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Dear Grant

**Impact Assessment**

**Charging arrangements associated with GB SQSS design variations based on customer requests**

I am writing in response to the above document that invites views and additional information on the potential impact of NGET's proposed modifications to the TNUoS charging methodology.

The impact assessment specifically seeks views that will contribute to the Authority's analysis of the impact of the proposed change. As an annex to this response, we present a detailed analysis of the proposed discount mechanisms that demonstrates:

- The circuit discount proposed by NGET does not reflect the capital saving made by the TO as a result of constructing a single, rather than double, circuit connection. Our analysis, based on the unit costs of Ofgem's consultants, suggests that the proposed discount reflects only one-third of the actual capital saving made by the TO.
- The substation discount proposed by NGET is extremely sensitive to two assumptions: (i) the size of the power station, and (ii) the design of the substation. A review of 30 new and existing power stations that would be eligible for the discount demonstrates that these

assumptions are unrepresentative and, as a result, the proposed discount is not cost-reflective and, for the majority of stations, too low.

- The proposed discounts assume that the eligible power station is connected to the main interconnected transmission system via a single circuit from the generator into a grid substation. This is an unrepresentative simplification of actual generator-grid connections which are designed to suit the local circumstances of the power station and the transmission network. As a consequence, the proposed discounts are a poor fit for the capital savings that they are intended to reflect.

Our analysis demonstrates that the proposed modifications to the TNUoS charging methodology are not consistent with NGET's obligations to ensure cost-reflective charging. This is inconsistent with NGET's licence conditions, will create arbitrary winners and losers under the methodology and, more fundamentally, will encourage inefficient connection design and hence unnecessary network investment. Consequently we cannot support the discount mechanisms that are proposed by NGET.

However we do support the principle behind the proposed discounts – that if a customer does not have full access to the GB transmission system then that customer should not be liable for full use of system charges. Furthermore we agree with the underlying principle that the discount to the use of system charge should reflect the capital saving made by the TO as a result of the customer opting for a lower connection standard than that specified in the GB SQSS.

The modifications to the TNUoS charging methodology proposed by NGET would result in discounts that, in our opinion, do not reflect the capital savings that would be made by the TO. Our analysis demonstrates that the proposed discounts are not cost-reflective as a result of the unrealistic and simplifying assumptions made by NGET in its methodology. In our view, such assumptions are unnecessary and, given the small number of generators that would be eligible, discounts should be calculated on a site-specific basis and derived, in each case, from the actual capital savings reported by the TO. Such an site-by-site approach would, in our view, be simple and transparent, be consistent with the principle of cost-reflective charging and transferable into the BCA.

Under this approach, the GBSO could provide the generator with the option of a discount derived from actual capital savings reported by the TO. This option would come with information on the local infrastructure that is not compliant with the GB SQSS and the situations when outages on these assets would result in a loss of access rights and no compensation. Further, the generator could be provided with a schedule of planned outages extracted from modelling work for the Seven Year Statement and an indication of the likelihood of other outages. Given these data, the generator would have sufficient information to take a balanced view of the benefits from a lower use of system charge and the costs of the loss of access rights with no compensation as a result of opting for a standard of security lower than that specified in the GB SQSS.

If the generator did opt for a lower standard of security, this would be reflected in the BCA – as is the case now under clause 10 – with the protections that this would afford to both parties under the CUSC. Clearly, should circumstances change in the future (for example, if a further party was to connect to the system or the generator wished to upgrade its connection or there was a change to the GB SQSS) then processes are already in place to address this.

In conclusion, we believe that such an approach would be simple and easy to understand by all industry parties. Further, by applying the same methodology consistently across all sites and linking this to clauses in the BCA, it would clear that no generator was unduly benefiting or being discriminated against as a result of this discount mechanism.

I hope our analysis and comments are helpful to the Authority when coming to a view on the proposed modifications to the charging methodology. If you would like to discuss this further then please give me a call.

Yours sincerely,

**Rob McDonald**
**Director of Regulation**

ANNEX

**Proposal to modify the Transmission Network Use of System charging methodology for the charging arrangements associated with SQSS design variations based on customer requests:**

**Review of the methodology to derive the discounts and the amount of the proposed discounts**

*The principle of cost-reflective charging*

NGET is proposing to modify the TNUoS charging methodology to include mechanisms that would adjust charges to reflect the capital savings arising from a customer request for a lower security standard than specified under the GB SQSS. This change is intended to ensure that an individual customer's use of system charges remain reflective of the cost to the TO of providing that customer with transmission services. The principle of cost-reflectivity is a fundamental component of the charging methodology and is critical to ensuring industry confidence in the tariffs.

This principle of cost-reflectivity is acknowledged in NGET's standard licence condition C5 and is stated by NGET as a key driver of the charging methodology. In the methodology statement, NGET state that the underlying rationale of the charging methodology is that *"charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs … These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy"*.

Hence users pay a use of system charge that is intended to reflect the actual costs incurred by the TO in providing and maintaining a firm network connection. Clearly, if the user does not have a firm network connection then it is correct that the use of system charge is reduced to reflect the standard of connection of that user. As the methodology used to determine the use of system charge is stated to reflect the actual investment and maintenance costs of the TO then, to maintain consistency in the application of the methodology, the reduction to the use of system charge should reflect the lower investment and maintenance costs of the TO as a result of providing a lower standard of connection. It is this rationale that lies behind NGET's proposed discount mechanisms.

This principle is recognised in paragraph 3.30 of the impact assessment: "*It is important … that the discounts that are being proposed accurately reflect the capital cost savings of connecting via a single circuit"*. Although acknowledging this principle that the proposed discounts should accurately reflect the capital cost savings made by the TO, NGET has used different analytical approaches to derive the proposed substation discount and proposed circuit discount.

Furthermore, the derivation of the proposed substation discount uses a very different methodology to that used to determine the general TNUoS tariffs. Clearly, and as noted in paragraph 3.16 of the impact assessment, the use of different approaches could potentially undermine the integrity of the charging methodology – if a number of different approaches are used, then can the principle of cost-reflectivity be maintained?

From the perspective of the system user, other users receiving different treatment will always lead to the question of who is getting the best deal. This, we believe, is the reason for the range of views and contradictory messages that are described in paragraphs 3.7 to 3.10 of the impact assessment.

The purpose of this annex is not to question the principle of the cost-reflective discount – which SSE supports – but rather is to examine the different approaches used by NGET to derive the proposed discounts and, in particular, examine how well the proposed discounts reflect the capital cost savings made by the TO. As TO in the north of Scotland, where a single circuit design is generally the most efficient connection for small remote intermittent generators, SHETL is perhaps uniquely placed to comment on the relationship between the capital savings of the TO and the savings to the generator as a result of the proposed TNUoS tariff discounts.

*Circuit discount*

The proposed circuit discount is intended to reflect the actual capital cost saving to the TO of constructing a single, as opposed to a double, circuit connection. The cost-reflectivity of the proposed discount is not easy to establish as the discount is not derived from actual capital cost data, but rather is determined by multiplying the length of the second circuit that is not constructed by the expansion constant used in the TNUoS charging methodology. The expansion constant is a proxy for the capital investment required for system expansion.

The simplest way to examine the cost-reflectivity of the proposed circuit discount is through a worked example. In Appendix 3 to the impact assessment, NGET has provided a simple example of the application of the discount to a 110 MW generator connecting to the main interconnected transmission system with 14 km of 132 kV overhead line. This generator is located in tariff zone 9, South Scotland, where in 2006/07 the tariff is £12.14/kW. Hence the 2006/07 use of system charge is 12.14 * (110*1000) = £1.335 million.

The proposed circuit discount for this example generator is calculated using the parameters in the charging methodology as shown below.

132 kV overhead line expansion factor = 2.61

Expansion constant (£/MWkm) = 10.07

$$\text{Discount} = \frac{\text{Single circuit length (km) * Expansion factor * Expansion constant (£/MWkm)}}{1000}$$

$$= \frac{14 * 2.61 * 10.07}{1000}$$

$$= £0.37/\text{kW}$$

Hence the annual charge after the discount is (12.14-0.37) * (110*1000) = £1.295 million. This is a saving to the generator of £0.040 million or 3% of the undiscounted charge.

For this discount to be cost-reflective, the annual saving to the generator should be equal to the annualised value of the capital saving made by the TO as a consequence of constructing a single rather than a double circuit overhead line. As shown above, the annual saving to the generator is £0.040 million. The annuity factor used in the charging methodology is 0.066; hence the implied total capital saving made by the TO is 0.040/0.066 = £0.606 million.

In order to examine whether £0.606 million a good approximation of the actual capital saving that would be made by the TO as a result of constructing 14 km of single circuit 132 kV overhead line rather than 14 km of double circuit 132 kV overhead line we have used the unit cost data of Ofgem's consultants, KEMA, at the recent transmission price control[1].

Table 11 of KEMA's report on Scottish Power's asset management shows KEMA's unit cost data for individual assets. These data are presented in 04-05 prices and so have been inflated using RPI to 06-07 prices (+5.8%) for the purposes of this analysis. Further, we have made the assumptions that:

- A single circuit connection would comprise: 14 km 132 kV conductor, 14 km earthwire, 49 132 kV steel towers.
- A double circuit connection would comprise: 28 km 132 kV conductor, 14 km earthwire, 49 132 kV steel towers.

These assumptions minimise the difference between the capital costs of a single and double circuit connection. This is because the costs for double circuit steel towers have assumed. In practice, if the customer opted for a single circuit connection this would be constructed either using a wood pole line or a lighter construction single circuit steel tower line (both of which would be significantly lower cost than a double circuit steel tower line); however, we have not included this in our analysis as KEMA did not publish unit costs for single circuit lines.

[1] Review of electricity transmission asset management policies and processes of Scottish Power Transmission Ltd: Assessment of Electricity Transmission Asset Management. Report by KEMA for Ofgem, July 2006.

| **Single circuit** | Unit cost (£m/unit) | Units | Total (£m) |
|---|---|---|---|
| Conductor 132 kV | 0.14 | 14 | 1.96 |
| Earthwire | 0.06 | 14 | 0.84 |
| Steel tower 132 kV | 0.15 | 49 | 7.35 |
| | | | **£10.15 m** |

| **Double circuit** | Unit cost (£m/unit) | Units | Total |
|---|---|---|---|
| Conductor 132 kV | 0.14 | 14 * 2 | 3.92 |
| Earthwire | 0.06 | 14 | 0.84 |
| Steel tower 132 kV | 0.15 | 49 | 7.35 |
| | | | **£12.11 m** |

For NGET's example, and based on the assumptions above, the difference in capital cost between a single circuit design and a double circuit design is the cost of 14 km of 132 kV conductor. This difference is £1.96 million. This is significantly greater than the £0.606 million difference implicit in the proposed circuit discount.

This analysis, in our view, clearly demonstrates that the amount of the proposed circuit discount is not cost-reflective. The capital saving made by the TO as a result of constructing a single rather than double circuit connection is significantly in excess of the saving that would be passed on to the generator through the proposed circuit discount.

For the example given by NGET in the impact assessment, the proposed discount is £0.37/kW or an annual saving to the generator of £0.040 million. Based on KEMA's unit cost data, the actual capital saving to the TO would be £1.96 million. Using the annuity factor in the charging methodology, this equates to an annual capital saving of £0.13 million, or more than three-times the proposed annual saving to the generator. For the discount to be cost-reflective, our analysis suggests that the discount to the TNUoS tariff should be £1.12/kW rather than £0.37/kW. Our analysis is summarised in the table below.

| | Basis for determining discount to TNUoS tariff: | |
|---|---|---|
| | NGET charging model | Actual capital saving - KEMA unit cost data |
| Proposed/cost-reflective discount (£/kW) | 0.37 | 1.12 |
| Annual saving to generator/TO (£m) | 0.040 | 0.13 |
| Total saving to generator/TO (£m) | 0.606 | 1.96 |

In conclusion, while in principle we support the circuit discount, we believe that the discount that is offered should be cost-reflective. The analysis we have undertaken, in our view, clearly demonstrates that the proposed circuit discount is not cost-reflective. On this basis, we cannot support the circuit discount as it is proposed by NGET. As we explain in the covering letter, we believe that the discount should be determined on a site-specific basis and reflect the actual capital saving made by the TO as a result of providing a lower standard of security (as set out in the generator's BCA).

*Substation discount*

In contrast to the proposed circuit discount, the proposed substation discount is derived from the actual costs for a range of substation assets as submitted to the GBSO by all three TOs. The average cost differential (capital) presented in NGET's October 2006 consultation document is consistent with our view of the actual capital saving that would made by a TO as a consequence of procuring and installing the lesser substation assets specified in the information request.

However, the annual cost differential, shown in the same table in the October 2006 document, is not calculated in a consistent manner to other equivalent annualised capital costs in the charging methodology. The charging methodology uses an annuity factor of 0.066. In this instance, an annuity factor of 0.082 has been used. This is illustrated in the table below. A higher annuity factor implies either a higher rate of return or a shorter asset life.

| | 33 kV substation (£k) | 132 kV substation (£k) | 400 kV substation (£k) |
|---|---|---|---|
| Average cost differential (capital) | 1,900 | 1,400 | 4,700 |
| Average cost differential (annual) | 156 | 115 | 387 |
| Annuitisation factor | 0.082 | 0.082 | 0.082 |
| Average cost differential (annual) - annuitisation factor of 0.066 | 125 | 92 | 310 |

This observation notwithstanding, the methodology used to derive the proposed substation discount appears cost-reflective. The actual capital savings made by the TO set out in the table above are converted into an annualised saving over the life of the asset, and this is used to derive a discount to the TNUoS tariff.

There are, however, two key assumptions made in the derivation of the proposed TNUoS tariff discount:

1. The design of the substation; and
2. The size of the power station.

It is these assumptions that underpin the amount of the proposed discount and, as raised in paragraph 3.11 of the impact assessment, the differences between the amounts proposed at the three voltages. In essence, these assumptions “standardise” the discount and deviations from these assumptions will affect the cost-reflectivity of the discount as described below.

We consider first the design of the substation. NGET’s analysis assumes that the generator connects to the main interconnected transmission system at an existing grid substation and, hence, the TO can make savings by installing a lesser number of assets in the substations to facilitate the new connection. On this basis, the GBSO requested from the TOs costs for substation designs at three connection voltages. This information request is described in Appendix 2 of NGET’s conclusions report, and the type and number of assets to be costed at each voltage are shown in the table below.

| Substation | Asset | Single circuit | Double circuit |
|---|---|---|---|
| MITS | Feeder bays | 1 | 2 |
| New connection | Busbar arrangement | Single | Double |
| | Bus coupler | 0 | 1 |
| | Feeder bays | 1 | 2 |
| | Skeletal bays | 2 | 2 |
| | SGTs (33 kV only) | 1 | 2 |

The substation discount proposed by NGET is based on the actual capital costs to the TO of those assets described in the table above. However, every generator has a unique connection design. If additional substation assets to those described by NGET are required, then the saving to the TO would be greater than that made by the generator through the substation discount. Conversely, if lesser substation assets are required, the saving made by the generator would be greater than that made by the TO. Hence, while the difference in capital costs for the single and double circuit configurations are cost-reflective; it is only cost-reflective for the configurations described in NGET’s information request.

Similarly, in order to derive the proposed substation discount, NGET has made an assumption regarding the typical power station size at each voltage as shown in the table below.

| | 33 kV | 132 kV | 275/ 400 kV |
|---|---|---|---|
| Average cost differential (annual) (£k) | 156 | 115 | 294 |
| Typical power station size (MW) | 50 | 110 | 600 |
| Proposed discount (£/kW) | 3.12 | 1.05 | 0.49 |

The average annual cost differential at 33 kV for the substation assets described above is £156,000. Divided by NGET’s typical power station of size at this voltage of 50 MW, the proposed discount is 156,000/50,000 = £3.12/kW. Hence, while the proposed discount is cost-reflective for a power station of that size, the methodology used means that it is less cost-reflective for other sizes of station. For example, a station of half the size (25 MW) should, for the discount to be truly cost-reflective, be eligible for twice the amount of discount, i.e. 156,000/25,000 = £6.24/kW.

In order to be cost-reflective, the discount would have to be produced on a generator-by-generator basis using the actual capital savings of the TO and the TEC of the station. It is understandable that to produce a simple discount mechanism NGET have chosen to make these simplifying assumptions. However, given that the discount is very sensitive to these assumptions, it is valid to question the basis of these assumptions – how representative are the generic substation designs and power station sizes of generators either connected or likely to connect at a standard lower than that specified in the GB SQSS?

For the purpose of this impact assessment, we have undertaken a review of:

- Twenty operational SSE Generation power stations with a standard of connection to the main interconnected transmission system that is lower than that specified in the GB SQSS; and
- The first 10 applicants in the GB queue located in the SHETL operational area where, in our view, the most efficient connection design would be to a lower standard than that specified in the GB SQSS.

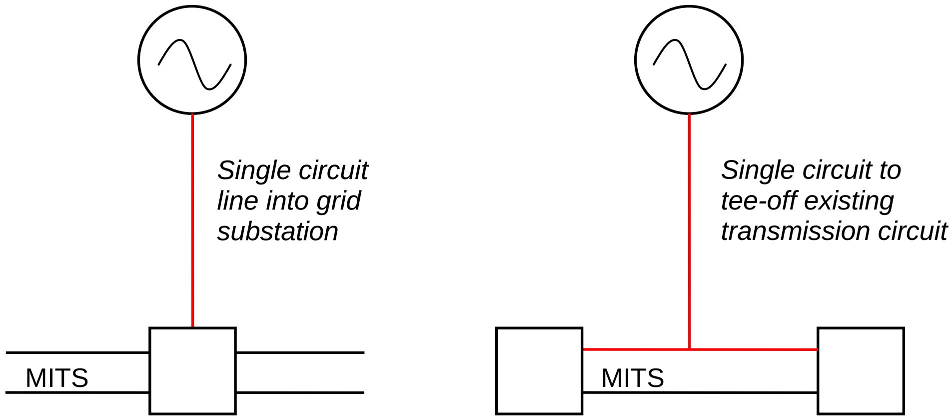
There are two key observations from this analysis:

1. The assumptions made by NGET for the infrastructure design do not reflect the wide range in actual designs for new connections to the transmission system. Indeed, of the 30 power stations we reviewed, only one has an infrastructure design broadly equivalent to that assumed by NGET.

   Our analysis shows that the connection design for every generator is unique. The ‘typical’ configuration proposed by NGET assumes that a non-firm connection comprises a new build single circuit from the substation at the power station into an existing grid substation. This is rarely the case and two common variations from this are worth comment:

   – Firstly, that the point of connection with the main interconnected transmission network is commonly not at a substation but rather a tee-off requiring a tower rebuild and downdroppers. A design of this type is used for 18 of the 30 power stations that we reviewed. This infrastructure design is schematically illustrated, with that assumed by NGET, below and the length of single circuit connection in each illustration is shown in red.

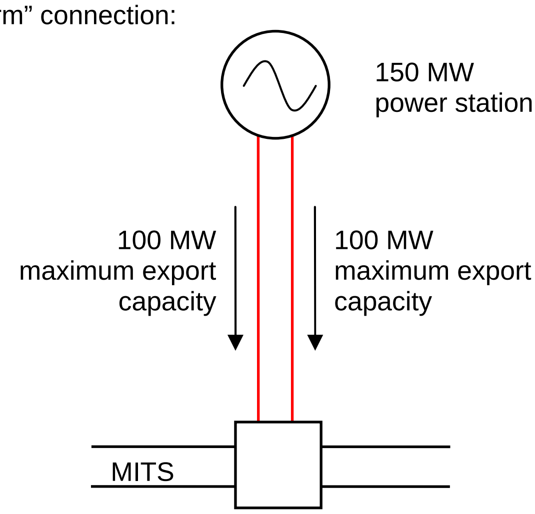
NGET assumption: Actual infrastructure:




This connection design avoids the need to build a new substation at the point of the tee-off; the cost of a new tower and downdroppers is significantly lower than the cost of a new substation. Further, depending on the existing load, this design may avoid the need to undertake additional deep system reinforcements on the existing transmission line. The result is significant savings to the TO that are not captured in NGET's proposed discount mechanisms.

– Secondly, that the connection may comprise multiple lines that each has the capacity to transmit only a proportion of the generators output. A design of this type is used for 10 of the 30 power stations that we reviewed. This means that the generator is "partially firm" such that the loss of one line would result in the loss of a proportion of the station output as is illustrated in the schematic figure below.

"Partially firm" connection:



In this illustration, the generator has a TEC of 150 MW. The capacity of each of the two circuits connecting the power station to the main interconnected transmission network is 100 MW. Hence, if one of these lines was unavailable, the maximum export limit on the generator would be reduced to 100 MW; that is, two-thirds of the TEC. For a standard of connection compliant with the GB SQSS, either a third circuit would be required or the ratings of the existing lines would need to be increased. The capital cost of these works is the saving to the TO that is intended to be captured in the proposed discount.

The illustrations given here are necessarily schematic and do not capture the wide range of infrastructure designs available to facilitate new connections to the transmission network. It is true to say that every generator is unique and the design of the transmission connection depends on local circumstances including the characteristics of the existing grid. It is not clear how such inconsistencies between assumed and actual connection designs would be dealt with if the proposed discounts were implemented.

2. The ‘typical’ power station sizes proposed by NGET, while possibly reflecting a GB-average size, do not reveal the wide range in station sizes that connect to the transmission system. Our analysis shows that there is a wide range in power station sizes connecting at both 132 kV and 275 kV, as summarised in the table below. Of the stations we reviewed, the key factor in determining the connection voltage of an individual station appears to be the voltage of the nearest existing transmission circuit rather than the size of the power station.

| | NGET | Our analysis | | |
|---|---|---|---|---|
| | Assumption: typical station size (MW) | Number of stations | Range of station size (MW) | Average station size (MW) |
| 33 kV | 50 | 0 | n/a | n/a |
| 132 kV | 110 | 25 | 15-226 | 60 |
| 275 kV | 600 | 5 | 67-1,524 | 420 |
| 400 kV | 600 | 0 | n/a | n/a |

On average, for these 30 power stations, the ‘typical’ station size assumed by NGET is too low. Hence the proposed substation discount is too low. Overall, if all 30 generators were eligible for a discount, NGET’s assumption on ‘typical’ station size means that 25 would receive a discount lower than the cost-reflective value and 5 would receive a discount greater than the cost-reflective value.

The results of our analysis of existing power stations and future power stations, in our view, clearly demonstrates that the assumptions made by NGET in deriving the proposed substation discounts are not representative of generators that would be eligible for the discount. Our observation that, of 30 new and existing power stations eligible for the discount, only one has an infrastructure design close to that assumed by NGET suggests that for the majority of eligible generators the proposed discount mechanisms will not be cost-reflective. Typically, these assumptions result in proposed discounts that are too low. This, in our view, could potentially undermine the integrity of the charging methodology and, hence, industry confidence in the charging regime.

In conclusion, while in principle we support a discount and support an approach based on the actual capital savings of the TO, we cannot support the substation discount as it is proposed. We believe that rather than an approach that requires broad, and demonstrably non-representative, assumptions on substation design and power station size, discounts should be cost-reflective and calculated on a generator-by-generator basis using actual infrastructure connection designs, actual capital savings and actual power station size.