Locational BSUoS Charging Methodology - GB ECM-18

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Target audience: Transmission licensees, generators, suppliers, consumer groups, Connection and Use of System Code parties and any other party who has an interest in the transmission arrangements.

Overview:

National Grid Electricity Transmission plc has proposed GB ECM-18, a modification to its use of system charging methodology – specifically the aspect relating to the Balancing Services Use of System charge. National Grid's proposal is a response to the rapid increase in actual and forecast constraint costs associated with managing transmission capacity shortages. The proposal seeks to provide a more cost reflective charging signal, targeting these constraint costs to the generators that cause them.

Currently the costs of operating the system are recovered equally from generators and suppliers across Great Britain on a non-locational basis. Under GB ECM-18 the costs of managing constraints behind a derogated transmission boundary will only be recovered from generators that are located behind the derogated transmission boundary.

This document seeks views on the impacts we have identified, and any other impacts respondents consider are associated with this proposal. This document does not express a view on the merits of GB ECM-18 or a decision on the proposal. The Authority will make its decision following consideration of, amongst other things, responses to this impact assessment.

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Context

Standard condition C5 of National Grid Electricity Transmission plc's (NGET) electricity transmission licence requires it to keep its use of system charging methodology under review at all times. NGET is also required to make proposals to modify that methodology where it considers a modification would better achieve the relevant objectives: (a) in relation to competition, (b) in relation to cost reflectivity and (c) taking account of developments in transmission licensees' transmission businesses.

We have longstanding concerns about the increasing level of constraint costs on the National Electricity Transmission System (NETS). The latest information from NGET shows that these have increased from £70m in 2007/08 to £262m in 2008/09, with a forecast cost of £198m for 2009/10.

On 17 February 2009 Ofgem published an open letter to NGET, highlighting our concerns about rising constraints costs. In the letter we asked NGET to conduct an urgent review to consider (and if appropriate consult on) whether urgent changes to the existing commercial and charging arrangements are necessary to manage more effectively the costs of constraints, and to ensure that any constraint costs are recovered on an equitable basis from customers, suppliers and generators.

On 22 May 2009 NGET submitted a modification proposal to the Gas and Electricity Markets Authority (the 'Authority')[1] for assessment. Under this proposed modification, the constraint costs that the System Operator incurs in relation to a derogated transmission boundary (or, in other words, a boundary that is not compliant with National Electricity Transmission System Security and Quality of Supply Standards) would be targeted at generators located behind that boundary.

On 17 June 2009 we asked NGET to withdraw this proposal to conduct further analysis to enable us to fully assess the potential impacts of the proposal. On 26 November 2009, NGET re-submitted the modification proposal with additional analysis to the Authority.

The Authority is required to assess proposed modifications to the use of system charging methodology and to decide whether or not to veto any proposal. Under Section 5A of the Utilities Act 2000 the Authority is required to carry out an impact assessment where it considers a proposal is important, within the meaning set out in section 5A. The criteria we believe may be engaged are:

- 2b) since locational BSUoS may have a significant impact on persons engaged in the generation, transmission, distribution or supply of electricity;
- 2c) since locational BSUoS may have a significant impact on persons engaged in commercial activities connected with the generation, transmission, distribution or supply of electricity; and/or
- 2d) since locational BSUoS may have a significant impact on the general public in Great Britain or in a part of Great Britain.

[1] Ofgem is the office of the Authority. The terms 'Ofgem' and 'the Authority' are used interchangeably in this document.

This document sets out our impact assessment and consultation on GB ECM 18. All views expressed in this Impact Assessment are preliminary views only. We invite respondents to this consultation to present their views on the proposed change to the charging methodology, together with any further evidence they would like the Authority to consider in reaching its final decision. We are open to respondents putting forward reasons, arguments and evidence challenging our analysis of the costs and benefits and such other of our initial views set out in this document.

Associated Documents

Ofgem Letter: Managing Constraints on the GB Transmission System, February 2009.
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/20090217Managing%20constraints.pdf

GB ECM-18 Consultation document: Locational BSUoS, March 2009.
http://www.nationalgrid.com/NR/rdonlyres/57D1F291-949D-4EE9-8606-79ADA1775F8C/32945/ConsultationGBECM18LocationalBSUoS.pdf

GB ECM-18: Locational BSUoS: Constraint Costing Methodology, March 2009.
http://www.nationalgrid.com/NR/rdonlyres/2FBDED81-ECB6-4AD0-B66D-C2F4185BA82D/33001/ConsultationGBECM18CostingMethodology250309.pdf

GB ECM-18 Letter, 17 June 2009: Locational BSUoS.
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/Charging/Documents1/090617%20Letter%20re%20analysis%20locational%20BSUoS%20final.pdf

GB ECM-18 Letter, 17 June 2009: NGET withdrawal of GB-ECM18 report to the Authority
http://www.nationalgrid.com/NR/rdonlyres/115B7821-4AEF-4E85-BFF8-BE96C1C906BE/35080/LocationalBSUoSlettertoStuartCookOfgem.pdf

GB ECM-18 Conclusions report, November 2009: Locational BSUoS.
http://www.nationalgrid.com/NR/rdonlyres/B9BD2D45-195A-479F-A369-B5BE6A3D22E9/34447/GBECM18conclusionsdocumentvolume1.pdf
http://www.nationalgrid.com/NR/rdonlyres/AEAB153C-DC3A-4816-92EF-2A14ED7554C0/34448/GBECM18conclusionsdocumentvolume2.pdf

GB ECM-18 Addendum to Conclusions report, November 2009: Locational BSUoS.
http://www.nationalgrid.com/NR/rdonlyres/CF064BAF-E8AB-412F-A06B-AD52AE737F35/38612/AddendumtoLocBSUoS_cleandated26Nov2009.pdf

Additional documents on National Grid's website:
http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc

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Summary

Context

NGET is responsible for operating the National Electricity Transmission System (NETS) as the System Operator (SO) (sometimes referred to as the 'NETS SO'). NGET incurs costs, including those associated with managing constraints, when there is insufficient transmission capacity to transmit electricity from where it is generated to where it is consumed. These costs are subject to an incentive mechanism where NGET is paid (or makes a payment) if costs are below (or above) a target level. NGET recovers these costs, net of any incentive reward or payments, through Balancing Services Use of System (BSUoS) charges. BSUoS charges are calculated for each settlement period on a £/MWh basis and are charged equally to generators and suppliers based on their metered volume in the relevant period.

The costs incurred by the Transmission Owners (TOs) in providing the physical networks are currently regulated under a five yearly price control and the maximum allowed revenues are recovered through Transmission Network Use of System (TNUoS) charges which are levied on transmission system users. The TOs are obliged by their licences to comply with the NETS Security and Quality of Supply Standards (NETS SQSS) when planning and developing their transmission networks, unless the Authority grants a derogation relieving them of that obligation. The calculation of the wider locational element of the generators' TNUoS charge assumes that the wider transmission system is compliant with the requirements set down in the NETS SQSS.

We have longstanding concerns about the increasing level of constraints costs. We wrote a letter to NGET in February 2009 expressing concerns about the current and forecast level of constraint costs. In that letter we asked NGET to conduct an urgent review to consider (and if appropriate consult on) whether urgent changes to the existing commercial and charging arrangements for access to the GB transmission system are necessary to more effectively manage the costs of constraints, and to ensure that any constraint costs are recovered on an equitable basis from customers, suppliers and generators.

GB ECM-18

Following the February 2009 open letter, NGET issued Use of System Methodology modification proposal GB ECM-18 to industry for consultation and after performing additional analysis submitted it on 26 November 2009 to the Authority for a decision.

Under the proposed modification, the costs arising as a result of the management of transmission constraints due to the non-compliance of a derogated transmission boundary would be levied on a locational basis to all exporting generators located behind a derogated transmission boundary. In addition, there would be a downward adjustment to the TNUoS charge for these generators, reflecting the fact that a lower level of transmission capacity is provided relative to the amount of access rights sold (the shortfall is made up in through residual charges).

Overview of impacts

Our initial view is that the proposal may provide more cost-reflective locational signals in the timescale relevant to that in which constraint costs are incurred. This could better protect consumers and better facilitate competition.

The illustrative analysis focusing on the Cheviot boundary (the only derogated boundary currently) shows that:

- If there is no behavioural change from generators located behind a derogated boundary there would be no adjustment to the cost of constraints, but that the way this cost is recovered would change;
- If generators behind a derogated boundary responded by reducing their output, this would result in reduced constraint costs; and
- Where market power exists, parties could still profit from their influence on bid prices, albeit to a lesser extent.

In the longer term, if the proposal were to result in the closure of a marginal plant it could give rise to local issues such as voltage considerations.

Whilst the implementation of GB ECM-may have merit in providing more cost-reflective signals and potentially leading to lower constraint costs, we also acknowledge that there may be potential concerns on a number of issues, including: the extent to which the proposal will be effective in influencing decisions to be efficient; the potential unequal impact on parties in the presence of market power; the possibility of wholesale price impacts; and whether there are objective grounds for targeting costs at generation but not on demand customers, and within the generation sector at larger generation but not small distributed generation. Furthermore, the re-design of the enduring access regime could impact on the way access rights are priced. The changes introduced under GB ECM-18 may be replaced by new charging arrangements to be developed as part of new enduring access regime. The Department of Energy and Climate Change (DECC) intervention is likely to have a limited scope[2] and hence it is likely that full development of the regime will be via industry processes. There is therefore a possibility that the impact of GB ECM-18 will be time limited, though the period to which it would, if implemented, remain in force pending an enduring solution being developed (and implemented) is uncertain.

Purpose of this document and way forward

Ofgem considers that modification proposal GB ECM-18 meets the "importance criteria" set out in section 5A the Utilities Act and is therefore carrying out an assessment of the likely impact of implementing the proposal. The purpose of this document is to set out the impacts of the proposed change and provide an opportunity for parties to comment on those impacts.

To reflect the fact that the consultation spans the Christmas period, we are allowing seven weeks for responses to this consultation. The Authority will take responses, and any other relevant information, into account in making its decision as to whether or not to veto the proposal.

If the Authority's decision is not to veto, NGET is seeking to implement the modification proposal in the greater of 30 days or the 1st day of the following month after the Authority has made its decision. If the decision is made before the start of March 2010 this will be on the 1 April 2010, the start of the charging year.

[2] See DECC consultation document http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx).

1. Introduction

Chapter Summary

This chapter provides both a brief summary of the current charging arrangements for generators using the electricity transmission system and also the background to this document.

Overview of the electricity charging arrangements

1.1. There is a single electricity licence relating to the National Electricity Transmission System (NETS). This licence covers both System Operator (SO) activities and Transmission Owner (TO) activities. There are currently three transmission licensees each of which is permitted to develop, operate and maintain a high-voltage transmission system within a distinct transmission area[3]. Only one licensee, National Grid Electricity Transmission plc (NGET), is permitted to carry out SO activities for the whole of NETS (the 'NETS SO').

1.2. In addition, Standard Licence Condition (SLC) C5 of the electricity transmission licence requires NGET to keep its Use of System Charging methodology under review at all times. NGET is also required to make proposals to modify that methodology where it considers a modification would better achieve the relevant objectives in relation to: (a) competition, (b) cost-reflectivity and (c) taking account of developments in transmission licensees' transmission businesses.

Recovery of System Operator costs via BSUoS charges

1.3. As NETS SO, NGET keeps the electricity system in balance and maintains quality and security of supply. The 'Balancing Services Activity' is the activity undertaken by NGET to coordinate and direct the flow of electricity onto and over the NETS and for the purpose of balancing the NETS, including real time operation of the transmission system and the procuring and using of Balancing Services.

1.4. NGET is incentivised to minimise operational costs via the SO Incentive Scheme. Under this scheme, a target level of costs is agreed with NGET together with incentive sharing factors. Together, the target and sharing factors are designed to provide an appropriate balance of risk and reward between NGET and consumers, who ultimately pay for the costs of system operation. Users pay for the allowed cost and any incentivised payment/receipts through the Balancing Services Use of System (BSUoS) charges.

1.5. All Connection and Use of System Code (CUSC) Parties are liable for BSUoS charges based on their metered energy in each half-hourly settlement period. At present, the total BSUoS revenue cost to be collected via the BSUoS charge is split equally between generation and demand and does not vary by location.

[3] Each licence contains special conditions that limit the area in which the licensee is authorised to carry out TO activities. NGET's area is England and Wales, Scottish Power Transmission Limited's transmission area is the south of Scotland, and Scottish Hydro Electric Transmission Limited area is the north of Scotland.

Recovery of Transmission Owners' costs via TNUoS charges

1.6. The TOs are responsible for providing transmission capability at different locations by building, operating and maintaining their transmission assets. The revenue the TOs are allowed to recover is set by Ofgem, including as part of the price control process. The costs incurred by the TOs are recovered from all users of the NETS via Transmission Network Use of System (TNUoS) charges.

1.7. TNUoS charges contain locationally varying elements that are aimed at reflecting the long-run average incremental costs of accommodating the generation or demand within defined zones. The calculation of the wider locational element assumes that the wider infrastructure system is compliant with the criteria and methodologies set out in the NETS SQSS. The TOs are obliged by their licences to achieve such compliance unless granted derogation by the Authority.

Derogation and cost of constraints on Cheviot Boundary

1.8. In the four years after privatisation, system operation costs doubled in real terms to £509 million per annum. In particular, constraint costs have a long history. Offer's[4] Pool Price Inquiry (PPI) report of December 1991 concluded that two major generators had increased the bid prices of certain plants at times when transmission system constraints made it likely that these plants would be constrained on. To resolve the problem of increasing system operation costs, NGET has been subject to incentives to control the costs of balancing the system since 1994. This proved effective and continued to reduce system operation costs throughout NETA.

1.9. The British Electricity Trading and Transmission Arrangements (BETTA) were established as a result of Chapter 1 of Part 3 of the Energy Act 2004. BETTA replaced the separate trading and transmission arrangements which existed prior to 1 April 2005 in Scotland and in England and Wales.

1.10. Ofgem and the then DTI established principles to apply to the allocation of transmission system access rights during the transition period to BETTA. These principles were set out in Standard Licence Condition (SLC) C18. The effect of SLC C18 was that connection offers to the then 'existing users' would neither be dependent on any upgrades on the interconnector circuit between Scotland and England & Wales nor works in England & Wales if a user is located in Scotland (and vice versa).

1.11. As a consequence of SLC C18, a certain volume of generation ('existing users') gained firm access rights which were not restricted, as they otherwise would have been, by the need for network reinforcement across the interconnection boundary and further downstream to ensure compliance with NETS SQSS. The TOs were issued with derogation from the requirement to comply with the NETS SQSS for the interconnection boundary, known as the Cheviot or B6 Boundary.

1.12. When BETTA was being introduced, the issue of system operation costs and the possibility of incorporating a locational element into the BSUoS charge was raised. The Authority did not progress this at that time because it considered that the costs

[4] On 16 June 1999, the former regulatory offices, OFFER and Ofgas, were renamed the Office of Gas and Electricity Markets (OFGEM)

associated with addressing this issue would outweigh the potential benefits, given the level of BSUoS costs that had locational cost drivers at that time (around 20%). Locational cost drivers were considered to be the costs of black start, reactive power and transmission constraints. The Authority was of that view that NGET should keep the situation under review post BETTA Go Live[5].

1.13. Since the implementation of BETTA, the costs of constraints have increased from £70m in 2007/08 to £262m in 2008/09 (see Table 3). NGET is forecasting £198m[6] of constraints, for this year 2009/10.

Ofgem's February 2009 open letter

1.14. On 17 February 2009 Ofgem published an open letter to NGET, highlighting the rapid increase in both actual and forecast constraint costs in recent years. We asked NGET to conduct an urgent review to consider (and if appropriate consult on) whether urgent changes to the existing commercial and charging arrangements are necessary to manage more effectively the costs of constraints, and to ensure that any constraints costs are recovered on an equitable basis from customers, suppliers and generators.

1.15. We noted in our February 2009 open letter that a significant proportion of the constraints costs arise as a result of available transmission capacity shortages, relative to transmission entry capacity rights sold to generators in Scotland (and to a lesser extent England and Wales). We also noted that the level of available transmission capacity (and forecast constraints) will be heavily influenced by transmission outages as part of the investment the three transmission companies are making to increase network capacity.

1.16. We set out in our open letter that NGET's review should seek to address matters including:

- The options for reducing the level of constraint costs (both constraint volumes and prices), and
- Whether the current use of system charging mechanisms are equitable and appropriate and whether constraints costs are appropriately targeted on the parties that give rise to the need for constraint actions.

Transmission Access Review interim measures

1.17. The Transmission Access Review (TAR) carried out jointly by Ofgem and DECC found that the existing access arrangements are acting as a significant barrier and preventing new renewable and low carbon generation accessing the generation market. The joint TAR Final Report[7] identified key strands of work required to remove such barriers: to develop enduring access arrangements, to facilitate timely and efficient transmission investment for a system fit for the achievement of the 2020 goals, and to develop short term measures to facilitate earlier connection in the

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[5] http://www.ofgem.gov.uk/Networks/Trans/BETTA/Publications/Documents1/10033-8005.pdf

[6] These figures have been updated since we published our 17 February 2009 open letter. The latest forecast 2009/10 figure was provided by NGET in November 2009

[7] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=84&refer=Networks/Trans/ElecTransPolicy/tar

interim period. It was noted that as part of the short term measures, transmission licensees would be working to identify opportunities to use derogations from minimum standards in the NETS SQSS.

1.18. On 8 May 2009, Ofgem published its decision[8] on the interim approach to NETS SQSS derogations to facilitate the earlier connection of generation. We set out in our 8 May 2009 decision letter that our approach will facilitate the connection of the 450MW of Scottish renewable generation identified by the transmission licensees as being capable of advancement. We also set out that our approach will apply to other generation in a comparable situation where the scope to advance connection dates is limited by the need to grant a derogation from the NETS SQSS. We are currently considering derogation requests from the transmission licensees and expect that our decision is likely to result in the existing derogation against the Cheviot boundary being extended, and additional derogations against other boundaries.

Wider context

CAP170 - Category 5 System-Generator Operational Intertripping Scheme

1.19. CUSC Amendment Proposal CAP170 "Category 5 System to Generator Operational Intertripping Scheme" was also raised by NGET in response to Ofgem's letter of February 2009.

1.20. CAP170 seeks to reduce constraints costs by limiting the costs associated with intertrip schemes for generators behind a derogated non-compliant transmission boundary. CAP170 proposes a new category of operational intertrip, which could be applied to both existing and future generators, with remuneration in line with the administered pricing arrangements that currently apply to certain categories of existing operational intertrips.

Competition Concerns

1.21. In April 2008 Ofgem opened a Competition Act investigation into the conduct of Scottish Power ('SP') and Scottish & Southern Energy ('SSE') in the wholesale electricity sector, following allegations that the companies had a position of dominance arising from transmission constraints between England and Scotland, and had abused this position by withholding generation plant from the wholesale forward market while using the same plant to supply balancing power to NGET at excessive prices. Ofgem has looked into a number of allegations concerning similar behaviour since BETTA was introduced in April 2005, and these other periods were also considered within the scope of the Competition Act investigation.

1.22. While Ofgem recently closed the investigation into SP and SSE on grounds of administrative priority, noting that the likelihood of making an infringement finding under the Competition Act was low, we did identify concerns in the relevant market. These included the fact that output from SP's and SSE's generation plant in Scotland appears to have been much more expensive than that of comparable generators in England & Wales at times of constraint, which could indicate the existence of market power.

[8] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=153&refer=Networks/Trans/ElecTransPolicy/tar

1.23. On 30 March 2009, we published a consultation on our initial policy proposals for addressing market power concerns in the electricity wholesale sector[9]. The Secretary of State has recently announced that the Government intends to include a Market Power Licence Condition (MPLC) in the forthcoming Energy Bill.

Impact on cash-out mechanism

1.24. Constraints costs impact on the wholesale market through the energy imbalance pricing mechanism, known as the cash-out arrangements. As a result of deficiencies in the current methodology for calculating cash-out charges, some of the costs of resolving constraints can feed into cash-out prices and "pollute" the prices charged to out-of-balance parties. Since cash-out prices are closely correlated with market prices, "pollution" of cash-out prices can lead to distorted signals for generation investment. BSC modification P217[10], which has been implemented in November 2009, aims to address this problem by removing many of the constraint costs from the calculation of cash-out prices.

Transmission access review

1.25. DECC has published their initial proposal for access reform, in their consultation document. DECC currently propose to introduce a variation of the Connect & Manage[11] approach.

1.26. Under some of the models consulted upon, the re-design of the enduring access regime could impact on the way access rights are priced. The changes introduced under GB ECM-18 may be replaced by new charging arrangements to be developed as part of any new enduring access regime established by DECC or through industry processes. There is, therefore, a possibility that the impact of GB ECM-18 will be time limited, though the period to which it would, if implemented, remain in force is uncertain (pending an enduring solution being developed and implemented).

Process to date

1.27. Subsequent to Ofgem's February Open Letter, NGET issued modification proposal GB ECM-18 on 13 March 2009 for industry consultation. NGET concluded that it would target, in a more cost reflective manner, the costs arising as a result of the non-compliance of a derogated transmission boundary. On 23 March 2009 NGET published, as a further explanatory note to GB ECM-18, a Constraint Costing Methodology that gave further detail on the approach that NGET will take to calculate the costs that will be directed by the locational BSUoS charge.

1.28. On 22 May 2009, NGET submitted a conclusions report to the Authority for decision on a proposal to modify the use of system charging methodology to address the deficiencies described above.

[9] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=Market%20Power%20Concerns-%20Initial%20Policy%20Proposals.pdf&refer=Markets/WhlMkts/CompandEff
[10] http://www.elexon.co.uk/ChangeImplementation/modificationprocess/modificationdocumentation/modProposalView.aspx?propID=237
[11] Under a connect & manage approach, generation could be connected ahead of transmission investment

1.29. In the course of considering the conclusions report, Ofgem reached the view that there was insufficient information to assess the potential impact of the proposal. Therefore, on 17 June 2009 we asked NGET to withdraw this proposal to conduct further analysis to enable us to fully assess the potential impacts of the proposal. We asked them to address three specific questions:

- The impact of Locational BSUoS if there was no behavioural change including impact on the wholesale price;
- The impact of Locational BSUoS if there is behavioural change including impact on the wholesale price (assuming no generators have market power); and
- The impact of Locational BSUoS as above if there is behavioural change and generators do have market power.

1.30. NGET withdrew the conclusions report and re-submitted it on 26 November 2009 with an addendum containing additional analysis that supported the original conclusion.

1.31. On 03 December 2009, we published an open letter setting out our intention to undertake an impact assessment on NGET's proposed modification with a view to making a decision on NGET's proposal by 02 March 2010. In accordance with the requirements of licence condition C5 (4), the Authority will have 28 days from receipt of a Conclusions Report to notify the licensee of either its decision (veto or non-veto) or that it intends to undertake an Impact Assessment (IA) consultation. In the latter case, the Authority will then have a period of 3 months to issue the direction. The 3 month time limit will start from the date we notify the licensee an IA is required.

Structure of the document

1.32. The remainder of the document is structured as follows:

- Chapter 2 sets out a brief description of NGET's proposed modification to the use of system charging methodology.
- Chapter 3 provides an assessment of the impact of the proposal in relation to the relevant objectives.
- Chapter 4 provides an assessment of the proposal in relation to the Authority's wider duties, including those associated with the environment.
- Chapter 5 sets out the way forward.

1.33. A description of the legal framework against which this modification is assessed is set out in Appendix 3.

2. Outline of NGET's modification proposal

Chapter Summary

This chapter summarises NGET's proposed modification to the use of system charging methodology, the principles and its revenue implications.

➔ **Question:** There are no questions in this chapter.

Modification proposal

2.1. NGET's modification proposal GB ECM-18 seeks to make use of system charges reflect more explicitly the long-run and short-run costs associated with derogated non-compliant transmission boundaries. Where the document refers to derogated boundaries we mean derogated non-compliant transmission boundaries.

2.2. NGET proposes to introduce two component parts to BSUoS charges:

- **A targeted constraint tariff** reflecting the costs of constraints arising as a result of the non-compliant nature of transmission boundaries. This would be charged to all exporting Balancing Mechanism Units (BMUs) liable for existing BSUoS charges, located behind such boundaries; and
- **A residual tariff** incorporating the remaining costs. This would be charged to all BMUs.

2.3. In addition, NGET proposes that there would be a downward adjustment to the wider locational tariff element within the TNUoS charge for generators located behind a derogated boundary to reflect the fact that, relative to the amount of generation provided with access to the system, a lower level of transmission capability is provided across a non-compliant boundary. The residual element of the TNUoS charge would recover the shortfall from all generators.

2.4. A summary of the main features of the proposal is included below. More details are provided in Appendix 4.

BSUoS charges

New locational element

2.5. Currently, a User's BSUoS charge is calculated based on its proportion of the total BMU metered volume for each settlement period multiplied by a non-locational BSUoS tariff applicable for that settlement period. GB ECM-18 would introduce two elements to the BSUoS charge for a User:

- A Targeted Constraint Tariff that will recover the cost of constraints arising from non-compliance with the NETS SQSS. This will be levied on all exporting BMUs located behind a derogated boundary and liable for existing BSUoS charges, based on their Meter Adjusted Volume. Aimed at reflecting the cause rather than the result of the constraint actions, the Meter Adjusted Volume is defined as the load level that parties would have been generating if the derogated boundary were not constrained. It will be derived post event and be calculated as the BMU final metered position adjusted to incorporate any pre or post gate closure actions that the NETS SO may have taken on that BMU; and

- A Residual BSUoS Tariff that will recover the remaining BSUoS costs. This will be levied on all BMUs who normally incur a BSUoS charge, based on their proportion of the Total BMU Metered Volume for each Settlement Period.

Targeted constraint volumes and costs

2.6. A transmission system that was fully compliant with the NETS SQSS planning criteria would still require a certain level of constraint management. GB ECM-18 would require NGET to determine the proportion of constraints that are incurred solely as a result of the fact that a transmission boundary is non-compliant. This is calculated as the volume of total constraints across that transmission boundary, capped by the shortfall of transmission capability due to non-compliance (which in turn is the difference between the boundary capability required by NETS SQSS compliance and the actual existing capability). The transmission capability shortfall will be updated annually.

2.7. NGET's proposed calculation of the cost of constraints will include:

- The costs of any action required to buy or sell energy, or to take another form of action such as arming an inter-trip, to resolve a constraint which arises on a derogated boundary;
- An adjustment to reflect the fact that resolving the constraint may have also resolved the system imbalance elsewhere;
- The costs of any replacement energy triggered by this action, i.e. to resolve an energy position (either buy or sell); and
- The costs of replacing any generation margin that was made inaccessible or sterilised as a result of NETS SO actions to resolve a constraint.

Nested boundaries

2.8. Currently there is one derogated transmission boundary, the Cheviot or B6 boundary between Scotland and England and Wales. In future, it is possible that additional boundaries may be granted derogations for non-compliance. If this occurs, generators could be connected behind multiple non-compliant boundaries (these are often referred to as "nested" boundaries).

2.9. Actions to relieve constraints across one transmission boundary could interact with the action required to relieve constraints in a nested boundary. In addition to the approach to targeting of constraint costs for a single derogated boundary, NGET's proposal also includes an approach to allocating constraint costs for nested non-compliant boundaries. This is based on the following broad steps:

- An assessment would be made of the constraint costs for each of the non-compliant boundaries, ignoring interaction between boundaries;
- The charges that a generator would be liable for against each derogated boundary would be calculated;

- All transmission boundary costs and related charges for each generator would be scaled such that the total costs recovered equal to the actual total costs of resolving all the constraints together.

2.10. NGET provided an example of the way in which this adjustment would be made in the Constraint Costing Methodology (Locational BSUoS)[12].

TNUoS charges

2.11. One of the four elements of the TNUoS charge paid by generators – the wider locational tariff – is currently calculated using the assumption that the wider transmission system is compliant with the requirements set down in the NETS SQSS.

2.12. Under ECM-18, the wider locational tariff of TNUoS charges will be amended so that it is calculated on a pro-rata basis in proportion to the required reduction of the TEC of generators behind a derogated boundary such that the generators could be accommodated by the existing system in accordance with the NETS SQSS. This would result in a reduction of the wider locational TNUoS tariff, and overall TNUoS charge, for generators behind non-compliant boundaries in order to reflect the shortfall of physical transmission capacity at the relevant transmission boundary.

Implementation date

2.13. Subject to the Authority not vetoing the proposal, NGET is seeking to implement the modification proposal in the greater of 30 days or the 1st day of the following month after the Authority has made its decision. The implementation date must ensure that changes to the TNUoS tariffs and the BSUoS charging principles can be coordinated.

[12] http://www.nationalgrid.com/NR/rdonlyres/2FBDED81-ECB6-4AD0-B66D-C2F4185BA82D/33001/ConsultationGBECM18CostingMethodology250309.pdf

3. Assessment of impacts in relation to the relevant objectives

Chapter Summary

This chapter sets out an assessment of the impact of the modification proposal in relation to the relevant objectives of NGET's electricity transmission licence. That is, it considers the relevant impacts in terms of cost reflectivity, competition and taking account of developments in transmission licensees' transmission businesses. .

Question box:

Question 1. Do respondents have any comments on NGET's analysis?

Question 2. Do respondents wish to present any additional quantitative analysis that they consider to be relevant to assessing the proposal?

Question 3. Do respondents consider that there are any aspects of the proposal that have not been fully assessed?

Question 4. Do respondents consider that the key features of the proposal strike an appropriate balance between cost reflectivity, transparency, complexity and stability?

Question 5. Do respondents consider that this modification promotes more effective competition? Conversely, do respondents wish to provide further detail of any discrimination concerns?

Question 6. Do respondents consider that the proposal complements the changing nature of the transmission network and assists the operation and development of an economic and efficient transmission system?

Question 7. Do respondents consider that the different methodologies used in the proposal are appropriate?

Impact in relation to relevant objectives

3.1. Ofgem assesses proposed modifications to the Use of System Charging Methodology against the relevant objectives as set out in standard condition C5 of NGET's transmission licence. In considering whether to approve implementation of a modification proposal, the Authority will consider (amongst other matters) whether the modification better achieves the relevant objectives compared to the baseline. Standard condition C5 requires Ofgem to assess proposed modifications in the light of their:

- Impact on cost reflectivity;
- Impact on competition; and
- Impact on the developments in transmission licensees' transmission businesses.

3.2. In undertaking this impact assessment we have taken account of consultation responses to NGET's consultation on GB ECM-18 and further analysis performed by NGET in response to our request on 17 June 2009. We have also taken account of analysis which we have undertaken (based on data provided by NGET) in order to consider the impacts of this proposal. Data were provided in May 2009. We have used these data to look at the possible indicative impact of the proposal.

3.3. The remainder of section 3 looks at the impacts of GB ECM-18 in relation to the relevant objectives.

3.4. The first subsection considers the quantitative analysis performed both by us and by NGET that is relevant to the assessment of GB ECM-18.

3.5. The second subsection on cost reflectivity, considers the different aspects of the proposal that we believe impact on our consideration of whether GB ECM-18 fulfils the objective of cost reflective charging. In particular we consider the principle of GB ECM-18, moving part of locational signal from long-run TNUoS charges to short-run BSUoS charges as well as looking at who it is appropriate to charge for these constraints costs, and the methodology of GB ECM-18.

3.6. The third subsection considers the aspects that might impact on whether GB ECM-18 fulfils the objective of facilitating competition. This section considers the impacts of competitive advantage, discrimination, barrier to entry and complexity.

3.7. The fourth and final subsection considers whether GB ECM-18 adequately reflects developments in the transmission licensees' transmission businesses.

Quantitative Analysis

3.8. The quantitative analysis has addressed a number of aspects of the proposal, including the allocation of charges between generators within and outside a derogated boundary. The analysis has also considered different generator operation characteristics, different charges on demand users, and the consequent impact on customer bills as well as the impact on the wholesale price.

3.9. NGET's assessment is based on analysis of both actual data from 2008/9 and a probabilistic model that optimises least cost generation to meet demand using a static merit order and then honours all transmission boundary constraints by taking bids and offers whilst again optimising for balancing costs. More detail can be found in the addendum to the NGET conclusions report, submitted on 26 November 2009[13].

3.10. The key input of our own analysis includes the data provided by NGET in May 2009 on the actual, historical and forecast cost of constraints and volumes of energy generated (including the "adjusted" volumes prior to NETS SO constraint management) behind the Cheviot boundary. The Cheviot boundary is currently the only derogated boundary and hence analysis has focused on this as an example. NGET also provided forecast TNUoS tariffs for corresponding years, pre and post GB ECM-18.

3.11. The base case of the forecast generation background is consistent with NGET's Seven Year Statement. We have also obtained from NGET equivalent data for an illustrative sensitivity scenario. This scenario assumed an extra 350MW[14] behind the Cheviot boundary without adding any transmission capacity, to assess the impact of this proposal against further increased constraints. Detailed data, by settlement

[13] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc
[14] This is chosen to be broadly in line with the level of transmission generation that are likely to advance their connection in the next couple of years.

period and by generator was provided for May and June 2008 BSUoS charges and energy volumes as well as energy demand by period. Short Run Marginal Costs for each generator were assumed based on fuel prices, efficiency assumptions, transport costs and operational expenses. These were used to derive approximate merit orders.

3.12. The sections below describe the quantitative impacts, including charges, output and revenue seen in both NGET's and our analyses. We seek views on these impacts and in particular on: the impact on generators, the impact on demand customers, and the impact on end-consumers' bills.

Impact on generators

No behavioural change

3.13. We have considered the impact of GB ECM-18 in a situation where there was no change in generator behaviour, as explained above, the Cheviot boundary was used as an example of a derogated boundary in this analysis. As expected, GB ECM-18 causes generator charges behind the derogated boundary to be increased, reflecting the costs being targeted at a much smaller group of generators. Generators not behind such a boundary see a small reduction in charges.

3.14. We have included our analysis of 4 different BMUs behind the current derogated boundary as an example before and after the implementation of Locational BSUoS in Appendix 5. The analysis shows the size of the change in charge and the nature of charging volumes prior to SO action.

3.15. To assess the overall impact of GB ECM-18, we have also collected from NGET equivalent data, but in monthly totals, for 2005/6 to 2008/9. We used this data to assess the impact of the GB ECM18 methodology on 500MW generating stations at different locations and with different load factors[15] (30%, 50% and 75%), and to compare the effects of the change in methodology with the status quo. 2008/9 was selected since it has the highest constraint costs. The results presented in the table below show a material increase of charges for generators in Scotland, but relatively minor decrease for generators elsewhere. We note that unlike the non-locational nature of differences for the latter group of generators, those for Scotland vary slightly between zones. We understand this is due to the approach NGET proposed to calculate the TNUoS rebate - adjusting the wider zonal generation tariff for all generators located behind a derogated boundary.

[15] For simplicity we have assumed in this part of the analysis that the output pattern is flat throughout each month. We recognise that in reality generators with the same load factor could experience different BSUoS charges depending on the timing of the output, as shown in Figures above.

Table 1: Impact on Targeted Constraint Cost related BSUoS, TNUoS and total charges by generator load factor by location in 2008/9

		BSUoS £m		TNUoS £m		Total £m		Difference	
Area	**Load Factor**	**Before**	**After**	**Before**	**After**	**Before**	**After**	**£m**	**£/MWh**
North Scotland	30%	0.38	5.76	11.13	8.53	11.51	14.28	2.77	2.11
	50%	0.64	9.59	11.13	8.53	11.77	18.12	6.35	2.90
	75%	0.96	14.39	11.13	8.53	12.09	22.92	10.83	3.30
South Scotland	30%	0.38	5.76	6.76	4.86	7.14	10.62	3.48	2.65
	50%	0.64	9.59	6.76	4.86	7.40	14.46	7.06	3.22
	75%	0.96	14.39	6.76	4.86	7.72	19.26	11.54	3.51
Oxon & South Coast	30%	0.38	0.00	-0.01	0.31	0.37	0.31	-0.07	-0.05
	50%	0.64	0.00	-0.01	0.31	0.63	0.31	-0.32	-0.15
	75%	0.96	0.00	-0.01	0.31	0.95	0.31	-0.64	-0.20

3.16. We also compared the aggregate amount paid by generators in Scotland, as opposed to generators in England and Wales, for each of the years 2005/06 to 2008/09, for targeted constraint costs. The result is shown in Table 2 below. We note that the total post GB ECM-18 charges for all generators add up to twice the current amount. This is due to the fact that whilst currently only 50% of the costs are allocated to generators, GB ECM-18 would allocate 100% to the targeted generators.

Table 2: Aggregate targeted constraint costs paid 2005/6 to 2008/9, £m

Year	**Area**	**BSUoS relating to targeted constraints costs pre GB ECM-18**	**BSUoS relating to targeted constraints costs post GB ECM-18**
2008/9	Scotland	12.1	194.2
	England & Wales	85.1	0.0
2007/8	Scotland	1.5	25.4
	England & Wales	11.2	0.0
2006/7	Scotland	1.8	29.3
	England & Wales	12.9	0.0
2005/6	Scotland	2.0	35.6
	England & Wales	15.8	0.0

3.17. Appendix 6 further examine the likely impact of the proposed modification in the future, we have used NGET's May 2009 forecast of the equivalent data for 2009/10, both for a base case, based on the Seven Year Statement background data as well as for a sensitivity case adding 350MW of new generation in Scotland.

3.18. We conclude that if there is no behavioural change, due to the change in the recovery of constraint costs, generators behind a derogated boundary will receive higher bills. The higher the cost of constraints, the higher the charge will be. However this charge is dependent on amount generated.

Behavioural change with no market power

3.19. NGET considered this area in the addendum to the conclusions report. We have considered below the impact on different types of generators. Appendix 7 illustrates the impact on different generators according to NGET's analysis.

3.20. *Marginal flexible plant behind the derogated boundary* - The 2008/9 historic data analysis performed by NGET showed generation output changes between zones as a result of GB ECM-18 affecting generator behaviour. Some units (behind the derogated boundary) fell out of merit in periods with high constraint costs. In general there was a change with a reduction of generation in North Scotland and South Scotland and increases elsewhere in England and Wales to replace this generation. This pattern of output was not affected by the sensitivity analysis which was carried out by National Grid, including sensitivities around the coal price and merit order.

3.21. This conclusion was supported by the probabilistic modelling carried out by NGET. The addition of locational BSUoS alters the marginal costs and so changes the order in which plant meets demand and also the volume and order of action taken by the SO.

3.22. NGET considered that locational BSUoS would increase the costs to generators behind the derogated boundary and therefore change the merit order such that these units are less likely to generate. This pattern was the case in all of the scenarios that NGET looked at, namely; changing fuel prices, modelling bid at 60% of level of England and Wales' bids, modelling the closure of plant as well as the recovery of marginal costs and the recovery of marginal and fixed cost by generators. Constraint costs reduced in all scenarios.

3.23. NGET's estimate of constraint cost reductions were based on a theoretical instant feedback loop between the locational BSUoS cost signal and generators' output decision. NGET pointed out that, in reality, this is subject to a generator's ability to forecast the timing and level of locational BSUoS charges and their willingness and/or ability to react to the charges by adjusting their position in the wholesale market.

3.24. Marginal flexible plant behind the derogated boundary are key affected parties, who would restrict their generation pre-gate closure due to the inclusion of the locational BSUoS costs with their other running costs.

3.25. *Inflexible plant behind the derogated boundary* - NGET's analysis indicates that inflexible parties who do not have a portfolio and are on the constrained side of the derogated boundary show a net reduction in revenue / margin from the addition of the locational BSUoS charge. The higher the constraint cost, the more their revenue will be reduced.

3.26. NGET's analysis also highlights that inflexible parties with a portfolio of units in both constrained and unconstrained areas, could attain a net gain in revenue when the constraint cost and hence the locational charge is low - the gain in revenue / margin from units in the unconstrained area counteracts the reduction in constrained areas. However, in the situation where there is a high constraint cost, the locational BSUoS charge is high for units behind the derogated boundary and this outweighs the benefits of a reduction in constraints and in unconstrained running in areas which are not subject to a derogation In these circumstances NGET's analysis implies that parties may experience a net loss in revenue / margin.

3.27. For example, In NGET's studies 2 – 4.2 which looked at unconstrained merit order and BM prices based on marginal costs, there was a total constraint cost of £58m and the constraint cost with behavioural change after the application of the locational BSUoS charge cycled[16] between £22m and £45m. The impact on the

[16] For a detailed explanation of cycling, caused by the feedback loop described in paragraph 3.23, please see NGET's addendum to the Conclusions report http://www.nationalgrid.com/NR/rdonlyres/CF064BAF-E8AB-412F-A06B-AD52AE737F35/38612/AddendumtoLocBSUoS_cleandated26Nov2009.pdf

inflexible generator British Energy (BE) when the cost was £22m was a net increase in total revenue / margin of approximately £4m. However, when NGET modelled the effect of constraints costs of £45m, BE would see a net reduction in total revenue / margin of approximately -£7m since it picks up a larger proportion of the Locational BSUoS than it saves in BSUoS and it receives no increase in unconstrained running in England and Wales.

3.28. In the same scenario, Scottish wind generation as a whole, is impacted in both the £22m and £45m situation in a negative manner, the reduction being -£1m and -£4m respectively.

3.29. *Plant not behind the derogated boundary* – Most parties in the unconstrained area have a net gain in revenue / margin as a result of the removal of the constraint related costs from their BSUoS charge. However, NGET's modelling suggests that parties in an unconstrained area who would have been constrained on in the Balancing Mechanism (BM) but who would now be generating in the unconstrained merit order (due to the effect of locational BSUoS) may not make as much revenue / margin as pre locational BSUoS.

Behavioural change with market power

3.30. NGET's analysis of the market shows a high market concentration[17], behind the Cheviot boundary, and identifies differences between the bid prices offered on each side of this boundary. NGET analysed the implications of a scenario where bids were set to 60% of the marginal cost in the non compliant area. It showed that where a generator behind a derogated boundary is able to exercise market power in the BM currently, it would still be able to do this following Locational BSUoS, albeit with reduced profits see Appendix 8.

Impact on demand charges

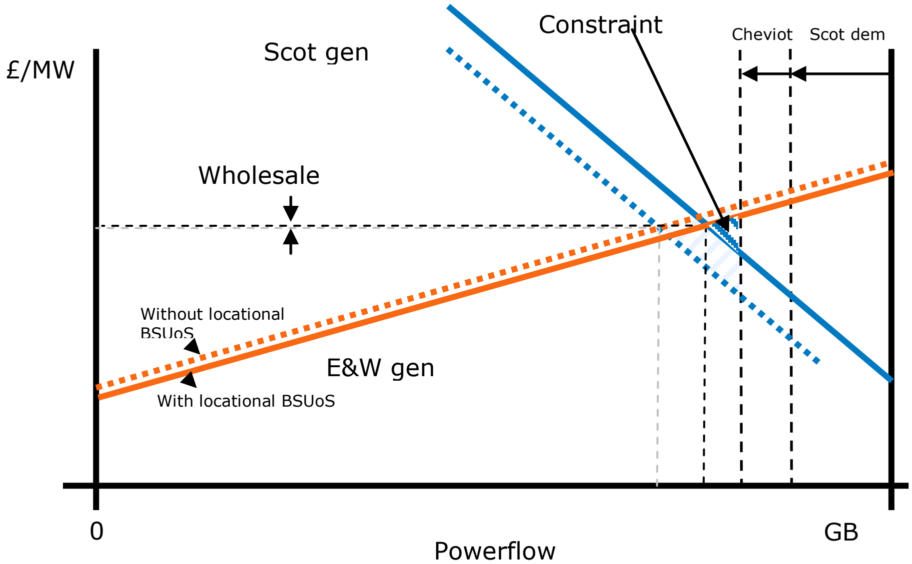
3.31. Under NGET's proposal, demand-side users will receive a lower BSUoS bill since they would no longer be charged for their proportion (50%) of targeted constraints costs. It is expected that this will be passed through to the customer (see 3.41 below).

Impact on the wholesale price

3.32. The effect of locational BSUoS on the marginal price[18] (wholesale price) was also examined by NGET in their quantitative analysis. They sought to illustrate the effect diagrammatically in the addendum to the conclusions report, as reproduced below.

[17] As per their analysis of the Herfindahl-Hirschman Index (HHI). HHI is the sum of squares commonly used to shown concentration in a market,
[18] Marginal cost is used as a proxy for the price of the marginal plant and therefore the price that the market is cleared at, the wholesale price. Marginal price and wholesale price are used interchangeably

Figure 1 Marginal production slopes with and without Locational BSUoS



3.33. The illustration shows the marginal cost of generation in Scotland and England and Wales, with and without Locational BSUoS. The point of intersection of the dotted lines is where the unconstrained market would be expected to clear. The intersection of the solid lines shows where the unconstrained market with Locational BSUoS would be expected to clear. In the diagram above this shows that the wholesale price is unaffected by Locational BSUoS. However, if the slope of the lines is different this could lead to an increase or reduction in the wholesale price.

3.34. NGET have stated that in scenarios where the production curve in England and Wales is steep (e.g. changing from marginal gas to marginal coal), the effect on the wholesale price in a period would be large. However, as the addition of Locational BSUoS is more likely to cause a within-fuel type increase and these slopes are relatively flat, the impact on the wholesale price is likely to be minimal.

3.35. In NGET's historical 2008/9 analysis, the most frequent outcome of adding a Locational BSUoS charge is to make no change to the wholesale price. The second most frequent outcome is a small reduction in wholesale prices (due to the reduction in BSUoS applied across all units).

3.36. The historical analysis also shows that when the plant margin is small and expensive generation has set the marginal price, there is likely to be a large increase in the marginal price. When coal price was increased, coal plants became the marginal plant, but the introduction of Locational BSUoS did not affect the marginal price more in this scenario. Little change was found when changing the merit order.

3.37. In terms of the probabilistic model, the wholesale price and hence the total market cost reduces with the introduction of GB ECM18. The only exception to this was in scenarios that assume that all plant receives the price of the marginal generator (its fixed and marginal cost), which NGET do not believe is the case.

3.38. Whilst it is theoretically possible for the wholesale price to both increase and reduce, depending on the merit order, the changes seen in both types of analysis carried out by NGET show little overall impact on the wholesale price.

3.39. In addition, we note that higher wholesale prices could result in a more efficient market outcome if they more accurately reflect all the relevant costs. Whilst a suppressed wholesale price is better for consumers in the short-run, it is inefficient and may ultimately damage consumer interest in the long-run.

3.40. On balance, it would appear that the wholesale price does not have a large impact on the case for introducing the proposed modification. We welcome comments on this view.

Impact on customers bill

3.41. Our initial view is that there are likely to be three main impacts on consumer bills:

(i) A direct impact due to the reduction in a supplier's BSUoS bill which we would expect to be passed through, over time, to customers;

(ii) An indirect impact due to the influence on wholesale prices. This depends on the merit order as described above. Notwithstanding this, if the wholesale price reduces, costs to customers will reduce and if it increases, customer costs will increase; and

(iii) The fact that generators behind the derogated boundary could potentially respond to the higher cost signal and seek to reduce the cost by lowering their output and / or their prices, resulting in overall reduction of constraint costs. The likelihood and degree of such reduction are subject to other factors that influence the generators' output decision.

3.42. On balance, our initial view is that the proposed modification has potential to reduce the customer's bill. We welcome comments and further evidence on this issue.

Cost reflectivity

3.43. One of the relevant objectives against which we need to judge proposed amendments to the charging regime is "cost reflectivity". We consider it is important that transmission charges are cost reflective – this will promote the efficient use and development of the transmission network and will help to ensure there is a "level playing field" for all types of generation. This will serve the interest of existing and future consumers.

3.44. The following key aspects of this modification proposal impact on the cost reflectivity of the resulting charges and are considered in turn below. Many questions posed by respondents to the NGET consultation in relation to the locational BSUoS methodology are addressed in the NGET conclusions report and its addendum. We welcome views on all aspects of the methodology:

- Moving part of locational signal from long-run TNUoS charges to short-run BSUoS charges;
- Targeting the cost of constraints relating to transmission boundary non-compliance at generators behind the boundary;
- Including in targeted constraint costs the cost of replacing required generation margin; and
- Calculation of the TNUoS rebate for generators behind a derogated boundary.

Moving part of locational signal from TNUoS charges to BSUoS charges

3.45. Economically efficient network prices are derived on the basis of marginal cost pricing principles, i.e. by considering the marginal impact of each user on network costs. However, it has been recognised that one of the major challenges in setting network charges is to find an optimal balance between:

- The choice of "optimal" timescales to estimate users' requirement in order to evaluate future network costs and network charges;
- The balance between the stability of prices and cost reflectivity; and
- Long-term versus short-term signals – if long-term signals are focussed on in pricing, it may not be easy to also resolve short-term efficiency issues.

3.46. In March 2005, as part of the development of the structure of distribution charges, Ofgem asked three organisations with expertise in this field[19] for their views on the preferred form of an economically efficient charging model. In particular, we asked for views on what the key features of such a charging model would be and whether the use of Long Run incremental Cost (LRIC) is appropriate.

3.47. The advice of these leading experts acknowledged the difference between short and long run[20] costs. The advice received suggested that the long run cost signals should influence investment and siting decisions; short run costs should be designed to affect capacity usage once installed. The consensus view amongst the academics was that capacity is the key driver of costs on the network determined by network design standards and that in transmission systems long term investment signalling is normally more important than short term signalling.

3.48. The current charging arrangements for TNUoS and BSUoS are based on an assumption that the system is compliant i.e. planned and developed to the level required by the NETS SQSS, which has been generally regarded as a proxy, under average circumstances, for optimised long term investments that take into account short term operation costs. Therefore the locational differentials calculated for TNUoS, based on generators' capacity, are regarded as providing total locational signals (including both long-run and short-run costs). If the system were compliant there would be argument that BSUoS charges should not contain additional short-run locational differentials.

[19] Frontier economics, University of Cambridge and the Centre for Distributed Generation and Sustainable Electrical Energy.
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=186&refer=Networks/ElecDist/Policy/DistChrgs

[20] Generally speaking, short-run refers to timescales when certain costs such as asset investment are fixed, whereas long-run to timescales when all costs can be varied, specifically asset investment cost.

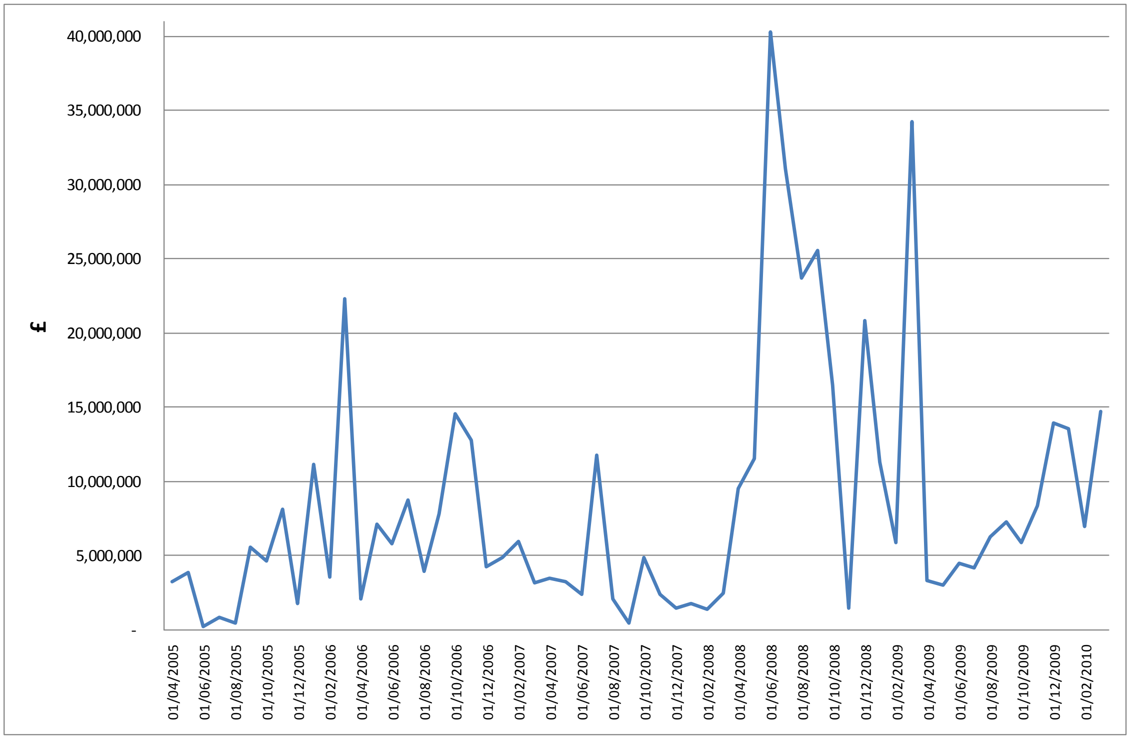
3.49. However, generators with the same capacity can make different decisions about their output, which could result in a different impact on short-run costs. The capacity-based long-run charging signal only accounts for the short-run costs of a generator with average behaviour pattern, not for each generator at time of use. In a situation where the network investment quickly catches up with the demands for capacity and achieves compliance with the NETS SQSS, the elements in the short run costs specifically caused by individual generators' varying usage pattern would be comparatively low. In this case, it has been argued that the lack of a short run locational signal is sufficiently counter-balanced by the relative benefit of a set of stable and predictable locational signals in the long-run charges. This is because:

(a) Locational generator behaviour has a low impact on short-run costs within a compliant system;
(b) TNUoS already contains long-run and short-run locational impacts by generators on transmission costs (albeit based on average usage patterns); and
(c) Locational signals in the short-run timescale could be volatile and unpredictable.

3.50. In a situation where transmission investment level falls substantially below the NETS SQSS compliant level, condition (a) above is often no longer valid, due to the locational behaviour of generators significantly impacting on high constraints costs. Furthermore, the assumptions in (b), that short and long run behaviours and costs are contained in the TNUoS locational signal, are less true. The loss of efficiency due to the lack of a short-run signal outweighs the benefit of stable charges. There is therefore an argument that a sharper cost reflective short run signal is required.

3.51. In the specific case of the Cheviot boundary, a significant proportion of commercial access in Scotland is not accommodated by the physical transmission system but through activity undertaken by the NETS SO. The short term costs on the transmission system, particularly those in relation to managing the constraints across the Cheviot boundary, have increased to levels substantially in excess of what would be considered efficient levels. The steep rise of constraints costs on the Cheviot boundary over the past few years is shown in Figure 2 below.

Figure 2 Cheviot Historic and Forecast Constraint Costs[21]



3.52. The cost of constraints could remain high for a significant period of time given the high demand for transmission capacity from a long queue of generators waiting to gain access to the grid and the practical difficulties for transmission capacity to increase at the same pace. As explained above in this situation, the shortcomings of no short term signal under the current charging arrangements may outweigh its benefits, since it causes greater costs from generators not being given a cost signal to make economically informed decisions on the usage of their commercial access.

3.53. NGET's proposal would introduce in BSUoS the short-run locational signal specifically relating to transmission capacity shortfall which results from grid non-compliance, while removing from TNUoS the relevant signal for the same shortfall of transmission capacity.

3.54. Our initial view of NGET's proposal is that it may provide a sharper cost-reflective signal in the short run in areas where the long term investment lags significantly behind the level of generation being allowed access. We welcome views on this issue.

Costs and users to be targeted

Targeting constraint costs relating to boundary non-compliance

3.55. In moving part of the locational signal from long-term TNUoS charges to short-term BSUoS charges, GB ECM-18 focuses on the costs of resolving constraints across

[21] Please note this has been calculated from data provided by NGET in December 2009 and hence is their latest data

a transmission boundary where capacity falls short of that required by NETS SQSS. NGET argued that the short-term costs arising due to non-compliance (as observed on the Cheviot boundary) are significantly higher than those arising in a compliant system, hence the assumptions underlying the current charging arrangements. The gap between the actual short term costs and those in a compliant system could persist for a long time given the length of the queue of generators seeking connection to the grid and the speed with which transmission capacity can be built.

3.56. We note that one respondent to NGET's consultation argued that locational charging of BSUoS should be implemented across the system and not limited to a derogated boundary. We also note NGET's argument that only in the case of derogated non-compliant boundaries, in particular the Cheviot boundary, do short and long run costs depart significantly from those expected under a fully compliant system.

3.57. We further note from data provided by NGET that the vast majority of the historical constraint costs on the system relate to actions taken in Scotland, and a substantial part of the latter arose due to constraints caused by the capacity shortfall on the Cheviot boundary, as shown in Table 3. We therefore initially consider that there is a case for focusing on the costs relating to derogated boundaries.

Table 3: Historical Trends in Constraint Costs

Constraints costs (£m)	**2005/06**	**2006/07**	**2007/08**	**2008/09**
System total	84	108	70	262
Arising from Scottish Actions	70	80	42	231
Proposed Targeted Constraint Cost (i.e. due to non-compliance)	36	29	25	194

3.58. We note comments made by respondents to NGET's consultation that locational BSUoS should only apply to the current derogation on the Cheviot boundary since it was this derogation which permitted overselling of capacity at the time of the introduction of BETTA. Whilst we acknowledge that the Cheviot boundary is currently the only boundary that is non-compliant and which gives rise to significant constraint costs, we are not convinced that there is an objective basis for the charging methodology to be restricted to a specific boundary. In the event that any other boundaries were to become non-compliant, we can see no objective reason for treating them differently. Such further derogations are likely to arise as a result of our recent decision to implement an interim form of Connect and Manage.

Targeting generators behind non-compliant boundary

3.59. Under GB ECM-18, the costs of constraints associated with a derogated boundary will be targeted on generators located behind this boundary. NGET considers it is appropriate for generators to bear the targeted cost of constraints since the derogated non-compliance on an exporting transmission boundary arises primarily due to the over-selling of access capacity to generators behind this boundary. In addition, constraint costs arise directly from actions taken by these generators.

3.60. Our consideration of the merits of targeting certain cost signals to certain parties takes into account the following points:

- Targeting users vs. transmission companies;
- Targeting all or some generators;
- Whether demand users and distributed generation should also be targeted; and
- The impact of market power and uncompetitive bidding.

3.61. Targeting users vs. transmission companies – Some respondents to NGET's consultation questioned whether any parties should be targeted with the cost of constraints, because the constraints have arisen as a result of transmission companies' action such as underinvestment or taking existing transmission assets out of service. NGET responded to this by highlighting that the primary cause of the non-compliance is the decision to over-sell transmission capacity.

3.62. Ofgem recognises that costs on the transmission system arise due to the investment and operational actions of the transmission companies as well as the siting and output behaviour of users. There are regulatory arrangements such as TO price controls and SO incentive mechanisms through which the transmission companies are provided with incentives reflecting the impact of their actions on the transmission system. However, we also believe that it is important that users are provided with appropriate cost signals reflecting their impact on the overall system. In the specific case of the constraint costs associated with a non-compliant transmission boundary, as discussed above there are strong arguments for a sharper short run signal for the users and as such our initial view is that it is suitable to target them at users whose actions directly impact on the costs.

3.63. Targeting all or some generators – Although we recognise that the costs that would be targeted as a result of GB ECM-18 are incurred as a result of NETS SO actions on either side of a derogated boundary, they arise primarily as a result of excess generation relative to transmission network capacity behind the non-compliant boundary. The excess generation is a result of overselling capacity on one side of the boundary only, and as such, our initial view is that this is an objective ground for differentiating such generators from those elsewhere. In addition, we note that some respondents to NGET's consultation were in favour of only targeting costs on generators who had recently connected to the transmission system and who were therefore deemed to trigger the non-compliance. Under the current access arrangements all access rights, once allocated, are treated in the same way in terms of ongoing commitment to the use of the system and charges they face. We are therefore not convinced that there is an objective reason to treat generators located behind the same boundary differently according to the timing of their connection. We invite views on these issues.

3.64. Whether demand users and distributed generation should also be targeted – We note that some respondents to NGET's consultation argued that locational BSUoS charges should also be targeted at other parties, notably suppliers and distributed generators. Their reason was that demand and distributed generators contribute to the environment which gives rise to constraints.

3.65. In its conclusions report, NGET accepts that under the current charging methodology, distributed generators below 100MW in size do not pay BSUoS or TNUoS charges[22]. The changes proposed under GB ECM-18 would not affect that different treatment. However, NGET intends to take forward a separate review on the treatment of distributed generation. We would expect NGET to bring forward proposals to modify the charging methodology to ensure that the arrangements do not lead to undue discrimination between transmission-connected and distribution-connected generators. There is a possibility that GB ECM-18 would provide an additional incentive for smaller generators to connect to the distribution system rather than the transmission system although initially we believe this additional effect to be marginal.

3.66. With regards to demand, NGET states in its report that the rising costs in constraints across the system are predominantly caused by the increasing generation capacity connected in a particular location, ahead of transmission reinforcement. In contrast, over the same period, the location of demand, putting aside the issue of distributed generation, has not significantly changed. Therefore NGET believes it reasonable to consider the short term increase in costs to be as a consequence of changes to generation patterns.

3.67. In addition, we note that this proposal aims to sharpen signals only in relation to derogated boundaries. We agree that the impact on transmission costs of small distributed generation located behind the same derogated boundary is, in aggregate regardless of their individual sizes, similar to that of larger generation. However, we also acknowledge that this is a wider issue that is better addressed systematically. Indeed we would like NGET to review the overall treatment of distributed generation in transmission charging and wider access arrangements[23]. We have also written to the DNOs[24] encouraging them to work with NGET to find practical solutions. We look forward to seeing progress in that area.

3.68. In the light of the above, our initial view on the treatment of demand and distributed generation as put forward in NGET's proposal is that it represents a practical and focused approach to addressing an important issue. However, we welcome further work in this area which could lead to new modifications if appropriate. We invite views on these issues.

3.69. Impact of market power and uncompetitive bidding **-** Some respondents to NGET's consultation expressed concern that this proposal would not be cost reflective due to the existence of market power and uncompetitive bidding behaviour by parties behind a derogated boundary. NGET in its conclusions report stated that it understands the concern that undue exploitation of market power may negate the intention of the proposal to accurately reflect the costs of access onto the appropriate parties. However NGET expects market power to be addressed through other actions.

3.70. We acknowledge parties' concerns regarding market power and note that market power could affect the cost of constraints and potentially distort the cost

[22] This is either by explicit rebate or implicit avoidance for BSUoS and exemption for TNUoS.
[23]http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=93&refer=Networks/Trans/ElecTransPolicy/TADG
[24]http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=207&refer=Networks/ElecDist/Policy/DistGen

reflectivity of charges. However, our initial view is that the proposed changes, by targeting relevant costs at all parties that have same impact on the constraints including those who may have disproportionate influence of the costs, represents an improvement to the current non-targeted charging. It is also worth noting that the Secretary of State (SoS) has announced the Government's intention to include a new Market Power Licence Condition (MPLC) in the Energy Bill, which we currently expect to be in place by June 2010 at the earliest.

3.71. We welcome views on all the issues relating to targeting of costs and users.

Including cost of replacing generation margin

3.72. NGET must maintain a level of operational energy reserve (generation margin) in order to maintain system security. Some respondents to NGET's consultation argued that the targeted constraint costs should not include the cost of replacing the generation margin. They considered that unlike replacement energy, the cost of replacing the generation margin is out of the control of generators who would be targeted by GB ECM-18 and is not based on a specific obligation on the part of the users. In response, NGET drew parallels between the lack of a specific obligation on users to provide generation margin and the lack of obligations for users to keep their output level below what could be accommodated by the transmission capacity. It argued that the incremental cost of replacing the generation margin is incurred by the NETS SO as a direct consequence of managing the constraints across a derogated boundary, and therefore should be included in the targeted constraint costs.

3.73. Maintaining the generation margin is an integral part of the NETS SO's action to fulfil its obligation of maintaining system and energy balance. Just as constraining generation behind a constrained transmission boundary is required to avoid overloading transmission equipment, maintaining the generation margin is essential to the security of the transmission system. To the extent that the costs for both actions are directly impacted by generators being over-allocated access behind a derogated boundary, our initial view is that they should both be included in the targeted constraint costs. We welcome further views on this issue.

Calculating the TNUoS rebate

3.74. Some respondents to NGET's consultation considered that instead of the proposed prorating-down of the wider locational tariff for generators behind the derogated boundary only, the rebate should be based on a system-wide recalculation with the relevant TEC reduced to a compliant level. NGET explained in its report that the proposed rebate calculation was a practical approximation of the cost reduction when comparing the current system to a compliant system. They pointed out that a full model would potentially depend on the particular system design solution with specific network topology changes.

3.75. We acknowledge that there could be alternative ways to calculate the TNUoS rebate. Our initial view is that NGET's proposal is a practical approach to adjusting TNUoS in line with the proposed changes to BSUoS such that together they provide consistent cost signals in the short-run and long-run changes. We invite further comment on this aspect of NGET's proposed approach.

3.76. Our initial view is that overall GB ECM-18 improves the cost reflectivity of charging relative to the current baseline. We invite views on this observation.

Competition

3.77. We consider that the proposals could impact on competition by:

- Altering the competitive balance in the wholesale market;
- Impacting on consistent and non-discriminatory treatment of users;
- Increasing regulatory uncertainty, leading to barriers to entry; and
- Increasing the complexity of the charging methodology.

Competitive advantage

3.78. We note that some respondents to NGET's consultation were concerned that some generators in the market are unable to respond to the price signals that would be created by GB ECM-18. Examples given included inflexible baseload generators, such as nuclear plants, as well as renewable generators such as wind.

3.79. In general, we believe that competition can be more effectively promoted if the charges for a service better reflect the costs of providing it. We recognise that the ability or willingness to respond to network cost signals varies according to users' specific circumstances. However, our initial view is that in general, improving cost-reflectivity of charges for the use and operation of the transmission network helps create a more level playing field for generators. In addition, charges for transmission and balancing services should not be used to compensate for any other areas of relative strength or weakness in competition.

3.80. However, we also must consider the merit or otherwise of an ex-post charge and whether there is a pattern that generators can observe to reach efficient output decisions. NGET in both the conclusions report and its addendum has considered the information it will provide and the extent to which this will be effective in facilitating the decisions taken by generators.

3.81. NGET has stated that the probability with which a constraint will be active will be dependent on a number of factors. The level of demand which is forecast on either side of the transmission boundary, the indicated output of generation each side of the boundary, and the capability of the boundary. The latter is determined by the level of outages on the circuits that make up the boundary and whether an inter trip on that boundary has been armed which effectively increases its operational capability.

3.82. NGET aims to signal this likely constraint volume to the market based on its evolving forecasts of the variables and evolving information provided by the market. However, NGET states that the accuracy of these forecasts is significantly impacted by the accuracy with which it can predict generator behaviour. We seek respondents' views as to whether we can expect parties to reach efficient decisions in light of the information provided ex-ante together with the cost-reflective charge received ex-post.

3.83. Another concern raised in the responses to NGET's consultation was that bidding behaviour from generators and pricing of services taken by the NETS SO to manage constraints could be subject to market power and therefore put parties who are price takers and not price setters in relation to charges at a further disadvantage. This concern highlights the risk that an unintended consequence of GB ECM-18 might be to increase the incentive on parties not currently wielding market power to use it, as well as the potential for different gaming strategies and indeed possible tacit collusion to be used.

3.84. We acknowledge parties' concerns regarding market power. To the extent that market power exists, GB ECM-18 would target the quantum of constraint costs that are due to the exercise of market power, at parties behind the derogated boundary. Therefore, the effect of GB ECM-18 would be to remove the impact of market power from all generators and concentrate it on a few behind the derogated boundary. However, this effect would need to be balanced against the way in which GB ECM-18 is likely to increase cost reflectivity by targeting the cost of constraints on generators behind the derogated boundary and away from generators whose actions did not contribute to the cost of the constraints.

3.85. We note that we are tackling the issue of undue exploitation of market power in the wholesale electricity sector.

3.86. We welcome respondents' views on these issues.

Discrimination

3.87. It is appropriate to consider the legal issues surrounding the differential treatment of generators. Situations can arise where differential treatment is lawful. This is sometimes referred to as due discrimination. Equally, differential treatment may be unlawful, and is sometimes referred to as undue discrimination. Undue discrimination arises where like cases are treated differently or where unlike cases are treated in the same way, without justification. It is the identification of relevant similarities (or differences) and the consequences of them along with consideration of the justification for different (or relevantly similar) treatment which is important in assessing whether or not treatment amounts to due or undue discrimination.

3.88. Various concerns were raised by parties in response to NGET's consultation that the proposal would not apply equally to: all generators; generators and distributed generators; generators and demand and hence there would be inconsistent and discriminatory treatment of users. These issues have been discussed above in the cost-reflectivity section.

3.89. In considering the merit of this specific charging proposal, we need to consider carefully whether it exacerbates or in fact causes any undue discrimination. Our initial views are:

- This proposal reduces the undue discrimination overall between generators benefiting from over-allocation of transmission access and those who do not;
- Whilst it is subject to a systematic review to establish whether there is wider unjustified distortion between small distributed generation and larger

generation, this proposal has no material impact (either reducing or exacerbating) on such distortion; and
- The different treatment between generation and demand (potentially excluding small distributed generation in demand groups) may be justified.

3.90. We invite respondents to provide comments including further detail of their discrimination concerns.

Barrier to entry

3.91. Several respondents to NGET's consultation shared the view that GB ECM-18 potentially increases regulatory and commercial uncertainty by providing an environment in which charges are more volatile and which will therefore create a barrier to entry for new plant by increasing investment risk. Some respondents cited the increasing charges as a specific barrier for generators to locate behind constrained boundaries.

3.92. We acknowledge that any changes to the charging methodology and hence to charges would cause some disturbance to the user's costs. However, charges should be reflective of the user's impact on the transmission system, and be consistent with nature of the rights and user's commitment therein.

3.93. Under the current access arrangements, all generators' access rights, once allocated, contain very little on-going financial commitment and are priced anew at least once a year, according to charging methodologies that can be modified any time. We consider there is strong merit in developing wider access and charging arrangements that provide long term stable charges reflective of users' impact on transmission costs and in line with users' financial commitments. In the interim however, we have to assess this specific charging modification proposal on its own merit against the current framework. In that regard, we consider that any potential uncertainty created by this proposal might be justified by the overall benefit of removing undue charges from parties who do not cause the costs. Also, our initial view is that by targeting part of the potentially more volatile transmission costs at parties who directly impact on them, could result in changes in behaviour that would result in greater stability for this cost element which in turn could be beneficial to all new entrants.

Complexity

3.94. It could be argued that GB ECM-18 increases the complexity of the charging methodology by splitting the BSUoS charges into locational and residual elements for parties behind derogated boundaries. In addition respondents to NGET's consultation argued that the level of BSUoS charges will be harder to predict.

3.95. We note in response to this concern that NGET pledges to publish ex-ante constraint management information. We also note that the unpredictability of the BSUoS charges would primarily arise due to the behaviour of the generators, not the way the charges are calculated.

3.96. We must weigh the increased complexity of the charging structure against the overall benefit that the proposal might bring. In light of our assessment of this proposal in all other relevant areas, and noting the areas that NGET has put forward practical compromises such as targeting BSUoS at a zonal level, our initial view is that the complexity of the proposed changes is reasonably balanced. However, we welcome further comments on this issue.

Reflecting developments

3.97. NGET's transmission charging methodology must also properly take account of developments in the transmission licensees' transmission businesses.

3.98. NGET considers a relevant development to be the increasing level of constraint costs due to the over-allocation of access rights. NGET recognises in its report that the lack of short-run signal in BSUoS charges could put parties at risk of not being able to make economically informed decisions as to their generation output. It has responded to this by proposing to sharpen the charging signal in the short-run (BSUoS) whilst adjusting the long-run TNUoS, so that both are in line with the costs and impact at relevant parts of network. In raising this modification proposal, NGET also acknowledges the TAR process including the development of enduring access reform proposals and states that the charging arrangements will be continually kept under review both in light of any conclusions through TAR and more generally in light of any incremental improvements or unintended consequences.

3.99. As we pointed out in our February Open Letter, we are seriously concerned about the escalating operating costs on the Transmission System, a significant part of which is constraint costs arising due to the over-allocation of access behind the existing derogated boundary. Given our recent decision on the interim approach to facilitate earlier connection of generation, having appropriate charging arrangements for relevant costs will have an even higher impact on the efficient operation of the overall system. Initially, we consider that NGET’s proposal could provide a better response to important developments in the transmission businesses. We invite respondents to comment on this.

4. Assessment against Authority's wider duties

Chapter Summary

This chapter sets out an assessment of the other key aspects of the proposal that are relevant to the Authority's wider duties. These include consideration of the impacts on consumers, non-discrimination, security of supply and the environment and the interaction with the Transmission Access Review process.

Question box:

Question 1. Do respondents wish to present any additional quantitative or qualitative analysis that they consider would be relevant to assessing this proposal?

Question 2. Do respondents consider that there are any aspects of the proposal that have not been fully assessed against the factors set out in this chapter?

Question 3. Do respondents consider that there is discrimination between transmission system users as a result of this proposal?

Question 4. We welcome further views on whether the proposal could have an adverse impact on security of supply.

Question 5. We welcome further views on whether the proposal could have an adverse impact on sustainability in particular the transition to a low carbon economy.

Question 6. Do respondents wish to present any further analysis on the wider implications of the benefit that may ultimately be expected to be passed through to consumers?

Question 7. Do respondents have any views on the interaction of NGET's charging proposal with TAR as set out in this chapter?

Areas for assessment

4.1. This section sets out an assessment of the impact of NGET's modification proposal on factors that the Authority must have regard to when carrying out its functions including its principal objective and statutory duties. This assessment is not intended to be an exhaustive assessment of all general duties but only those we consider are of relevance to the assessment of the impact of NGET's proposal.

Impact on consumers

4.2. It is in the interests of consumers that the transmission charging arrangements facilitate efficient use of the transmission system, which in turn ensures that the costs of operating the transmission system are not higher than they need to be. A substantial proportion of these costs are ultimately borne by electricity consumers.

4.3. As set out in our assessment in Chapter 3, the impact on consumers could be a result of the following:

- Overall reduction in the costs borne by suppliers which could be passed onto consumers;

- An indirect impact due to the influence on wholesale prices. This depends on the merit order as described above. Notwithstanding this, if the wholesale price reduces, costs to customers will reduce and if it increases, customer costs will increase; and
- The fact that generators behind the derogated boundary could potentially respond to the higher cost signal and seek to reduce the cost by lowering their output and / or their prices, resulting in overall reduction of constraint costs. The likelihood and degree of such reduction are subject to other factors that influence the generators' output decision.

4.4. Our initial view is that the proposed modification has the potential to reduce customers' bills. We welcome parties' views on our assessment above.

Non discrimination

4.5. This is discussed in Chapter 3 in full. However we invite respondents to provide further detail of their discrimination concerns here.

Security of supply

4.6. A key issue in relation to security of supply is whether the extra costs targeted at plants behind the derogated non-compliant transmission boundary will undermine security of supply. One respondent to NGET's consultation believed that the proposal would effectively force otherwise economic generation in Scotland to give up its network access rights and would adversely impact investment in renewables to the benefit of thermal generation in England and Wales, and that it would bring about early closure of existing Scottish generation. Closure of plant in the current economic climate, given the need for investment in generation to meet both the 2016 gap left by closing oil, coal and nuclear plants, and the 2020 climate change targets, (both of which are the focus of Ofgem's Project Discovery) would potentially increase the risk to security of supply.

4.7. One respondent to the NGET consultation considered that there would be an increase in the longer-term risks to security of electricity supply in Scotland. This would be because investment in 'base load' is in part economically attractive at present because of the potential to export excess power. This proposal may result in reduced exports and hence reduce the earnings of these generators.

4.8. One respondent to NGET's consultation believes that it would be the volatility of future BSUoS costs which will affect security of supply since there would thus be no meaningful signal given to generators planning to invest in Scotland and would threaten the viability of generators in Scotland. It therefore believes that the proposal could have a profound adverse affect on security of supply in GB.

4.9. Initially, we consider that the locational BSUoS charge will reflect the level of constraints due to non-compliance and will therefore send appropriate signals for investment. Higher charges would only apply to plant in Scotland whilst the Cheviot boundary is non-compliant. Were there to be no excess of generation, the boundary would be compliant, BSUoS charges lower and the locational BSUoS element absent.

4.10. There is an argument that if the marginal plant is behind a derogated boundary, it will continue to be able to recover its costs upon implementation of GB

ECM-18. If there was a shortage of generation capacity then the wholesale price would rise to ensure that the marginal plant can recover enough to enable it to run.

4.11. NGET's analysis included consideration of a scenario where a plant in Scotland closed down. In this situation there was still an excess of generation. Furthermore, NGET were confident that they would be able to deal with local network issues even if it were only provided with 5 days notice of plant closure. Our initial view is that GB ECM-18 would not result in a risk to security of supply in Scotland.

4.12. It is worth noting that since 5 November 2009 NGET has published close to real-time information on which power station units are in a constrained area. The publication of increased information on constraints should help to make the volatility more predictable.

4.13. It is our initial view that there should be no impact on security of supply as a result of GB ECM-18. We would welcome views on this.

Best regulatory practice

4.14. The modification proposal, and more explicitly Ofgem's approach to assessing the proposal, is relevant to the Authority's obligations regarding best regulatory practice. Our decision to publish this impact assessment and to give seven weeks for responses is in line with our published impact assessment guidance and recognises the consultation spans the Christmas holiday period.

4.15. We note that respondents to NGET's consultation commented on the process undertaken for GB ECM-18. In general, parties wished to have longer period for the industry process to develop and assess the proposal, and were keen to avoid within-year charging changes. Some also raised the interaction with the TAR and believed that concerns addressed under this charging modification should be taken forward in TAR. In its conclusions report NGET accepted that the timeframe in which it has raised and consulted on this proposal has been shorter than some others. However it believes the timeframe for the consultation is proportionate given the need to respond to the speed at which constraint costs have risen and are forecast to rise in the short to medium term. It further believes that the process undertaken meets its licence obligations with respect to proposing a change to the charging methodology, pointing out that it had sought to inform and consult with the industry before it formally issued the consultation document, and had discussed both the proposals and its additional analysis at industry fora afterwards.

4.16. Ofgem notes the process concerns that respondents have raised and the decision to issue this Impact Assessment is in part for this reason.

Impacts on sustainable development

4.17. We have considered GB ECM-18 in the context of five sustainable development themes, set out below, which were identified by the Authority and draw on the UK Government's Sustainable Development Strategy that set out how Ofgem will contribute to the sustainability agenda[25].

[25] See Ofgem's second annual Sustainable Development Report, November 2007.

Managing the transition to a low carbon economy

4.18. Several respondents to NGET's consultation commented on the effect that GB ECM-18 would have on renewable generation in Scotland and hence the achievement of the UK's renewable energy and CO_2 reduction targets. Respondents commented on several aspects that they believed would affect renewable generation and hence the transition to a low carbon economy:

- The implied charges could potentially be punitively high, especially if a generator is behind multiple derogated boundaries;
- The implied charges would be unpredictable and could be volatile;
- Renewable generators are high merit order, fuel-free generators that always want to generate when they can. It makes no environmental or economic sense for them to curtail their generation – consumers get best value from the Renewables Obligation from generators connecting and generating;
- It will act as a disincentive to the objective of investment in renewable and clean energy generation in Scotland and the UK. Reasons given by respondents included the difficulty of obtaining finance due to cost uncertainty and the lack of a stable regulatory regime.

4.19. Ofgem notes that as with all generation, there are options about where renewable generators are located and it is important that decisions about location take account of all of the costs including those of investment in the transmission system and system operation.

4.20. In addition, this modification will only prevent renewable investment if it would make such investment uneconomic. We further note that by reducing the charges for generators outside the derogated boundary, the business viability for new generators (many of whom are also renewable or low-carbon) would be improved.

4.21. We would not expect there to be an impact on the price of carbon.

4.22. We invite parties to provide us with information and evidence regarding the effect of GB ECM-18 on the viability of renewable generation in constrained areas. Respondents may request that this information is kept confidential. We would welcome views on these issues.

Promoting energy savings

4.23. Our initial view is that we do not believe that GB ECM-18 may reduce the volume of electricity generated north of the Cheviot boundary. To the extent that the proposal may reduce the incidence of constraints and the associated level of flows across the system, it may potentially lead to a decrease in transmission losses. Our analysis does not quantify the impact on transmission losses.

Eradicating fuel poverty and protecting vulnerable customers

4.24. The Authority has duties in relation to the impact of proposals on the sick, disabled, elderly, those on low incomes and rural customers, as well as to contribute to the achievement of sustainable development. In considering the impact of the proposals, the Authority is also required to have regard to guidance issued by the Secretary of State regarding the attainment of social and environmental policies.

4.25. Our initial view is that, further to the issues considered above in relation to sustainable development, the most important consideration from the perspective of social objectives is the overall impact of GB ECM-18 on consumers. We must make sure that measures we need to take to tackle climate change and other industry issues are not any more expensive than they need to be. To the extent that we consider the proposal could lead to more efficient operation of the transmission system and lower costs to users, there would be beneficial effects on tackling fuel poverty and protecting vulnerable customers in general.

Ensuring a secure and reliable gas and electricity supply

4.26. For the reasons set out above in section 4 our initial view is that GB ECM-18 is unlikely to affect security of supply detrimentally - see paragraph 4.6 and onwards above. Increased predictability of BSUoS charges and potentially reduced constraint costs could reduce barriers to entry for generators with higher efficiency overall (including costs of transmission) and hence support security and reliability.

Supporting improved environmental performance

4.27. To the extent that the proposal would lead to more efficient use of the transmission system, we consider that this would lead to more efficient investment and operation decisions by the TOs. Given the carbon footprint and impact on visual amenity of the transmission system, this should ultimately lead to a better trade-off between all aspects of transmission and hence better environmental performance.

Impacts on health and safety

4.28. Our initial view is that we do not consider that this proposal will have any impact on health and safety since it is related to commercial charging and does not have any technical impact.

Risks and unintended consequences

4.29. We have considered the different treatment between small distributed generators and larger generators under this proposal, and noted that this is a wider issue regarding the overall charging methodology. We believe a thorough review is required. Whilst our initial views are that the proposed changes do not reduce or exacerbate the differences, we acknowledge that there may be arguments otherwise. If the proposal were proven to exacerbate unjustified differential treatment, then it would impose an unfair disadvantage on the larger generators. This in turn could lead to inefficient outcome in generation development.

4.30. We welcome respondents' views on the above concerns and on any other potential risks and unintended consequences.

Interaction with TAR

4.31. GB ECM-18 is being considered at a time when there is a focus on a new regime for transmission access under the Transmission Access Review (TAR). The Government are now leading reforms of the access arrangements and their initial proposal for reform set out in their consultation document is to introduce a variation of the Connect & Manage[26] approach.

4.32. The re-design of the enduring access regime could impact on the way access rights are priced. The changes introduced under GB ECM-18 may be replaced by new charging arrangements to be developed as part of new enduring access regime. DECC are proposing a targeted intervention and hence full development of the regime will be via industry processes. However, our consideration of GB ECM-18 is on the basis of its own merit under the current access arrangements whilst taking into account the likelihood that its impact will be time limited , although the period to which it would, if implemented, remain in force pending an enduring solution being developed (and implemented) is uncertain.

4.33. We would welcome respondents' views on the interaction with TAR.

Other impacts

4.34. Several respondents to NGET's consultation were concerned that charges would be amended mid-year under GB ECM-18 for a number of reasons;

- Generators contract for a significant proportion of their output a number of months and years in advance. Respondents were concerned that introducing GB ECM-18 mid-year would result in the imposition of significant unforeseen costs on Scottish generation which cannot be recovered to the extent that output has already been contracted;
- The impact on system changes has not been considered;
- Within year changes increase the risk premium, due to regulatory risk, which must be factored into subsequent decisions;
- If a contract has no pass-through mechanism for BSUoS, as is the case in certain sectors of the retail market, then a tariff reduction within year will simply be a windfall gain for the supplier; and
- If implemented, TNUoS charges for the year would need to be re-run and generators allowed to revisit their TEC needs.

4.35. According to the current timetable, if the Authority does not veto the proposal we envisage that the Authority will publish its decision in time for implementation of GB ECM-18 to take place on 1 April 2010, the start of the charging year. We welcome views on any practical implementation concerns.

4.36. We also welcome views on any other impacts not covered in this assessment.

[26] Under a connect & manage approach, generation could be connected ahead of transmission investment

5. Process and way forward

Chapter Summary

This chapter sets out the process that we intend to adopt in order to reach a decision on the charging modification proposal and identifies a timetable for the publication of that decision.

Proposed process

5.1. This document provides seven weeks for respondents to submit any comments. The Authority will take responses, and any other relevant information, into account in making its decision on whether or not to veto the proposal. Responses are requested by 21 January 2010.

5.2. SLC C5(4) of NGET's electricity transmission licence sets out that, where the Authority intends to undertake an impact assessment, NGET will not make any modification to the use of system charging methodology within three months of the report being furnished to the Authority. Therefore, we intend to publish our decision on NGET's proposal on or before 01 March 2010.

Proposed implementation timescales

5.3. If the Authority's decision is not to veto, NGET is seeking to implement the modification proposal in the greater of 30 days or the 1st day of the following month after the Authority has made its decision.

Further information

5.4. Appendix 1 sets out both the details for responding to this Impact Assessment and the appropriate contact details should you have any questions. It also sets out a list of all the key areas where we have sought respondents' views in relation to the contents of this document. Respondents' views are welcomed on any other aspect of this Impact Assessment.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 5:00pm Thursday 21 January 2010 and should be sent to:

Dena Barasi
Transmission and Governance
Ofgem
9 Millbank
London, SW1P 3GE

Tel: 0207 901 7343

Email: dena.barasi@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Having considered the responses to this consultation, Ofgem intends to publish its decision on NGET's proposal by 02 March 2010. Any questions on this document should, in the first instance, be directed to the address above.

CHAPTER: Three

➔ Question 1. Do respondents have any comments on NGET's analysis?

➔ Question 2. Do respondents wish to present any additional quantitative analysis that they consider to be relevant to assessing the proposal?

➔ Question 3. Do respondents consider that there are any aspects of the proposal that have not been fully assessed?

➔ Question 4. Do respondents consider that the key features of the proposal strike an appropriate balance between cost reflectivity, transparency, complexity and stability?

➔ Question 5. Do respondents consider that this modification promotes more effective competition? Conversely, do respondents wish to provide further detail of any discrimination concerns?

➔ Question 6. Do respondents consider that the proposal complements the changing nature of the transmission network and assists the development of an economic and efficient transmission system?

➔ Question 7. Do respondents consider that the different methodologies used in the proposal are appropriate?

CHAPTER: Four

➔ Question 1. Do respondents wish to present any additional quantitative or qualitative analysis that they consider would be relevant to assessing this proposal?

➔ Question 2. Do respondents consider that there are any aspects of the proposal that have not been fully assessed against the factors set out in this chapter?

➔ Question 3. Do respondents consider that there is discrimination between transmission system users as a result of this proposal?

➔ Question 4. We welcome further views on whether the proposal could have an adverse impact on security of supply.

➔ Question 5. We welcome further views on whether the proposal could have an adverse impact on sustainability in particular the transition to a low carbon economy.

➔ Question 6. Do respondents wish to present any further analysis on the wider implications of the benefit that may ultimately be expected to be passed through to consumers?

➔ Question 7. Do respondents have any views on the interaction of NGET's charging proposal with TAR as set out in this chapter?

Appendix 2 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[27]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[28].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[29];
- The need to contribute to the achievement of sustainable development; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[30]

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

[27] Entitled "Gas Supply" and "Electricity Supply" respectively.
[28] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[29] Under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[30] The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed[31] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[32] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[31] Or persons authorised by exemptions to carry on any activity.
[32] Council Regulation (EC) 1/2003

Appendix 3 - Legal Framework for decision

Electricity Act 1989

1.1. The Electricity Act 1989 (the "Act") sets down the legislative structure under which the electricity industry operates including the roles and duties of the Authority. Sections 3A to 3C set out the Authority's principal objective and statutory duties.

1.2. The Authority's principal objective is "to protect the interests of consumers … wherever appropriate by promoting effective competition" amongst other things listed. In addition the Act places a number of other duties on the Authority including carrying out its functions in a manner which is best calculated to secure a diverse and viable long term energy supply and having regard to the effect on the environment.

1.3. On 5 October 2004 the Authority became subject to two additional statutory duties under the Energy Act 2004. These relate to contributing to the achievement of sustainable development and having regard to the principles of best regulatory practice. In carrying out its duties the Authority must also have regard to any additional guidance issued by the Secretary of State in relation to social or environmental policies.

1.4. In addition to the regulatory framework set out under the Act, the electricity industry is also subject to European law and competition law. Section 3D of the Act confirms that the obligations imposed on the Authority under Sections 3A to 3C of that Act do not override contradictory duties or obligations under European law including Directive 2003/54/EC concerning common rules for the internal market in electricity and Directive 2001/77/EC concerning the promotion of electricity from renewable sources in the internal market.

Licence obligations

1.5. Standard condition C5 of NGET's electricity transmission licence sets out the relevant licence objectives with which the use of system charging methodology must conform. These are:

a. to facilitate effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;
b. to result in charges which reflect, as far as is reasonably practicable, the costs incurred by the licensee in its transmission business; and that
c. so far as is consistent with sub-paragraphs (a) and (b), the Use of System charging methodology, as far as is reasonably practicable, properly takes account of the developments in the licensee's transmission business.

1.6. In making its decision whether or not to veto the proposed charging methodology the Authority will first consider if the proposals meet the relevant licence objectives.

Impact assessment

1.7. Section 5A of the Utilities Act 2000 (Duty of the Authority to carry out an impact assessment) applies where: (a) the Authority is proposing to do anything for the purposes of, or in connection with, the carrying out of any function exercisable under or by virtue of Part 1 of the Electricity Act or the Gas Act; and (b) it appears to the Authority that the proposal is important within the meaning set out in section 5A, but does not apply where the urgency of the matter makes it impracticable or inappropriate for the Authority to comply with the requirements of section 5A. Where section 5A applies, the Authority must either carry out and publish an impact assessment or publish a statement setting out its reasons for thinking that it is unnecessary for it to carry out an impact assessment.

1.8. Section 5A(2) sets out the matters which determine whether or not a proposal is “important” for the purposes of section 5A. These are where a proposal would be likely to:

d. Involve a major change in the activities carried out by the Authority;
e. Have a significant impact on market participants in the gas or electricity sectors;
f. Have a significant impact upon persons engaged in commercial activities connected to the gas or electricity sectors;
g. Have a significant impact on the general public in GB or in a part of GB; and
h. Have significant effects on the environment.

1.9. The Authority is required to assess a modification proposal and decide whether or not to veto it on the basis of whether it better achieves the relevant objectives set out in NGET's transmission licence and is in accordance with our wider duties and principal objective.

1.10. We consider the proposal to be "important" for the purposes of Section 5A on the basis that it represents a considerable change to the structure of NGET's use of system charging methodology, the derivation of applicable network charges for use of the transmission system and recovery of allowable revenue. In our view, these proposed changes would significantly impact the level of transparency and control over the costs that existing and future market participants in the electricity transmission sector impose on the system and the resultant charges levied on them.

Environmental issues

1.11. In assessing the impact of GB ECM-18 the Authority has taken account of the potential carbon savings which may arise from GB ECM-18. The Authority has also taken account of carbon savings in its preliminary assessment GB ECM-18 in terms of the Authority’s wider duties, e.g. in relation to economy and efficiency, the environment and sustainable development, and the Authority’s principle objective to protect the interests of existing and future consumers.

Appendix 4 – Additional Detail on NGET's modification proposal

1.1. This appendix provides further details on NGET’s modification proposal, based on NGET’s Use of System Methodology modification proposal consultation (GB ECM-18) published on 13 March 2009.

Further additional information on the Constraint Costing Methodology (Locational BSUoS) was published by NGET in a supplementary explanatory note on 23 March 2009. Both documents are available from NGET’s website. The areas covered by this appendix include:

- Calculation of targeted constraint costs;
- Allocation of charge based on adjusted metered volume; and
- Calculation of TNUoS rebate through adjusting wider zonal generation tariff.

Calculation of targeted constraint costs

1.2. The constraint costing methodology considers the following aspects in determining the direct and opportunity costs that the NETS SO incurs in managing a constraint, namely,

- The price of the first order constraint action in comparison to the price that could be achieved from a BMU in a non constrained part of the network.
- Whether the action brought the market closer to, or further from, energy balance and the cost of recovering that imbalance position.
- The services that were sterilised as a consequence of the constraint

1.3. In the event that this cost is incurred by resolving a constraint across a derogated boundary, the methodology sets out which types of constraint costs would be charged to the locational element of BSUoS. It also sets out how the costs would be apportioned between those incurred due to the fact that the transmission boundary is non-compliant and the costs that would have been incurred under a compliant boundary.

Assessment of the relative cost of such action against a similar action that may have been taken outside of the constraint zone

1.4. The methodology compares the price that has been achieved for a particular buy or sell action associated with management of a constraint with that which could have been achieved if the volume of energy had been bought or sold using an appropriate measure for the price of energy in the Balancing Mechanism in that half hour. Effectively it compares the price of the action against what could have been achieved in the notional “National Hub” price. For example, in a situation where bids are taken for a constraint in a long market these bids may be the only actions taken. However, these bids may be taken out of strict cost order relative to the price that could be achieved procuring services to resolve only the energy imbalance on the system.

Therefore, the cost to the NETS SO is the incremental cost of taking the constraint action beyond that which would have taken in the absence of the constraint.

1.5. Determining the differential in prices is accomplished by the calculation of an "Energy Reference Price" (ERP).This is derived by taking a volume weighted average of all submitted Bids or Offers required to meet market length as measured by the "Net Imbalance Volume" (NIV) in a given Settlement Period. As well as the price of these submitted bids and offers this calculation also looks at the accessibility of the energy by taking into account the MEL and SEL of the BMU on which the bids and offers are submitted.

Replacement Energy

1.6. Where the volume of actions taken to manage constraints is in excess of or in the opposite direction to the length of the market (NIV) then a volume of actions must also be taken to bring generation and demand back in to equilibrium. The actions that are needed to rebalance generation and demand, are termed "Replacement Actions".

1.7. The energy required to replace that lost through management of a constraint situation would be managed at a notional "National Hub" point which would be located outside of the constraint zone. This methodology again uses the "Energy Reference Price" as the cost of energy at that point.

Replacement of Generation Margin

1.8. When a unit's output is reduced to manage a constraint it can be assumed that the output level that unit is reduced to is the highest permissible level that the transmission system can support at that time. As such this imposes a maximum transmission export limit on the unit which is lower than the unit's technical maximum. The difference between the level of permissible export to the system and the maximum output of the unit is therefore now not available to the NETS SO. In such circumstances the sum of available MEL is also reduced. This reduction in available maximum generation due to a constraint is termed "Sterilised Headroom".

1.9. When actions to manage constraints reduce the level of available reserve below the required level, the NETS SO will buy services to fill the deficit. This predominantly accomplished through the synchronisation of additional generation units.

1.10. The volume and cost of reserve procured by the NETS SO, up to the volume of headroom sterilised by constraint management activity, is deemed to be necessary due to the constraint management activity.

Allocation of charge based on adjusted metered volume

1.11. Managing export constraints is likely to involve reducing the output of plant that sit behind that transmission boundary. The charge of accomplishing this reduction in output (and subsequent energy replacement activity) is then allocated on parties based purely on their MW position. Those parties that have had bids taken on them will be exposed to a lower value of costs as their metered position will have been effected.

1.12. Therefore BMU will be charged on their intended output position prior to any actions to resolve the constraint undertaken by the NETS SO. This Meter Adjusted volume is the sum of the BMU energy position and the net volume of any actions taken by the NETS SO to resolve the constraint.

1.13. The types of actions taken that would be assigned back to the BMU would be:

1. Bid Offer acceptances as defined in the BSC;
2. Locational trades as undertaken under schedule 7 of the GTMA agreement;
3. Pre Gate Balancing Transactions; and
4. PN capping contracts.

Calculation of TNUoS rebate through adjusting wider zonal generation tariff

1.14. Under this proposal the wider zonal generation tariffs will be recalculated. The locational element for generators within a geographical zone linked to a compliant transmission boundary will be scaled to be consistent with a compliant system boundary. This will be done by applying a Capacity Scaling Factor to the nodal TEC values of all generators located within a geographical zone linked to a non compliant transmission boundary.

1.15. The calculation of the nodal marginal MWkm for generation that is not within a geographical zone linked to a non-compliant transmission boundary is unchanged.

1.16. At present, the only system transmission boundary where a Capacity Scaling Factor will be applied is the B6 boundary, which corresponds to the boundary between SPTL's and NGET's transmission areas. Consequently, the revised calculation of nodal marginal MWkm will be applied to all generator nodes in generation zones 1 to 8.

1.17. The methodology for the calculation of the final tariffs from the locational component will be unchanged, albeit with the nodal marginal MWkm for generation coming from two separate calculations (i.e. one calculation for nodes for generators within a geographical zone linked to a non-compliant transmission boundary and another for generators not within a geographical zone linked to a non-compliant boundary).

1.18. The chargeable capacity for a generator will remain unmodified. This includes the method for determining the chargeable capacity for a generator in a negative zone.

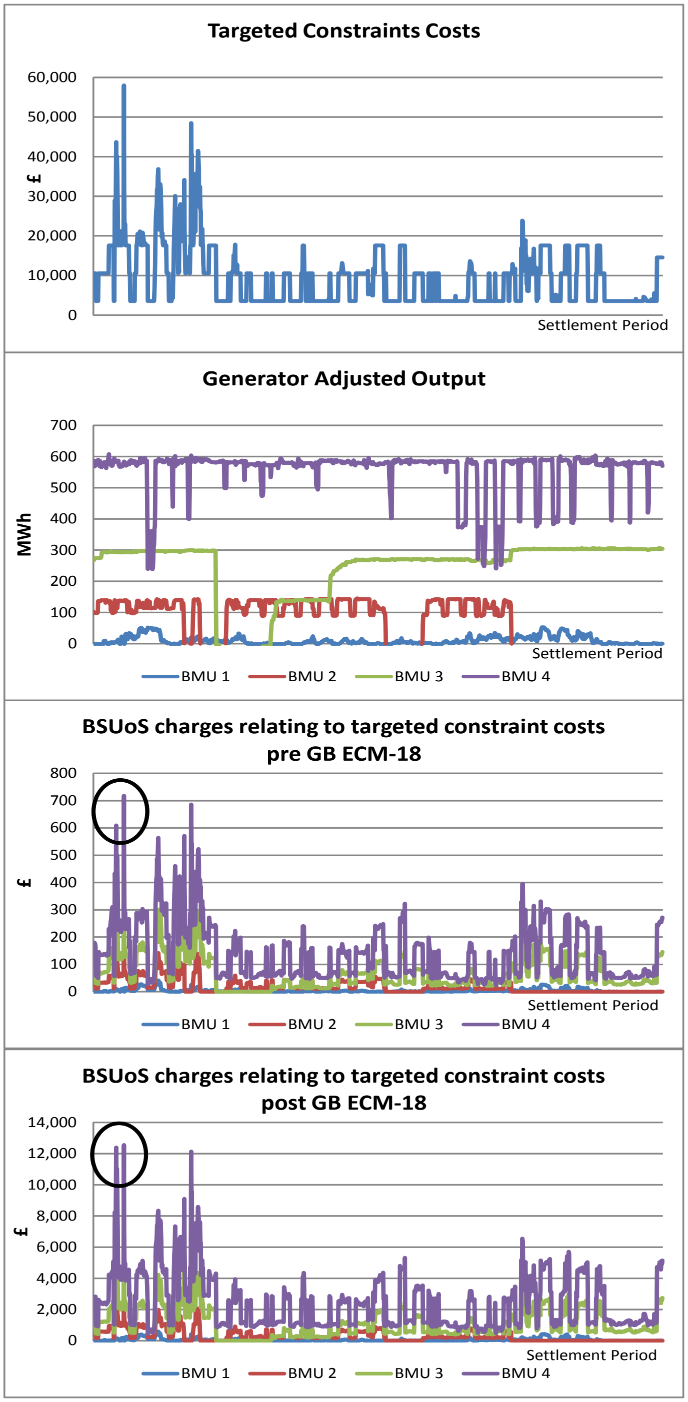
1.19. The new wider zonal generation tariff will be applicable from the 1st of the month following the Authority's decision. The change would be implemented midyear resulting in two sets of wider zonal tariffs applicable for a charging year. The annual liability for a generator would be calculated by pro rating the two tariffs across the year.

Appendix 5 – Size and nature of charging

1.1. This appendix looks at the size and nature of charging by considering the charges pre and post locational BSUoS, for 4 generator BMUs behind the derogated Cheviot Boundary in May 2008. The graphs below show the total targeted cost of constraints (i.e. those solely attributable to transmission boundary non-compliance) incurred in each settlement period in May 2008 on the Cheviot boundary, the adjusted output of four representative generator BMUs with different load characteristics, and the allocation of the total targeted constraint costs to these four BMUs pre and post GB ECM-18. As with the other analysis the Cheviot boundary is an example of a derogated boundary and is analysed to consider the impact of GB ECM-18.

1.2. As can be seen from the graphs all the BMUs shares of the targeted constraints costs rise substantially post GB ECM-18. It can also be seen that the BSUoS charges follows the combined trends of the costs of constraints and the adjusted volume of generation. In other words, a BMU would only face a high BSUoS charge for a particular settlement period if both the total targeted constraint costs and its adjusted output volume are high during that period. In addition, the highlighted sections in the graphs of the relevant charges pre and post GB ECM-18 show the effect of charging on the different bases - metered output as current and adjusted output as post GB ECM-18. Comparing costs, volumes and charges for the two settlement periods corresponding to the first two peaks in BMU4's BSUoS charges circled in the graphs, the relatively higher first peak of the post GB ECM-18 charges, despite the lower corresponding total targeted constraint costs, reflects the fact that NETS SO action has reduced BMU4 volume, yet the original volume is the true cause of the constraints. This shows that GB ECM-18 better targets all the relevant volumes that give rise to constraints.

Figure 3: Targeted constraint costs, generator adjusted output, relevant BSUoS charges pre and post GB ECM-18



Appendix 6 – Impact of Locational BSUoS in 2009/10

1.1. In the main body of the text we presented the historical impact of GB ECM-18, this appendix looks at the likely impact of the proposed modification in the future – again the Cheviot boundary is used as an example. We have used NGET's forecast of the equivalent data for 2009/10, both for a base case which is based on the Seven Year Statement background data as well as for a sensitivity case adding 350MW of new generation in Scotland. The data were provided by NGET to us in May 2009. The analysis has been used to give an indication of possible impacts.

Table 4: Impact on Constraint Cost related BSUoS, TNUoS and total charges by generator load factor by location in 2009/10

Year	Area	Load Factor	BSUoS £m		TNUoS £m		Total £m		Difference	
			Before	After	Before	After	Before	After	£m	£/MWh
2009/10	North Scotland	30%	0.31	5.81	10.79	9.23	11.10	15.04	3.93	2.99
		50%	0.51	9.68	10.79	9.23	11.31	18.91	7.60	3.47
		75%	0.77	14.52	10.79	9.23	11.57	23.75	12.18	3.71
	South Scotland	30%	0.31	5.81	6.80	5.88	7.11	11.69	4.58	3.48
		50%	0.51	9.68	6.80	5.88	7.32	15.56	8.24	3.76
		75%	0.77	14.52	6.80	5.88	7.57	20.40	12.83	3.90
	Oxon & South Coast	30%	0.31	0.00	-0.69	-0.53	-0.38	-0.53	-0.15	-0.11
		50%	0.51	0.00	-0.69	-0.53	-0.18	-0.53	-0.36	-0.16
		75%	0.77	0.00	-0.69	-0.53	0.08	-0.53	-0.61	-0.19
2009/10 with 350MW	North Scotland	30%	0.36	6.50	10.79	9.23	11.15	15.73	4.58	3.48
		50%	0.59	10.83	10.79	9.23	11.39	20.06	8.67	3.96
		75%	0.89	16.25	10.79	9.23	11.69	25.48	13.79	4.20
	South Scotland	30%	0.36	6.50	6.80	5.88	7.16	12.38	5.22	3.97
		50%	0.59	10.83	6.80	5.88	7.40	16.71	9.31	4.25
		75%	0.89	16.25	6.80	5.88	7.69	22.12	14.43	4.39
	Oxon & South Coast	30%	0.36	0.00	-0.69	-0.53	-0.34	-0.53	-0.20	-0.15
		50%	0.59	0.00	-0.69	-0.53	-0.10	-0.53	-0.44	-0.20
		75%	0.89	0.00	-0.69	-0.53	0.20	-0.53	-0.73	-0.22

Please note For the 2009/10 with 350MW scenario it is assumed that the TNUoS will be as 2009/10

Table 5: Forecast of aggregate targeted constraint costs paid 2009/10, £m

Year	Area	BSUoS relating to targeted constraints costs pre GB ECM-18	BSUoS relating to targeted constraints costs post GB ECM-18
2009/10	Scotland	7.7	155.3
	England & Wales	70.0	0.0
2009/10 350MW scenario	Scotland	9.1	179.4
	England & Wales	80.6	0.0

Appendix 7 – Illustration of impact on different generators – behavioural change with no market power

1.1. This appendix cites for illustrative purposes, studies 2 – 4.2 from NGET's addendum to the conclusions report which considered the impact of locational BSUoS with an unconstrained merit order and Balancing Mechanism prices based on marginal costs. These studies used the Cheviot boundary as an example and showed the impact on different generators. For fuller appreciation of the analysis please see the addendum report itself. NGET also considered different scenarios not discussed here:

- Unconstrained merit order and Balancing Mechanism prices based on fixed and marginal costs;
- Closure of marginal plant in Scotland with the unconstrained merit order and Balancing Mechanism prices based on marginal costs;
- Bid prices at 60% level with the unconstrained merit order and Balancing Mechanism prices based on marginal costs; and
- Coal and gas price switch with the unconstrained merit order and Balancing Mechanism prices based on marginal costs (Coal*0.9 & Gas*1.2).

1.2. Analysis indicated a constraint cost of £58m without locational BSUoS (only the effect rather than the absolute value can be drawn from these studies see addendum for more detail). The compliant situation was calculated to be £7m and therefore Locational BSUoS is targeting £51m.

1.3. In the locational BSUoS studies, the result cycles between £22m and £45m[33].

1.4. The impact of locational BSUoS on generators (reducing constraints from £58m to £22m) is shown below:

[33] This cycling effect was discussed in the NGET addendum and they would expect the market to settle somewhere within this range.

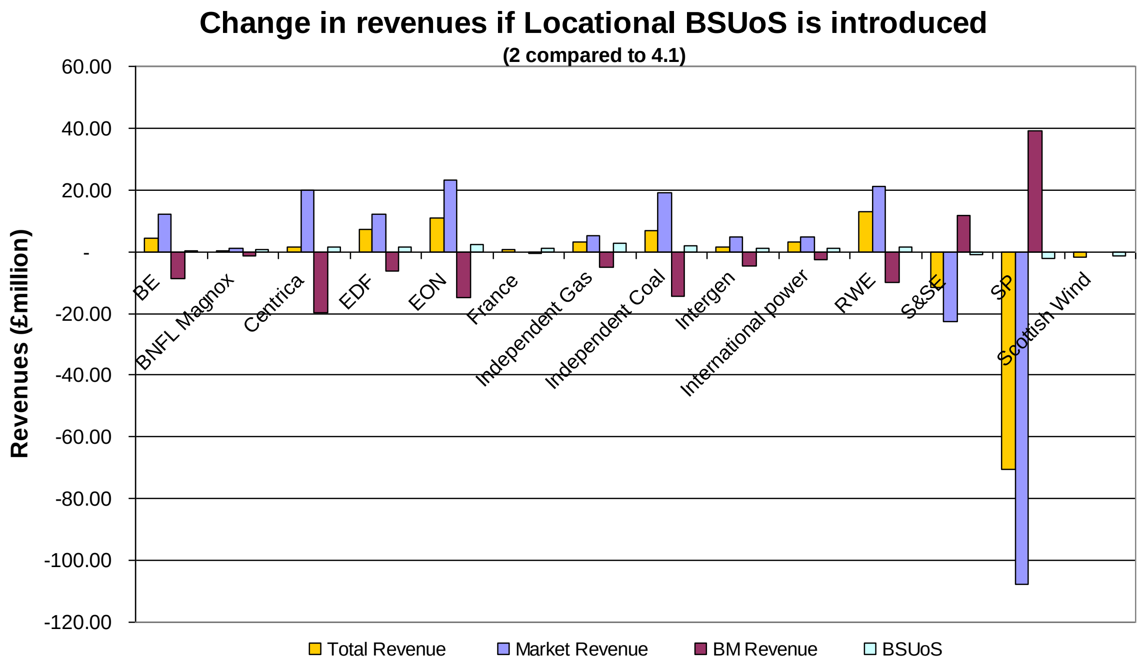


Figure 4:Change in revenues / margin if locational BSUoS is introduced (£22m)

1.5. NGET stated that this demonstrates that the key affected parties are those with marginal plant in Scotland where their pre-gate unconstrained running is reduced due to the inclusion of Locational BSUoS. The net effect of reduced market income and reduced bid payment overall results in reduced revenues.

1.6. They also stated that BE have a net gain in revenue / margin. This is due to a combination of the portfolio effect of their marginal plant on the unconstrained side of the boundary and a net gain in total BSUoS i.e. the GB saving in BSUoS (removing £51M) outweighs the targeting of Locational BSUoS behind the constraint boundary.

1.7. They further stated that other units in England and Wales see a net change in revenue / margin that is positive as they no longer contribute to the £51m constraint. Their revenue / margin previously under the Balancing Mechanism is replaced with revenue / margin received from unconstrained running. Due to the lumpiness of NGET's merit order this 'benefit' is slightly magnified. Similarly, the disbenefit to Scottish parties is also overstated as we would expect them to tailor their output so as to maximise output, but not cause a constraint and therefore incur locational BSUoS.

1.8. The impact of locational BSUoS on generators (reducing constraints from £58m to £45m) is shown below:

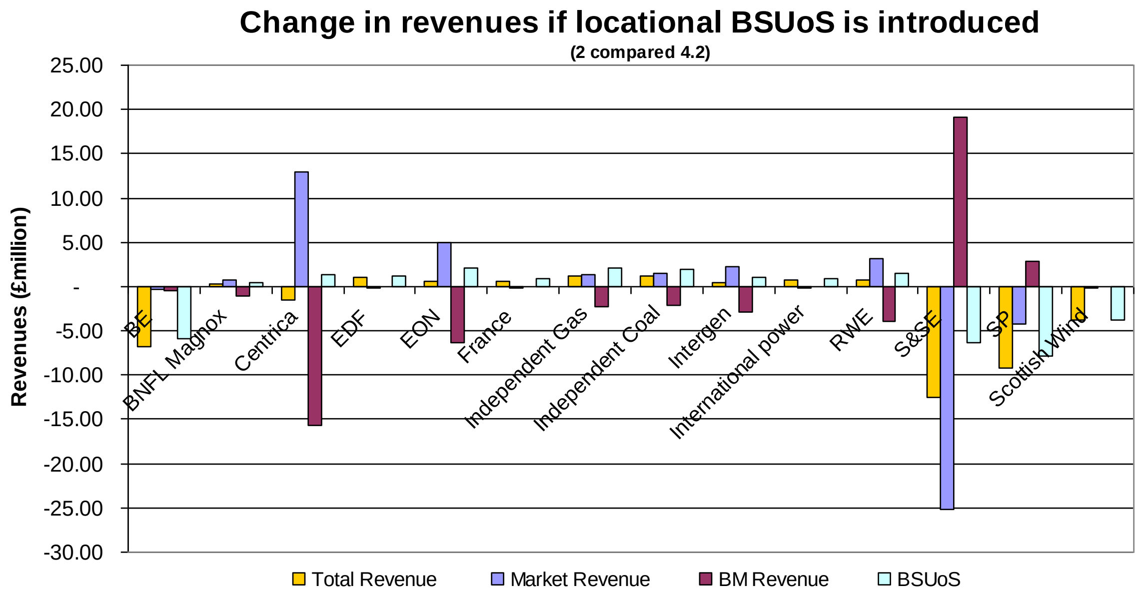


Figure 5:Change in revenues / margin if locational BSUoS is introduced (£45m)

1.9. This showed the effect of a smaller drop in constraints. NGET stated that this again shows that flexible plant in Scotland receives less running in the unconstrained study although to a lesser extent than the previous example.

1.10. In this particular example, NGET shows that the net effect on BE is negative as it picks up a larger proportion of the Locational BSUoS than it saves in BSUoS and it receives no increase in unconstrained running in England and Wales.

1.11. NGET's study also shows that the net effect on Centrica is very slightly negative. This is as a result of the slight difference in income from generating in the unconstrained merit order to that of being constrained 'on' in the Balancing Mechanism (Balancing Mechanism offers have been assumed to be 1.2 times unconstrained merit order price). Assuming the step change in prices post gate closure is cost reflective, this actual loss in revenue / margin will be balanced by a reduction in costs. It should also be noted that in the previous example, the much larger reduction in BSUoS nets this effect out.

Appendix 8 – Illustration of behavioural change with market power

1.1. This appendix cites for illustrative purposes some of the analysis in NGET's addendum to the conclusions report, namely studies 11 – 13.2 that considered the impact of locational BSUoS with bids at 60% level, with an unconstrained merit order and Balancing Mechanism prices based on marginal costs. For fuller appreciation of this and other analysis please see the addendum to the conclusions report.

1.2. Bids were set to 60% of the marginal cost in the non compliant area as per the table below taken from NGET's addendum where more detail can be found.

Table 6 Bid spread wide range

Price	Scot Avg BP	E&W Avg BP	Scot %	E&W %
>=£100			0.00%	0.00%
£0 - £100	£20.25	£33.40	28.39%	45.01%
(£0) - (£100)	-£38.62	-£37.23	8.07%	1.44%
(£100) - (£200)	-£110.55	-£111.36	0.12%	1.44%
(£200) - (£300)	-£247.95	-£230.84	0.39%	1.59%
(£300) - (£400)	-£300.00	-£330.67	0.01%	0.11%
(£400) - (£500)		-£442.63	0.00%	0.60%
(£500) - (£600)	-£554.04	-£503.81	0.78%	2.97%
(£600) - (£700)	-£666.00	-£600.25	0.03%	0.20%
(£700) - (£800)	-£748.83	-£750.00	0.10%	0.03%
(£800) - (£900)		-£800.11	0.00%	0.26%
<=(£1000)			62.10%	46.36%

1.3. NGET have stated that this increases the, without Locational BSUoS case from a £58m (see Appendix 7) to a £98m constraint cost. In this study the unconstrained solution is the same as for study described in Appendix 7 above. This is confirmed as the wholesale cost (without constraints), which is set by the marginal unconstrained unit is the same in both studies at £16,999m.

1.4. NGET have stated that the locational BSUoS studies change between two states, £28m and £75m, indicating a reduction in constraint cost of between £70m and £28m. The revenue / margin figure below provides the change in revenue / margin flows between the 60% base case without locational BSUoS and the study with locational BSUoS and a total constraint cost of £28m.

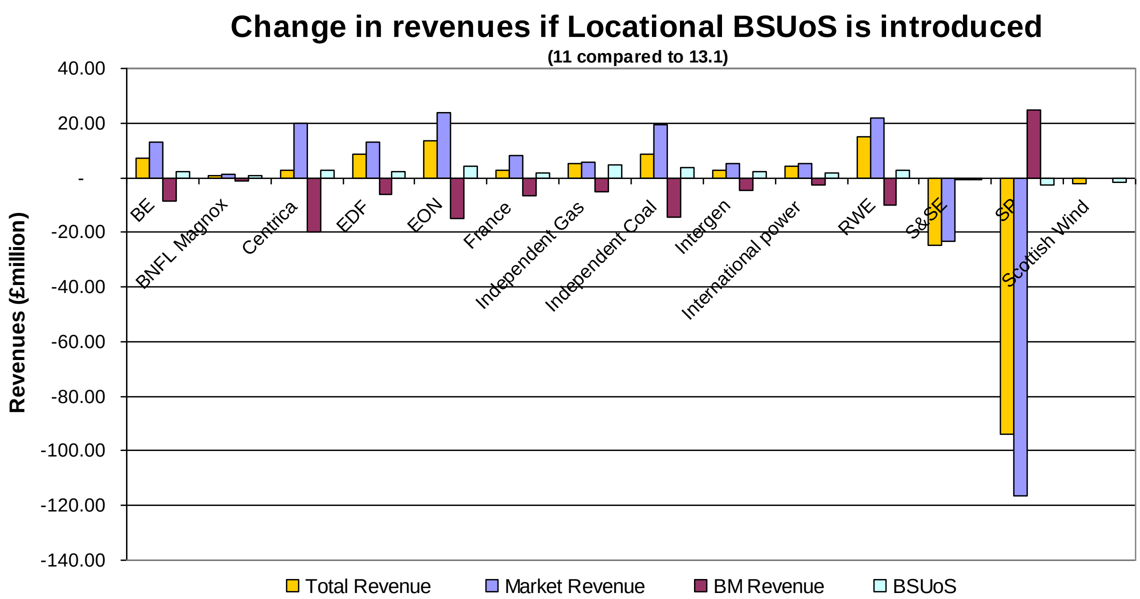


Figure 6:Change in revenues / margin if locational BSUoS is introduced (£28m)

1.5. Revenue / margin flows follow the same pattern as Appendix 7 above. NGET stated that when the constraint cost forecast high, Locational BSUoS has a big effect on behaviour. The difference in cost is as a result of the decrease in bid revenue / margin.

1.6. NGET further stated that British Energy's revenue / margin changes from positive to negative if marginal generation behind the non-constrained boundary does not react to Locational BSUoS.

1.7. NGET continued by asserting that the proposed Locational BSUoS modification is based on cost recovery so if an individual party chose to exercise locational market power it would only lessen the benefit rather than remove it.

Appendix 9 - Glossary

A

Access Rights

The rights to flow specified volume of electricity, usually from a specified location (node or zone) to an explicitly or implicitly defined destination (e.g. market hub), and for a defined period. For firm access rights, a failure to deliver access due to insufficient network capacity is associated with financial compensation. For non-firm access rights, the flow is terminated without compensation when capacity is unavailable.

The Authority/ Ofgem

Ofgem is the Office of the Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in GB.

B

Balancing Mechanism (BM)

The mechanism for the making and acceptance of offers and bids pursuant to the arrangements contained in the BSC.

Bid

In the context of the Balancing Mechanism, a bid is a tool used by the SO, whereby a user submits data representing its willingness to reduce generation or increase demand. NGET then decides whether or not to accept the bid.

British Electricity Trading and Transmission Arrangements (BETTA)

The arrangements for the trading and transmission of electricity across Great Britain which are provided for by Chapter 1 of Part 3 of the Energy Act 2004, which have replaced the separate trading and transmission arrangements which existed prior to 1 April 2005 in Scotland and in England and Wales.

Balancing Services Use of System Charges (BSUoS)

The charges levied by NGET in respect of the activities it undertakes to keep the transmission system in electrical balance at all time.

C

Connection Entry Capacity (CEC)

A measure of the maximum capability, expressed in MW, of a connection site and the associated generation units’ connection to the transmission system.

Connection and Use of System Code (CUSC)

Multi-party document creating contractual obligations among and between all users of the transmission system, parties connected to the transmission system and NGET is relation to their connection to and use of the transmission system.

Consents

The process of obtaining Consents for the construction of a new overhead line to serve, for example, a wind farm can essentially be broken down into two distinct areas. Consents to be obtained from the Secretary of State/ Planning authorities etc in relation to permission allowing a line to be built and secondly, and more practically, consent from landowners who will be affected by the construction of the new line. For a new line consent under section 37 of the 1989 Act will be required.

In addition to section 37 consent, the DNO/TO must also obtain consent from the landowners over whose land the line will run. If a voluntary agreement cannot be struck, then either the land will have to be compulsorily purchased, under the provisions of section 10 and Schedule 3 (which is usually used for substations), or a Necessary Wayleave obtained over it, under the provisions of section 10 (Schedule 4 paragraphs 6-8).

Constraints

In the event that the pattern of generation may exceed the safe operational limits of a particular line or transmission system equipment, the SO will take actions to reduce the output of generators at specific locations on the system. At present these actions are taken in the Balancing Mechanism in the form of bids, and also via ancillary services, such as Pre-Gate Closure Balancing Mechanism Unit Transactions (PGBTs). Where a user’s output is constrained down at a point on the system, the overall balance of energy will need to be retained, and costs will be incurred by the SO in bringing replacement energy onto the system.

Contracted background

This is the planning background against which National Grid assesses applications for connection and use of system. The contracted background includes all users that have entered into an (ongoing) agreement with National Grid for connection or use of system.

D

Deep reinforcement

Deep reinforcement refers to the works conducted on the wider transmission system in order to accommodate a change in the generation and demand pattern.

Distributed Generation

A generator directly connected to a distribution system or the system of another user.

K

Kilowatt (kW)/Megawatt (MW)/Gigawatt (GW)

A kW is the standard unit of electricity, roughly equivalent to the power output of a one-bar electric fire. A MW is a thousand kilowatts. A GW is a thousand megawatts.

Kilowatt hour (kWh)/Megawatt hour (MWh)/Gigawatt hour (GWh)

One kilowatt hour is the amount of electricity expended by a one kilowatt watt load drawing power for one hour. A MWh is a thousand kilowatt hours. A GWh is a thousand megawatt hours.

L

Long-run marginal costs (LRMC)

In the context of electricity transmission, long-run marginal costs are the marginal costs of establishing and using network capacity. They include, for example, marginal costs for network reinforcement, as well as resulting network losses and residual congestion costs.

Local works

Those works required to provide a generator with a connection to the transmission network that would enable it to export power.

N

NETS System Operator (NETS SO)

The entity responsible for operating the NETS and for entering into contracts with those who want to connect to and/or use the NETS. National Grid is the NETS system operator.

National Electricity Transmission System

The system of high voltage electric lines providing for the bulk transfer of electricity across Great Britain and offshore Great Britain.

O

Offer

In the context of the Balancing Mechanism, an offer is a tool used by the SO, whereby a user submits data parameterising its willingness to increase generation or reduce demand. National Grid then decides whether or not to accept the offer.

S

Short-run marginal costs (SRMC)

In the context of electricity transmission, short-run marginal costs are the marginal costs of using established network capacity. They include, for example, network losses and congestion costs.

Short Term Transmission Entry Capacity (STTEC)

STTEC is a firm capacity provided, provided within-year, in 4, 5 or 6 week blocks.

T

Transmission Asset Owner (TO)

There are three separate transmission systems in Great Britain, owned by three Transmission Asset Owners, National Grid Electricity Transmission plc, Scottish Hydro Electric Transmission Ltd and Scottish Power Transmission Ltd. National Grid also has the role of system across the whole of Great Britain.

Transmission Entry Capacity (TEC)

The contracted maximum amount of electricity that each user is permitted to export on to the GB transmission system at any given time.

Transmission Network Use of System (TNUoS) charges

Charges that allow National Grid to recover the costs of providing and maintaining the assets that constitute the transmission system.

Appendix 10 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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