Balancing Services Incentive Scheme (BSIS) 2011-13 Methodology Amendments

Published on: 12 July 2012
Responses requested by: 10 August 2012

About this document

This document sets out proposed amendments to the methodology statements that underpin the current (2011-13) Balancing Services Incentive Scheme (BSIS) in light of a number of identified issues with the current methodologies. The proposed amendments aim to increase the accuracy of the Constraint cost target model thereby maintaining a focussed incentive on us to reduce balancing costs on behalf of consumers.

We welcome views as to whether the amendments described within this document should be made such that the target cost of constraints provides a more accurate reflection of the costs faced in reality. Specific questions relating to the document can be found in Section 12.

If you have any questions about this document please contact:

Electricity SO Incentives team (soincentives@nationalgrid.com)

Responses should be submitted to soincentives@nationalgrid.com by **17:00 on 10 August 2012.**

The response proforma can be found on the following link:
http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

Executive Summary

1 National Grid Electricity Transmission (National Grid) undertakes the role of National Electricity Transmission System Operator (NETSO) for England, Wales and Scotland.

2 Following the SO Incentives Review (SO Review) in 2010, the 2011-13 Balancing Services Incentive Scheme (BSIS) ("current scheme") was developed on the principle that we, as NETSO, should be incentivised on the drivers of balancing costs that we can reasonably control and/or forecast. The intention behind this approach to incentivisation, which required development of new cost target models, was to reduce scope for windfall gains or losses and facilitate the move to longer term schemes (from 1 to 2 years in the first instance).

3 In practice this change to modelling means that, for those areas that we cannot control or forecast, inputs to the cost forecast models comprise outturn (or ex post) data and for those we can, inputs were agreed ex ante with Ofgem prior to scheme start. The methodology for determining the ex ante or ex post treatment of modelling inputs was therefore established by us and then approved by Ofgem prior to current scheme start (the "ex ante/ ex post methodology"). Similarly, methodologies were also established and agreed for determining the modelled cost targets for energy and constraint cost categories (collectively the "methodologies"[1]).

4 Despite the intention to focus SO incentivisation on those areas within SO control, there have been a number of unforeseen and uncontrollable events since scheme commencement on 1 April 2011 that have had a material impact to scheme costs which are not reflected in the incentivised cost target. These have resulted in either windfall gains or losses which we are seeking to remove via amendments to the methodologies as set out in this consultation. Many of these events have been previously reported and discussed with the industry at our Operational Forums.

5 In order for us to make any changes to the current scheme methodologies such that the models more closely reflect the efficient level of costs to us of procuring and utilising balancing services, we are required to consult with the industry in accordance our licence[2].

6 This consultation document proposes that these methodology changes be applied retrospectively from scheme commencement on 1 April 2011 which will allow the full impact of the amendments to manifest themselves in the final cost target for the scheme. The final scheme target will not be known until the end of the scheme in March 2013 due to the way in which ex ante inputs are employed in conjunction with ex post (or outturn) input components. The proposed changes should also eliminate the possibility of similar events having an adverse impact to the current scheme cost target for the remainder of the incentive period.

7 The output from the current Constraint model has been monitored and analysed since the scheme commenced on 1 April 2011. Operational experience of the scheme has therefore highlighted a number of areas for further model and methodology development. The resulting methodology amendments that we propose in this document are thus designed to increase the accuracy of the Constraint cost target model.

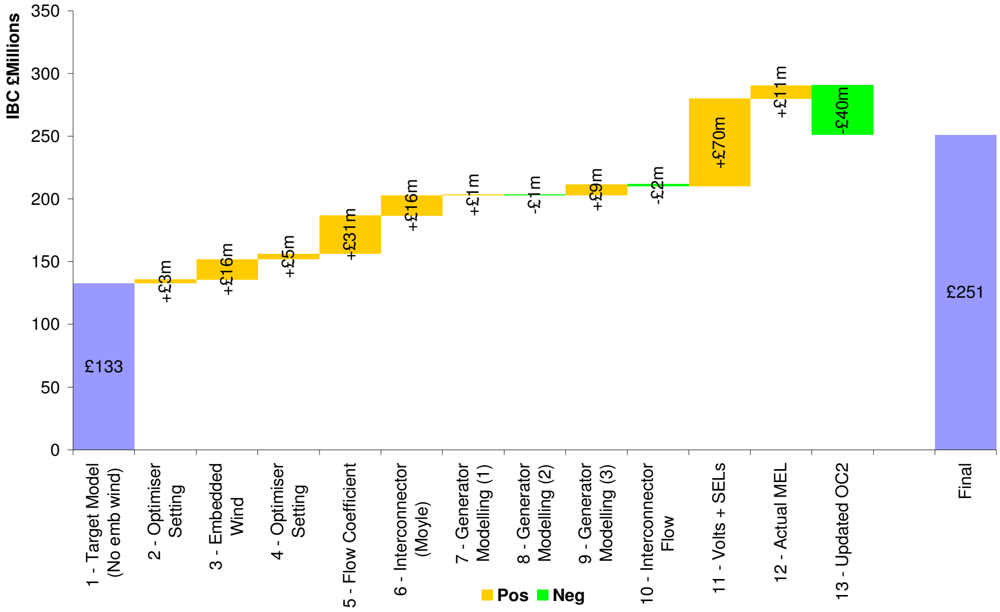
[1] These methodologies can be found on our website at: http://www.nationalgrid.com/uk/Electricity/soincentives/docs/
[2] Paragraph B2 (b) of Schedule A to Special Condition AA5A, Part B

8 It should be noted, however, that the majority of the issues discussed herein are related to model inputs rather than the model itself. Ensuring that model inputs are as accurate as possible will lead to a more accurate modelled output which is something that we think is critical for both the current and a longer term scheme.

9 Our drive to increase modelling accuracy is concerned with establishing the most transparent and accurate process possible. The model is, however, only used for post event balancing services cost allocation, and seeks to ensure that the NETSO is rewarded in part for the appropriate actions where it has delivered benefit, and is exposed to a proportion of those costs where a more economic solution could have been achieved. The model is therefore not used at all in our operational decision making; our focus continues to be the delivery of a secure system with managed risk at minimum cost.

10 Furthermore, we have looked to apply the amendments we are seeking to make to the current scheme to our SO Incentives proposals for a longer term incentive scheme for the RIIO-T1[3] period. This ensures that we apply incentive principles consistently and that a fair balance of risk and reward between us and consumers can be achieved.

11 The overall impact of improving the accuracy of the Constraint model in line with the changes proposed on the calculated constraints target for financial year 2011/ 2012 is to increase the constraint cost target by £118m as shown in the waterfall diagram below. In terms of scheme profit/loss position, these changes would serve to decrease the reported loss to National Grid (if applied across 2011/12 financial year) from (£43.4m) to (£13.9m) and refocus the incentive scheme for the remainder of 2012/13.



12 However, as detailed in Section 8 below, a more recent modelling deficiency in April/May 2012 has resulted in an increase to the cost target of circa £9.3bn. This has effectively pushed the scheme profit/loss back up to a maximum profit to National Grid of £50m. However, the methodology amendments proposed herein remove this windfall gain thereby pulling the scheme back to a loss to National Grid of (£17m)

[3] Our proposals for SO Incentives for the RIIO-T1 period can be found on our website at: http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

(estimated forecast as of the end of June 2012). This impact has not been reflected in the waterfall diagram above due to the scale of the recent issue.

13 A summary of the above changes is set out below which are described in more detail throughout this document:

(a) Various settings in the model's optimiser are proposed to be changed to allow the Constraint model to solve constraints correctly for all conditions (~£8m increase in constraint cost target – items 2 and 4 in the waterfall diagram above);

(b) Correction of a boundary flow setting within the model which has the incorrect sign (~£31m increase in target – item 5 above);

(c) A revised interconnector modelling methodology is proposed in order to more accurately account for outages and flows across each interconnector. (The Moyle interconnector fault experience across 2011/12 when modelled correctly increases the constraints scheme target by ~£16m and moving to modelling flows at gate closure reduces the target by ~£2m – items 6 and 10 above). The net result is a £14m increase in the target;

(d) Various changes to individual generator parameters in order for the model to more closely reflect actual running patterns (~£9m increase in constraints target – items 7, 8 and 9 above);

(e) Enable the modelling of voltage constraints via incorporating rules into the model to ensure that certain generators are running in order to provide location-specific dynamic voltage support (~£70m increase in constraints target – item 11 above); and

(f) Increasing modelling accuracy of all generators by reassessing generator availability as an ex-post input (using actual MEL data) rather than ex-ante (overall effect is to decrease the constraints scheme target by ~£29m – items 12 and 13 above).

14 Any model is a simplification of reality and our operational experience since the commencement of the scheme is that the current constraint methodology has not captured all conditions that have been experienced on the GB power system across the year. These proposed changes serve to increase modelling accuracy and maintain a focussed incentive on us to reduce constraint costs on behalf of the industry.

15 We recognise that transparency of the model and associated outputs are important to the industry. On this basis we are proposing to increase transparency, particularly of the outputs from the model and any possible future modelling methodology amendments, by publishing outputs on a regular basis. This aligns with the feedback we have received to date from the industry in terms of the benefits that greater transparency can bring by facilitating the market which is something that we fully support.

Contents

1 Introduction

16 In accordance with Special Condition AA5A (Part B) of our Electricity Transmission Licence, we are required to consult with the industry prior to making any amendments to the incentive scheme methodology statements, and hence models, that underpin the current scheme. This is something that we have looked to address in our proposals for a scheme under RIIO where we would be able to review the models periodically and transparently to ensure they remain robust and fit for purpose.

17 This consultation document sets out our proposals for amending 'The Statement of the Ex-Ante or Ex-Post Treatment of Modelling Inputs Methodology' and 'The Statement of the Constraints Cost Target Modelling Methodology' applicable to the current scheme.

18 Each proposed amendment is described in the following sections which are structured as follows:

(a) A high level description of the identified modelling methodology issue or modelling inaccuracy;

(b) Current and proposed treatment within the Constraint model and / or relevant methodology statement;

(c) The resultant change to the Constraint model cost target when applied across financial year 2011/12 (the first year of the 2 year incentive scheme);

(d) How the proposed change better meets the intended methodology and the modelling principles set out below; and

(e) Specific questions to seek industry views on our proposed amendments.

19 We also provide proposed change-marked versions of each methodology statement in Appendices A and B to this document (published separately).

20 In order for Ofgem to be able to authorise the more specific changes we propose to the model in terms of parameters for particular generators, we have provided Ofgem with further information (set out in Appendix D). Given the potentially commercially sensitive nature of this information, we have removed this Appendix in this published version.

Supporting Information

21 This consultation document should read in conjunction with the following documents on the National Grid website:

(a) **BSIS Methodology 2011-13: Treatment of Modelling Inputs**
Treatment of Modelling Inputs Methodology

(b) **BSIS Methodology 2011-13: Modelling Constraint Costs**
Modelling Constraints Cost Methodology

2 SO Incentive Modelling Principles

22 The high level principle behind the current incentive scheme is to focus the incentive on those areas that the NETSO can reasonably control and/or forecast thereby reducing scope for windfall gains or losses to the consumer. The current scheme is a 2 year scheme and thus more focussed application of this principle will facilitate the development of longer term incentive frameworks.

Constraint Modelling Process

23 The Constraint cost forecast model is described in the constraint modelling methodology statement developed for the current scheme. The current model is a zonal boundary model, consisting of a number of nodes which are connected by single lines across which maximum boundary transfers are prescribed.

24 Figure 1 below illustrates the process by which a constraint cost target is determined by the model and how this target is compared with outturn costs to arrive at scheme performance.

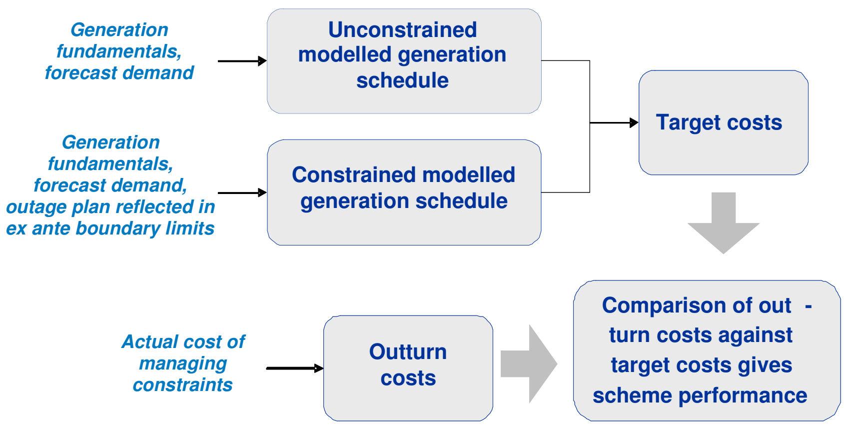


Figure 1: Overview of constraints target model calculation process

25 The high level constraint cost forecast process is:

(a) Produce an unconstrained generation and interconnector schedule based on various ex ante and ex post inputs as shown in Figure 2 below;

(b) Apply a number of constraint boundaries to the unconstrained generation schedule for which the model is required to resolve using ex post prices in the Balancing Mechanism (BM). This results in a constrained generation schedule being produced;

(c) If the model is accurate, the power flows should be a reasonable representation of real time conditions and hence reduce potential for wind fall gains or losses; and

(d) The difference between unconstrained and constrained model runs provides a target cost which is then discounted by 41%[4] and combined with an estimation of the costs of sterilised headroom[5] under the modelled conditions. The result is a constraint cost target against which actual costs are compared to determine our performance under the incentive scheme.

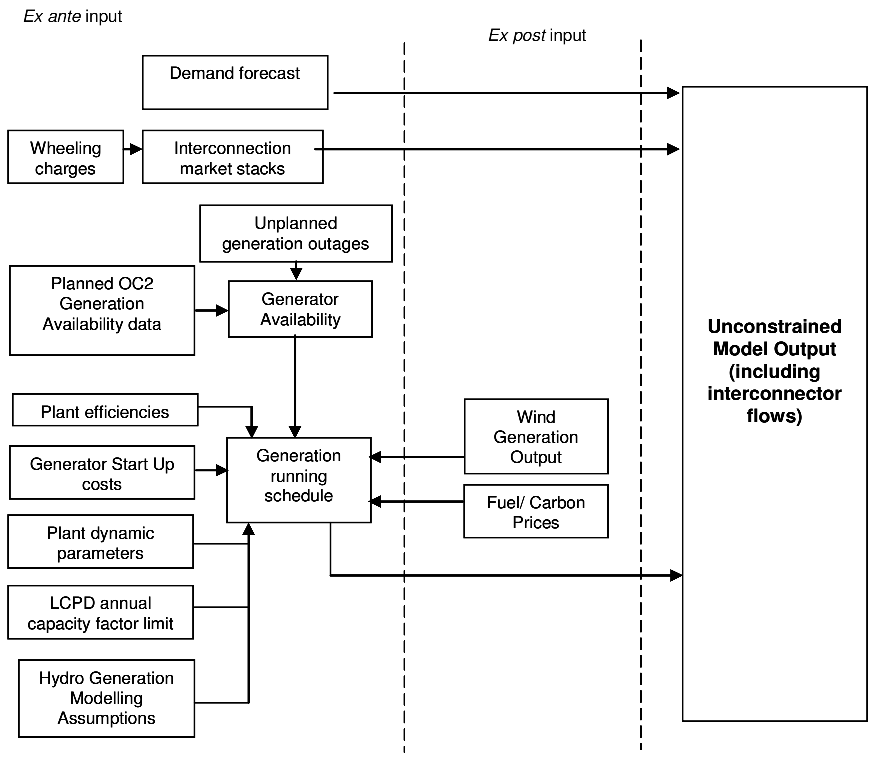


Figure 2: Overview of the current ex-ante and ex-post inputs into the unconstrained model

26 In order for us to be able to focus on, and reduce costs associated with, areas that we can control (and avoid potential wind fall gains or losses), it is imperative that the model is able to represent power flows and generator availability / running patterns as closely as possible. As we have experienced for the current scheme, it is also critical that the optimisation method and setup are appropriate within the Constraint model itself.

27 As the current scheme is a relatively new approach to electricity SO incentives, we recognise that there will be a period of learning based on operational experience, particularly of the new Constraint forecasting model. We have put considerable resource into developing this new approach to incentive schemes and continue to devote this resource to adapting the approach such that longer term schemes can be realised. We recognise and support the principle that longer term schemes should focus the System Operator to minimise costs to the end consumer.

Modelling Principles

28 Through our discussions with Ofgem over the previous few months, more specifically with regard to future incentives for the RIIO-T1 period, we have determined some

[4] A 41% discount factor is applied to reflect that in reality not all constraints will be resolved in the Balancing Mechanism and that tools such as constraint management contracts and intertrips can be used to create savings against Balancing Mechanism prices submitted by generators.

[5] Sterilised headroom is a volume of reserve that cannot be taken into account or used for system operation because it is located behind a constraint boundary.

high level modelling principles against which to assess any model enhancements that we make prior to the next incentive scheme. For consistency, these principles should also apply to the current scheme, thus any model development should meet the following criteria:

(a) Provide an incentive on the NETSO together with TOs to optimise and reduce costs to the end consumer;

(b) Avoid perverse incentives e.g. a model development which removes the incentive for us to contract for a service ahead of real time rather than leaving it to be managed in the BM;

(c) Be better for consumers than an ex post monitoring or the current model i.e. the development maintains the incentive on us to reduce costs;

(d) Be understandable, where key processes, inputs and outputs are easy to explain to our stakeholders;

(e) Enable holistic modelling of the system e.g. the new Constraints model is used to determine a constraint cost target for the whole of GB;

(f) Demonstrate that the NETSO is adding value to end consumers; and

(g) Enable the model to be more robust and accurate over a longer incentive period in terms of determining an incentive cost target.

29 If the above principles are met, scope for windfall gains or losses to the end consumer should be minimised and the incentive further focussed on those elements that we can control and influence. The modelling methodology should therefore enable reflection of the decisions and actions that we take as NETSO to reduce costs. For example, striking economic and efficient contracts for constraint management above an agreed baseline should be reflected in actual constraint costs being lower that the target set by the model. This provides the correct strength of incentive on us to deliver the lowest possible costs for managing the NETS and hence the lowest possible costs for consumers.

30 The modelling principles set out above are considered for each proposed model and methodology amendment in the sections that follow.

3 Voltage Constraint Modelling

Overview of the Issue

31 The Constraint model is a simplified model of the transmission system comprising a series of nodes and interconnecting lines across which maximum system boundary transfers are prescribed. Weekly limits are then applied to the modelled boundaries based upon studies carried out by Power System Engineers using an off line tool that allows thermal, voltage and stability limits to be determined.

32 These weekly limits were determined on an ex ante basis, at 2 years ahead, for application to the current scheme and remain fixed throughout the scheme duration.

33 The system studies used to determine the boundary limits focus, for the majority of the year, on the peak of the day as it is highly resource intensive to set-up a study to analyse every period of every day at 2 year ahead timescales. In addition, there are a range of generation scenarios that can occur in any day and hence the generation that is studied in advance of the scheme may not represent the generation that runs in reality.

34 Over the course of 2011/12, we have been required to buy on generation overnight for management of the system voltage profile and to avoid excessively high system volts in order to maintain system security. The main drivers of this issue have been:

(a) Falling overnight MW and Mvar demand as shown in Figure 3 below; and

(b) Lower than expected output from CCGT generators due to relative changes to spark and dark spreads.

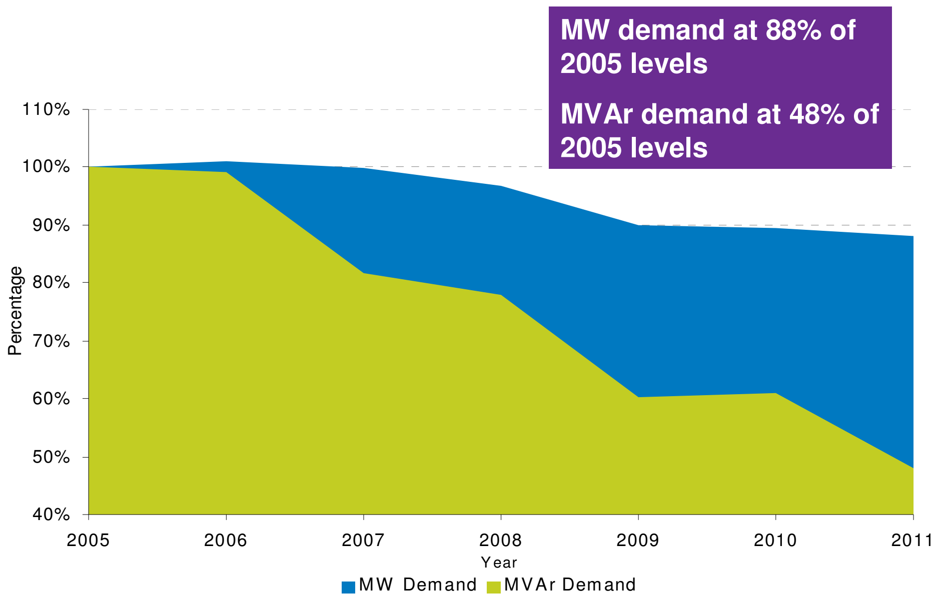


Figure 3: MW and Mvar demand changes since 2005

35 The effect on the power system has been high overnight voltage profiles which have required generation in specific locations to run in order to provide dynamic Mvar support and hence lower the system volts.

36 This effect has not been modelled in the constraints model within the 2 year ahead boundary limits as it is not an issue that has been historically evident. It is, however, noted that even if the current Constraint model were to include a full Transmission model, the optimisation software does not have the capability to determine voltage and stability constraint limits.

Proposed solution

37 The current model has therefore not captured the effect or the consequential costs of managing these overnight voltage constraints as part of the target cost. We have undertaken analysis to determine if it is possible to improve the Constraint model to recognise these voltage constraints given that they cannot be modelled as a boundary transfer limit. The proposed approach would be to create a set of voltage constraint rules and apply them to the model.

38 Based on off-line studies carried out on this issue, specific combinations of generation have been identified within Scotland, south-east England and on the south coast which are required to generate in order to maintain a suitable voltage profile in these regions.

39 These rules would apply overnight (23:00 to 06:59), as this is the time at which the issue has been most prevalent, between:

(a) March and November;

(b) 19 December 2011 and 4 Jan 2012; and

(c) 17th December 2012 to 4th Jan 2013.

40 As set out above, these rules have been derived from extensive off peak studies that have been carried out across 2011/12 in the day to day management of the power system. As indicated, when setting up the original boundary limits, the focus was on day time peak studies as it is resource intensive to study every period of the day with various generation scenarios at a year ahead stage.

41 We therefore propose to add a new paragraph to the “The Statement of the Constraint Cost Target Modelling Methodology” document as follows:

New paragraph 2.19
In addition, NGET will apply logical rules to generators to model constraints which are not able to be modelled via inter-zonal boundaries. For example, if a specific number of generators are required for voltage support, then the model will ensure that they are running. If there is an outage at a substation that is local to that substation, then this can be modelled by a logical rule which restricts the output of the generator accordingly.

42 If these rules are applied retrospectively within the model across 2011/12, the result is an increase to the constraints cost target of ~£70m as shown below in Figure 4.

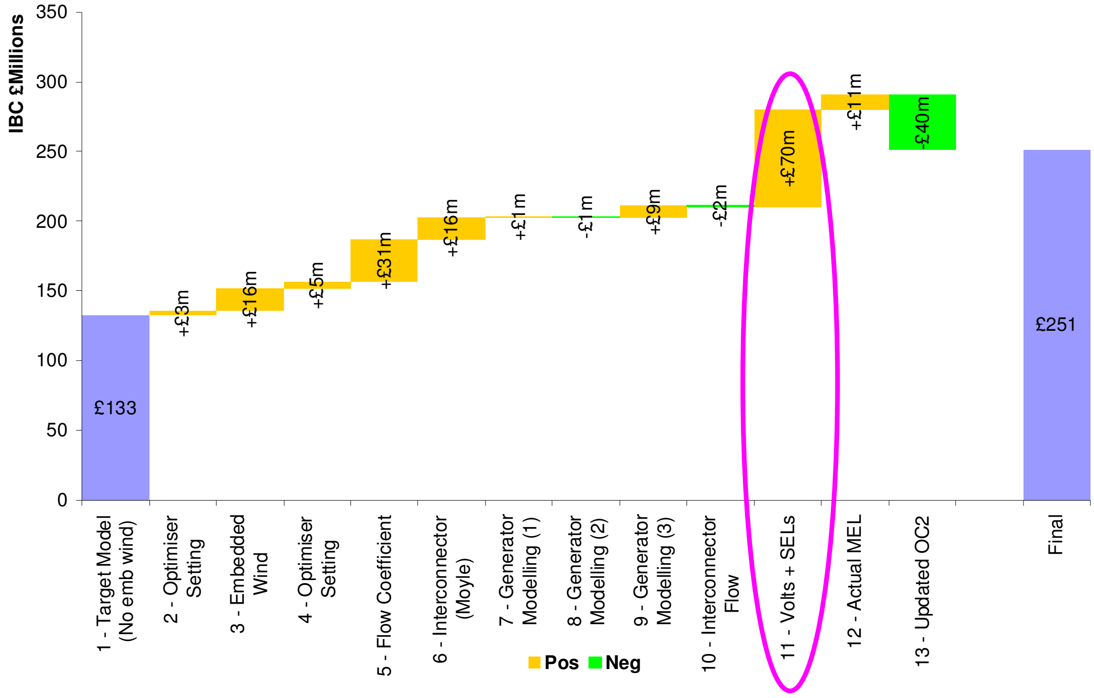


Figure 4: Effect of voltage modelling rules on constraints scheme target

Assessment against modelling principles

43 This proposed amendment to the constraint modelling methodology serves to increase the accuracy of model via the application of rules to reflect actual voltage constraints that can occur on the system. This, in turn, means that the model can produce a cost target for such constraints which we, as NETSO, are then incentivised against. If a target cannot be produced by the model for this type of voltage constraint then the incentive on us to reduce costs associated with managing these on the system is weakened.

44 The proposed solution allows for better modelling of the whole system and therefore enables us to demonstrate any value that can be created in managing the system through reduced costs to consumers. We can seek to reduce the costs associated with managing voltage constraints by, for example, contracting with generators and working with the TOs to provide asset-based solutions.

Question 1: Do you agree with the proposed approach to modelling the voltage constraints experienced since the commencement of the current scheme?

Question 2: Do you have any suggestions as to how we could better model these effects on the transmission system?

4 Generator Availability and OC2 Data

Overview of the Issue

45 Generation availability is a key input to the Constraint cost forecast model. In the current scheme methodology for the ex ante or ex post treatment of modelling inputs, both long-term and short-term generation availability are determined as ex ante inputs to the models. This is despite:

(a) Long-term generation availability (OC2 data) currently being assessed as 'low-medium' in terms of our ability to forecast and control this input; and

(b) Short-term generation availability (MEL data) currently being assessed as 'none' in terms of our ability to forecast and control this input.

46 The reasoning behind ex ante treatment in the current scheme was in recognition that we have the ability in theory to contract with a generator in order to influence its availability e.g. by contracting with a generator to bring forward or delay an outage such that constraint costs can be reduced. However, in practice the scope for taking such action is small given the level of change to generator outage programmes within year and lack of competition in this type of service provision can make it difficult for us to influence the price we would have to pay.

47 Currently, for long-term generation availability, OC2 data is input to the model at the start of each incentive year on an ex ante basis. This is a direct input to the Constraint model and is used to determine the plant available for the model to utilise in either the unconstrained or constrained runs. OC2 data is subject to significant change throughout a 1 year period, for example the 1 year ahead outturn success rate for submitted OC2 data for 2011/12 was only 5% for significant outages[6]. This means that a very small proportion of the significant planned outages at the year ahead stage were taken as submitted by generators.

48 Further, the extent to which we can forecast this data in reality is actually low, rather than low-medium, due to the inability to apply historical data to form any kind of trend, and the volatility of the dataset within year. As an example, gas generating plant maintenance programmes tend to be based upon operating patterns and running hours of the plant and are therefore sporadic in nature. These factors contribute to the difficulty in forecasting generator outage programmes.

49 Similarly, for short-term generation availability, unplanned outages are currently an ex ante input entered into the model as a stochastic simulation based on normal historic breakdown rates (estimated for each plant). In the event that a generator is available to run within the model but not available in reality (and vice versa) then the target cost may be inaccurate and windfall gains and losses can occur. Given the random nature of generator faults, we can neither control nor forecast when these may occur. They also have the potential to impact significantly on actual balancing costs which should be recognised by the cost target model.

Proposed solution

50 To better align the ex ante / ex post methodology with the constraint modelling methodology, and to reflect the limited extent to which we can control or forecast this input, it is proposed that generation availability be reassessed from an ex ante to an

[6] Significant outages are defined as full unit outages apart from small hydro units and OCGTs, excluding weekend outages or outages of a day or less.

ex post input. We propose that the source of data for this input be outturn Maximum Export Limit (MEL) data which would mean that the requirement to have long-term generation availability, and OC2 data as an input to the model, is negated. It also means that 'forced outage rates' that the model currently applies to forecast unplanned unit outages are also no longer required as a model input.

51 Outturn MEL parameters would be taken for each BM Unit for each settlement period and input to the model on a monthly basis in line with other ex post inputs. The source of this data will be the National Grid Economic Data warehouse (NED), a system that stores and aggregates operational and half-hourly settlement data. On the rare occasions that a generator does not submit a MEL but is available, a rule will be applied such that there is no missing data.

52 We therefore propose to add a new paragraph to the "The Statement of the Constraint Cost Target Modelling Methodology" document as follows:

New paragraph 3.14
Generation availability is treated as an ex post input to the unconstrained run of the model where actual outturn MEL data is employed as the source data. This will be taken for each BM Unit for each settlement period and input to the model on a monthly basis in line with other ex post inputs. The source of this data will be the National Grid Economic Data warehouse (NED), a system that stores and aggregates operational and half-hourly Settlement Data. On the rare occasions that a generator does not submit a MEL but is available, one of the following alternatives will be used (in order of preference):

i. The last submitted MEL value by that unit; or
ii. An average of submitted MEL from other units at the same power station.

53 The re-assessment of generation availability to ex post treatment will significantly increase modelling accuracy and reduce scope for windfall gains or losses by, for example, more accurately representing within the model:

(a) New generators that are late in commissioning their plant;

(b) Existing generators that opt to put their plant into 'preservation mode'[7]; and

(c) Unplanned generator faults.

54 To provide an example, 4 generators have declared to National Grid within year that they are placing their plant in preservation mode during the current incentive scheme period. This means that those plants are unavailable to National Grid for system operation in reality but temporarily remain available within the model (until the true availability is captured in the model by an annual update of OC2 generator data input). In addition, those generators that become unavailable during the scheme may be required to manage system constraints and therefore we would seek to contract with this generation to become available for a period of time. As it stands the model would not recognise this scenario or model this requirement as a cost within the constraint target, thereby underestimating the cost to manage these types of constraint.

55 The combined effect of modelling generator availability on an ex post basis is to lower the constraints model target by ~£29m when applied across financial year 2011/12. This is shown graphically in Figure 5 below.

[7] This is where a generator does not necessarily reduce its Transmission Entry Capacity (TEC) but chooses to withdraw from the market in the short to medium term.

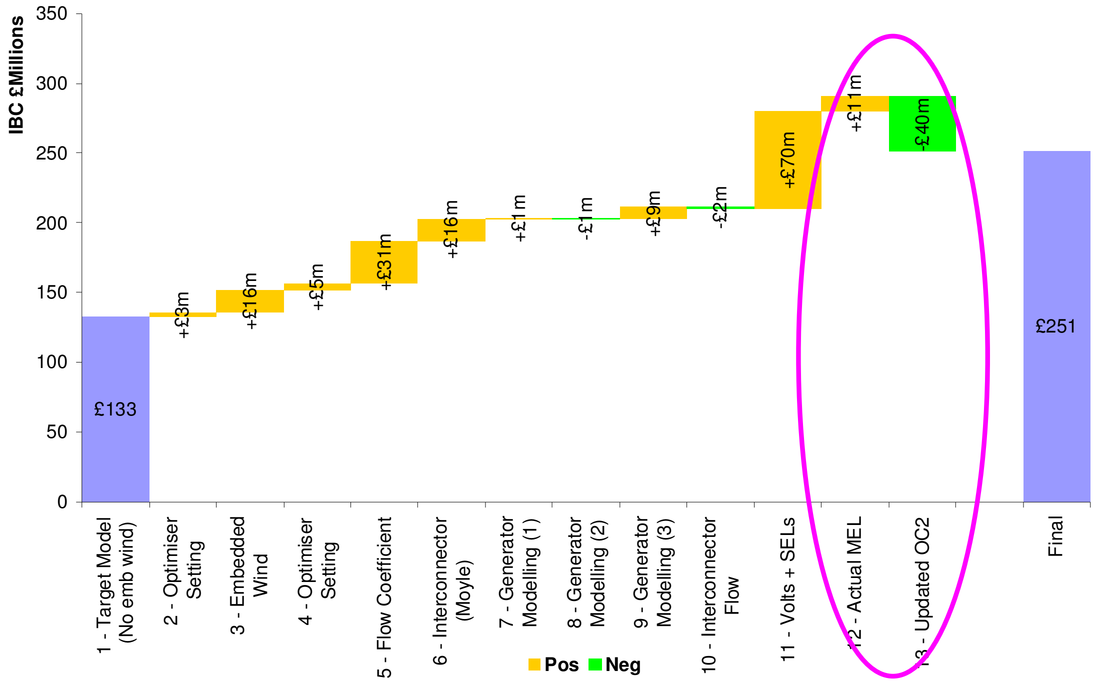


Figure 5: Effect of ex post generation availability on constraint cost target

56 As can be seen from the above chart, OC2 data has also been applied in addition to ex post MEL in this analysis as OC2 data is also read as an input to the Constraint model leading to units being unavailable in both OC2 and ex post MEL, but not necessarily at the same time. In reality, a unit may move their outage, perhaps as a result of a fault, and reflect this in MEL but the current scheme methodology would also include the original outage in OC2 as seen at 31 March 2011. In other words, at stage 12 in the chart above this is the current model with original OC2 and ex post MEL, stage 13 is outturn OC2 and ex post MEL (and all prior changes in both cases).

57 For the proposed RIIO-T1 incentive scheme OC2 data would be used as a predictive input i.e. for the purposes of producing a forecast, whilst ex post MEL would provide actual outturn generation availability thus avoiding the issue set out above.

58 This is a significant change to the current methodology and subsequent materially in terms of the constraints scheme target. However, it also serves to significantly increase the accuracy of the modelled constraint cost target and therefore sharpening the incentive on us to reduce costs.

Assessment against modelling principles

59 Most importantly, re-assessment of generation availability does not remove the incentive from us to reduce system operation costs as we are still required to forecast generation availability on an ex ante basis in order to make decisions on contracting for balancing services, trading and outage optimisation ahead of real time. One concern with this approach might be that if generation availability were to be ex post, we have the ability to influence this input and therefore impact upon the incentive cost target e.g. through contracting with a generator. Two constraint contracting scenarios are considered here:

i. We contract with a generator to be available and generate when it was not originally available in the market to manage an import constraint; and

ii. We contract with a generator to generate at a pre-determined or capped output to manage an export constraint.

60 Under option 1, if generator availability is determined ex post, actual (contracted) MEL data of the unit would be employed in the model and it becomes available for the constrained run. In an import constraint scenario, the contracted generator is required to run to manage the constraint. Therefore if the contracted MEL in this situation had not been used (i.e. the non-contracted MEL of zero had been employed), the unit would not be available in the model to resolve the constraint in the constrained run. This means that the model would not produce a target forecast cost to manage the constraint in the balancing mechanism to which the cost of actually contracting with the unit is compared. So the use of actual (contracted) MEL in this instance results in a more appropriate outcome from a modelling perspective than the use of a non-contracted MEL of zero. It also maintains the incentive on us to negotiate a contract at the lowest cost as the generator will seek to receive a premium for providing availability when it was not originally economic to be so.

61 Under option 2, the MEL parameter that a generator submits during the contracted period should be unchanged from the original or non-contracted MEL level. In fact, when we contract with a generator for a capped PN contract to manage constraints, we ensure that the relevant MEL parameter is still submitted to provide confidence that the unit would otherwise be available, and to provide the option for effectively unwinding the contract (i.e. increasing output beyond the cap) if necessary e.g. to manage a wind-driven requirement. This type of contract is the most common of the two options because it is used to manage export constraints (particularly in Scotland) which again are more common on the system.

62 Employing ex post MEL will also more accurately represent the system impact, and therefore costs, of any generator unplanned faults. Currently the model will not recognise when a generator is actually unavailable due to a fault, in the same way that within year changes to OC2 data are also not captured. Again, this change serves to reduce the scope for windfall gain or loss resulting from circumstances that are outside of our control.

63 Similarly, whilst the use of ex post MEL reduces the scope for windfall gains and losses throughout the scheme, it does not reduce the risk of taking constraint contracting decisions. For instance, in an export constraint scenario where we have contracted to constrain generation off we are not protected by the use of ex post MEL in the model if something else in the group falls off. Correspondingly, in an import group where we have contracted with generation to run and something cheaper becomes available, we are not protected by ex post MEL. The incentive to contract ahead of real time and the risk associated with contracting decisions is therefore maintained.

Question 3: Do you agree with the proposed approach to reassess generation availability as an ex post rather than an ex ante input to the Constraint model and that it serves to increase Constraint model accuracy?

Question 4: Do you have any suggestions as to how we could better model generation availability on an ex ante basis?

5 Boundary Flow Error

Overview of the Issue

64 The constraints model does not contain a full electrical model of the transmission system; instead the system has been simplified to a set of zones and nodes. Each node represents an area of the country which is defined by a unique combination of interfaces (boundaries). The Scottish electricity network is represented within the model as shown below in Figure 6.

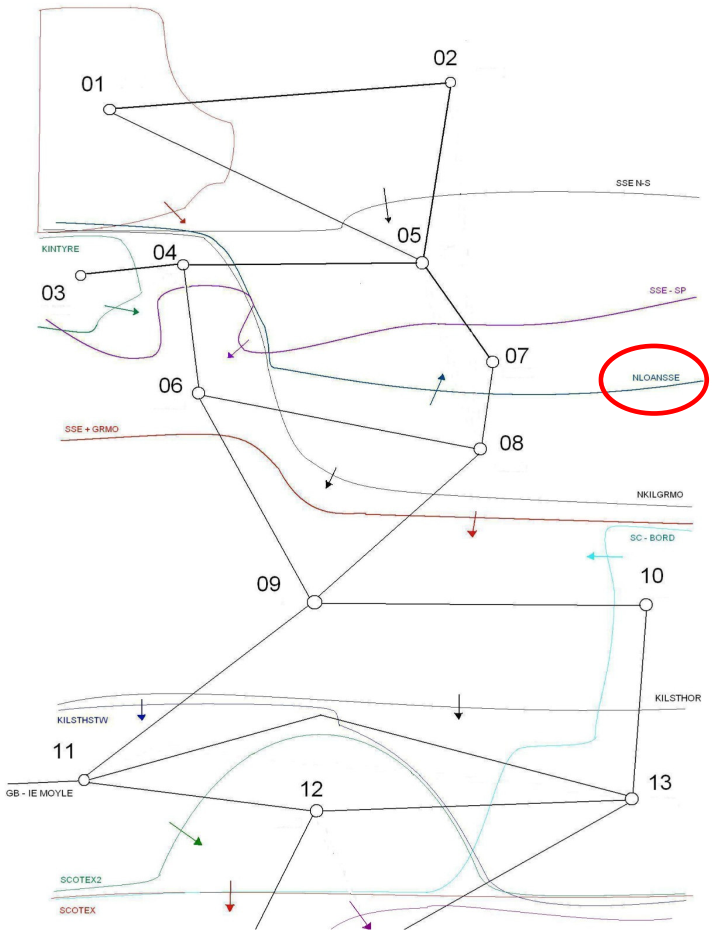


Figure 6: Scottish electricity model for 2011 to 2013 Incentive Scheme

65 Each boundary has a weekly limit that was calculated by Power System Engineers before the scheme commenced (ex ante) and included in the model. Depending on the demand and generation in a zone, the flow across each boundary may exceed the limit and result in a constraint which the Constraint model optimiser will then resolve.

66 For one of the boundaries in Scotland (NLOANSSE - as indicated by the red circle in Figure 6 above), an error in the model has been detected which calculates the boundary incorrectly. The error is due to employing the incorrect direction of flow as a reference against the limit set for the boundary on the line between node 7 and node 8. This results in the flow on the line between nodes 7 and 8 being subtracted from

the flow on the line between nodes 4 and 5 making the optimiser believe flows across the NLOANSSE boundary are lower than they should be and hence reducing the volume of constraint to be resolved.

Proposed Solution

67 The solution to this issue does not involve a proposed change to the constraint modelling methodology. Rather the change is to correct the "Flow coefficient" (direction of flow for the boundary) on the line between nodes 7 and 8 from 1 to -1 in order for the model to correctly calculate flows.

68 The financial impact of this sign error is a £31m difference between the target cost and outturn cost as the model is unable to calculate the correct constraint forecast target. This is highlighted below in Figure 7.

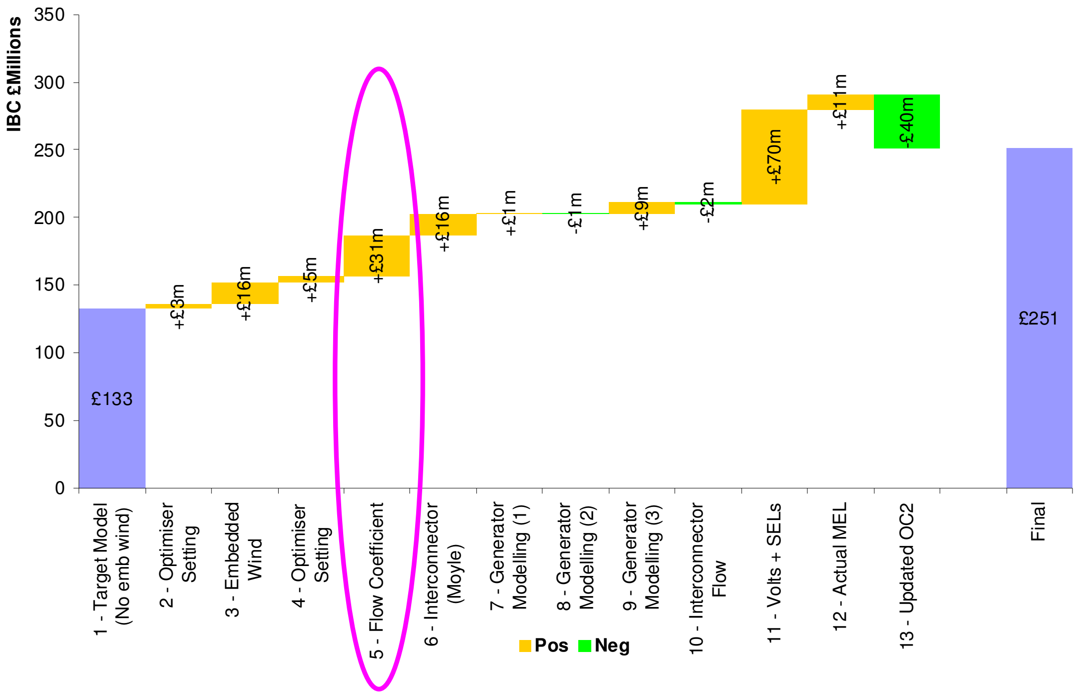


Figure 7: Overview of flow coefficient change on constraints target

69 While an audit has been undertaken of all other boundaries, with no immediate issues found, we propose to include the following paragraph into "The Statement of the Constraint Cost Target Modelling Methodology" to cater for any similar errors should they occur:

New paragraph 2.22
When NGET become aware of errors in the Constraint model related to calculating boundary flows, NGET will report these to Ofgem and propose amendments to the model as appropriate. No changes will be undertaken without prior written approval from Ofgem.

Assessment against modelling principles

70 This proposed amendment will only serve to increase the accuracy of the model by adjusting an identified error within its set-up. It will therefore ensure that we continue to be incentivised against a more realistic cost target produced by the model which,

in turn, means that we can better demonstrate the value we deliver to consumers as we undertake our role as NETSO.

Question 5: Do you agree with the proposed changes to the methodology statement in relation to boundary flow model setup errors?

Question 6: Do you agree that Ofgem are best placed to audit and approve these changes in future?

6 Modelling of Interconnectors

Overview of the Issue

Interconnector Availability

71 The Moyle Interconnector directly connects Scotland to Northern Ireland via a High Voltage Direct Current (HVDC) Interconnector. Typically, the Interconnector exports power from Scotland to Northern Ireland (due to lower GB prices) and has a commercial capability to export 450MW from Scotland to Northern Ireland.

72 On 26 June 2011, a fault on the Moyle Interconnector reduced its capacity to half and subsequently to zero on 24 August 2011. This fault outage continued until 19 February 2012 thereby lasting for 8 months in total. This is a significant period of time and from an historical perspective, has not been experienced since the introduction of BETTA. The effect on NETS power flows of a Moyle Interconnector outage is that exports from Scotland to England over the Cheviot boundary[8] increase as indicated in Figure 8 below.

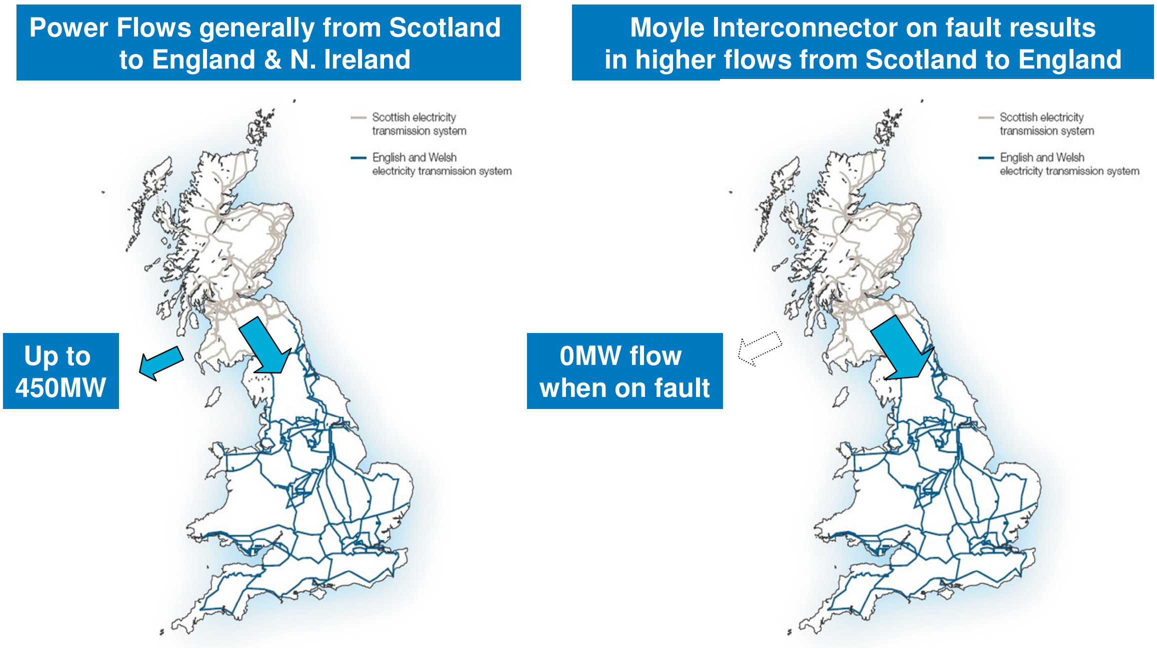


Figure 8: Overview of power flows with and without the Moyle Interconnector

73 The derogated Cheviot boundary does not have sufficient capacity to export all of the available generation from Scotland to England and hence we are required to routinely constrain off generation in Scotland to maintain system security. This leads to an increase in constraint costs. The maximum capability of the Cheviot boundary is around 3100MW under intact conditions and considerably less under summer planned outage conditions.

74 With the Moyle Interconnector on an unplanned fault outage, the exports that would have flowed to Northern Ireland in reality become additional to the exports across the Cheviot boundary which leads to a considerable increase in Scottish constraint costs. However, the model assumes that all interconnectors are available on a continuous basis and therefore the costs that we have faced in reality in managing the Moyle fault outage have not been reflected through to the target cost of constraints for the

[8] The Cheviot Boundary is the boundary between the Scotland and the England & Wales systems.

incentive scheme. This has resulted in a windfall loss to us on this occasion but had the outage occurred on a different interconnector, the result would have been a windfall gain.

Interconnector Flows

75 Within the current scheme model, flows on the interconnectors will occur only if the price differential between the importing and the exporting market is larger than a pre-determined wheeling charge. The model was calibrated at the start of the scheme by adjusting the wheeling charge to match annual historic interconnector flows. However, these wheeling charges are not necessarily an indication of future flows. Moreover, the non-GB market is represented in the model by a simple generation stack, comprising the predominant fuel type(s) in that market (e.g. French market represented by nuclear and gas) to meet a simple demand profile.

76 Experience gained from operating with the current scheme demonstrates that the model is not able to accurately represent the direction of interconnector flows due to the number of drivers that can potentially influence this input. The drivers of interconnector flows are set out in Figure 9 below. Most of the drivers comprise the original six cost categories[9] of BSIS costs as the relative levels of these inputs in each market either side of an interconnector may drive flows across that interconnector in a particular direction.

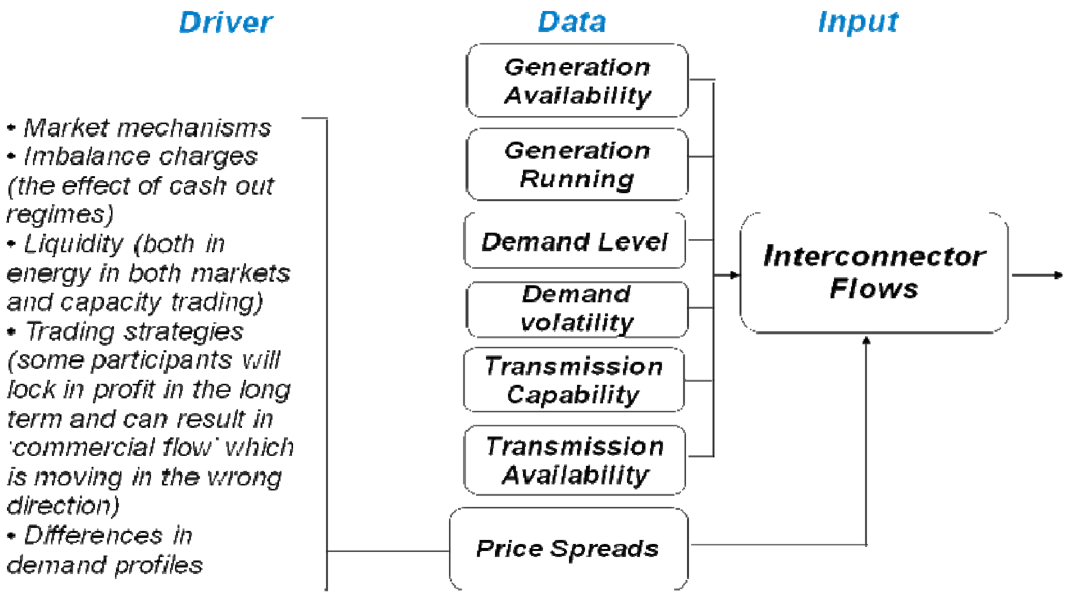


Figure 9: Drivers of Interconnector Flows

77 The above diagram goes some way to displaying the complexity surrounding the drivers of interconnector flows and therefore indicates that the current modelling methodology is too simplistic. This has resulted in modelling inaccuracies and therefore further potential for windfall gains and losses. Our ability to forecast or control these drivers, particularly for the non-GB market, is low. This issue is compounded when interconnector flows may be influenced by factors that do not originate in the market with which the interconnector connects e.g. events on the German system may have a knock-on impact to flows on the French-UK interconnector.

[9] The six categories of cost drivers are identified within the 'Ex ante or Ex post Treatment of Modelling Inputs' methodology: http://www.nationalgrid.com/NR/rdonlyres/AF9269A3-F5CA-4153-897B-4EB0B74ADE4B/47902/Treatment_of_Modelling_Inputs_Methodology_Issue1_18July2011.pdf

Proposed Solution

78 As described above, Interconnector availability and flows are currently modelled on an ex ante basis within the Constraint model.

79 The drivers of interconnector availability are similar, although not identical, to those already set out in the ex ante/ ex post methodology for generation availability and therefore this category of input is proposed to be expanded to include interconnector availability (the diagram below in Figure 10 illustrates the amended version).

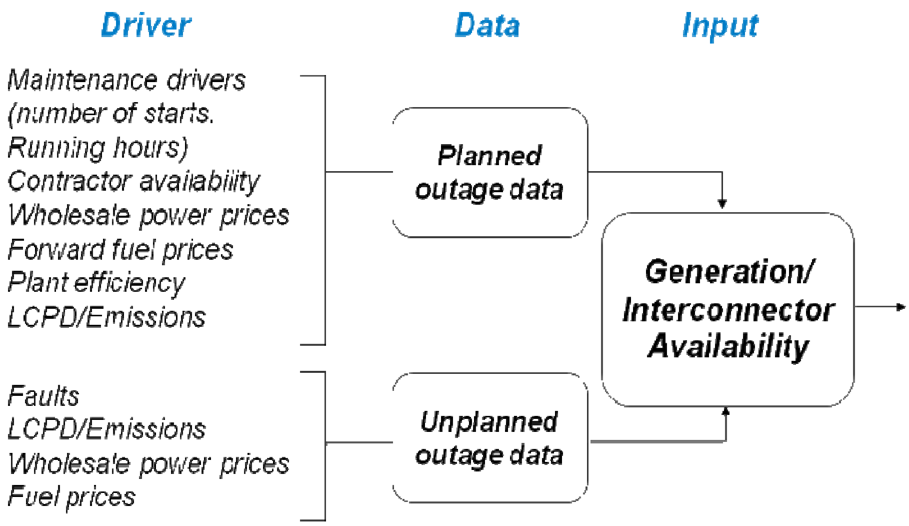


Figure 10: Drivers of generation and interconnector availability

80 For consistency, in the same way that generation availability is proposed to be reassessed to an ex post input (as detailed in Section 4), interconnector availability is also proposed to be input to the constraint model on an ex post basis. This removes the issues experienced during the current scheme in terms of the long term unplanned outage of the Moyle interconnector. It also looks to reflect that our ability to forecast and control this model input is low thereby further focussing the incentive on those elements that we can control.

81 Similarly, in order to increase modelling accuracy, and recognising that our ability to forecast or control interconnector flows pre interconnector gate closure[10] is low, it is proposed that this input also be assessed as ex post. Given that we are able to call upon balancing services on interconnectors post gate closure, it is proposed that flows on each interconnector are input to the model as the gate closure nominated flows rather than ex post metered quantities, thereby excluding any of our actions. This change should mean that interconnectors are more accurately represented in the model than at present and reflects flows as the market has determined them.

82 Thus, any action that we take on an interconnector to manage system costs will be determined by the difference in the unconstrained and constrained run within the Constraint model where actual (gate closure) interconnector flows are used to determine the unconstrained run.

[10] Following the introduction of the Use It or Lose It arrangements, National Grid cannot take action on any interconnector pre-gate closure.

83 We therefore propose to add new paragraphs to "The Statement of the Constraints Cost Target Modelling Methodology" as follows:

New paragraph 3.16
Interconnectors flows (HVDC) will be modelled at the intraday gate closure position i.e. will be input to the model on an ex-post basis. This input data will be derived using Elexon settlement Final Physical Notification (FPN) for interconnector BMUs, excluding system/error admin accounts, minus trade volumes from NGET's Energy Trade Management System (ETMS).

New paragraph 5.17
In order to accurately reflect interconnector flows within the model, Interconnectors flows (HVDC) will be modelled at the intraday gate closure position i.e. will be input to the model on an ex-post basis. This input data will be derived using Elexon settlement Final Physical Notifications (FPNs) for interconnector BMUs, excluding system/error admin accounts, minus trade volumes from NGET's Energy Trade Management System (ETMS).

84 The above amendments also mean that the original methodology for modelling interconnector flows can be removed from the methodology statement. This includes application of wheeling charges and modelling of interconnected (non-GB) markets.

85 We estimate that, if the Moyle interconnector is made unavailable within the Constraint model for the outage period in question, the increase to the target constraint cost is on the order of £16m. This is shown below in Figure 11.

86 The resultant impact on the constraints model in terms of treating interconnector flows on an ex post basis is to decrease the cost target by £2m, also shown below in Figure 11. This is an additional change after the Moyle outage is considered and so the cumulative effect is therefore a £14m increase in constraint target across financial year 2011/12.

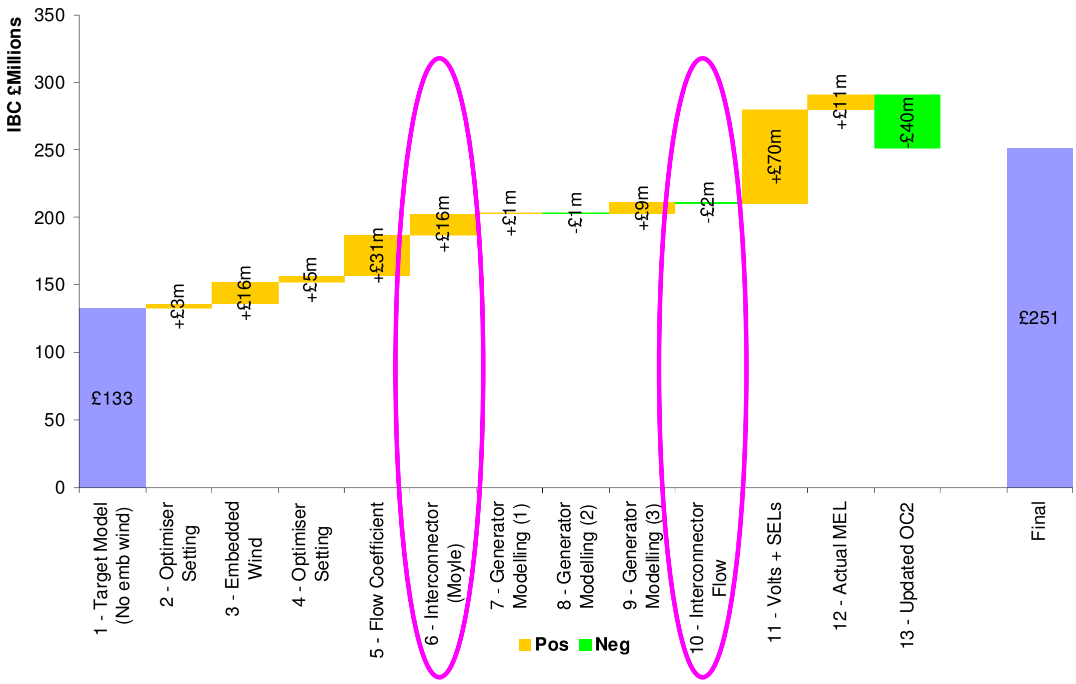


Figure 11: Overview of proposed Interconnector modelling changes on constraints target

87 It is therefore proposed that the above amendments are effected through developments to both the Constraint modelling methodology and the ex ante/ex post methodology statements. The result of this change is shown in Figure 12 below.

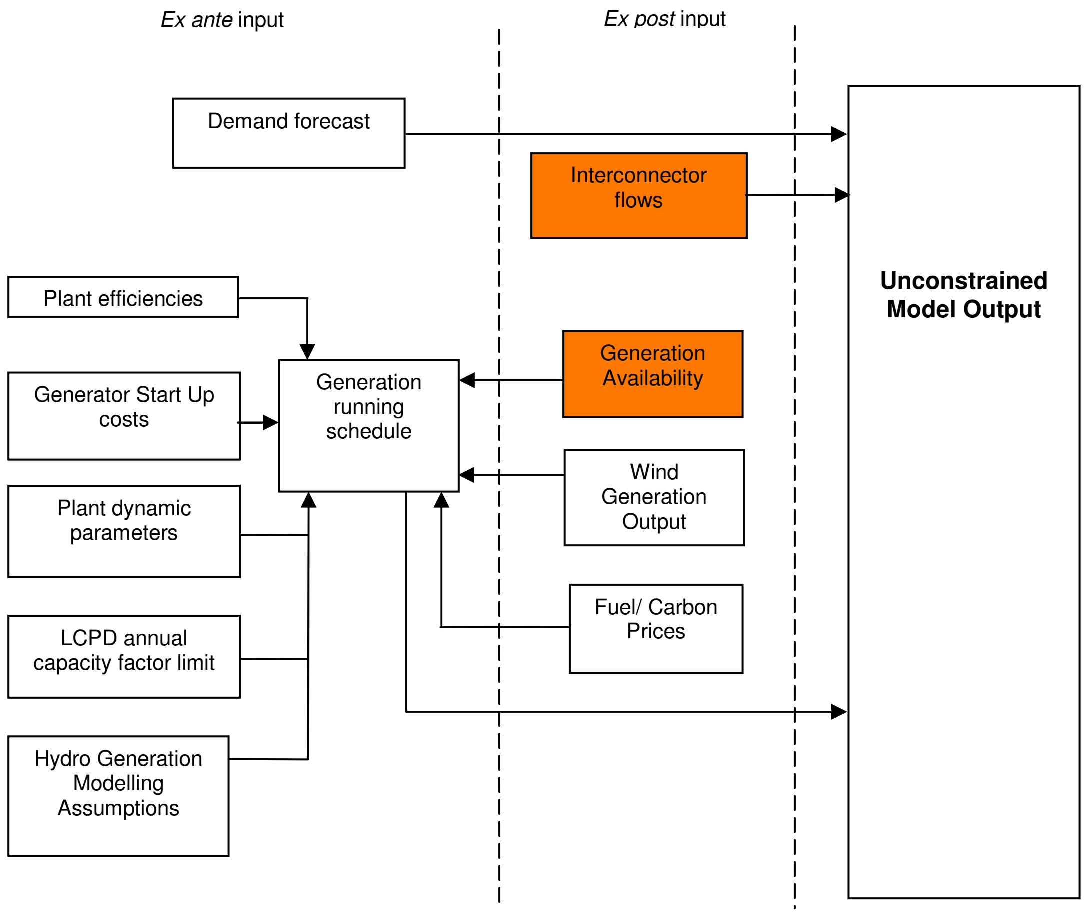


Figure 12: Overview of proposed ex ante/ex post methodology amendments

Assessment against modelling principles

88 The proposed solution to modelling interconnectors enables a more holistic modelling approach than exists currently. It is also a more transparent and straight forward approach for the industry.

89 This reassessment of treatment from ex ante to ex post does not reduce our incentive with regard to the use of interconnectors for managing and reducing balancing costs. It merely ensures that interconnectors are accurately represented within the model which, if represented incorrectly, can result in large windfall gains and losses.

90 In the event that interconnector modelling introduces inaccuracy to the constraint cost target, it is more difficult to pinpoint and demonstrate that the NETSO is delivering value to consumers.

Question 7: Do you have any comments on the proposed changes to the modelling methodology for Interconnectors availability?

Question 8: Do you agree that moving Interconnector flows to an ex post input is appropriate and provides a more accurate modelling methodology?

7 Embedded Wind Generation – Methodology Clarification

Overview of the Issue

91 We do not currently meter all wind generation on the system. For example, small scale embedded wind generation is not metered directly due to the cost and practicalities of installing metering at these sites. Embedded wind generation in certain regions in Scotland is a significant proportion of the generation in those areas and the lack of accurate metering can lead to the Constraint model reflecting inaccurate real time flows on the power system.

92 An example of the variation of demand experienced at a Grid supply Point (GSP) with levels of significant embedded generation is provided below in Figure 13.

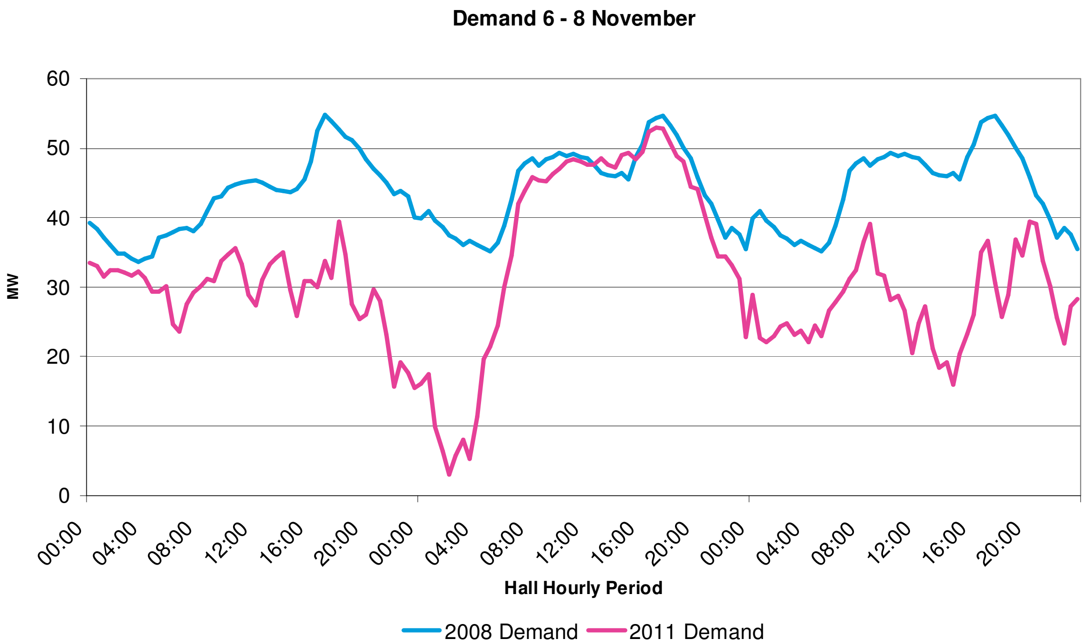


Figure 13: Grid Supply Point (GSP) with high level of embedded generation

93 The growth of embedded wind at this Grid Supply Point since 2008 can be clearly observed. On days when the wind is blowing, the demand taken from the GSP is considerably different from a low wind day.

94 As new wind farms commission, the current methodology allows us to add them into the model such that it can be kept current. For large wind farms, monthly data is obtained from Elexon. For embedded (non-metered) wind farms, this source of data is not available via Elexon although the level of embedded wind can be inferred from the metered data e.g. the effect of embedded wind on windy versus non windy days at a GSP can be observed. It is this non-metered embedded generation that we need to reflect more accurately within the model.

95 We do have access to other auditable sources of information for embedded wind farms via the 'Connect & Manage' regime and Grid Code data submissions and, based on operational experience of maintaining the constraints model, we would propose to use these sources of information where Elexon data is not available.

96 It should be noted that modelling of embedded wind farms is not double-counting against demand level which is also an input to the BSIS cost target models as this assumes zero output from wind farms, i.e. “true” demand, and the sources of data for both are discreet.

Proposed Solution

97 The current methodology allows us to model all wind farms and this is stated in section 5.5 of “The Statement of the Constraint Cost Target Modelling Methodology” as follows:

Original Paragraph 5.5
It is important to ensure that as new wind farms are connected to the network, the model is kept up to date to ensure that the metered output of the wind farms ex post can be input. Hence, a list of all wind farms along with the nodes at which they are connected and their connection dates will be maintained and checked against any metered data available from Elexon on a monthly basis in order to ensure that the models are updated in a timely manner.

98 However, the above paragraph does not fully clarify how we model embedded generation in reality. It is therefore proposed to clarify the above statement to reflect how we model embedded wind farms such that it reads as follows:

Amended Paragraph 5.5
It is important to ensure that as new wind farms are connected to the electricity network, the model is kept up to date to ensure that the metered output of the wind farms ex post can be input and their contribution to meeting demand properly modelled. Hence, a list of all wind farms along with the nodes at which they are connected and their connection dates will be maintained and checked against any metered data available from Elexon on a monthly basis in order to ensure that the models are updated in a timely manner. Updates to new generation connections for which Elexon data is unavailable, such as for embedded wind farms, will be made using an appropriate auditable source such as (Connect and Manage) or (Grid Code data submissions).

99 When the model is updated with all commissioned embedded wind generation from 1 April 2011 to 31 March 2012, the cost target calculated by the Constraint model is increased by £16m (as shown below in Figure 14). This demonstrates the extent to which the level of embedded wind generation can impact upon constraint costs.

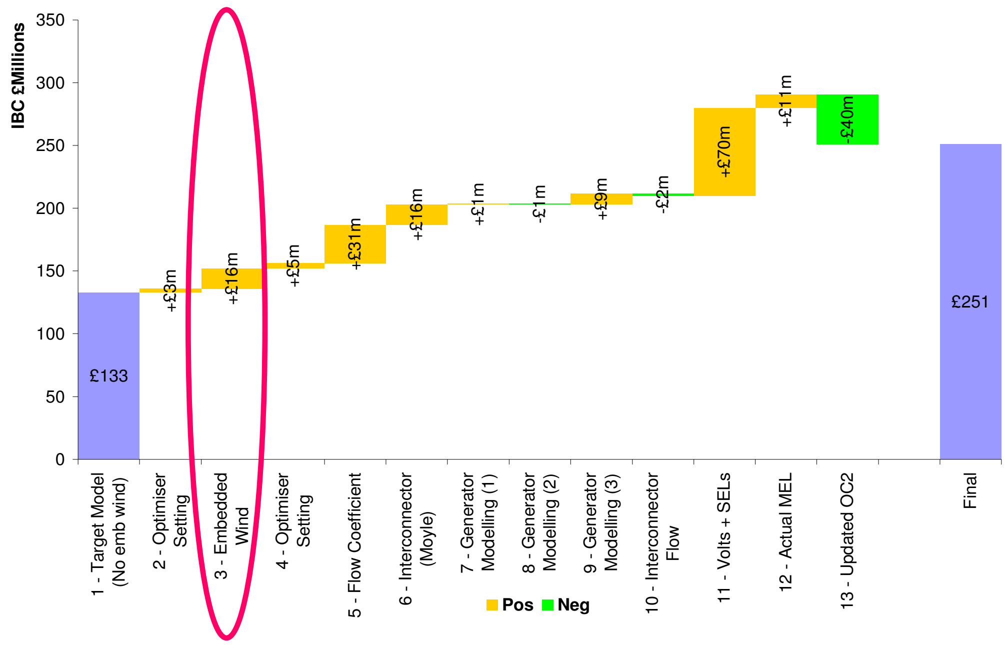


Figure 14: Overview of proposed embedded wind generation modelling changes on constraints target

Assessment against modelling principles

100 This is considered to be a fairly minor clarification of the current scheme methodology which should only serve to increase the transparency of the modelling approach and model inputs to the industry. It enables a more holistic modelling of the system where it has been shown that embedded generation can have a significant impact on constraint costs. It is therefore critical that this type of generation be accurately represented within the model.

Question 9: Do you agree that this clarification with regard to embedded wind generation should be made to the modelling methodology?

8 Generator Modelling

Overview of the Issue

101 The Constraint model employs a number of inputs to determine whether a generator is run in the unconstrained schedule. Of these inputs, the ex ante elements include generator efficiency factors, run up and run down rates and the costs associated with starting and shutting down the plant. These inputs were obtained from externally sourced datasets and were set at the start of the scheme.

102 Since scheme commencement, we have carried out ongoing analysis on both the unconstrained and constrained modelled generation running patterns and compared this output with reality. It has been concluded that a number of generators are not modelled correctly and run at either a higher or lower level of output than the optimising software suggests should occur. This leads to wind fall gains / losses in the modelled cost target leading to modelling inaccuracies.

103 Examples of generation running pattern inaccuracies which are as a result of inaccurate generation model input assumptions detected thus far are described below.

(a) A large CCGT in an exporting constraint zone generates for significant periods in reality than against the unconstrained and constrained generator models as graphically shown below in Figure 15. This has resulted in a £1m difference between target and actual constraint costs for 2011/12.

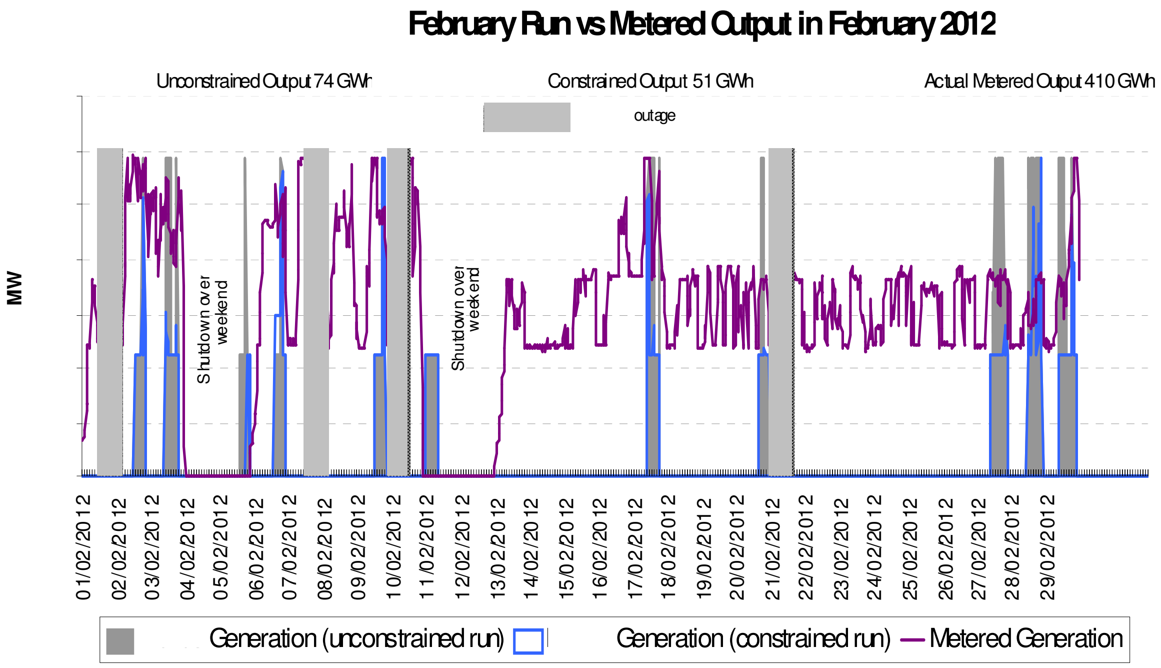


Figure 15: Example of a CCGT running differently than modelled

(b) Two Combined Heat and Power (CHP) generators which supply process steam to industrial plant have been identified as being inaccurately modelled. The result is that the unconstrained model has a low utilisation rate for these units which in reality have a high output due to being CHP plant. This has resulted in a ~£9m difference between the target and actual cost of constraints for the 2011/12 financial year; and

(c) A large commissioning CCGT that is located in an export constraint zone was due to commission in late 2011 but was significantly delayed. The unconstrained and constrained model assumes this generator is commissioned (as the data is currently an ex ante input) which has resulted in a £1m difference between target and actual costs for financial year 2011/12.

104 In terms of item (c) above, the output of a commissioning generator will be naturally variable as the plant is being tested and will be prone to unplanned events such as trips or fast de-loads. Neither will it necessarily follow market fundamentals (e.g. fuel prices) in relation to its decision to generate. In essence the commissioning test programme will dominate the output of the plant and will be unique to each generator.

105 Currently, the Constraint model uses OC2 data input at year ahead to determine whether a generator is available to use either in the unconstrained or constrained runs of the model. The commissioning generator will input to OC2 the date from which it anticipates to operate (i.e. the date that it can physically generate) but the date upon which the generator is actually commercially available (and therefore available to the NETSO) may be much later than the initial stated date. This means that the model will be able to run the generator in the unconstrained run when in reality the generator is not available or running. This then has an impact on the system constraints observed by the model, the outcome of the constrained run and therefore the cost of constraints.

106 In more recent months (April/May 2012), the current modelling methodology approach for commissioning generation has resulted in an increase to the constraints target of ~£9.3bn. This has resulted in the overall scheme moving to it a maximum profit position to National Grid of £50m. The reason for this increase to the target is that the current methodology has assumed that a commissioning generator is fully available, causing an active constraint that requires the generator to be bid down at its submitted price of -£99,999. In reality, the constraint would still have existed if the generator had been fully commissioned however the generator would most likely have submitted more realistic pricing.

107 The examples listed above demonstrate that in the absence of accurate modelling of generation, the resultant cost target output can over or under forecast. Despite recognising these inaccuracies we are currently unable to address the issues within the current modelling methodology.

Proposed Solution

108 To address the fact that the current methodology does not allow ex ante generator parameters and inputs to be altered throughout the scheme in order that they are modelled more accurately, it is proposed to create an additional paragraph in "The Statement of the Constraint Cost Target Modelling Methodology" as follows:

New Paragraph 3.13
NGET will analyse the unconstrained modelling of generation. Where there is a material change between the output of the generation to what is predicted by the model, NGET will propose changes to Ofgem to improve the modelling to better reflect actual running patterns. No changes in generation parameters in the model will be implemented without written approval from Ofgem.

109 Ofgem is best placed to approve these changes which are specific to individual generators as it has both industry oversight and access to the model itself.

110 In theory, there are over 50 generator parameters that could be changed within the modelling software. However, for those generators where we have identified inaccurate modelling to date (of which there are three), we propose to adjust relevant start up and shut down costs applicable to those generators within the model in order to derive a running pattern that more accurately reflects reality. For future changes, there may be different parameters that require adjustment.

Commissioning Generation

111 In order to reduce the possibility of windfall gains or losses associated with commissioning generation, it is proposed that actual ex post commissioning generation output be input to the model for a period of 6 months following energisation. 6 months represents an average timescale for plant that has recently commissioned.

112 The basis for temporary ex post treatment within the model is that a commissioning generator will not generate according to market fundamentals and hence its output is not possible to be accurately forecast by the model. These generators are also not controllable by National Grid as the commissioning schedule dominates the generator's behaviour. Hence ex post treatment of generation output for a limited period would more accurately reflect how we as NETSO treat commissioning plant in operating the system (i.e. we assume that it is not available for system operation) and reduce scope for windfall gains and losses associated with a modelled cost target.

113 As such, we propose to create an additional paragraph within the "The Statement of the Constraint Cost Target Modelling Methodology" as follows:

New Paragraph 3.15
Commissioning generation will be treated as an ex-post input to the model for the first 6 months of operation. Its output will be modelled in the same way as all other generation thereafter.

114 Consequently, these proposed changes will need to be reflected in the 'Statement of the Ex-Ante or Ex-Post Treatment of Modelling Inputs Methodology' which is shown in Figure 16 below. The proposed change to the treatment of commissioning generation as a model input is highlighted in orange below (in addition to the other changes previously discussed in this document).

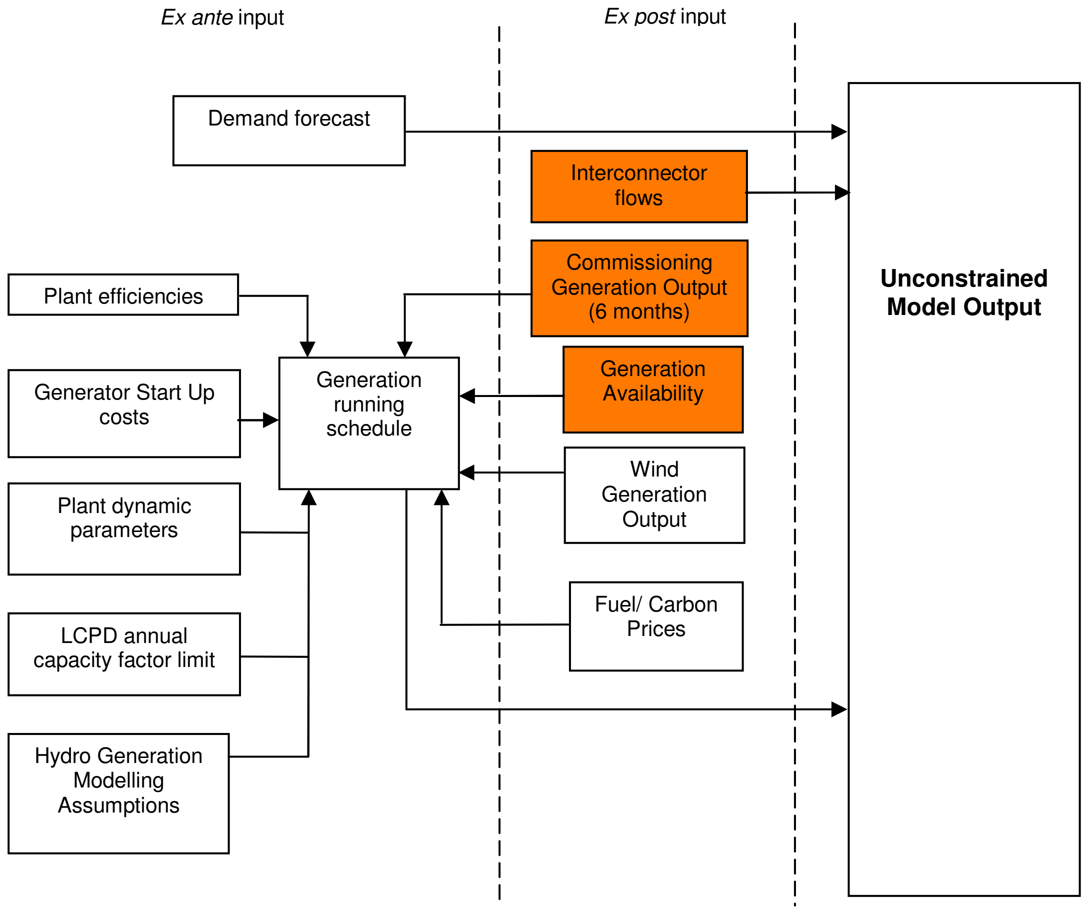


Figure 16: Overview of proposed change to methodology for commissioning generation

115 The impact of the proposed changes to generator modelling to the constraint cost target across financial year 2011/12 is shown in Figure 17 below. As discussed previously in paragraph 106, the constraints target across April/May 2012 has increased by ~£9.3bn and hence these proposed changes would also remove this significant recent windfall gain.

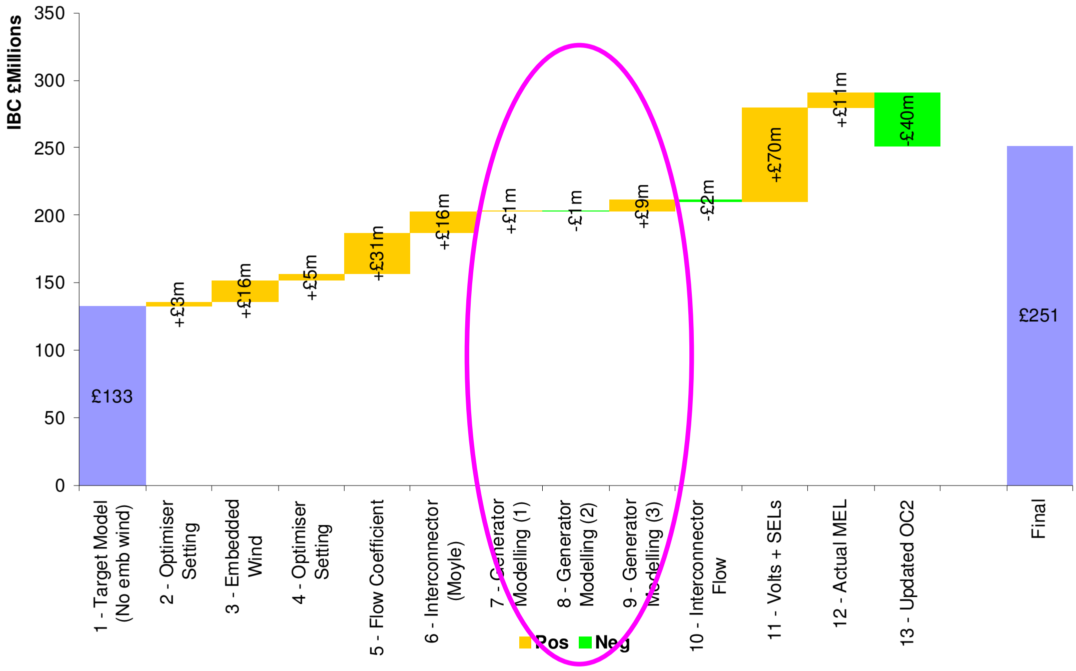


Figure 17: Overview of proposed generator changes on constraints target

Assessment against modelling principles

116 In order to ensure that the model remains accurate, particularly in terms of modelling generation patterns of key generators that impact on major system constraint boundaries, it is important to review actual running patterns versus modelled on an ongoing basis. In the event that the model produces an inaccurate unconstrained generation running schedule, this inaccuracy will also feed through to the second run of the model when it is required to resolve system constraints using actual BM prices.

117 Generator running behaviour can change over time and it will be imperative that the model, through amendments to generator parameter inputs, can be adapted accordingly. This will ensure that the incentive remains focussed on those elements that we can control as NETSO.

> **Question 10:** Do you agree with the proposed changes to the modelling methodology that allow us to detect and seek amendment to material differences in generator running patterns compared to model forecasts?
>
> **Question 11:** Do you agree with treating commissioning generation as an ex-post input for a period of 6 months while the generator undertakes its commissioning programme?

9 Model Optimiser Settings

Overview of the Issue

118 The optimising software that we employ for constraint cost modelling is a powerful and professional optimiser. As for all optimisers, there are a number of settings within the software. However, in order to model the entire NETS a compromise is required between accuracy of output and the speed of optimisation.

119 The solutions delivered by the optimiser are sensitive to a number of limitations placed on the optimisation itself. A number of such limitations have come to light through operational experience of the scheme which include:

(a) Sub-optimal solution due to problem simplification; and

(b) Unsolved dump energy[11].

120 In addition it has been identified that some parameters have the potential to mean that the model fails to:

(a) Meet demand rather than take available Offers from generation in the BM; and

(b) Price the actions taken in the solution at the submitted BM price.

121 However, so far, not all of the above limitations have been observed to have an impact on the output of the model. They have, however, been identified by the software developer (and NGET) as enhancements which ideally should be made. Therefore we are proposing some preventative changes to the model to eliminate any chance of a potential impact.

Proposed Solution

122 Whilst the current Constraint modelling methodology does not allow any changes to be made during the scheme, we propose to prevent future model optimisation issues by carrying out the following amendments:

(a) Change the optimisation method from “Rounded Relaxation” to “Mixed Integer Programming” based on advice from the software owner;

(b) Changing a parameter called “BM price Cap” from £800/MWh to £100000/MWh in order that the optimiser uses all submitted offers;

(c) Changing the “Price of Dump Energy” from £-1000/MWh to a level that ensures all feasible actions are taken e.g. £-500,000/MWh; and

(d) Changing the “Value of Loss Load[12]” from £1000/MWh to a level that ensures all available offers are exhausted before demand is not met e.g. £100000/MWh.

---

[11] Dump Energy occurs when the optimiser “throws away” energy within a constraint group rather than produce a secure solution that meets the interface limits.

[12] This is a “price” attached to cutting off demand to enable the optimiser to decide if it should take higher priced actions or “pay” to not meet demand. This payment for not meeting demand is internal to the optimiser and does not appear in the target value which is based purely on Cleared Offer Costs from the constrained run (i.e. simulated BM Actions).

123 The overall changes to the optimiser settings (of those that have had a material impact to date) increase the constraints target by ~£8m as shown below in Figure 18.

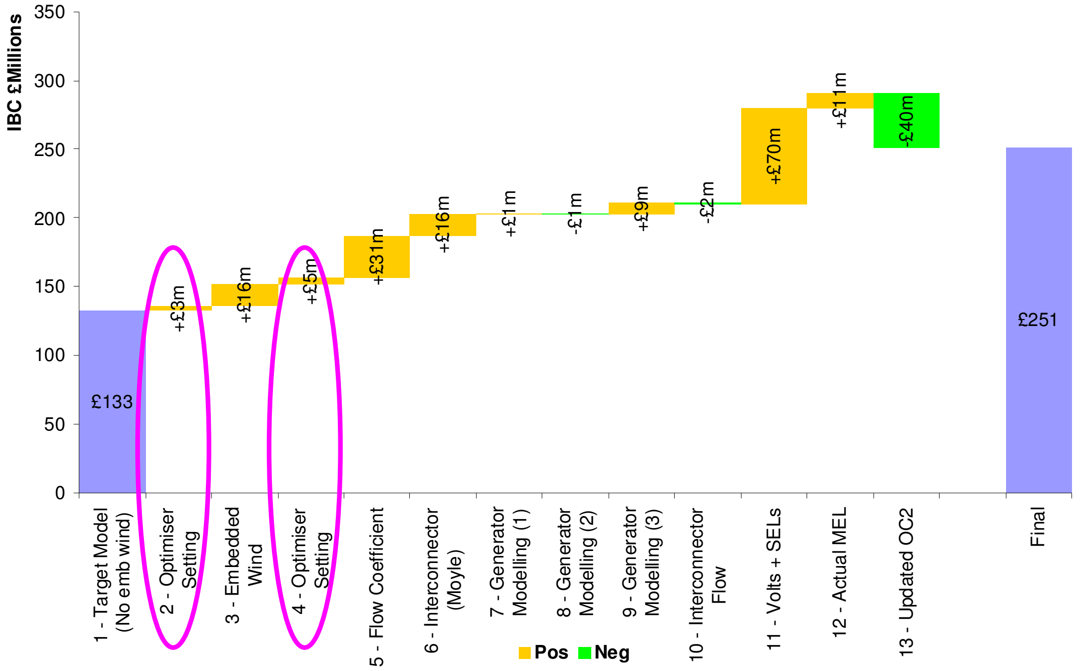


Figure 18: Overview of the proposed optimiser settings changes

124 We recognise that the industry, who are not familiar with the software optimiser that is used in the Constraint model, may not be is a position to comment on the above changes. Hence it is proposed to add a paragraph to 'The Statement of the Constraint Cost Target Modelling Methodology' to allow us to make these technical changes upon written approval from Ofgem:

New paragraph 2.24
NGET will analyse model optimisation to ensure the unconstrained / constrained model settings are appropriate. Where NGET find settings that it believes are not appropriate and are leading to optimiser inefficiency, it will investigate and propose changes to Ofgem. No changes to optimiser settings shall be implemented without written approval from Ofgem.

Assessment against modelling principles

125 Ensuring that the optimiser within the model remains robust will enable holistic modelling of the system and result in a more accurate cost target. Similarly it ensures that the model is working as intended and reduces the possibility of modelling error for the remainder of the scheme.

Question 12: Do you agree with our proposal to change these optimiser settings?

Question 13: Do you agree with the approach that Ofgem oversee and approve any future optimiser setting amendments?

10 Erroneous BM Data Submissions

Overview of the Issue

126 When calculating a constraint cost target, the Constraint model is required to increase or decrease output of particular generators to resolve system constraints (as determined by system boundary limits). The model will 'select' the generators required to resolve those constraints on the basis of actual Balancing Mechanism prices as submitted by generators. BM price is therefore an ex post input to the model to reflect our limited ability to control or forecast this input. However, occasionally a market participant will submit prices in error which are then fed to the model, as the methodology requires, on a monthly basis.

127 A recent example is a market participant submitting a positive £99,999 bid price for an hour (when they intended to submit -£99,999) during April 2012 as highlighted below in Figure 19. While in theory, the Control Room can accept this bid, thus benefitting from an arbitrage opportunity, the reality is that if the bid instruction was issued and accepted, the market participant would most likely successfully appeal this action.

£99,999 bid prices submitted in error

1	2012-04-17 18:00	410.000	2012-04-17 18:30	410.000	70.00000	77.75000
-2	2012-04-17 18:30	-210.000	2012-04-17 19:00	-210.000	20.00000	25.00000
-1	2012-04-17 18:30	-200.000	2012-04-17 19:00	-200.000	35.00000	38.00000
1	2012-04-17 18:30	410.000	2012-04-17 19:00	410.000	70.00000	77.75000
-2	2012-04-17 19:00	-210.000	2012-04-17 19:30	-210.000	99999.00000	99999.00000
-1	2012-04-17 19:00	-200.000	2012-04-17 19:30	-200.000	99999.00000	99999.00000
1	2012-04-17 19:00	410.000	2012-04-17 19:30	410.000	99999.00000	99999.00000
-2	2012-04-17 19:30	-210.000	2012-04-17 20:00	-210.000	99999.00000	99999.00000
-1	2012-04-17 19:30	-200.000	2012-04-17 20:00	-200.000	99999.00000	99999.00000
1	2012-04-17 19:30	410.000	2012-04-17 20:00	410.000	99999.00000	99999.00000
-2	2012-04-17 20:00	-210.000	2012-04-17 20:30	-210.000	20.00000	25.00000
-1	2012-04-17 20:00	-200.000	2012-04-17 20:30	-200.000	35.00000	38.00000
1	2012-04-17 20:00	410.000	2012-04-17 20:30	410.000	58.00000	63.00000
-2	2012-04-17 20:30	-210.000	2012-04-17 21:00	-210.000	20.00000	25.00000
-1	2012-04-17 20:30	-200.000	2012-04-17 21:00	-200.000	35.00000	38.00000

Figure 19: Example of erroneous data submission by a market participant

128 Events where erroneous data is submitted in obvious error to the Balancing Mechanism are rare and we have not detected any discrepancies such as the example shown above prior to April 2012.

129 However, when these data errors do occur, the constraints software cannot detect that this data was incorrectly submitted and hence will optimise and arbitrage system operation actions accordingly. For the example set out above, the total arbitrage opportunity identified by the model was of the order of ~>£30m.

130 Erroneous data submissions therefore have the potential to create significant inaccuracies in the cost target setting process with no ability to automatically rectify the problem.

Proposed Solution

131 Within the current scheme constraint modelling methodology, all model input data provided by market participants will be fed into the model unchanged.

132 It is however proposed that the following paragraph be inserted into “The Statement of the Constraint Cost Target Modelling Methodology”:

New paragraph 2.25
If NGET detects data that it believes is erroneous (i.e. bad data), NGET will investigate the materially on the model output. If the materially is greater than £2m, NGET will propose specific changes to the data and agree those changes with Ofgem. No changes to the data will be approved without written Ofgem approval.

133 In order to correct any erroneous data, a rule is required to determine what price is to be used to replace the ‘bad data’. If applied to the example highlighted above in Figure 19, NGET would overwrite the data with the submission in the previous hour.

Assessment against modelling principles

134 Introducing the ability to amend BM data that has been submitted in error ensures that the constraint cost target remains an accurate reflection of the costs that we face in reality to balance the system. This in turn means that any perverse incentives to take inefficient actions are removed and that the model remains robust.

Question 14: Do you agree that if a market participant submits erroneous data in error that we should have the ability to remove the error such that the target cost remains unaffected?

Question 15: Do you agree with the approach that Ofgem oversee and approve these changes?

11 Model Transparency

Further Amendments to Modelling Inputs

135 There are a number of instances throughout this consultation where we propose that if any further issues are identified with the model or modelling methodologies, we will seek to rectify those issues following written confirmation from Ofgem e.g. if any generator parameters change such that modelled generation output significantly differs from output observed in reality. In these instances we consider it equally important that the industry is also kept abreast of any modelling amendments throughout the scheme.

136 We therefore propose that upon making any such amendment to the Constraint model, we will publish an amendment report to the industry on our SO Incentives website page[13]. We will also continue to provide the industry with BSIS updates at our Operational Forums.

Model Outputs

137 Further transparency of the outputs of the Constraint cost target model would also provide greater visibility and oversight to the industry with respect to our actions and those of the wider market. For example, we consider that there is significant industry value gained in publishing the modelled outputs on a monthly basis compared to actual BMU outturns, which in turn would allow the industry to self police to a greater extent, albeit post event.

138 This aligns with the feedback we have received to date from the industry in terms of the benefits that greater transparency can bring by facilitating the market which is something that we fully support.

> **Question 16:** Do you consider that there is value to the industry from publication of BSIS model outputs e.g. modelled MWh per BMU versus actual BMU output?

[13] Our SO Incentives web page can be found at: http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

12 Consultation Questions

The consultation questions detailed here are also summarised within a response pro forma in Appendix C.

Question 1: Do you agree with the proposed approach to modelling the voltage constraints experienced since the commencement of the current scheme?

Question 2: Do you have any suggestions as to how we could better model these effects on the transmission system?

Question 3: Do you agree with the proposed approach to reassess generation availability as an ex post rather than an ex ante input to the Constraint model and that it serves to increase Constraint model accuracy?

Question 4: Do you have any suggestions as to how we could better model generation availability on an ex ante basis?

Question 5: Do you agree with the proposed changes to the methodology statement in relation to boundary flow model setup errors?

Question 6: Do you agree that Ofgem are best placed to audit and approve these changes in future?

Question 7: Do you have any comments on the proposed changes to the modelling methodology for Interconnectors availability?

Question 8: Do you agree that moving Interconnector flows to an ex post input is appropriate and provides a more accurate modelling methodology?

Question 9: Do you agree that this clarification should be made to the modelling methodology?

Question 10: Do you agree with the proposed changes to the modelling methodology that allow us to detect and seek amendment to material differences in generator running patterns compared to model forecasts?

Question 11: Do you agree with treating commissioning generation as an ex-post input for a period of 6 months while the generator undertakes its commissioning programme?

Question 12: Do you agree with our proposal to change these optimiser settings?

Question 13: Do you agree with the approach that Ofgem oversee and approve any future optimiser setting amendments?

Question 14: Do you agree that if a market participant submits erroneous data in error that we should have the ability to remove the error such that the target cost remains unaffected?

Question 15: Do you agree with the approach that Ofgem oversee and approve these changes?

Question 16: Do you consider that there is value to the industry from publication of BSIS model outputs e.g. modelled MWh per BMU versus actual BMU output?

13 Responding to this Consultation

Responses should be submitted by replying to the consultation questions within the response pro forma, attached as Appendix C and e-mailing the completed pro forma to soincentives@nationalgrid.com

If you do not wish any elements of your response to be made publicly available, please mark these as confidential.

Responses are therefore requested by **10 August 2012**. Following the consultation, a report will be produced and submitted to the Authority within seven days of the consultation close. Due to the timescales for the Authority report, it may not be possible to accept late consultation responses.

14 Next Steps

Following receipt of responses to this consultation, National Grid will prepare and submit a report to the Authority in accordance with Electricity Transmission Licence Special Condition AA5A, Part B. The consultation document, consultation report, and all responses, will be published on National Grid's website:

www.nationalgrid.com/uk/Electricity/SOincentives/doc

Appendix A - Proposed changes to The Statement of the Constraint Cost Target Modelling Methodology

Please see separate document.

Appendix B - Proposed changes to The Statement of the Ex-Ante or Ex-Post Treatment of Modelling Inputs Methodology

Please see separate document.

Appendix C - Consultation Questions

National Grid invites responses to this consultation by 10 August 2012. The responses to the specific consultation questions (below) or any other aspect of this consultation can be provided by completing the following proforma.

Please return the completed proforma to soincentives@nationalgrid.com

Respondent:	
Company Name:	
Does this response contain confidential information? If yes, please specify.	

No	Question	Response (Y/N)	Rationale
1	Do you agree with the proposed approach to modelling the voltage constraints experienced since the commencement of the current scheme?		
2	Do you have any suggestions as to how we could better model these effects on the transmission system?		
3	Do you agree with the proposed approach to reassess generation availability as an ex post rather than an ex ante input to the Constraint model and that it serves to increase Constraint model accuracy?		
4	Do you have any suggestions as to how we could better model generation availability on an ex ante basis?		
5	Do you agree with the proposed changes to the methodology statement in relation to boundary flow model setup errors?		
6	Do you agree that Ofgem are best placed to audit and approve these changes in future?		
7	Do you have any comments on the proposed changes to the modelling methodology for Interconnectors availability?		
8	Do you agree that moving Interconnector flows to an ex post input is appropriate and		

No	Question	Response (Y/N)	Rationale
	provides a more accurate modelling methodology?		
9	Do you agree that this clarification should be made to the modelling methodology?		
10	Do you agree with the proposed changes to the modelling methodology that allow us to detect and seek amendment to material differences in generator running patterns compared to model forecasts?		
11	Do you agree with treating commissioning generation as an ex-post input for a period of 6 months while the generator undertakes its commissioning programme?		
12	Do you agree with our proposal to change these optimiser settings?		
13	Do you agree with the approach that Ofgem oversee and approve any future optimiser setting amendments?		
14	Do you agree that if a market participant submits erroneous data in error that we should have the ability to remove the error such that the target cost remains unaffected?		
15	Do you agree with the approach that Ofgem oversee and approve these changes?		
16	Do you consider that there is value to the industry from publication of BSIS model outputs e.g. modelled MWh per BMU versus actual BMU output?		

Appendix D - Specific Modelling Amendments [for Ofgem]

This appendix contains confidential information that will be considered by Ofgem as part of this consultation process. Therefore, the more specific changes that we are seeking to make within the model that are generator specific are contained herein.

[Text Deleted]