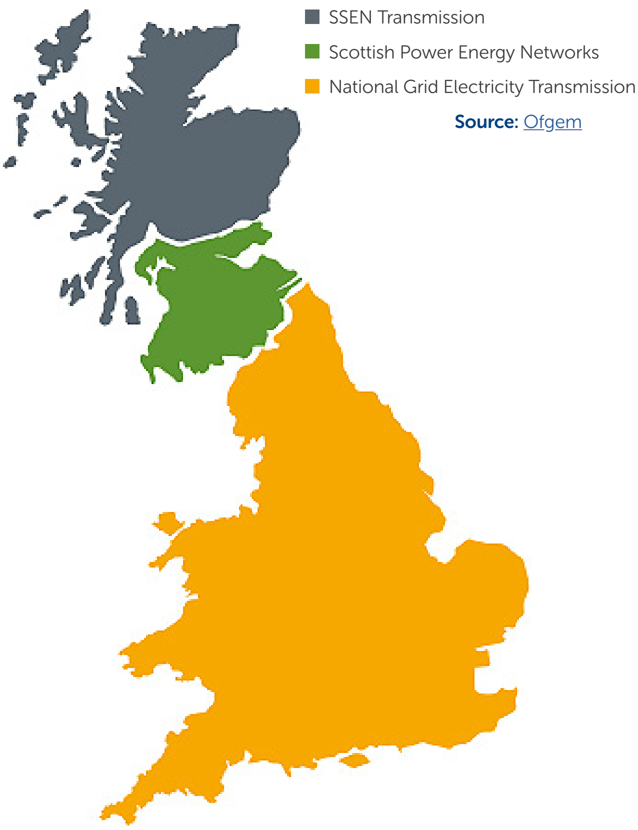


Figure 1 The GB Transmission Owners (TOs)

Role of the Electricity System Operator (ESO)

While the physical infrastructure of the GB transmission network is owned by the three TOs, the job of moving electricity through the network is undertaken by the ESO. It is the ESO that ensures that 24 hours a day, 365 days a year the amount of electricity being generated equals the amount that homes and businesses need across GB. To do its job, the ESO makes use of the GB transmission network. Under industry rules set by Parliament, the ESO is the sole user of the transmission network and so pays the full charges for that use to the TOs (Figure 2). Currently, this is done by each TO sending the ESO a monthly bill for one-twelfth of their annual allowed charge, which the ESO then pays. Ofgem has recently decided to change how this payment system will work in the future.

The ESO then recharges the amount it is billed by TOs to the users of the transmission network – both generators and consumers of electricity. The ESO determines how much each user should pay by applying its Transmission Use of System (TNUoS) charging methodology. The total amount that the ESO is billed each year by the TOs is equal to the total amount that the ESO expects to recover through TNUoS charges.

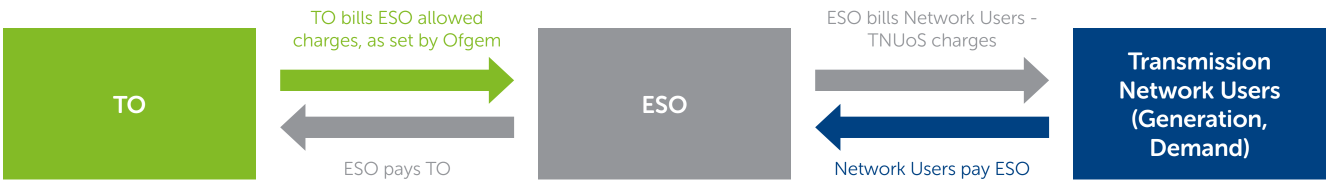


Figure 2 Charging flows for use of the GB transmission network

[2]Final TNUoS Tariffs for 2020/21. TNUoS also recovers the allowed revenue set by Ofgem for Offshore Transmission Network Owners (OFTOs) and pass through costs from the Electricity System Operator (ESO). For the purposes of this paper we have focussed on Onshore Transmission Owners revenue.

Transmission Network Use of System (TNUoS) Charges

Users of the GB transmission system must pay TNUoS charges.

Generators are charged based on their declared capacity, known as Transmission Entry Capacity (TEC). Energy suppliers pay TNUoS based on the actual electricity demand of their customers. Thus:

TNUoS tariff * **TEC *or* Demand** = **TNUoS charge**

Each generator connected to the transmission system has a bespoke TNUoS tariff (see box to the right). For suppliers, the applicable tariff depends on the geographic location of the electricity use. There are 14 regional TNUoS demand tariffs across GB.

TNUoS tariffs are set in January for the upcoming year starting 1 April. The ESO calculates the tariff for each generator and the 14 demand regions using the TNUoS methodology.

As set out in the Connection and Use of System Code (CUSC), the underlying rationale behind the TNUoS methodology is:

"that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems."

This results in TNUoS tariffs that vary by location and change over time to reflect the changing overall use of the transmission network. This is commonly called a marginal cost approach to setting tariffs.

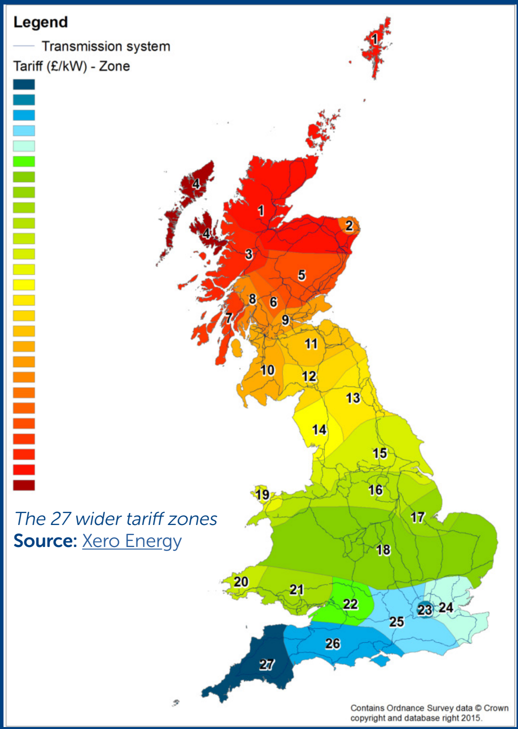
The TNUoS methodology is published in section 14 of the CUSC. Thus everyone can see the methodology and, under code governance rules, signatories to the CUSC can propose amendments to the TNUoS methodology. Such amendments are determined on by Ofgem.

The ESO publishes extensive information on the TNUoS methodology, tariffs and charges, including an annual charging statement and guidance to assist generators and suppliers. An example of the calculation of the TNUoS charge for a north of Scotland generator is shown overleaf.

TNUoS Tariffs for Generators

There are four parts to the generator TNUoS tariff:

1. **Local Circuit Tariff:** this tariff applies to generators that are not directly connected to the Main Interconnected Transmission System (MITS). The local circuit tariff is bespoke to each generator based on the cost and flows on the infrastructure between the connection point and the MITS.
2. **Local Substation Tariff:** there are ten GB-wide tariffs based on voltage, rating and redundancy of the first transmission substation to which the generator connects.
3. **Wider Tariff:** there are currently 27 wider tariffs across GB that apply within specified geographic zones (see map below). The wider tariff is bespoke to each generator in each zone based on its technology and previous output.
4. **Residual Tariff:** this is common to all generators and is set to match TNUoS charges with TO allowed charges.

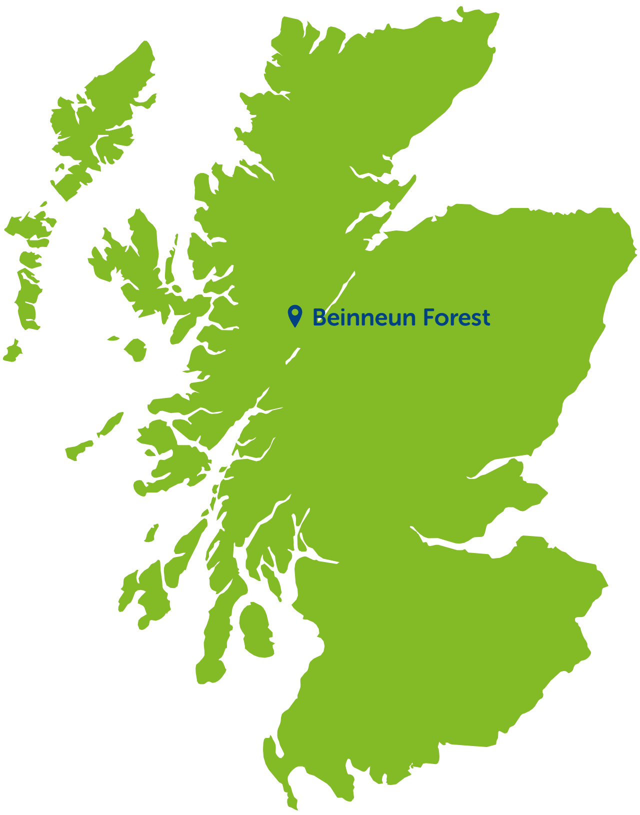


The 27 wider tariff zones
Source: Xero Energy

TNUoS Charge 2020/21: Beinneun Wind Farm

Beinneun Wind Farm is located near Fort Augustus in the Scottish Highlands. It comprises 32 wind turbines, with a total installed capacity of 108.8 MW. It was energised in January 2017.

It is a directly transmission connected generator and so must pay annual TNUoS charges.



Local Circuit Tariff

Where a transmission connected generator is not directly connected to the MITS, the local circuit tariff reflects the cost of overhead lines and cables between the connection and the MITS. Local circuit tariffs are updated annually for inflation and for changes to network use (e.g. new connections).

Beinneun Wind Farm is connected to the MITS at the Fort Augustus grid substation via 15km of 132kV overhead line. The use of this infrastructure is charged for through the local circuit tariff.

Tariff (£/kW)	1.519952
2020/21 Charge (£)	165,675

Local Substation Tariff

Local substation tariffs reflect the cost of the first MITS substation that each transmission connected generator connects to. These tariffs are updated annually for inflation.

Beinneun Wind Farm connects to the GB transmission system at its local 132/33kV substation.

Tariff (£/kW)	0.203179
2020/21 Charge (£)	22,147

Both the local circuit and substation tariffs are derived from a range of TO unit cost data for the relevant type of infrastructure. The cost data used to derive the tariffs are reviewed at the start of each price control period and the tariffs are reset.

Wider Tariff

Wider tariffs are intended to signal to generators the impact to the transmission system of connecting at different locations. As such, wider tariffs vary by geographic location of the point of connection with 27 charging zones across GB.

Beinneun Wind Farm is connected in generation zone 3.

Generation charging zones are reviewed at the start of each price control period.

Wider tariffs also vary by the generator type and historic output levels.Beinneun Wind Farm is an intermittent generator. In 2018/19, its output (load factor) was 37.9%.

For charging purposes, based on two full and one partial year of operation, the load factor for Beinneun is 31.5679%. The load factor for each generator is re-calculated each year based on the three median outputs from the past five years of operation.

There are two wider tariffs for intermittent generators in zone 3: the shared year round tariff and the not shared year round tariff. These two tariffs are determined using the transport model (Figure 3) under two different scenarios for generation operation. The shared year round tariff is pro-rated by the load factor.

The input parameters of the transport model are updated each year. The unit cost data associated with circuit types is reviewed at the start of each price control period.

Shared Year Round Tariff (£/kW)	19.428157
Load Factor (%)	31.5679
Not Shared Year Round Tariff (£/kW)	14.818277
2020/21 Charge (£)	2,283,696

Residual Tariff

The residual tariff is a 'balancing item' and is set to ensure that the average TNUoS charge for all generators does not exceed the legal limit of €2.50/MWh. All generators pay the same residual tariff.

The residual tariff is re-calculated each year.

Tariff (£/kW)	-4.849145
2020/21 Charge (£)	-528,557

Total TNUoS Charge

The total TNUoS charge for the 108.8 MW Beinneun Wind Farm in 2020/21 is **£1.9 million.**

Local Circuit Charge (£)	165,675
Local Substation Charge (£)	22,147
Wider Charge (£)	2,283,696
Residual Charge (£)	-528,557
TOTAL (£)	1,942,961

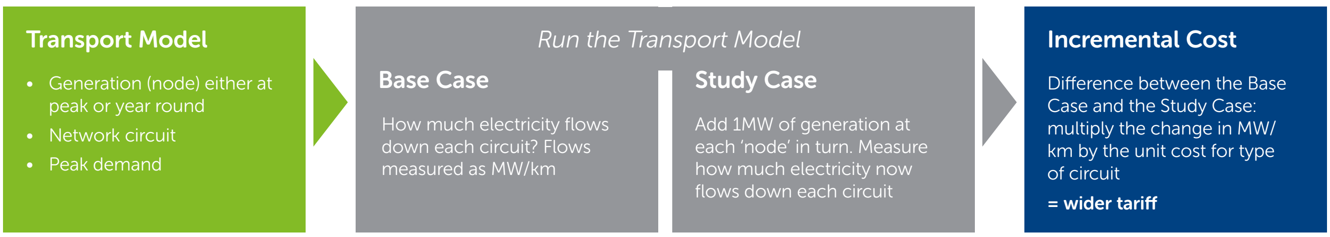


Figure 3 Overview of the transport model used to derive wider tariffs

Concerns with the TNUoS Methodology

Generators' Views

During our day-to-day operations we speak regularly with generators who have sites connected, or are planning future developments, in the north of Scotland.

These generators express concern over the relatively high cost of TNUoS charges (compared to similar generators elsewhere in the UK), the year-on-year volatility of tariffs and the difficulties in being able to accurately forecast charges even a single year ahead. Together these factors push up the cost of renewable energy generated in the north of Scotland or, at worst, act as a barrier to such renewable generation developments ever being built. The impact of TNUoS charges on generators has a knock-on impact on our ability to efficiently plan and invest in the transmission network. Generators express uncertainty, or can change their plans at short notice, in response to changes to the TNUoS tariffs. This creates a significant challenge when planning strategic transmission network investment, which can require up to a decade of planning and construction in anticipation of future generation connections.

Our Analysis

Given the widespread and strongly felt views of north of Scotland generators of TNUoS charges, we have undertaken our own independent analysis of the impact of these charges.

In particular, we wanted to understand how much (if any) of the issues were related to our actions as the TO. If so, what steps were available to us to address generators' concerns. In this regard, we know that the maximum amount that Ofgem allows the three TOs to charge the ESO has been largely stable in recent years and is forecast to remain so (Figure 4).

Our analysis has followed three steps:

First, we identified representative generators of three different technologies (onshore wind, offshore wind and CCGT) located in the north of Scotland, south of Scotland and in England and Wales (Figure 5). As far as possible, the selected generators were chosen to be of similar installed capacity for the technology type. For this population of nine generators, we then used published TNUoS charging information to calculate their wider TNUoS tariff.

Second, using this dataset of wider TNUoS charges, for each generator by technology and by location we:

- Compared the absolute charge paid. This allowed us to assess concerns about the relatively high cost of TNUoS in the north of Scotland (see page 10).
- Measured year-on-year variation in the absolute charge paid. From this, we could assess concerns about the annual volatility of TNUoS charges (see page 11).
- Measured the difference between the forecast TNUoS charge and the actual charge. We did this using forecasts for each of the five years prior to the charging year. This allowed us to assess the predictability of TNUoS charges (see page 12).

Finally, using these results, we sought to understand the underlying reasons and drivers for variability between, and annual changes in, the TNUoS charges paid by different generators. We consider whether these drivers are justified in the prevailing policy environment of reducing greenhouse gas emissions and the transition to a smarter, flexible energy system. We welcome the advice and support that the ESO has provided us in undertaking this work.

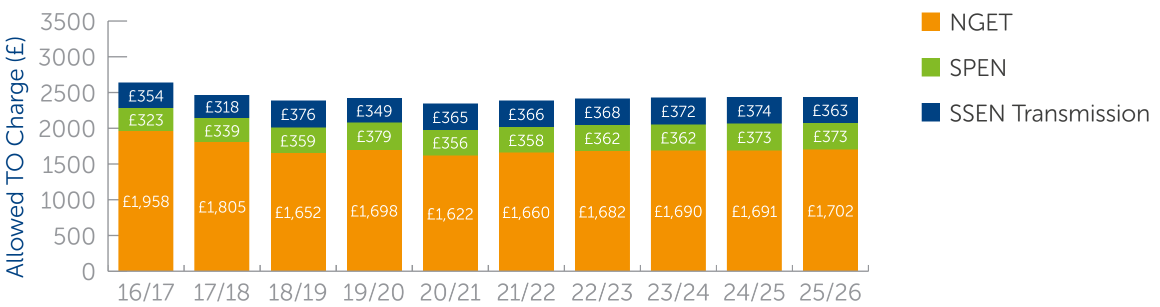


Figure 4 The maximum allowed TO charges (in 2019/20 prices)

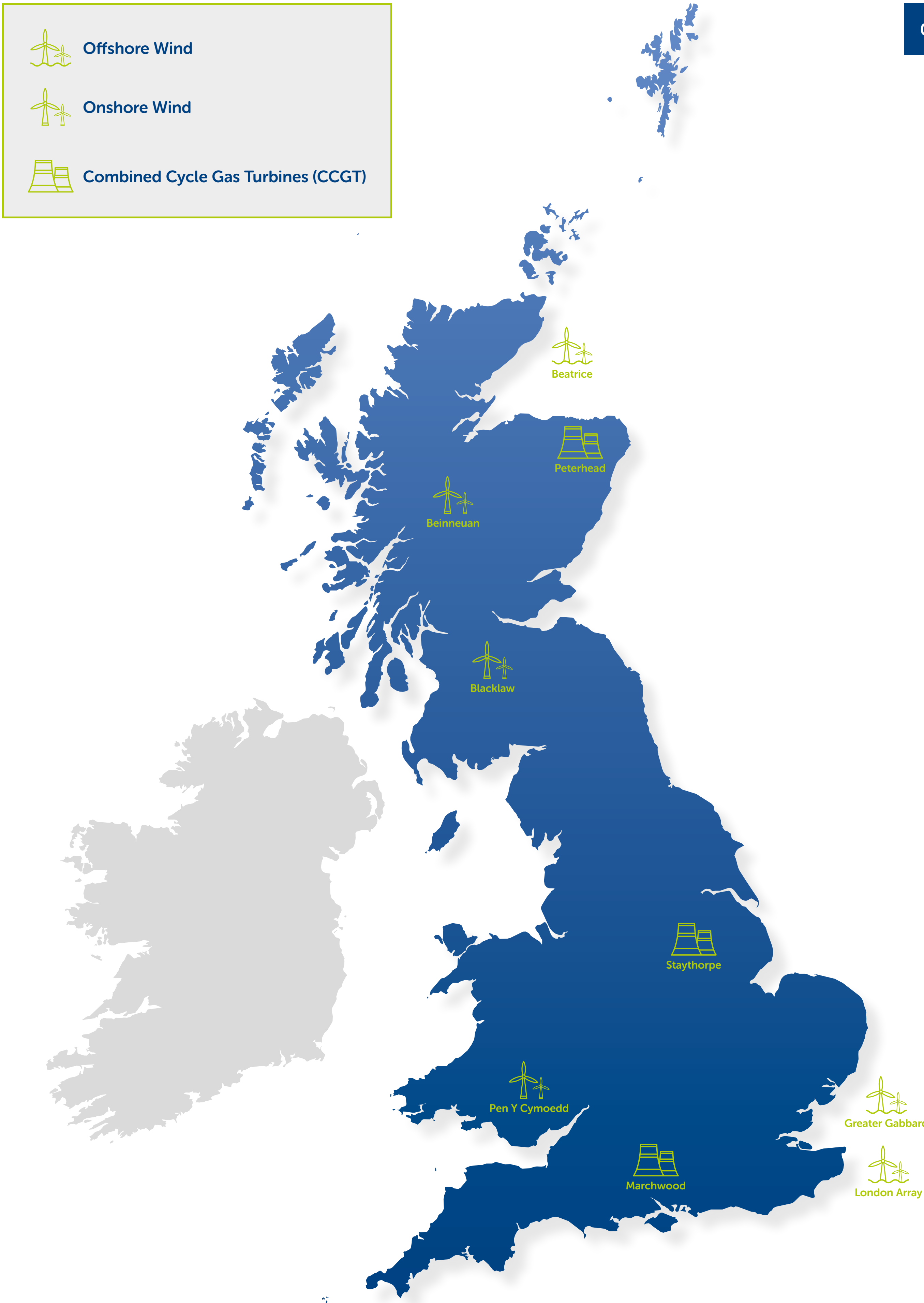
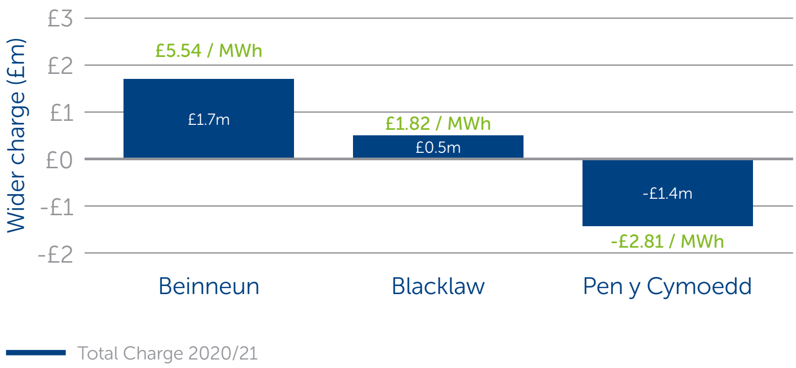


Figure 5 The nine representative generators used in our analysis

TNUoS Charges by Location

The graphs below (Figure 6) compare the wider TNUoS charge (including the residual) paid by each representative generator in 2020/21. The graphs show the total charge paid and the charge paid per unit (MWh) of electricity generated.

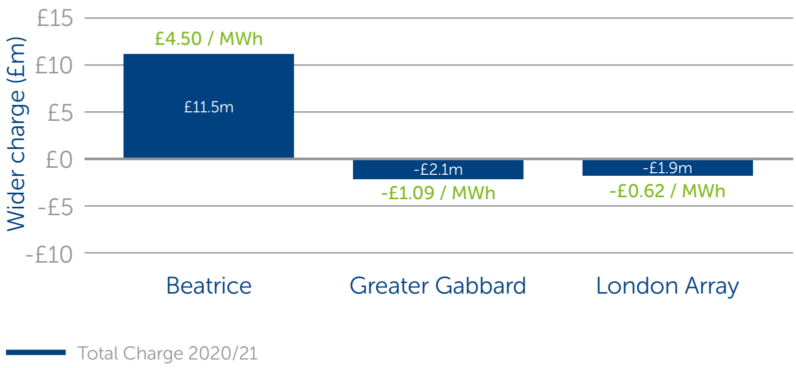
Our analysis shows that the locational differences in 2020/21 are typical of both previous years and those forecast for the RIIO-2 period. Overall, it is clear that, regardless of technology, generators pay significantly higher wider TNUoS charges in the north of Scotland than elsewhere in GB.



Onshore Wind

The declared capacity and load factor for the three wind farms are:

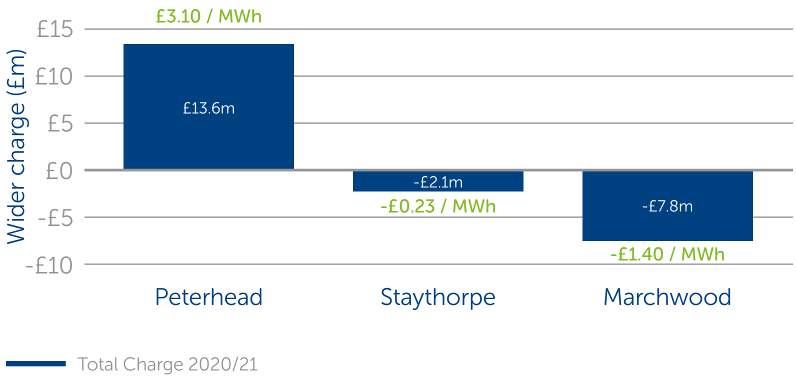
Beinneun 109 MW 32%;
Blacklaw 118 MW 26%;
Pen y Cymoedd 228 MW 32%



Offshore Wind

The declared capacity and load factor for the three wind farms are:

Beatrice 588 MW 49%;
Greater Gabbard 500 MW 44%;
London Array 630 MW 56%



CCGT

The declared capacity and load factor for the three wind farms are:

Peterhead 1,180 MW 42%;
Staythorpe 1,752 MW 61%;
Marchwood 920 MW 69%

Figure 6 Wider TNUoS charge paid: in total and by MWh for representative generators by technology

Year-on-Year Volatility in TNUoS Charges

We have assessed the volatility in wider TNUoS charges by measuring the percentage change in the charge per MWh from one year to the next (Figure 7a-c). To ensure comparability, the charge for each year has been calculated using the actual electricity generated (MWh) in 2019/20.

Figure 7d shows the year-on-year change in the GB-wide residual TNUoS tariff in £/kW of connected capacity. In all graphs, an adjustment has been made to remove the effect of Retail Price Index (RPI) inflation.

Our analysis shows that all generators, regardless of technology or location, experience significant year-on-year volatility in the wider TNUoS charge.

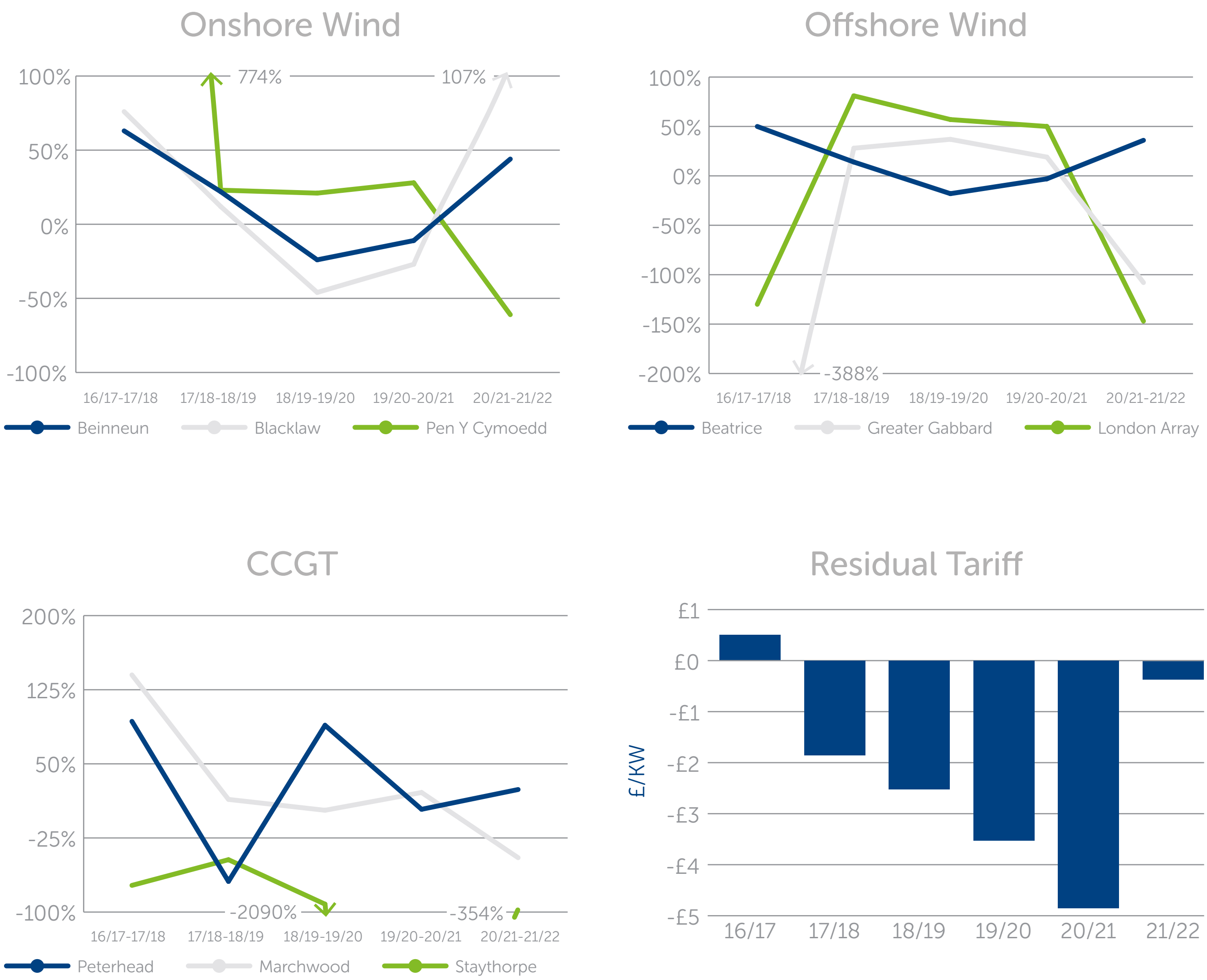


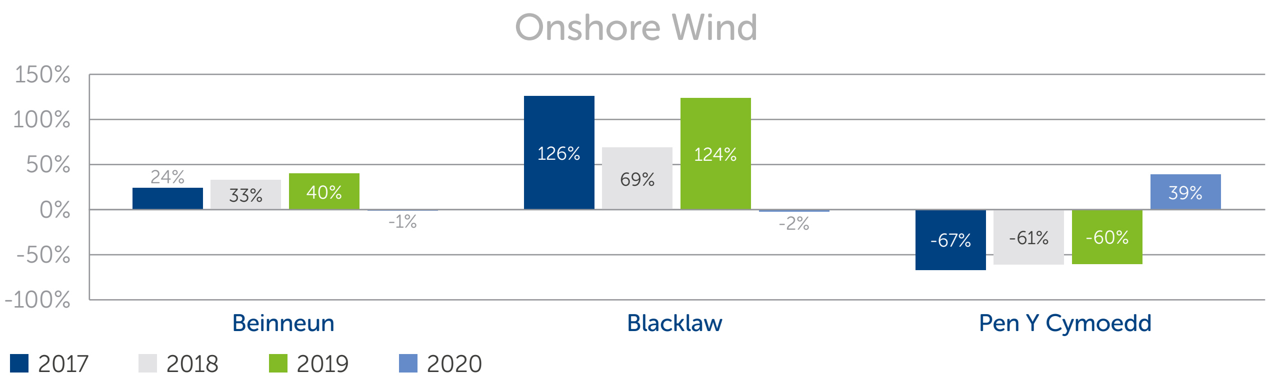
Figure 7 Year on year variation in TNUoS

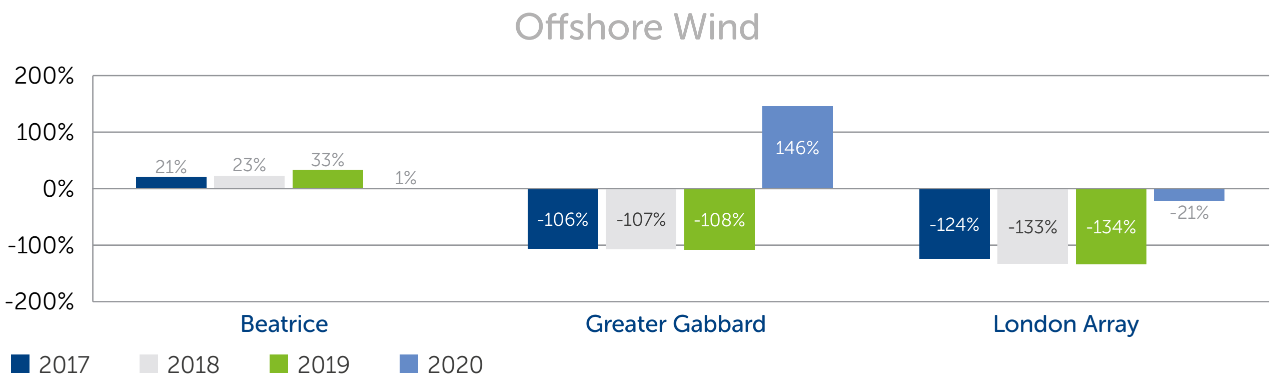
Predictability of TNUoS Charges

The ESO publishes a five year ahead view of TNUoS tariffs, with supporting data and sensitivities. We have used this data to assess the predictability of the 2021/22 wider TNUoS charge for each of the nine representative generators.

The graphs below (Figure 8) show the difference (%) between the final tariffs for 2021/22 charges and the forecast that was published by the ESO between one and five years in advance. An adjustment has been made to remove the effect of RPI and CPIH inflation.

Overall our analysis shows material differences between the forecast charges. This variability is experienced by all generators, regardless of technology or location.





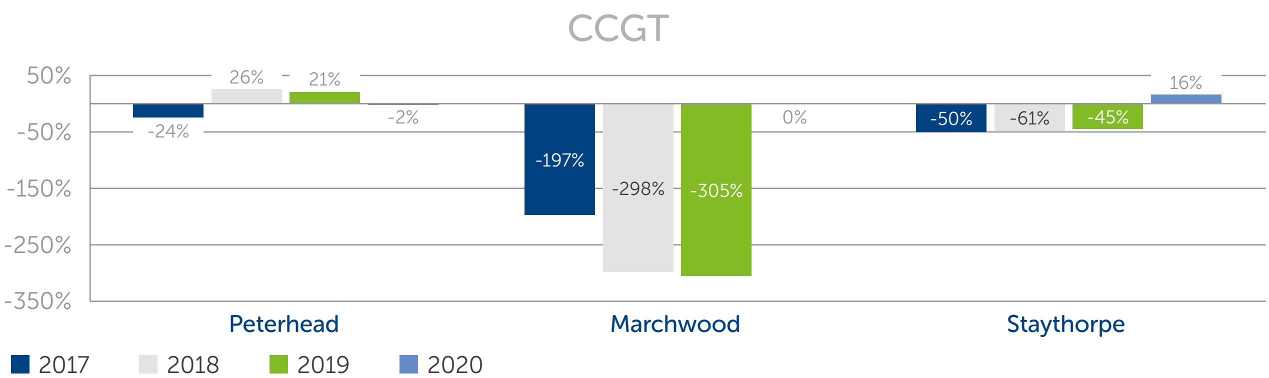


Figure 8 Difference between previous years forecasted charge and actual charge

Our Findings

Concerns with TNUoS Charges

It is evident from the analysis that we have undertaken that the concerns expressed by north of Scotland generators are valid. TNUoS charges are higher than the rest of GB, are volatile and unpredictable.

The potential consequences of these features of TNUoS charging are also evident: contributing risk and uncertainty to the commercial decision to invest in generation in the north of Scotland. Electricity generation is a multi-decade investment and, once made, there is limited opportunity to respond to year-on-year unexpected fluctuations in TNUoS charges.

Risk has a cost, and we expect that TNUoS charging risk will impact on the cost consumers pay for electricity.

However, we assume that there must be good reason for these features of the TNUoS charging regime. We explore this below and question whether there are underlying benefits to consumers that outweigh the disbenefits to generators.

Higher charges in the north of Scotland

Why do generators in the north of Scotland have higher wider TNUoS charges than equivalent generators elsewhere in GB?

As we described on pages 5-7, the TNUoS methodology is designed to have locational differences in the tariff. Locational differences come both from the local circuit and substation charges that are bespoke to each generator, and from the wider charges that apply to generators connected within a geographic zone. The wider TNUoS tariff is intended to provide a forward-looking signal. It does this by deriving the tariff from the notional level of investment that would be required on the network if generation at that location was to increase in capacity. Put simply, the result is:

- Where generation output in an area (such as the north of Scotland) exceeds local energy consumption, then the wider TNUoS tariff is high; and
- In the opposite case (such as the south east of England), then the wider TNUoS tariff is low or even negative.

Hence, while TNUoS is described as a charge for use of the GB transmission system and recovers the TOs costs for the existing system, the tariff is actually set based on the notional investment costs that would be required to accommodate future generators in that area. This is termed incremental, or marginal, cost pricing.

This methodology was developed for England and Wales in 1992, following privatisation, and extended to Scotland in 2005. The clear intention was for TNUoS tariffs to provide a 'signal' that encouraged future generators to build close to consumers.

Nearly 30 years later, it is more challenging to accept the reasoning for this approach to charging for use of the GB transmission system being the most appropriate.

As the GB energy system is decarbonising, there is a reconfiguration of the electricity networks. Historically, networks have been organised to transport power from a small number of large generating stations (coal, gas, nuclear) to homes and businesses. Now, the networks are accommodating both decentralised energy sources (rooftop solar, demand-side response) and remote renewables (onshore and offshore wind). This change is a direct, and essential, response to Government policies that encourage and support clean energy systems.

There is an intrinsic tension between Government policy to transform the energy system and a TNUoS methodology that discourages new generation in locations that require network investment: the Government says build renewables; TNUoS says don't.

Some might point out that more transmission system is needed to transport renewable energy from remote locations. Hence, wider TNUoS charges simply reflect the cost of the network – a 'user pays' principle.

Yet the wider TNUoS tariff is forward looking – generators pay not for their actual use of the transmission system, but based on the notional cost of network investment to connect future generation in the vicinity. As a consequence, charges can be either positive or negative. This is very different from 'user pays'. It is hard to argue that any generator can have a negative use of the transmission system.

To conclude, the wider TNUoS charges in the north of Scotland are significantly higher than elsewhere in GB. This is a consequence of a methodology that derives today's TNUoS charges from the notional costs of connecting new generation in the future.

The reason for this is to send a 'signal' that discourages new generation in remote locations. This both penalises the currently connected generators in the north of Scotland and is contrary to Government policy that encourages and supports renewable energy growth.

Volatility in TNUoS charges

Why do wider and residual TNUoS charges move significantly between years?

Our analysis clearly shows that the wider TNUoS charge paid by generators can change materially from year to year (Figure 7a-c). This, in large part, reflects the number of inputs to the TNUoS methodology that can change each year such as:

- Contracted generation
- Assumed electricity demand
- Power flows from interconnectors
- The model of the GB transmission system
- Methodology changes due to approved code modifications
- RPI inflation applied to network investment costs

At the start of each RIIO price control period (currently every five years) a number of other factors are reset including network investment costs and geographic zones. Certainty over the changes is limited. Most of the input parameters are fixed within the six month period leading up to the start of the charging year. Changes can be made up to the week before final tariffs are set.

The impact of making these changes to the methodology inputs is volatility in wider TNUoS charges. The number of variable inputs and their interdependency within the modelling mean that the impact of combined changes is very difficult to predict (see next section).

This volatility is in sharp contrast to the total allowed revenue of the TOs that TNUoS charges are set to recover. As shown in Figure 4, the cumulative allowed revenue of NGET, SPEN and SSEN Transmission has been stable: within 5% of £2.5 billion over the past five years. Ofgem's assessment for the next five years is for allowed revenue to fall by around 0.6%.

The contrast between the stability in TO revenues and the volatility of the wider TNUoS tariffs can be explained, again, by the difference between actual costs (TO revenue) and sending a forward looking 'signal' (wider TNUoS charges).

The reason for making regular changes to the TNUoS methodology is to ensure that charges are derived using the most up-to-date information about the future. The volatility in TNUoS charges might be seen as reflecting uncertainty about the future – and this is exacerbated during the uncertainty of the clean energy transition.

The materiality of the observed volatility also raises questions about the accuracy of the underlying model. Can all the volatility be attributed to the pace of change and uncertainty about the future, or is it also indicating weaknesses in the model?

This is a difficult question to answer given the 'black box' nature of the TNUoS model. However, from the perspective of the north of Scotland TO, we observe weaknesses in the model's treatment of 'non firm' and refurbishment solutions to the accommodation of new generation capacity.

In summary, volatility is an inherent feature of the TNUoS methodology linked to the objective of sending 'sharp signals' to future generators. The accuracy of these signals is questionable.

Turning to the residual TNUoS tariff, this is in effect a balancing item.

The total amount that can be charged to generators for use of the transmission system is capped by law at €2.50/MWh. The residual TNUoS tariff makes an adjustment to all generators tariff to keep the total amount charged below this limit: as such, it is typically a negative adjustment (Figure 7d).

In recent years, as locational charges have increased, so the negative value of the residual has also increased to keep the overall amount charged within the legal limit.

In late 2019, Ofgem issued a direction to remove residual charges for generators. This change is due to be implemented for the 2021/22 charging year. Eighty four options were identified to make this change.

In December 2020, Ofgem decided on a 'stop gap' measure where an adjustment mechanism can be used if revenues fall outwith the permitted range. Under this, local circuit and substation charges will be excluded from the assessment of the €2.50/MWh cap. Hence the adjustment is likely to be small, if required at all.

Ofgem has asked the ESO to bring forward revised proposals for implementation in 2022/23.
The ESO's assessment of the impact of this decision is shown in Figure 7d.

The setting of the generator residual TNUoS tariff to near zero in 2021/22 (from -£4.85/kW in 2020/21) will have the impact of increasing (or making less negative) TNUoS charges for all GB generators. This will contribute to year-on-year volatility.

Predictability of TNUoS tariffs

What makes TNUoS charges so difficult to accurately predict even a single year ahead?

In our analysis, we have used the five-year ahead reports published each year by the ESO. We assume that the ESO is best placed to predict future TNUoS charges. Also that many network users, especially small parties, will use these reports to estimate their future charges. However, our analysis clearly demonstrates that the ESO's predictions are widely erroneous. The ESO acknowledges this likelihood of error by including sensitivities and commentary on potential changes in its five year ahead reports. Yet even these caveats, with the benefit of hindsight, can be themselves flawed.

Again, this contrasts with the total allowed revenue of TOs which is largely predictable, with the exception of price control determinations. Of lesser magnitude, the timing of some large strategic infrastructure investments can be uncertain. Subject to ascertainment of need and regulatory approvals, the decision to proceed with such investments can impact TO allowed revenue.

Prediction of TNUoS charges is hindered, in part, by uncertainty in forecasting the variables that change each year in the TNUoS methodology, as we describe above. This particularly impacts the wider and residual tariff elements every year. In contrast, the local circuit and substation tariffs are only materially unpredictable every five years at the price control. A further, and in many instances more material, reason for unpredictability in TNUoS tariffs is changes to the CUSC. The methodology for determining, and the eligibility for paying, TNUoS charges is set out in the CUSC.

Summary of CUSC Charging Objectives

- **a.** Facilitates effective competition in the generation and supply of electricity and facilitates competition in the sale, distribution and purchase of electricity;
- **b.** Charges reflect the costs incurred by transmission licensees in their transmission businesses;
- **c.** Takes account of the developments in transmission licensees' transmission businesses;
- **d.** Compliance with the €2.50/MWh legal limit; and
- **e.** Promotes efficiency in the implementation and administration of charging.

All industry parties can propose changes, subject (in most instances) to approval by Ofgem. Proposed changes must clearly explain how the change would better achieve the CUSC Charging Objectives (see box). It is notable that the objectives do not include stability and predictability of tariffs. In addition, there is no explicit regard to Government policy or legislative targets to achieve net zero GHG emissions.

As we described above with the example of the generator residual TNUoS tariff, changes to the CUSC can result in significant changes to TNUoS charges. These changes are hard to predict, as many options might be proposed and ultimately the decision is with Ofgem (or the Courts).

In late 2020, we identify around a dozen proposed modifications to the CUSC that, if approved, would impact upon TNUoS charges in 2021/22 or beyond.

Summary of our findings

- Our analysis supports generators' concerns that TNUoS charges in the north of Scotland are higher than the rest of GB, are volatile and unpredictable
- In contrast, TO allowed revenue is stable and largely predictable
- Higher charges are intended to send a 'signal' to potential future generators not to connect in remote locations – penalising existing renewable generators and acting as a barrier to decarbonisation
- Volatility is an inherent feature of the methodology for calculating TNUoS charges and is exacerbated by uncertainty during the energy transition
- Volatility might also be, in part, due to spurious accuracy in the modelling
- Like volatility, unpredictability is due to uncertainty about future modelling variables and changes to the modelling methodology
- We have not been able to identify any ascribed consumer benefit that would offset the additional risks to generators arising from volatility and unpredictability in future TNUoS charges – we expect these risks feed through to increase the cost of energy to end consumers

Nearly 30 years after it was established, we conclude that there is a strong case to urgently review the transmission charging regime.

We have undertaken the analysis presented in this paper in response to widely and strongly expressed concerns about the current approach to charging for use of the transmission system.

Our analysis supports generators' concerns over the relatively high cost of TNUoS charges (compared to similar generators elsewhere in the UK), the year-on-year volatility of charges and the difficulties in being able to accurately forecast charges even a single year ahead.

Our analysis also shows that the volatility and unpredictability of charges for use of the transmission system are in stark contrast to the stability and predictability of the underlying costs of the transmission system (TO revenues).

Given the national focus on decarbonisation and the energy system transition, the current approach to transmission charging appears out of date.

By publishing this paper, we hope to open a wide ranging and inclusive debate about the need for reform of the transmission charging regime. We actively invite views and contributions from all affected parties from the generators of electricity to the end consumer. We intend to publish the findings of this dialogue in the spring.

If you would like to get involved in this conversation, then please get in touch.

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Data Sources

The analysis presented in this paper has been undertaken using public data issued by the ESO. Key data sources are listed in the table below.

Our analysis has been subject to independent assurance by Baringa Partners LLP to ensure consistent and correct application of the TNUoS methodology and accuracy in data sourcing.

2016/17 Final Tariffs	https://www.nationalgrideso.com/document/50211/download
2017/18 Final Tariffs	https://www.nationalgrideso.com/document/50276/download
2018/19 Final Tariffs	https://www.nationalgrideso.com/document/106726/download
2019/20 Final Tariff	https://www.nationalgrideso.com/document/137351/download
2020/21 Final Tariffs	https://www.nationalgrideso.com/document/162431/download
2021/22 Final Tariffs	https://www.nationalgrideso.com/document/186176/download
2016 5 Year Forecast	https://www.nationalgrideso.com/document/50371/download
2017 5 Year Forecast	https://www.nationalgrideso.com/document/102051/download
2018 5 Year Forecast	https://www.nationalgrideso.com/document/125821/download
2019 5 Year Forecast	https://www.nationalgrideso.com/document/140806/download
2020 5 Year Forecast	https://www.nationalgrideso.com/document/176486/download

Baringa has assured the TNUoS calculations that have been included in this paper. This assurance covers:

- Confirmation that sources used are valid;
- Validation of tariff values, calculation methodology and correct application; and
- Confirmation that values used within the final paper are correct

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