Addendum to the Electricity SO Incentives Initial Proposals for 1st April 2011

Modelling Transmission Constraints

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UK Electricity Transmission
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Electricity SO Incentives: Initial Proposals for 1st April 2011

Constraints Addendum

Issue 1 - National Grid, 13th December 2010

Introduction

1. On 23rd November 2010, National Grid published its initial proposals consultation document for a two year incentive scheme commencing 1st April 2011[1].
2. In that initial proposals consultation document it was set out that National Grid has procured new software (Plexos[2]) in order to model constraint costs. In addition to replacing its current suite of in-house constraint models, Plexos also enables the modelling of generation despatch decisions using plant characteristics and market fundamentals. Implementation of this software has been ongoing and therefore information relevant to the modelling of constraint costs in the initial proposals document was more conceptual than that presented for the energy-based models.
3. This addendum to the initial proposals consultation document therefore sets out, in further detail, how the procured constraint model will be used to determine target constraint costs for the purposes of incentivisation. It sets out how the inputs to the model are proposed to be determined (including whether these inputs are to be ex-ante or ex-post), explains how the model has been constructed and calibrated, and discusses options for determining the prices to be used for determining the cost of resolving constraints.
4. The implementation of Plexos software that will be used to support the scheme from 1st April 2011 is known as the 'interim solution', which uses a simplified, boundary-based model to represent the transmission network. In the longer-term, it is anticipated that an 'enduring solution' Plexos implementation will feature a full modelled representation of the transmission network. It is envisaged that this enduring solution will be available to support the development of future incentive schemes. This document sets out detail relevant to the interim solution only. The boundary-based approach is intended to represent the transmission network as a series of zones corresponding to existing and potential future constraint boundaries.
5. Plexos is capable of modelling generation running using fundamental economic principles and applying that generation running to both unconstrained and constrained network representations, so that a modelled level of constraint costs can be determined. This addendum therefore sets out how these three elements are achieved by Plexos in order to derive a constraint cost forecast.
6. To guard against the risk that the procured software would not be available in time to support the operation of the incentive scheme, National Grid also developed an in-house contingency constraints model in parallel to the procurement process. However, now that it is apparent that the new software will be available for the incentive scheme starting on 1st April 2011, the development of the contingency model has ceased.
7. It should be noted that Ofgem's conclusions from phase 3 of the SO Review – which relates to the examination of National Grid's proposed methodology, including its models and modelling approach, to determine its appropriateness for application to an SO incentive scheme covering at lease two years – may require further development of the proposals contained within this document if an SO incentive scheme covering multiple years is to be agreed. Where recommendations for further

[1] This document can be found at: http://www.nationalgrid.com/NR/rdonlyres/F8797D2D-C0C0-4319-8961-DF39CD434037/44154/Initial_Proposals_Final.pdf

[2] More specifically Plexos v6.20x r0y, an electricity market optimisation software, written by Energy Exemplar

work regarding the models or modelling approach arise, either from phase 3 of the SO Review or through other stakeholders, National Grid expects to act upon such recommendations with a view to delivering revisions that result in models and a modelling approach that are acceptable and suitable to support Ofgem's Final Proposals for a two-year incentive scheme starting on 1st April 2011.

8. As set out in the initial proposals consultation, responses to this consultation will be considered by Ofgem, along with its conclusions following phase three of the SO Review, when developing Final Proposals for a two-year electricity SO incentive scheme to be implemented from 1st April 2011. These should be available by the end of February 2011.

9. The Initial Proposals consultation period closes on **22nd December 2010 at 17:00**. Responses to the Constraints Addendum would be appreciated by the same date. However, **should the additional time be useful, we will be able to accept late responses to the Constraints Addendum only, up to 17:00 on 29th December 2010.** Please get in touch if this date is still challenging, however please note that in order to keep on track with the timescales for the Final Proposals consultation (and subsequently the licence consultation to implement the incentive scheme) we are aiming to publish our report on responses to the Initial Proposals consultation on 31st December. **Responses to the Initial Proposals, and this Constraint Model Addendum, should be sent to soincentives@uk.ngrid.com.** All responses received will be placed on our website (unless explicitly requested not to) and will be sent in full to Ofgem.

10. Some of the questions posed in this addendum are the same as those set out in the Initial Proposals consultation document (and are labelled as such). As the information contained in this document is more extensive than in the Initial Proposals, further questions have been added to seek industry views on the additional detail. These further questions are labelled 'CA1', 'CA2' etc. Respondents to this addendum can therefore respond only to the newly posed questions in order to avoid duplication.

Associated Documents:

11. This Constraints Addendum document should be read in conjunction with the following documents, available on the National Grid website:

http://www.nationalgrid.com/uk/Electricity/soincentives/docs/

- BSIS 2011/13 Initial Proposals: Consultation document
- BSIS 2011/13 Initial Proposals: Appendices
- BSIS Reference Document

Contents

1. Constraints Model Development

Overview

12. The principles applied when modelling constraints costs are as shown in Figure 1 below:

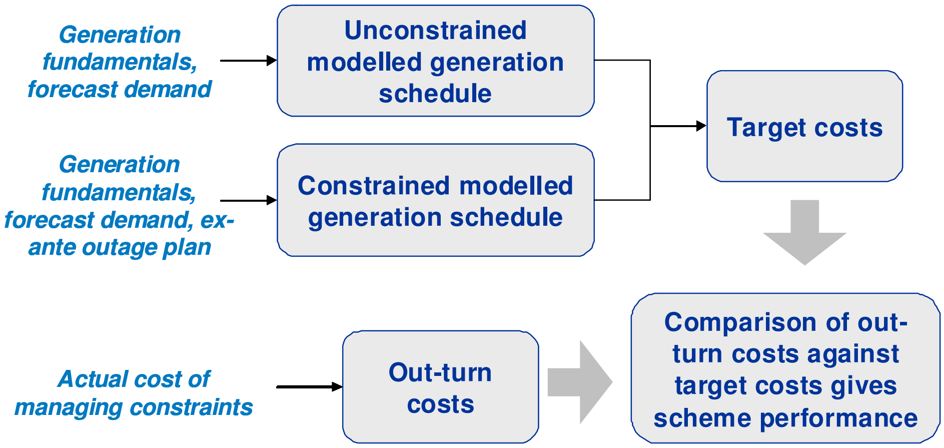


Figure 1: Overview of constraint modelling process

13. The generation fundamentals model is used to generate a schedule of plant running to meet demand. The output of this schedule will be 'unconstrained' – i.e. it will assume infinite transmission capacity. The model is then re-run with a boundary model applied, which will represent the ability of the transmission network to transfer power between pre-defined zones. The boundary capabilities of each zone will be modified to represent the transmission outage plan for the period covered by the scheme. Where a boundary's capability is exceeded, resulting constraints are resolved by re-scheduling plant using a representation of offer/bid prices, to give an overall 'constrained' schedule of plant running to meet demand.

14. The difference in cost between the unconstrained and constrained model runs will give the modelled 'target' costs against National Grid's out-turn will be compared to determine its performance under the SO incentive.

1.1 Determining generation output

15. The use of the Plexos software model for constraints modelling is based on the application of optimisation techniques aimed at minimising total costs.

16. The first run of the model consists of a simulation of market behaviour whereby, assuming an efficient market, the self-despatched position of generators, in order to meet forecast demand, is defined by minimising the total operating costs (mainly fuel and start up costs), subject to a number of plant dynamics constraints such as minimum run time, minimum time between runs, run up rates, run down rates, etc. The diagram in Figure 2 below illustrates this initial run of the model which will determine an unconstrained generation output. The diagram shows what inputs are to be ex-ante and which are to be ex-post – this is explained in further detail in the following section.

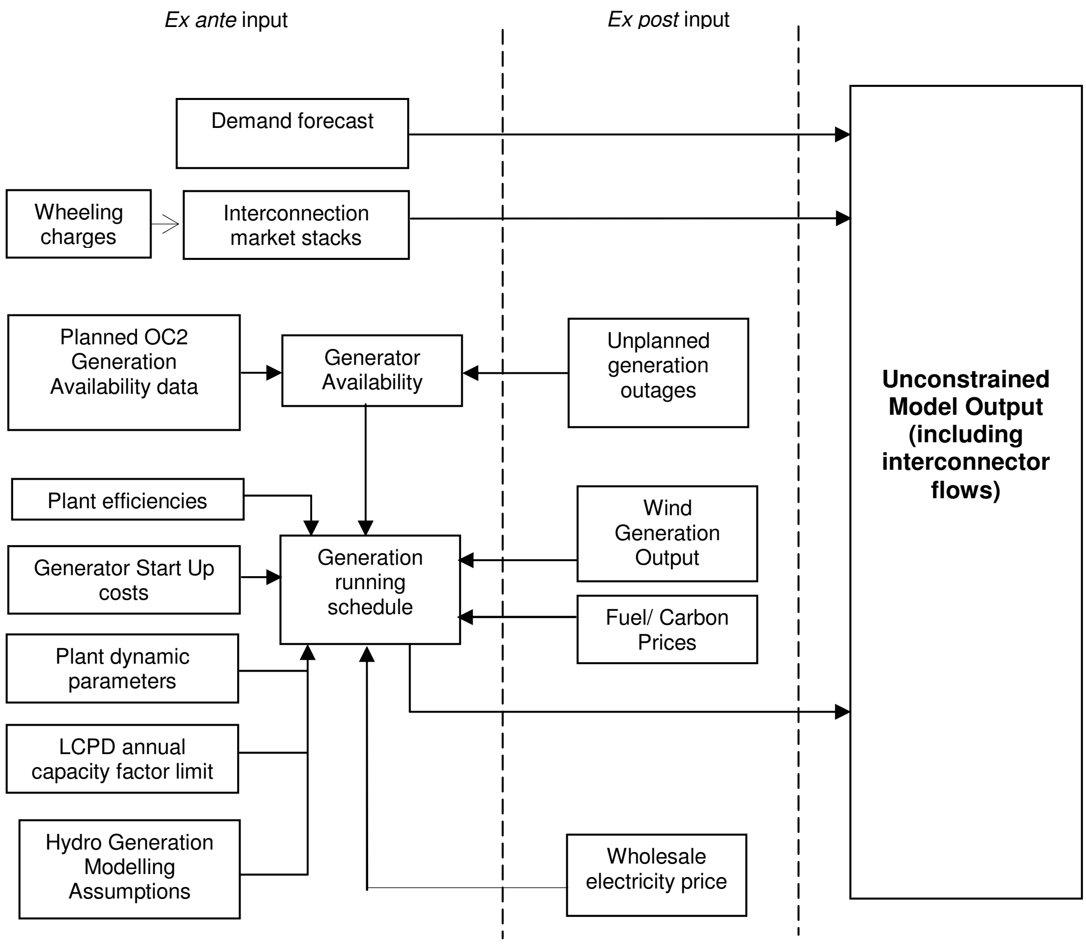


Figure 2: Unconstrained Output Model

1.1.1 Required input data to the unconstrained model

17. The first basic data required is the demand forecast which is to be met by generation in the model.

18. To achieve the initial run from a supply or generation perspective (the unconstrained despatch), a number of assumptions are made for each generation unit:

- Fuel price
- Carbon prices
- Plant efficiencies
- Start up costs
- Availability
- Plant dynamic parameters

19. In addition to the above, further inputs are required to fully represent generation levels on the system. These are:

- Wind generation output
- Hydro generation running assumptions
- Treatment of Large Combustion Plant Directive (LCPD) opted out plant
- Interconnector assumptions

20. All of the above inputs, and the sources of relevant data, are described in detail below.

1.1.2 Sources of input data to the unconstrained model

Demand Forecast

21. Demand forecast, an ex-ante input, is obtained through the well established processes within National Grid. Demand is forecast at a GB level and apportioned to grid supply points based on observed and understood relationships. The demand forecast will be performed immediately prior to the creation of the ex-ante dataset for the period covering the incentive in order to take into account the latest national econometric data. A current view of the demand forecast for the incentive period, and the methodology used to derive such a forecast, can be found in the Frequency Response model section (p48) in the recently published Initial Proposals consultation document[3].

Fuel and Carbon Prices

22. The prices actually incurred by each power station when procuring the fuel for their consumption and the associated lead-times are unknown and, as a proxy, an ex-post spot price will be used. Spot prices will be sourced from Argus and are measured in £/Giga Joule (GJ).

23. Although some generating units will have a duel fuel capability, it should be noted that the model does not take this capability into account and only applies the primary fuel type for that generator.

24. In addition to fuel price, a carbon price is also employed in the model to fully reflect the cost of generation. As for fuel prices, carbon prices will be input ex-post to the model and will be sourced from Argus, measured in £/kg.

25. Aside from price, for each fuel where CO2 is emitted when burned, a secondary property emissions production rate is applied. These production rates are the emission factors expressed in kg/GJ and represent the mass of carbon emitted per GJ of fuel burned. The production rates to be used within the model are displayed in Table 1 below for each fuel type and are sourced from DEFRA[4], using summer 2009 data. Although DEFRA has revised these values in 2010 to include indirect emissions ('fuel cycle emissions'), this change in methodology causes an inconsistency in the emissions estimation and hence the 2009 values have been retained.

Fuel Type	Production Rate (kg/GJ)
Coal	94.5
Gas	51.1
Gas Oil	73
Heavy Fuel Oil	77.3

Table 1: CO_2 Production rates by fuel type

Plant Efficiencies

26. Plant efficiencies are strategic information not easily obtainable through data in the public domain. The best practice in the industry to arrive at an estimation of these parameters is to assume that the efficiency for each generator's technology lies within a (publicly available) range and that the individual unit's efficiency is somehow correlated with the year it has been commissioned (the newer the generator, the more efficient it is expected to be).

[3] This demand forecast can be found on page 48 of the initial proposals document: http://www.nationalgrid.com/NR/rdonlyres/F8797D2D-C0C0-4319-8961-DF39CD434037/44154/Initial_Proposals_Final.pdf

[4] This data can be found at: http://www.defra.gov.uk/environment/business/reporting/older-ghg-conversion-factors.htm

27. In order to arrive at an acceptable estimate for existing generating units, historic market conditions are simulated and generic established efficiencies adjusted to a level that reflect the actual observed running regime and fuel usage/ emissions. Parameters for future units can be estimated from similar (same technology/age) existing ones. Using this methodology, the efficiency ranges set out below in Table 2 are to be used as ex-ante inputs to the unconstrained model.

Plant type	Efficiency
Coal	35% - 39%
CCGT	42% - 52%
OCGT	28%
Oil	30%

Table 2: Generator efficiency factors by fuel type

Start Up Costs

28. Start up costs are relevant information to the extent that they indicate the likelihood of certain generators to two-shift (desynchronise between two runs, typically overnight). These costs depend as much on the actual incurred costs by the generator to staff the station, warm the unit up and ramp it up to the state where it's ready to synchronise as they do on the perceived risk of failing to synchronise at a critical time of the day or the implicit additional maintenance costs resulting from manufacturers' related warranty conditions in the number of starts between programmed outages. Start up costs for existing units are estimated in a similar way as that of efficiencies, i.e. through simulating historic market conditions and adjusting the costs until a reasonable match is reached.

29. Typical start costs for a 500MW coal unit and 500MW CCGT to be used in the model are shown in Table 3 below. There is a fuel element to recognise the additional fuel used at start up i.e. fuel oil for a coal plant and gas for a CCGT. As mentioned above, there is also a fixed element, representing the financial costs of a start such as additional maintenance costs. These two cost item are additive. Information for future units will be derived from similar (same technology/age) existing ones.

	Coal	CCGT
start fuel offtake (GJ)	1,000	500
start cost (£)	50,000	12,500

Table 3: Start up costs for coal and CCGT plant

Generation Availability

30. Plant availabilities can, broadly speaking, be split into two groups: planned and unplanned. Planned outages will be based on submitted information by generators through the OC2 process (taken at a lead-time that lines up with that used for the transmission outage plan), although it is recognised that the accuracy of such data can vary, tending to decrease as lead-time increases.

31. Unplanned outages can be estimated by the normal historical break down rates, at the moment estimated at around 10% (i.e. on average, 10% of the generation capacity declared to be available is on forced outage). The simulation model is capable of dealing with stochastic unavailability as a standard feature.

32. However, as discussed in a later section below (from paragraph 45 onwards, but more specifically in paragraph 53) National Grid propose that unplanned generation outages are treated as ex-post within the model thereby negating the requirement to make an ex-ante assumption as to what this level of unplanned unavailability should

be. This is ultimately so that the possibility of wind fall profits/losses from the scheme can be avoided.

Plant Dynamic Parameters

33. Plant dynamic parameters for existing units will be obtained from historical submissions in the balancing mechanism (these are available via the Balancing Mechanism Reporting System (BMRS) or National Grid's off-line systems); for future units, they can be estimated from similar (same technology/age) existing units.

34. The specific dynamic parameters to be used for each unit, and as ex-ante inputs to the model, are displayed in Table 4 below along with a description of each parameter:

Dynamic Parameter	Description
Maximum Export Limit (MEL)	Maximum level at which a generating unit can generate (MW)
Stable Export Limit (SEL)	Minimum level at which a generating unit can generate (MW)
Minimum Zero Time (MZT)	The minimum amount of time that a generating unit must remain off (minutes)
Minimum Non-zero Time (MNZT)	The minimum amount of time that a generating unit must be on for (minutes)
Ramp-up Rate (RUR)	The rate at which a generating unit can increase its output level (MW/min)
Ramp-down Rate (RDR)	The rate at which a generating unit can decrease its output level (MW/min)

Table 4: Dynamic parameters to be employed in the Plexos model

Wind Generation Output

35. As set out in Section 2 of the initial proposals consultation document, wind generation output will be input to the model ex-post using actual out-turn data. The source for wind generation output data is National Grid's NED system[5] and therefore only metered wind output is to be input to the model.

Hydro Generation

36. Hydro generation is to be modelled in two ways within Plexos in order to simulate its behaviour:

- Pumped storage - pumped storage is despatched based on wholesale electricity price differential within each day. If there is sufficient price differential between within-day peak and off-peak periods, there will be pumping at off-peak times and generation at peak times.
- Reservoir – reservoir is modelled by assuming a monthly water inflow into a head pond/top lake which is to be an ex-ante input to the model. The model then optimises the release of this water to generate electricity. This is based on Eurostat data[6] where observed monthly hydro generation is used to calculate the average load factor of 36% which is to be employed within the model.

Treatment of LCPD opted out plant

[5] NED is the National Grid Economic Data warehouse - a system that stores and aggregates operational and half-hourly Settlement Data

[6] More information can be found at: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database

37. To capture the behavioural effect that LCPD has on certain generating units, the model applies an annual capacity factor limit on those units which have opted out of the directive. This limit is based upon historic observations since the directive came into effect in January 2008 (up until June 2010) and represents an upper bound on load factors of opted out power stations.

38. The factor, calculated as 35%, is therefore to be an ex-ante input to the unconstrained model i.e. it is assumed that each LCPD opted out station will have a load factor of up to 35% each year until closure. Station closure dates have been predicted on the basis of running hours used to date, using Elexon data[7], which are extrapolated forward.

Treatment of interconnectors

39. Interconnected markets can drive constraint levels across certain key boundaries by either importing or exporting power into, or out of, constrained zones. For example, the direction and extent of flows on the Moyle interconnector, which connects Scotland to Northern Ireland, can impact the volumes of constraints observed across the boundary between Scotland and England (the Cheviot boundary).

40. The GB system currently has two interconnectors: one connecting GB to France (Interconnexion France Angleterre or IFA) and the aforementioned Moyle interconnector. However two new interconnectors are under construction, which are to connect GB with the Netherlands and GB with the Republic of Ireland. In order to model such interconnected markets, a simplified stack is applied to represent the market at the non-GB side of the interconnector, which is meeting a simplified demand profile. In particular:

- The French market is represented by a simple nuclear and gas stack - nuclear is to represent French generation and gas is to represent times when France may be importing power through its transmission system from Germany and other North West European markets.
- The Irish market is modelled using a gas and coal plant mix
- The Netherlands is modelled primarily using gas plant

41. The fuel prices for the plant modelled at the other end of each interconnector will be the same as for the UK generators and will also be sourced from Argus.

42. 'Wheeling charges' are also applied to interconnectors in the model. Wheeling is a term applied when interconnector users export power from, for example, the GB market via one interconnector and then import power via another interconnector back into the GB market (thus creating a wheeling effect). Application of this charge means that a certain price differential across the interconnector is required before such flows will occur.

43. A wheeling charge in Plexos is a variable cost applied to interconnector flows. These can be used to represent any actual charges faced by interconnector users which influence flows (e.g. historically Transmission Network Use of System (TNUoS) charges on GB exports at winter peak). In addition, following model calibration, the wheeling charges may also include a 'risk premium' reflecting the lack of perfect foresight in scheduling flows between non-coupled markets. Given that BritNed will be market coupled for day ahead, it is likely that flows on the interconnector will be much more closely aligned with the price differentials. If this turns out to be the case then a wheeling charge is not likely to be required on BritNed.

44. The simplified market stacks and wheeling charges are to be ex-ante inputs to the unconstrained model which ultimately determine the direction of flow on each interconnector. In future, due to implicit interconnector capacity auctions and price coupling, it will be rare for an interconnector to not either be fully exporting or fully importing and therefore these flows will be represented as binary within the model.

[7] This data can be found at: http://www.bmreports.com/bsp/staticdata/LCPD/LCPD_2010-06-02.xls

Question CA1: To what extent do you agree that the way in which ex-ante inputs to the unconstrained model have been derived, as set out in paragraphs 21 to 44 above, is appropriate? Are there any further inputs you think should be considered?

1.1.3 Issues with generation input data

45. From a constraint management perspective, whether or not a generator is available to run can have a significant impact on whether or not a transmission constraint is active. In the context of National Grid's proposed new approach to incentivisation, if a generator is seen as available in the Ex-Ante dataset, the generation fundamentals model will schedule it to run in accordance with the relevant parameters.

46. It is possible that the level of generation running modelled by fundamentals in an unconstrained run will exceed one or more of the boundary transfer limits. The availability of a generator may trigger an allowance for constraint management, associated with its running, to be included in National Grid's target costs for constraints.

47. National Grid's view on the potential issues this may cause is as follows:

Planned Outages

48. Whilst planned generation outages (including those associated with generator commissioning), are subject to change, National Grid considers it appropriate that they should be treated as ex-ante inputs to models. National Grid considers that this would ensure that it would be incentivised to account for planned generation outages in the co-ordinated delivery of an overall efficient outage plan.

49. The Grid Code (OC2[8]) process for planning generation outages allow for outages to be submitted from current year to up to five years ahead. Of particular relevance to a two-year incentive scheme, by the end of engineering week 48 in any year, National Grid seeks to agree (to the extent that agreement is possible) a Final Generation Outage Programme with generators for the following two years. It is this Final Generation Outage Programme that will form the basis of the generation availability aspect of the Ex-Ante dataset.

50. Notwithstanding the extent of the agreement regarding the Final Generation Outage Programme in week 48 each year, it is the case that outages continue to be refined, moved, created or removed beyond this point. In reality, the generation outage plan for year 2 (and to a lesser extent for year 1) can vary significantly from that seen in week 48.

51. National Grid considers that the dynamic nature of generation outages could lead to the possibility of windfall profit or loss if the variability of the plan is not sufficiently represented in the Ex-Ante dataset.

52. Accordingly, National Grid proposes that incentivisation might be better served either by updating planned generation outages in the Ex-Ante dataset on an annual rolling Ex-Ante basis, rather than simply fixing two years' worth of generation outages in the Ex-Ante dataset prior to the start of the scheme; or by adopting a more conceptual 'outage requirement'-based approach to determining future generation outages, for example based on expected maintenance requirements.

[8] Section 2 of the Operating Code within the Grid Code.

Question 14 (from Initial Proposals): To what extent do you consider that there exists the potential for windfall profit or loss under the scheme if a single snapshot of the generation outage plan were to be taken prior to scheme start (and used in the models for the duration of the scheme)?

Question 15 (from Initial Proposals): To what extent do you consider that a rolling Ex-Ante approach to modelling planned generation outages, as notified via Grid Code OC2 processes, is an appropriate mechanism to ensure the modelled outage plan remains representative (and suitable for incentivisation)? What other mechanisms could be considered?

Unplanned Outages

53. Unplanned outages are random in nature and can occur at any time; hence they would not be included in the ex-Ante dataset agreed prior to the start of the scheme; although stochastic modelling of unplanned outages will be possible. National Grid is concerned that, even with stochastic modelling of unplanned generation outages, there exists the potential for generator faults to give the potential for windfall profit or loss, if availability is modelled when setting target costs, but that availability does not materialise in practice. To avoid this risk, National Grid proposes that unplanned generator availability should be treated as an ex-Post input to models.

Question 16 (from Initial Proposals): To what extent do you consider that there exists the potential for windfall profit or loss under the scheme if unplanned generator availability is not considered when calculating target costs for constraint management incentivisation?

Question 17 (from Initial Proposals): Do you agree that treating generation faults as an Ex-post input to [constraint] models is an appropriate mechanism to ensure the modelled target cost remains representative (and suitable for incentivisation)?

1.1.4 Calibration of the Unconstrained Model

54. To ensure that the model can provide a suitable level of accuracy when forecasting generation volumes and interconnector flows, a calibration process has been undertaken using historic data. A short-run marginal cost[9] (SRMC) model was created using generating unit technical parameters as described above in paragraphs 33 and 34, in accordance with out-turn daily fuel and emissions prices, to determine a forecast of generating unit Final Physical Notification (FPN)[10] data for the financial year 2009/10. Each generating unit is therefore forecast to self-despatch at its calculated SRMC in the model (on an unconstrained transmission network). Only plant opted out of LCPD were constrained below their SRMC forecast availability in the model.

55. The output of this first run is a modelled predicted FPN for all units which is then compared against actual submitted FPNs and metered output for the period in question. This exercise identified three significant discrepancies where the model did not represent the observed behaviour - two for generating stations and one for an interconnector on the system.

56. To account for these discrepancies, adjustment factors are applied to these generators in the model to either increase or decrease, according to the nature of the discrepancy, the SRMC of those units (and hence the modelled FPNs) accordingly. Discrepancies identified for the two generators can be explained as follows: one is a

[9] Short-run marginal cost is the change in short-run total cost created by a change in output.
[10] The Final Physical Notification for a BM Unit is the expected level of export (or import) for each half hour settlement period which is submitted in the balancing mechanism.

low merit plant that would, based on fundamentals, be expected (and was correctly predicted by the model) not to run but did; the other is an LCPD opted out plant whose running regimes differ from the basic assumptions in the initial model.

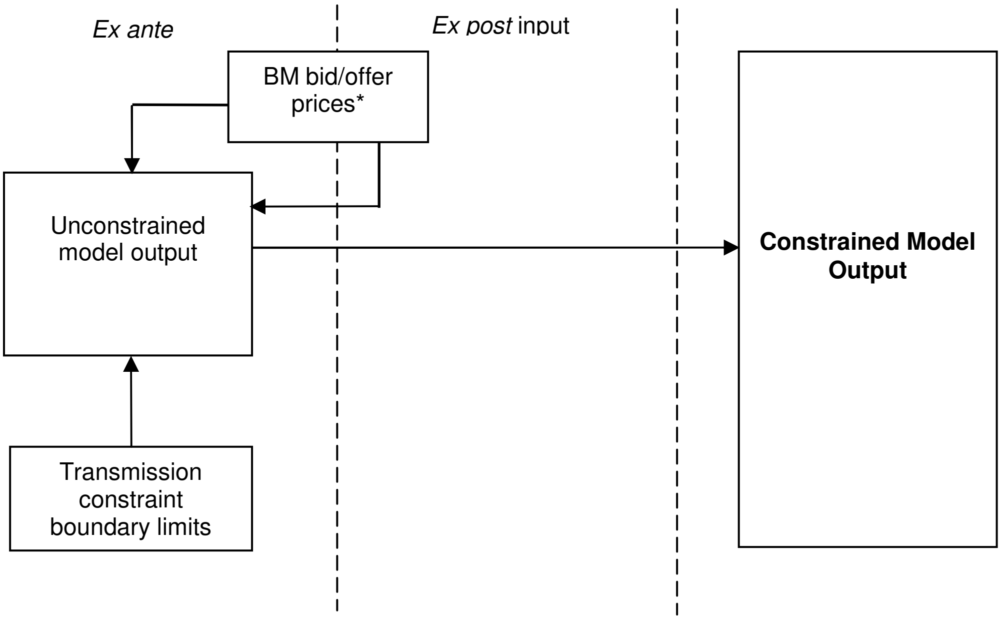
57. To ensure that the identified interconnector was more accurately represented by the model, increases were made to the mark-ups on the plant in the market stack at the other end of the interconnector. This served to increase the price in the non-GB market and therefore increase exports on the interconnector.

58. Having calibrated and made adjustments in this way, the output of the unconstrained model can be input to the constrained model to determine a constraint cost forecast.

Question CA2: To what extent do you consider that the approach taken to calibration of the model provides a reasonable ongoing representation of generation output for the duration of the incentive scheme?

1.2 Determining transmission network capability

59. As described above, the unconstrained despatch model output emulates generators' FPN submissions to National Grid, and interconnector flows, given the assumptions described. The next step is to include transmission system constraints and re-run the optimisation algorithm, this time aiming at minimising the cost of moving from the unconstrained despatch to a feasible (constrained) one. The diagram in Figure 3 below illustrates the constrained model along with which inputs are proposed to be ex-ante and which are proposed to be ex-post. These inputs are discussed in more detail in the following section.



**BM Prices could either be ex-ante or ex-post and this is discussed further from paragraph 111 onwards below.*

Figure 3: Constrained model

60. This second run of the model factors in the limitations of the transmission network, where the difference between the two runs represents the model's assessment of the required volume and associated cost of constraint management activities. The generation output levels from the unconstrained model are therefore used as inputs to the constrained model where Plexos re-despatches generation to meet demand in light of the boundary constraints applied and the cost of actions in the Balancing Mechanism.

61. Where a boundary's capability is exceeded, resulting constraints are resolved by re-scheduling plant using a representation of offer/bid prices, to give an overall 'constrained' schedule of plant running to meet demand.

62. The difference in cost between the unconstrained and constrained model runs will give the modelled 'target' costs against National Grid's out-turn will be compared to determine its performance under the incentive.

63. The way in which the model is constructed, including simulation of the Balancing Mechanism is described in the following section.

1.2.1 Required input data to the constrained model

64. The interim solution models the transmission system as a series of interconnected nodes. Each node represents a distinct zone defined by one or more constraint boundaries. Calculated boundary limits are applied to the interfaces between nodes. The initial data required is used to define the constraint boundaries which represent the system's limited capabilities. The diagrams in Figure 4 (Scotland) and Figure 5 (England and Wales) below show the aforementioned nodes and zones applied to model the transmission system.

65. The nodes are connected by lines in order to model a simplified version of the transmission network. Where actual transmission system zones are connected by one or more transmission circuits, connections between nodes in these zones are modelled.

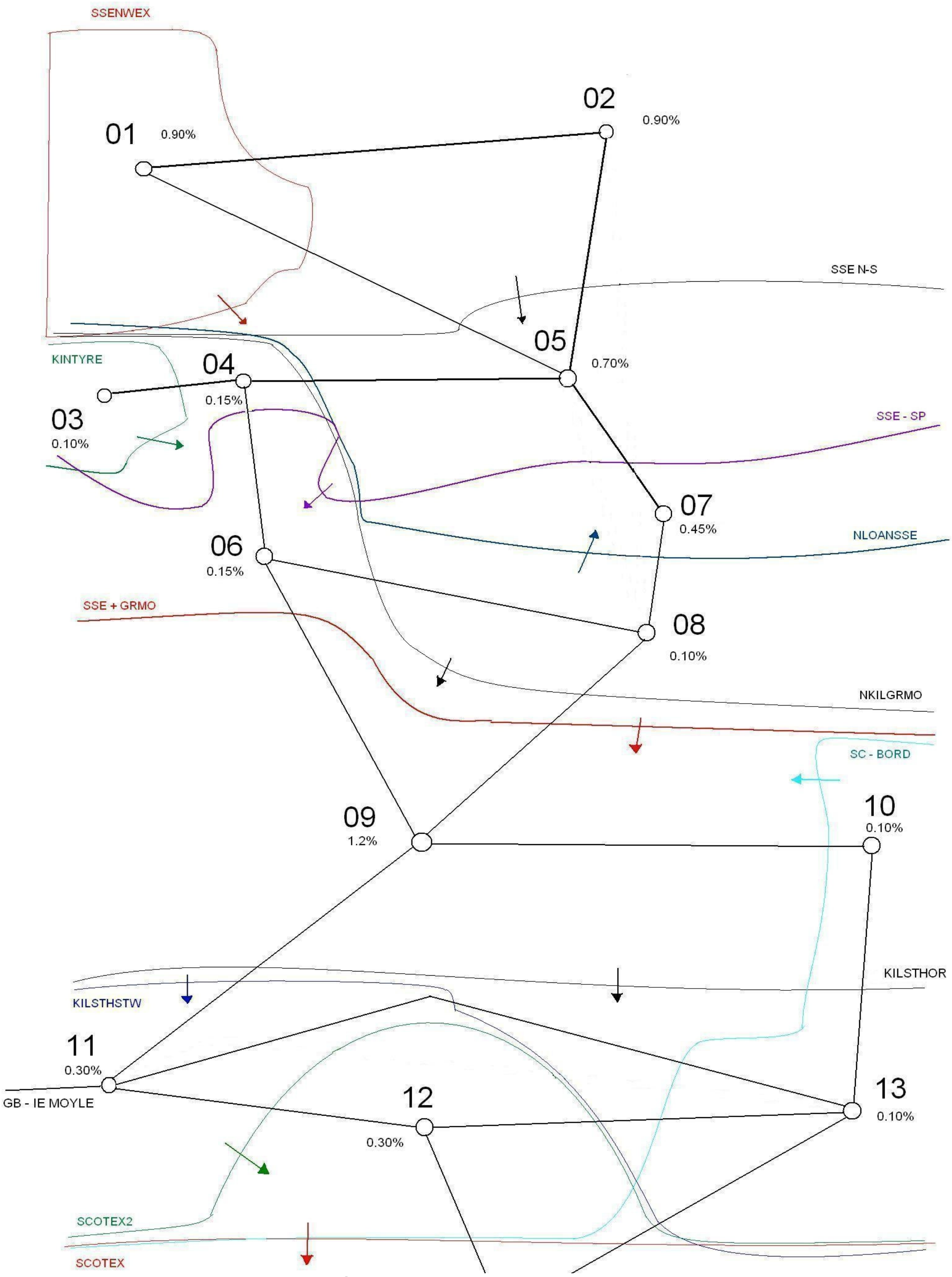


Figure 4: Transmission system (Scotland) model represented by nodes and zones to determine constraint boundaries[11]

[11] Diagrams provided by Redpoint Energy Limited

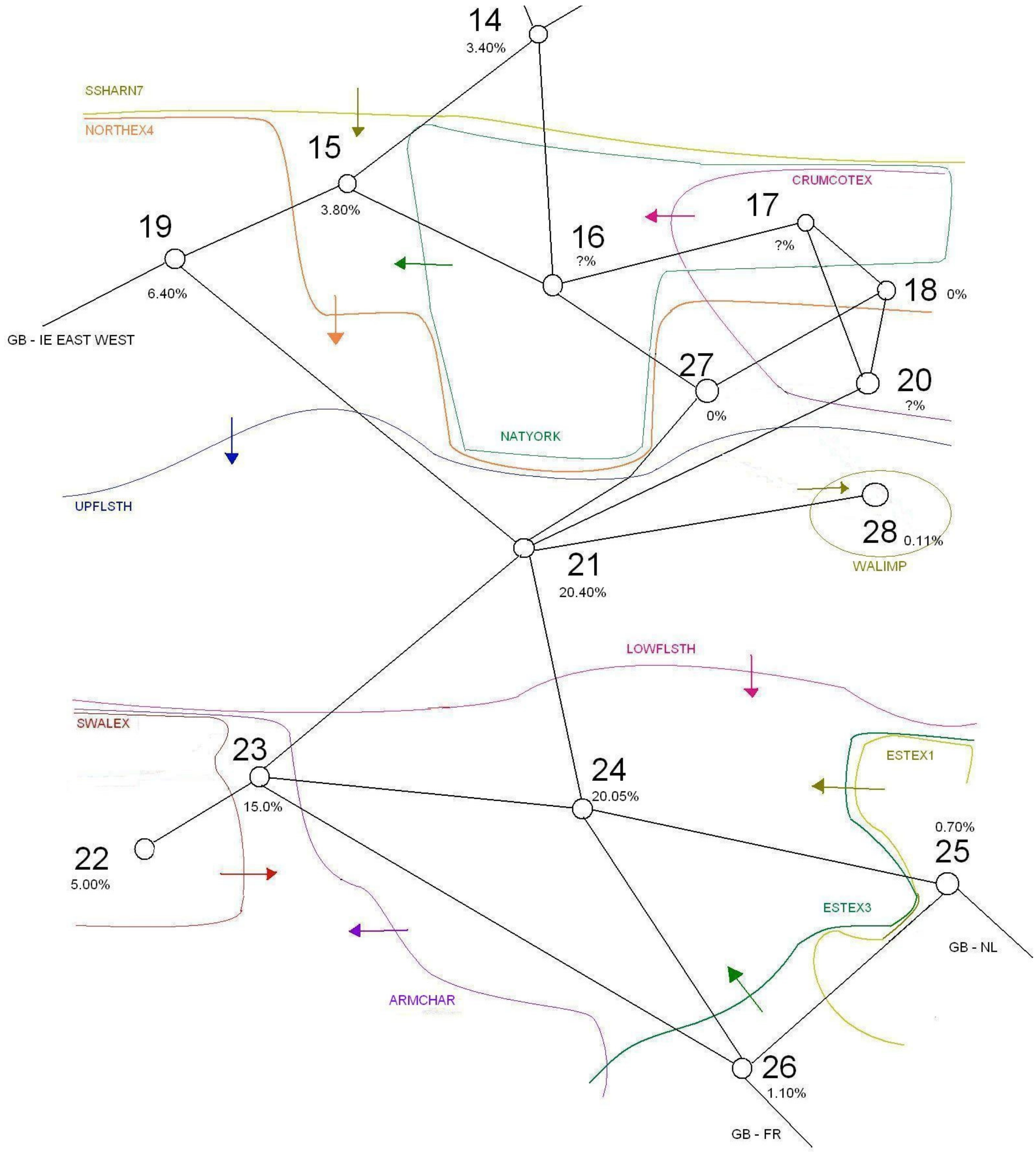


Figure 5: Transmission system (England and Wales) model represented by nodes and zones to determine constraint boundaries

66. An example of how this representation of the transmission system works, looking at the first diagram of Scotland in Figure 4 above, is as follows:

- Node 01 represents the zone 'Behind SSENWEX' – the zone is therefore defined by the boundary SSENWEX
- Node 02 represents the zone 'Between SSE NW and SSE N-S' - the zone is therefore defined by the area between these two boundaries
- Node 05 represents the zone 'Between SSE NS and SSE SP' – the zone is therefore defined by the area between these two boundaries

67. The calculated maximum constraint boundary limits for 'SSENWEX' are applied to the interface which consists of the lines connecting Node 01 to Node 02 and Node 01 to

Node 05. Therefore the interface in the model is representative of the selected constraint boundary 'SSENWEX'. It should be noted that the two lines connecting these nodes are modelling the transmission lines connecting the two zones.

68. In this example, even though node 01 and 05 are electrically connected in reality, the line 01-05 is not strictly required in the zonal model. This is because whether power takes the route 01→02→05, or direct 01→05, it has to cross the SSENWEX and SSE N-S interfaces. Therefore these two routes are assumed to be equivalent by the model. This is true even when there are constraints on both the SSENWEX and SSE N-S interfaces.

69. Plexos is free to choose line flows to meet zonal generation and demand, subject to the boundary constraints. Take the example of zone 01 in Table 5 below, connected to zones 02 and 05 by lines 01-02 and 01-05, which both cross the SSSENWEX boundary.

70. If generation in zone 01 exceeds demand by for example 300MW, then the flow on the two lines must sum to 300MW. There is no constraint on the flow on each line individually and flow direction (positive or negative) is determined by the constraint type (export – positive, import – negative) being modelled. Therefore the combinations in Table 5 below are all valid given that this example illustrates an export constraint:

Flow on line 01-02	Flow on line 01-05	Flow across SSENWEX
300	0	300
0	300	300
150	150	300

Table 5: Example line flow combinations

71. Having defined the system boundaries, the following information is determined which are inputs to the constrained model and are described in more detail in the following section:

- Zonal demand to be attached to each node
- Zonal generation to be attached to each node
- Boundary limits during outage conditions

1.2.2 Sources of input data to the constrained model

Boundaries to be modelled

72. The location and number of boundaries have been selected by National Grid based on the most common current and most likely future bottlenecks in the system, according to the operational experience of Power System Engineers.

73. The boundaries used have been chosen to cover many of the potential issues the transmission system will face. However, the consequence of using a generic boundary approach is that actual transmission system constraints experienced operationally may be different to those applied to the model.

74. To ensure the longevity of the model, some boundaries have been included which are not expected to have an active limit in place for the immediate future; that is to say it is not envisaged that any generation pattern in the short term would result in flows which exceed those boundary limits.

75. A summary of the boundaries to be modelled, and a description of each, can be found in Appendix A.

Zonal demand and generation

76. Zonal demand has been derived based on the historical percentage of each zone's demand with relation to the total GB system demand. The demand for each zone is applied to the node representing that zone.

77. Zonal generation has been defined by the physical location of plant on the system. The generation in each zone is applied to the node representing that zone via a manual process using system diagrams.

Boundary limits during outage conditions

78. Boundary limits during outage conditions are calculated through the development of offline power system studies. For each boundary, a subset of the outages planned to take place throughout the outage year are selected. The selection process is based on historic data and the operational experience of power system engineers, and represents the most significant outages in relation to their impact on boundary transfer capabilities. Less significant outages planned during the outage year will therefore hide behind those selected in relation to their impact on boundary transfer capabilities.

79. The offline power system studies are used to calculate the maximum power flow that can be accommodated across a particular boundary. For each boundary, multiple contingencies (circuit trips) are run to establish the most onerous fault conditions. For the most onerous fault conditions, the maximum power flow that can be achieved across the boundary is calculated according to NETSQSS[12] requirements.

80. In the case of a thermal constraint, the boundary limits have been calculated using the 20 minute short term rating of the worst overloaded circuits. This means that the maximum power flow across a boundary will be calculated to ensure that the power flows on these overloaded circuits can be reduced to their post fault continuous rating within 20 minutes. It's important to realise that this limit is achieved by selecting the most effective generation available in reducing those overloaded circuits. The post fault generator effectiveness is considered in a similar way for other types of constraint that can occur.

81. Limits are also a function of generation and demand backgrounds and can for example change between night and day or weekday and weekend.

82. The calculated boundary limits are applied to the interfaces between the interconnected nodes.

Limitations of approach to setting boundary limits

83. The maximum boundary limits are assessed in the context of the outage plan for the week being studied using the power system analysis therefore, a number of limitations need to be recognised.

84. It does not necessarily follow that an equivalent outage taking place at a different point in time would result in an equivalent maximum power flow that can be achieved across a boundary.

85. Notwithstanding the changing transmission system outage pattern, boundary capability on a static network topology will vary through the year, taking into account the varying capacity of transmission components in relation to ambient temperature. Seasonal rating schedules are used to manage this variation. It should be noted that, there are five types of transmission constraint: (Thermal, Voltage, Stability, Fault Level and Response/Reserve). Changes in rating season materially affect thermal limits; however, the applicable limit for a boundary at any point in time will be the most onerous of the five types. Thermal, Voltage and Stability limits are the three types most commonly encountered on the transmission system.

86. When resolving a transmission constraint issue, generators (and demand) have a considerable range of effectiveness on any post fault actions. The implication of this is that the constraint limit values on the real system for a given transmission system topology (outage pattern) and rating season will change dependent on plant despatch and demand pattern. The extent to which they change is thus a function of both the volatility of generation despatch and demand profile, and the relative effectiveness of the contributory generation (and demand).

[12] National Electricity System Security and Quality of Supply Standard

87. Since the boundary model does not take into account these limitations, constraint volumes calculated by the model are likely to deviate from those witnessed in reality, even if transmission system topology, rating season etc remain constant.

88. It is envisaged that the enduring model will utilise actual network data, with a different set of assumptions, which will address many of these issues. However, this document sets out to describe the Interim Solution only.

Generation effectiveness on boundaries

89. In moving from unconstrained modelled generation to constrained modelled generation a re-scheduling of plant may be required for those boundaries which exceed their calculated limits.

90. The model assumes that all generators within a constraint boundary are 100% effective when moving from unconstrained modelled generation to constrained modelled generation.

91. For example, looking at Figure 4 above, assume that the SSENWEX interface has an export limit of 200 MW. Actions must be taken to reduce generation on node 01 and increase generation elsewhere. Generation on node 01 must be reduced 100 MW. This is the only way to reduce flow across the SSENWEX interface.

92. Generation must be increased a node on the other side of the SSENWEX constraint. This could be at 02, 05 or any other node further south. The model will choose to increase generation from the cheapest generator outside of zone 1 whilst also satisfying all boundary limits. In the interim solution, the constraint is resolved equally well whether the increase in generation occurs in zone 02, or a zone that is physically far away from node 01. In this model, all generators that are outside the SSENWEX are 100% effective at providing the replacement energy.

Limitations of approach to generation effectiveness on boundaries

93. A simplicity of the boundary model approach is that all generation (and demand) within a constraint boundary will be considered by the model to be equally effective in managing a transmission constraint issue. In reality the effectiveness of generation for post fault actions is also considered when selecting plant to re-schedule.

94. For example, where a generator is more effective at reducing the post fault overload of a specific circuit then this generator may be selected to manage the system constraint pre-fault, even though that generator may not necessarily be the cheapest option in the BM.

95. This simplification will be addressed in the enduring solution where the location of the generator has an impact on how effectively it can resolve the constraint by adjusting generation.

Question CA3: To what extent do you consider the proposed approach to modelling the transmission network as a series of boundaries allows for a pragmatic representation of transmission capability for the purposes of incentivisation?

Question CA4: To what extent do you agree that the proposed approach to modelling generator effectiveness on boundaries will result in appropriate constraint volumes being determined?

Outage durations

96. The outage durations will be taken from the Final Outage Plan in the Transmission Outage and Generation Availability (TOGA) system as agreed at the end of the calendar year prior to scheme start, adjusted to reflect changes up to either the start of the incentive scheme or an agreed point beforehand. Note that the final outage plan covers one year only; whilst construction outages are known to some extent for subsequent years, it is likely that many outages for maintenance will not have been planned for the second year of the proposed incentive period.

1.2.3 Key assumptions for transmission input data

97. Generation dispatch assumptions alter the transfer which can be secured across any boundary. A complex optimisation model would be required to accurately reflect the interaction between generation and transfer limits. A pragmatic view of generation output has been taken when calculating transfer limits, to flex the transmission system so that likely issues are identified while not attempting to capture all potential issues; this would imply an accuracy level which is not possible from such a generic approach.

98. The work required to derive a limit for each boundary is such that it is not possible to calculate a limit for each boundary for each week. As the limits calculated seek to reflect typical system conditions rather than a specific outage, generation and demand scenario, preparation of a limit for each individual week would again imply greater accuracy than is possible from this approach. However, a valid limit may remain in place for a number of weeks. Where it is possible to use a calculated limit across a number of weeks, this approach has been taken.

99. Outage planning processes are set out in the Grid Code and System Operator-Transmission Owner Code (STC)[13]. Currently, the draft outage plan for years 2 to 5 only includes construction and refurbishment outages. It is not until the final outage plan for year 1 is created at the end of each calendar year that maintenance outages are added in – maintenance work tends to be fitted around the construction and refurbishment work to allow for efficient use of outages. Hence the outage plan for the year-ahead represents the most complete outage plan to consider from an incentivisation perspective. National Grid is concerned that, by fixing outages in an Ex-Ante dataset prior to the start of a two year incentive scheme, the data for the second year will not be sufficiently representative of the actual outage plan to act as an efficient means of setting a modelled target cost, which is likely to have an impact on the suitability of those target costs for incentivisation.

100. Whilst National Grid continues to believe that planned transmission outages should be treated as an Ex-Ante input to models, it is concerned that the dynamic nature of transmission outages could lead to the possibility of windfall profit or loss if the variability of the plan is not sufficiently represented in the Ex-Ante dataset. One view is that incentivisation might be better served either by updating planned transmission outages on an annual rolling Ex-Ante basis, rather than simply fixing two years' worth of transmission outages prior to the start of the scheme; or, an alternative option could be to adopt a more conceptual 'boundary capacity'-based approach to determining future transmission capability. This is considered further below.

Proposal for Year 2 Transmission Outage Plan

101. The outage plan is required to deliver National Grid's programme of construction and maintenance activities. The majority of energy constraint volume and costs are incurred against construction outages due to their long duration and the inflexibility of their placement, particularly when they are tied to contracted customer connection work. The capital plan is continually updated in line with changing customer requirements, updated asset condition data and external factors, e.g. planning consents. Capital investment projects will be moved through the sanctioning, detailed design and delivery phases, on a 'just in time' basis to maintain flexibility for National Grid customers and to ensure that our highest priority assets are replaced, whilst ensuring that the work is deliverable.

102. Within National Grid business processes, we have been refining the list of individual schemes that we will deliver during 2012-13. However there is still uncertainty surrounding a number of these schemes. Also, a large portion of these schemes have only recently entered the detailed design phase and hence there is still significant uncertainty about the detailed outage requirements to deliver the schemes.

[13] National Grid is currently working with the industry to develop the outage management and investment planning processes set out in the STC. Further information can be found in the initial proposals document.

103. To derive a year 2 plan, National Grid proposes that the list of schemes currently planned for delivery during 2012-13 will be used as the basis of the determining the relevant ex-ante input data. Those schemes which are well developed will already have detailed outage requirements identified. Engineering and planning expertise will be used to identify the outage requirements for the remaining schemes. These outages will then be allocated against the appropriate boundaries in the Plexos model.

104. National Grid considers that there is insufficient certainty in the detailed outage requirements to build a full outage plan and perform detailed computer based modelling with its network analysis programmes. National Grid considers that it would require a significant engineering resource which would not be justified by the accuracy of the outage data at this stage of the planning process. It is therefore proposed that a combination of the recent detailed analysis of the 2011-12 plan build, current year analysis and engineering expertise be used to determine the constraint limits for the individual outages in the model for year 2 using an 'expert group'. All of the boundaries within the Plexos model will be determined on a weekly basis.

Question CA5: To what extent do you consider that there exists the potential for windfall profit or loss under the scheme if an 'expert group' methodology is used to determine a year 2 outage plan as described above?

2. Costing constraints

105. The choice of the objective function to be minimised can affect the result of this constrained optimisation. National Grid has a number of constraint management tools at its disposal, such as the BM, intertrip services, traded solutions and balancing services contracts. A modelled approach to determining a target level of constraint costs needs to be able to accommodate this range of services; and of particular importance is the derivation of prices to represent the cost of re-scheduling plant in the BM.

106. If the costs used to describe the financial impact of moving from the unconstrained position to the constrained one are based solely on market fundamentals, there is a risk that the whole dynamics of the balancing mechanism are ignored. This may lead to the wrong generators being selected by the model to resolve a constraint, which will in turn cause the volumes to be wrongly allocated to generators. Further, it is highly likely that the re-scheduling costs would be underestimated, as generators have been observed to charge a premium over costs predicted by analysis of fundamentals in their BM offer and bid price submissions. For this reason, an important input to the constraint model is the function describing the generators' BM offer and bid price submissions, given prevailing market conditions.

2.1 Simulation of the Balancing Mechanism

107. The balancing mechanism is simulated in Plexos through bid/offer price quantity pairs, using the unconstrained despatch model as an input. This unconstrained despatch is re-despatched with respect to boundary transfer capabilities using the various BM bid/offer prices.

108. Therefore the basis from which generating units can be issued a BOA to satisfy the constrained model is the unconstrained generation or FPN output from the first model run. Each BMU in the BM simulation will have four possible prices per half-hour settlement period for making changes to its output. These are set out in Table 6 overleaf.

Price Band	Effect on output
Desynchronise Bid	Reduce from SEL to zero
Energy Bid	Reduce from MEL to SEL
Energy Offer	Increase from SEL to MEL
Synchronise Offer	Increase from zero to SEL

Table 6: Modelled BM price bands

109. Four prices are used because there are broadly four categories of actions in the BM that have different price drivers; they, and their drivers, as follows:

- De-sync Bids - the submitted bids on a unit to reduce its output from SEL to zero. One would expect the price to reflect the value of the fuel saved, and also the cost of increased maintenance due to the extra synchronisation caused.
- Energy Bids - the submitted bids on a unit to reduce its output from FPN towards SEL. One would expect the price to reflect the value of the fuel saved.
- Energy Offers - the offers on a synchronised unit above SEL. One would expect the price to reflect the cost of fuel used.
- Sync' Offers - the submitted offers on a unit to switch the unit on and increase its output to SEL. One would expect the price to reflect the cost of fuel used, and the maintenance cost due to the synchronisation event.

110. The model will only take one of the above actions in the BM on a particular unit if it is feasible to do so, given its dynamic parameters. For example, if the outcome of the unconstrained model run is that a particular unit will have an FPN level equivalent to its Maximum Export Limit level then it is not feasible to take an action on that unit in the BM to increase its output to resolve a constraint in the second run of the model.

2.1.1 Deriving BM prices Ex-Ante

111. During phase 2 of the SO Review, National Grid attempted to develop a methodology that would derive bid and offer prices submitted in the Balancing Mechanism ex-ante, based on observing relationships between those submitted prices and the underlying fuel and carbon prices associated with Balancing Mechanism activities.

112. The results obtained through this approach were inconclusive - no robust means of describing the likely behaviour of each generator in the Balancing Mechanism was identified (whilst it was possible to identify relationships for certain BM Units, for the vast majority (some 80%) it was not possible to identify any discernable logic behind BM pricing behaviour). This may be due to the fact that different 'markets' might be in play at different times – for example there may be localised constraints markets in addition to the wider energy balancing market.

113. Figure 6 and Figure 7 below show examples from the outcome of this exercise to model BM prices ex-ante (employing a similar four band structure as set out in Table 6 above) using source data from summer 2009[14]. Modelled BM prices were determined as a function of the fuel type and therefore (clean) fuel price for each unit; an efficiency factor for the unit; and a price mark-up or profit element.

114. Figure 6 shows that the modelled price (red line) for the unit in question bears little relation to actual submitted prices (blue dots), nor to the underlying fuel price for the unit (grey line). Figure 7 below is an illustration of where attempts to model BM price ex-ante were more successful. The x axis on the below graphs are the number of half hours for which the price type applies and the y axis is bid/ offer price. The modelled price function of each of the units is also displayed on each graph.

[14] Summer data is used to reflect a typical outage season.

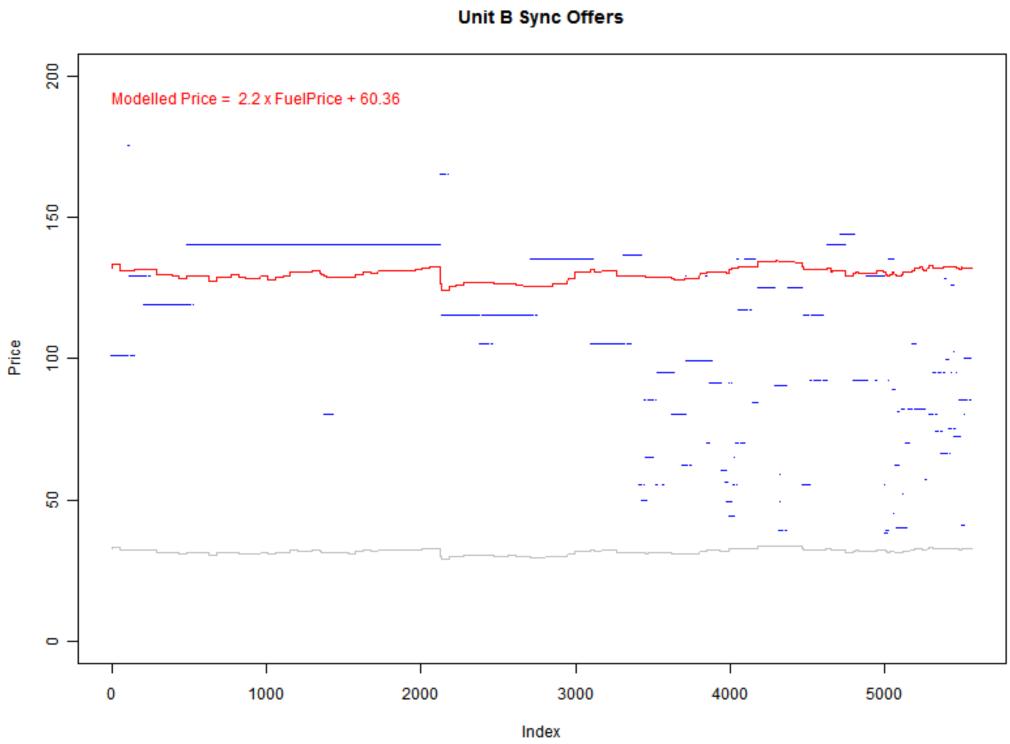


Figure 6: Modelled Sync Offer BM Price versus actual submitted prices for 'Unit B'

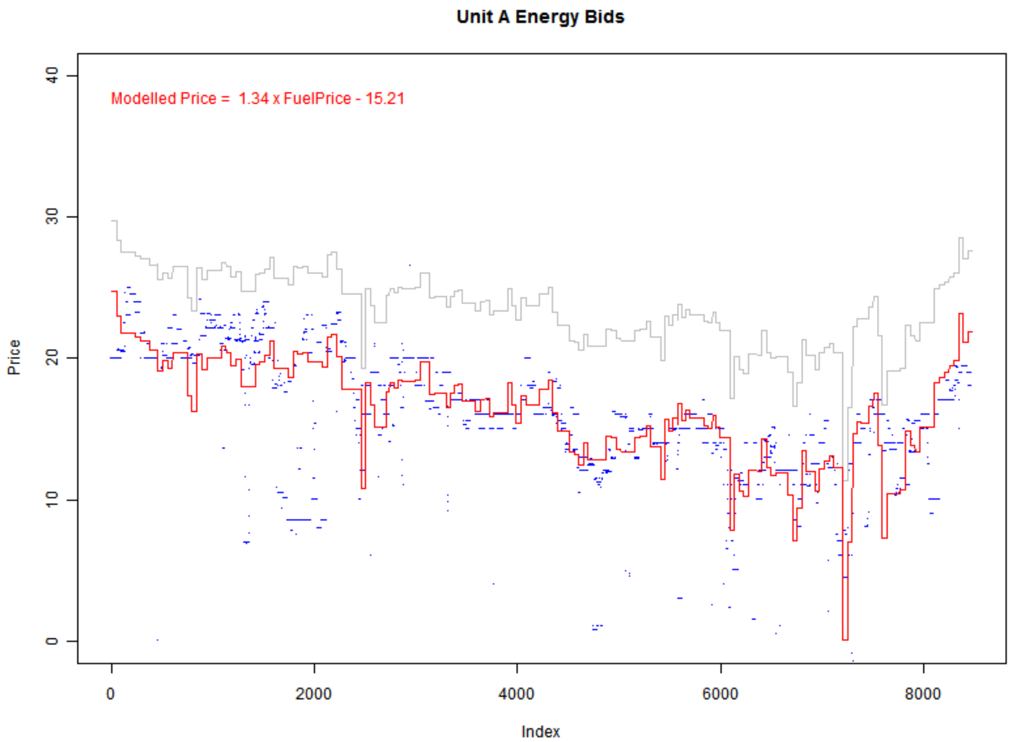


Figure 7: Modelled Energy Bid BM Price versus actual submitted prices for 'Unit A'

115. In light of the above, National grid went on to consider whether an alternative Ex-Post approach might present improved scope for incentivisation whilst minimising the potential for windfall profit/loss.

2.1.2 Utilising BM prices Ex-Post

116. Ex-Post BM prices would be sourced from actual half-hourly prices submitted by each BM unit in the Balancing Mechanism. Volume weighted average calculations would be carried out on these submitted prices in order to derive the four price bands to be applied in the model as highlighted in Table 6.

117. The use of Ex-Post prices would get around the issue of not being able to realistically forecast BM pricing behaviour Ex-Ante. However, from an incentivisation perspective, modelling the target cost for constraint management using actual prices submitted into the BM raises a number of issues, For example:

a) Where is the incentive to beat BM prices?
b) What is the incentive to contract?

118. Taking these points in turn:

Beating BM price

119. It could be argued that National Grid could leave constraint management to BM timescales in the knowledge that it will be allowed to incur costs based on submitted BM prices. It is important to note that the price is only one element of the incentive. The target cost for constraint management would be derived based on the modelled volume and duration of the constraint as well as the Ex-Post BM prices, so there will still be the need to deliver volume efficiencies to beat modelled target costs.

120. However, it should also be noted that it would be possible to apply a discount factor to the Ex-Post BM prices used in the model, so as to incentivise efficient constraint management from a price perspective as well as through minimising constraint volumes. A number of related price issues arise when considering the incentivisation of National Grid's constraint contracting activities – these are considered further below.

Maintaining the incentive to contract

121. One of National Grid's key mechanisms for contracting to manage constraints is where output levels at a power station are restricted in return for a fee. Additional elements might include utilisation of intertrip capability or the application of caps/floors to BM prices. The decision to contract tends to be based on a view of the likely costs and the risk that those costs might escalate.

122. For a contract form that looks to restrict output levels in exchange for a fee, the incentive to enter into such contracts should still exist, although there is the risk that knowledge regarding system conditions gained in the course of negotiations could influence resultant BM price submissions. Whilst the Ex-Post use of BM prices should mitigate National Grid's incentive exposure if further action was required in the BM, any softening of BM prices (e.g. submission of lower offer prices post-contract) could result in a lower that expected modelled target cost and convert what was seen as an efficient contracting activity at the time into an inefficient one. This could adversely affect National Grid's risk appetite when entering into such contracts.

123. For a contract form that looks to cap/floor BM prices in exchange for a fee, the incentive to enter into such contracts could be said to diminish if Ex-Post BM prices are used to model constraint costs. This is because, all other things being equal, National Grid would pay a fee to limit prices and the modelled constraint cost would only allow for recovery of costs based on the prices National Grid had contracted for – hence the option fee would be a sunk cost.

124. A potential mechanism to address these price-related issues could be through a mechanism to substitute the relevant Ex-Post BM prices with 'representative' ones. For example, the average price for each half hour for each day could be taken, for one week prior to and one week following on from the period covered by the contract. Alternatively, a contractual requirement could be placed on the counterparty to provide as a contract parameter a pseudo BM price that would apply as if contract was not in place, perhaps with an arbitration process if prices were deemed

unreasonable. Such an approach might be appropriate for contracts that aim to restrict output levels; however it may be that knowledge of the method of incentivisation might have an influence on generators' negotiating stance, rendering such contracts unworkable.

Question CA6: To what extent do you consider it possible to forecast BM price submissions ex-ante? Do you consider there to be alternative mechanisms to that considered by National Grid for determining BM Prices ex-ante?

Question 20 (from Initial Proposals): What are your views on the use of submitted BM prices Ex-Post as a means of determining target costs for constraint management?

Question CA7: To what extent do you consider that a 'discount factor' could be used in conjunction with Ex-Post BM pricing to deliver efficient incentivisation of constraint management activities?

Question 21 (from Initial Proposals): What are your views on the use of a 'pseudo BM price' to apply to contracted BM Units when calculating target constraint costs? To what extent do you agree that the options outlined in paragraph 124 might be suitable?

Incremental contracting efficiency

125. A further question is the extent to which National Grid should be incentivised to deliver incremental efficiencies with respect to previous contracting activity, for example where a similar outage has previously been managed through the use of a constraint contract, to what extent is it feasible to incentivise National Grid to deliver a more efficient constraint management solution to that achieved previously?

126. Where a particular outage has been previously managed using a contract, it would be necessary to in some way map the parameters of the previous contract onto that outage. A mechanism to achieving this might be to modify the assumptions used to generate the constrained schedule to reflect the previously-agreed parameters, so that a theoretically more efficient solution to constraint management could be modelled.

127. This presents a number of difficulties:

- The original contract price might have been struck based on a package of constraint management measures (for example capped physical notifications, intertrip prices, capped offer prices); and the required volume, which would to a certain extent have driven the price level, would have been specific to the outage for which the original contract was struck. For example, a contract price may reflect the cost of constraining off wind at one extreme or a low cost intertrip at the other.
- There is no guarantee that the duration of, or circumstances surrounding, the new outage would be the same (or similar) to the outage that generated the original contract, hence it would prove difficult to use (for example) a price target for offers, bids or commercial intertrips based on the previous contract in a meaningful way. An example of this is that the market conditions when the contract price is struck will differ over time, e.g. a price struck during short markets in the winter will significantly differ from a price struck during a long market in the summer.

128. Developing a methodology for the application of previous contract parameters to the planned outages in the ex-ante dataset would not be straightforward. National Grid considers that a potentially more straightforward option would be to compare out-turn actions with target constraint costs based on Ex-Post BM prices, but with a discount factor applied as discussed above.

Question 22 (from Initial Proposals): Do you agree that National Grid should be incentivised to beat historic constraint contracting performance?

Question 23 (from Initial Proposals): If yes, what in your view is the most appropriate way to achieve this in practice?

2.1.3 Further modelling considerations

129. Once the simulation is performed, a total cost to move the system from the 'unconstrained' position to the 'constrained' position is obtained. A methodology will be developed to describe how this total cost shall be split so that a reasonable allocation is made to each active constrained zone, including the costs for replacing sterilised headroom behind active export constraints (more information on this subject can be found in the 'Margin Volume – Constrained Margin Management' part of Section 3 in the main initial proposals consultation document).

130. We expect to base this methodology on the well established processes currently used within year to monitor actual performance against the BSIS target. This process involves manually 'tagging' constraint boundaries and their limits against actions taken to alleviate those constraints.

131. The 'tagged' constraint boundaries described above are recorded in National Grid databases. This facility allows the recorded weekly constraint limits to be output for every active system constraint. As Plexos uses a sub-set of the possible active system constraints a manual mapping process will have to be undertaken between the 'tagged' constraint boundaries and this sub-set used in Plexos. In order to back test the performance and accuracy of the model, the 2009-2010 constraint limits can be fed into the model, where the modelled outputs are then compared to actual recorded historic costs.

3. Constraints Incentive

132. The overall aim of constraint cost incentivisation manifests itself in a number of different ways. Constraint costs can be minimised through actions that influence volumes, for example by altering the level of constraints presented by the outage plan or by maximising the efficient use of the transmission system; or through actions that influence prices, for example by delivering efficiencies in generation running or the prices at which their running can be altered. For a constraint management incentive to be effective the modelled target cost needs to be reflective of the underlying drivers – National Grid considers that the approach to constraint management being proposed should ensure that, as far as possible, this is the case.

3.1 Managing the outage plan

133. The Grid Code contains provisions for the co-ordinated development of outage plans to undertake construction and maintenance work on generation, transmission and distribution systems. Placing a constraint cost incentive on the SO encourages and rewards further efficiencies in this area, for example by enhancing the effectiveness of processes within existing code frameworks or by proposing changes to those frameworks.

134. For the modelled target cost to effectively incentivise constraint management, the Ex-Ante dataset needs to contain a reasonable view of the outages that will take place in carrying out these construction and maintenance works.

135. Under current processes, the outage plan for year 1 should be comprehensive enough that its use in the calculation of target costs should act as a reasonable incentive. Whilst at the moment National Grid is not convinced that the outage plan for year 2 is sufficiently comprehensive for it to be used 'unmodified' to calculate a reasonable incentive target, it notes that optimisation does take place between

National Grid as SO and National Grid as Transmission Owner for years 2 to 5; and that work is underway to develop the outage planning and investment planning processes under the STC to encourage greater co-ordination with other TOs over the same timescales. National Grid notes, however, that greater co-ordination with other TOs over years 2 to 5 is likely to be contingent on developments under RIIO-T1 that encourage greater co-operation in this area.

136. National Grid considers it important that developments in SO incentivisation and TO developments under RIIO-T1 are compatible and collectively support co-ordinated action to manage constraint costs. Whilst this should be achievable for an SO incentive scheme starting 1st April 2013 (coincident with the provisions of RIIO-T1), National Grid is of the view that, without the corresponding TO developments, it will only be possible to deliver limited optimisation of the year 2 outage plan, based on construction and refurbishment works in England & Wales; and that without considering the year 2 outage plan in a more holistic manner (through the use of an 'Expert Group' as described in section 1.2.3), there is the risk that modelled target costs might not representative, undermining the aims of the new approach in removing the potential for windfall profit/loss.

3.2 Maximising the use of the transmission system

137. The incentive on constraint management encourages National Grid to develop innovative configurations for running its substations and to develop and agree mechanisms for Users to provide actions post-fault to manage the impact of faults. In the longer-term, it encourages National Grid to consider development of (or further deployment of) innovations such as weather-related enhancements to equipment ratings; and also to work with other TOs to investigate the potential for wider roll-out of such schemes.

3.3 Delivering efficiencies in generation running/pricing

138. National Grid also considers that the incentive on constraint management encourages it to develop ancillary services that facilitate as much competition as possible in the provision of constraint management services. It also considers that it encourages innovation in wider trading strategies, and the development of suitable information provision to the wider market.

Question CA8: To what extent do you agree with the areas of constraint incentivisation outlined in section 3? Are there other activities that you consider should be covered by constraint incentivisation?

Question CA9: To what extent do you think that National Grid's proposed approach to delivering a modelled target cost for constraints will act as an appropriate incentive to deliver cost efficiencies?

4. Contact Us

139. If you would like to discuss any aspect of SO Incentives, please contact us via the contact details below:

On the web:

The dedicated web pages for this process are available at the following addresses:

Electricity SO Incentives: http://www.nationalgrid.com/uk/Electricity/
Gas SO Incentives: http://www.nationalgrid.com/uk/gas/

Contact us:

Gas
Juliana Urdal Tel: 01926 656195 juliana.urdal@uk.ngrid.com

Electricity
Ian Pashley Tel: 01926 653446 ian.pashley@uk.ngrid.com

General enquiries: SOincentives@uk.ngrid.com

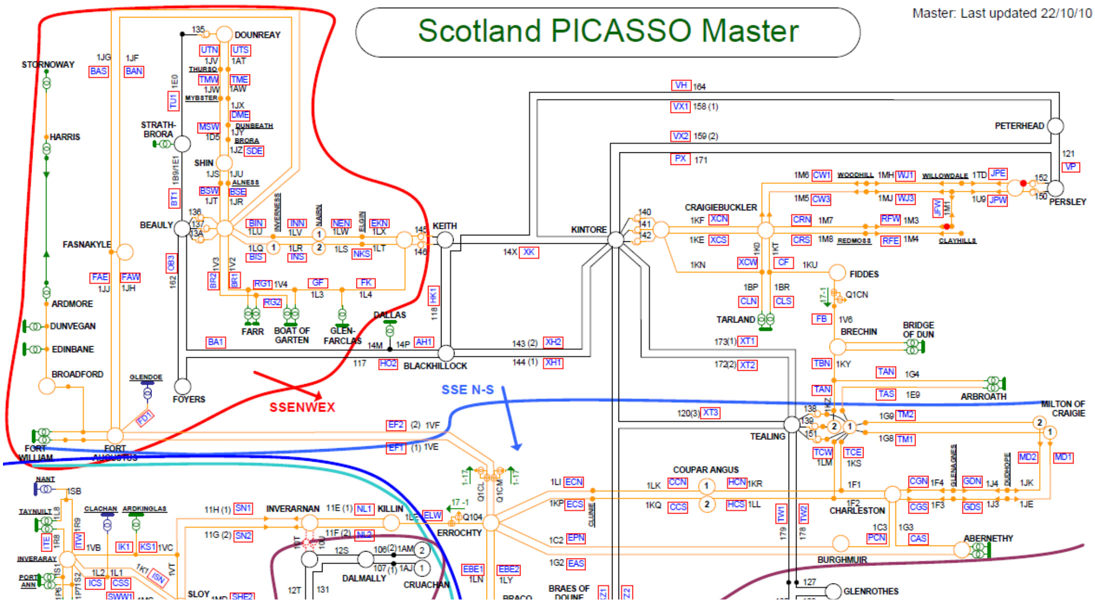
140. To register your interest in receiving future communications on this consultation process please email **soincentives@uk.ngrid.com**.

5. Appendix A: Modelled Transmission System Boundaries

Boundaries included in the model:

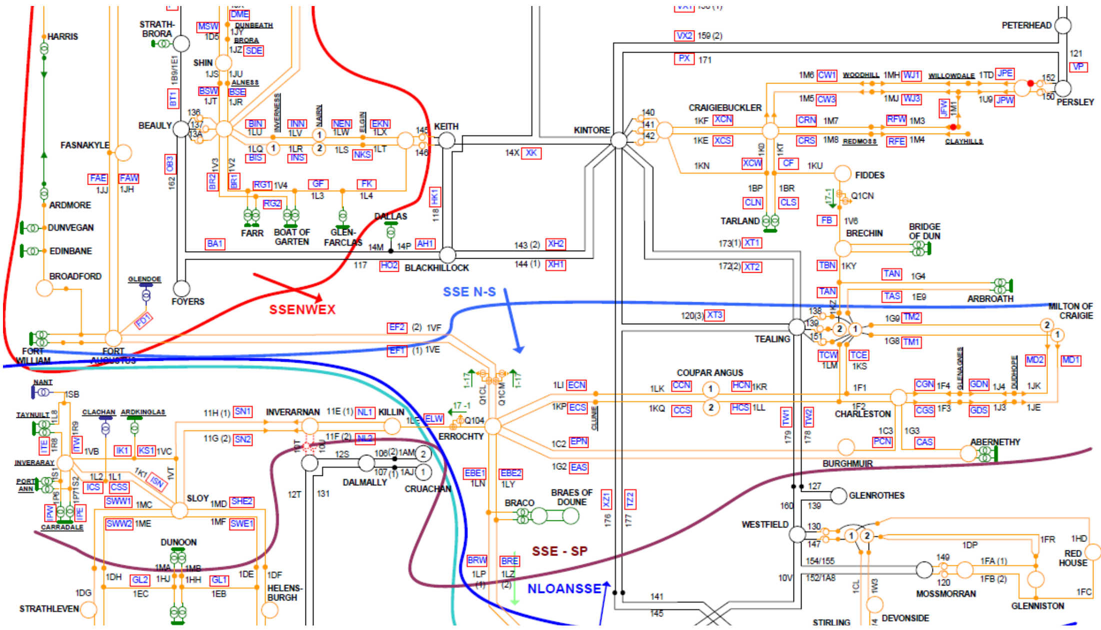
Scotland North:

SSENWEX



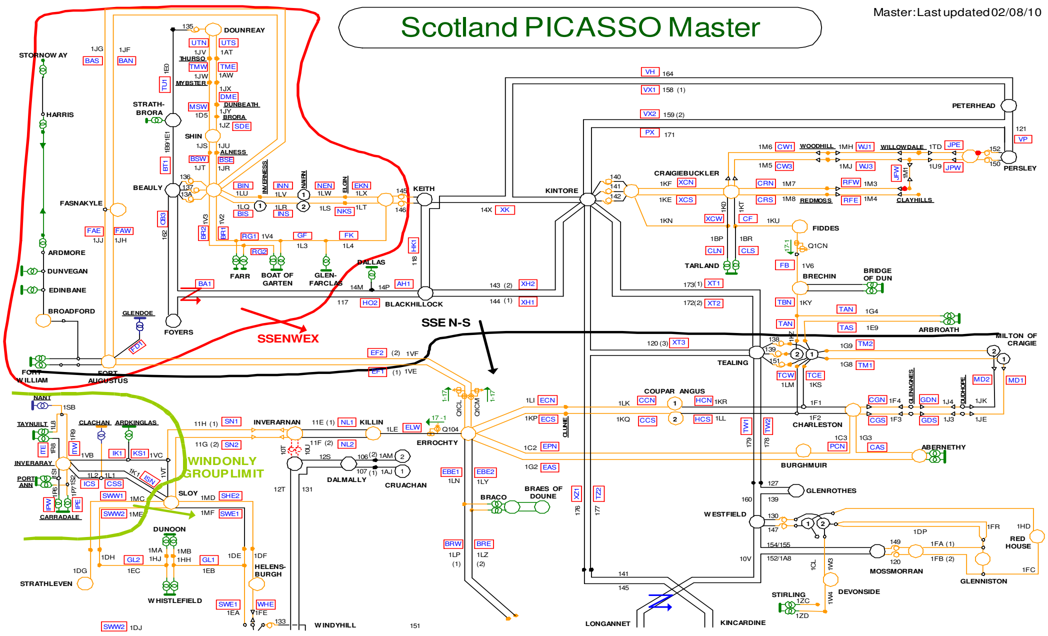
141. This boundary captures the issues resulting from the heavy concentration of wind generation in the area. (Beauly – Denny circuit planned to resolve)

SSE N-S



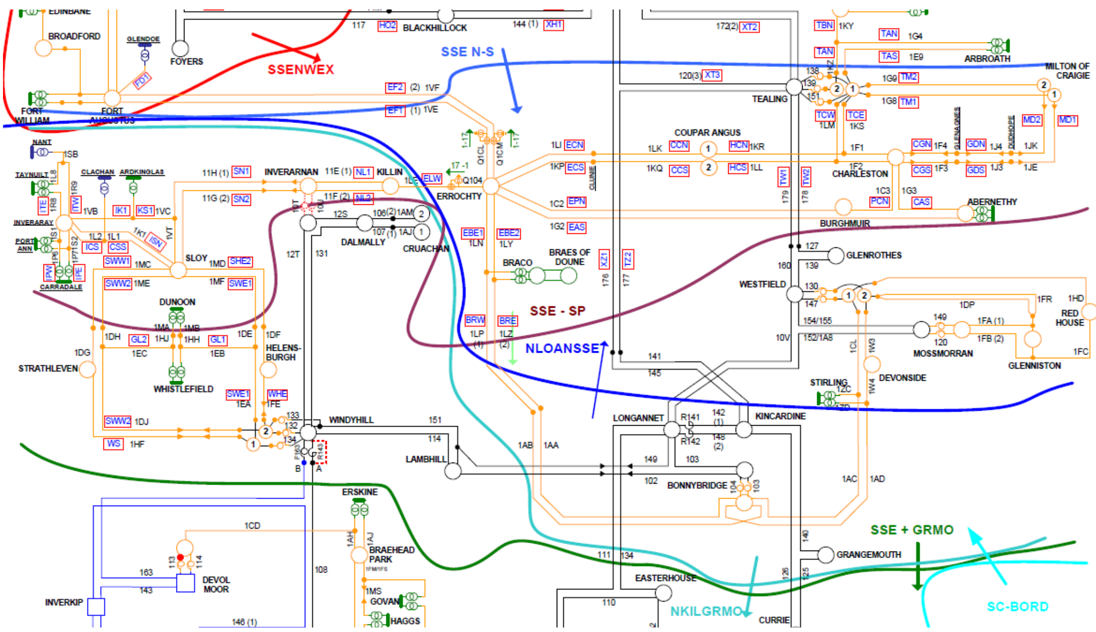
142. The boundary is used to capture all issues associate with high transfers from wind generation combined with generation at Peterhead. The loss of either of the 275kV routes (shown in black) which the boundary crosses can lead to unacceptable overloads on the remaining circuits.

KINTYRE WIND ONLY



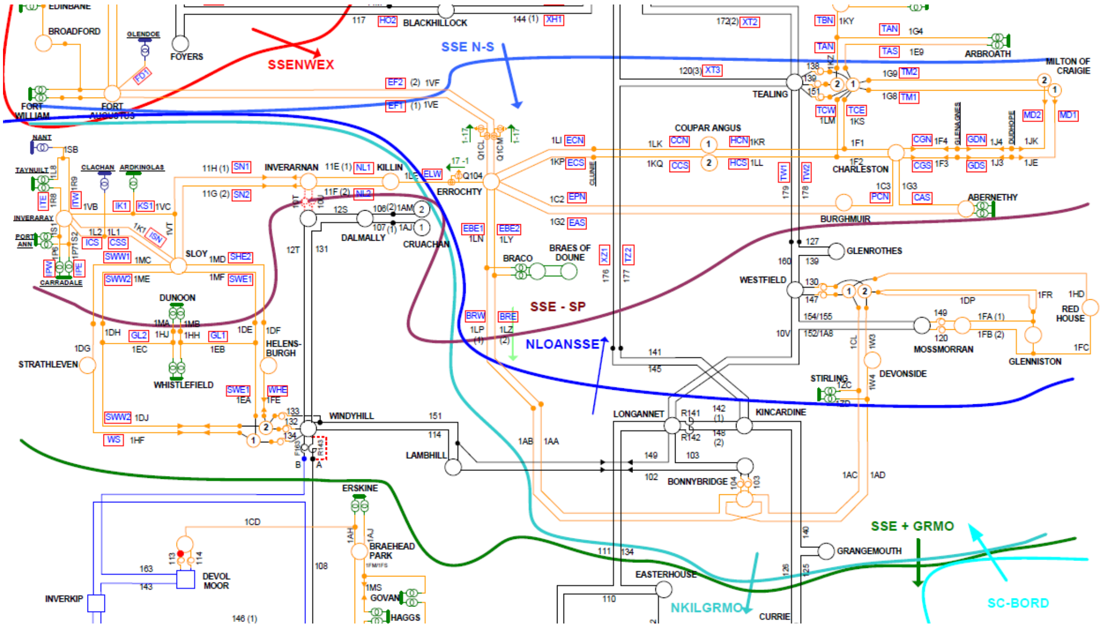
143. All generation behind this boundary is wind generation. As such, costs to manage any constraints can be significant. Under the Connect and Manage Regime, this boundary is likely to become active under pre and post fault conditions.

SSE- SP



144. SSE –SP boundary is not typically used in Operational timescales as a boundary to describe a specific issue in more detail would be preferred. For modelling purposes, it can be used to adequately describe issues associated with the loss of a 275kV route against a combination of Peterhead and all northern wind generation.

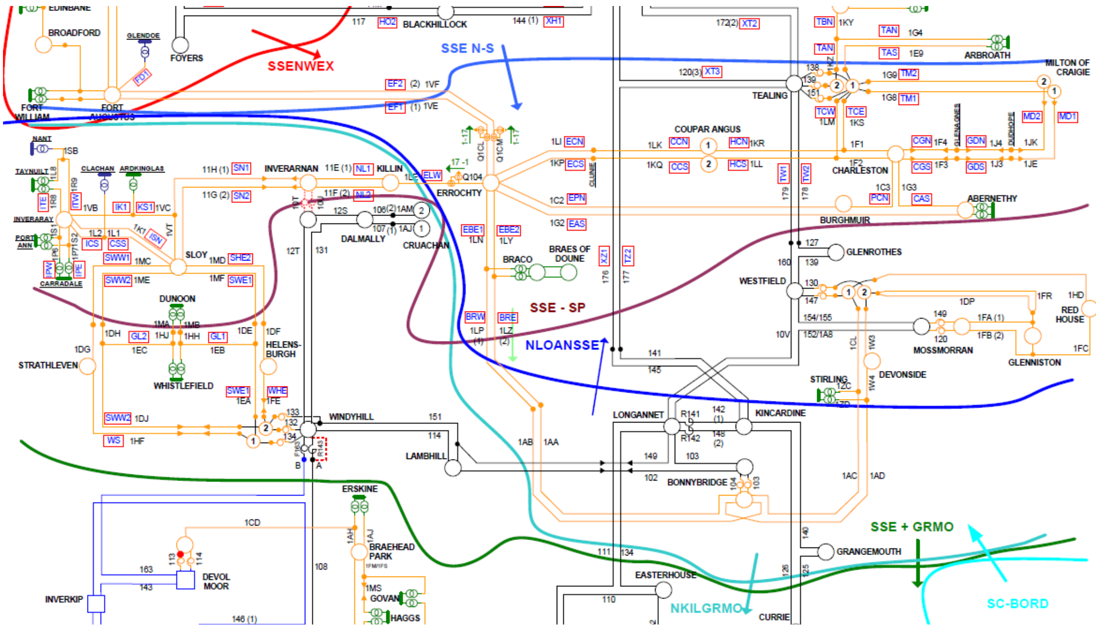
NLOANSSE



145. NLOANSSE becomes active when there is insufficient generation in the North of Scotland to meet demand and high flows from Southern Scotland are observed.

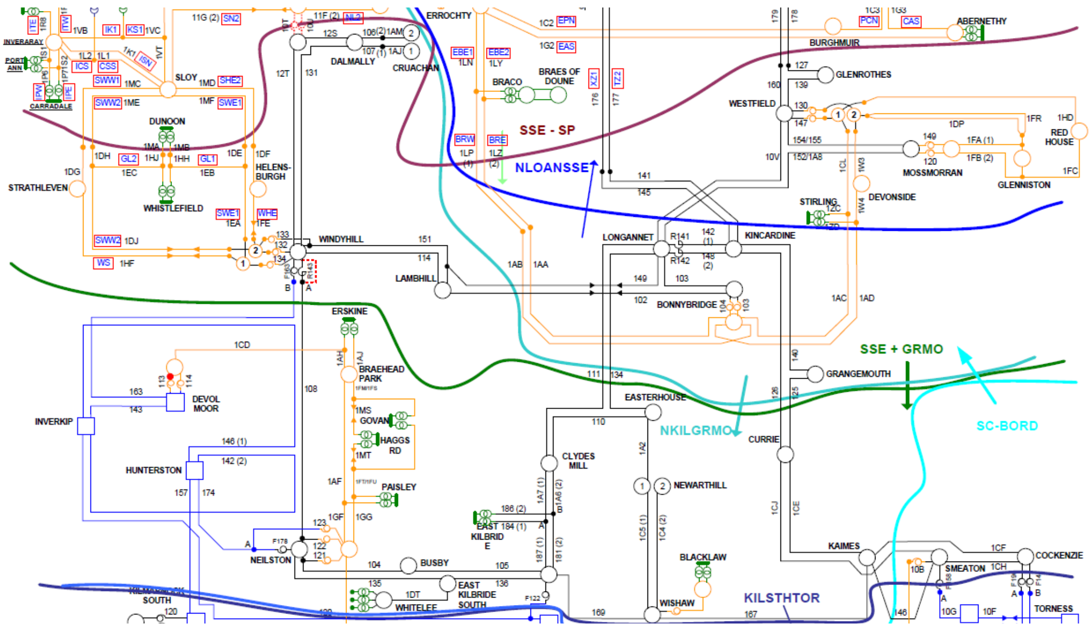
Scotland Central:

NKILGRMO



146. System instability constrains the transfer that can be secured across this boundary. The transfer that can be secured across this boundary is heavily dependant on the number of Longannet generators synchronised and the output of each generator. This is modelled by considering only the output of generation at Longannet and using the corresponding limit.

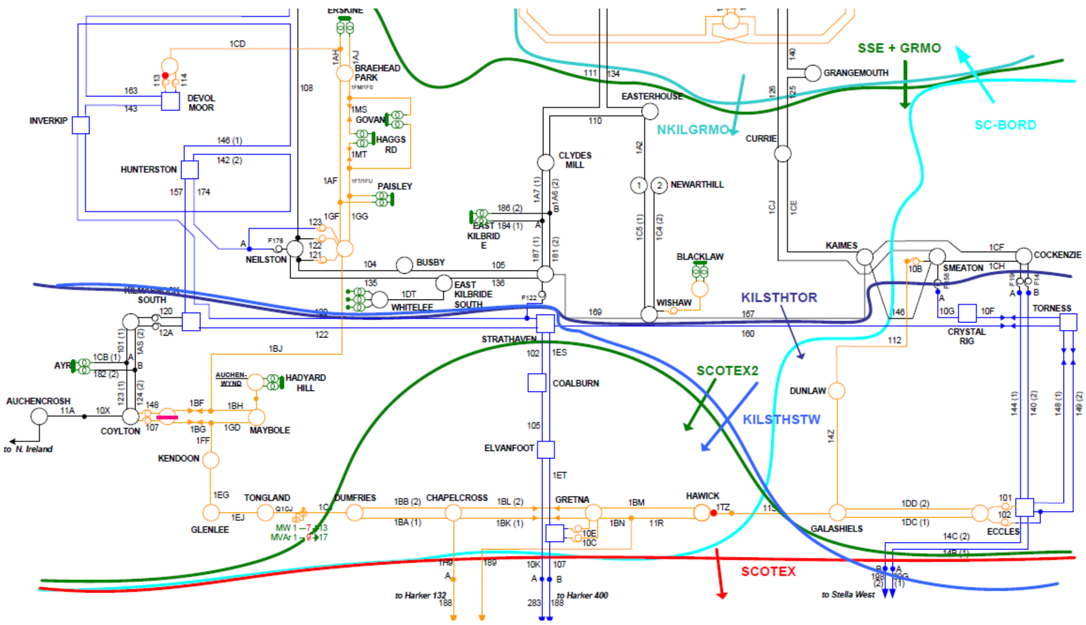
SSE + GRMO



147. This boundary describes a thermal limit on the transfers which can be secured. A programme of works at several substations on the boundary has increased the boundary capability. It is not likely to be a limiting boundary on the system prior to completion of the Beauly-Denny circuit.

Scotland South

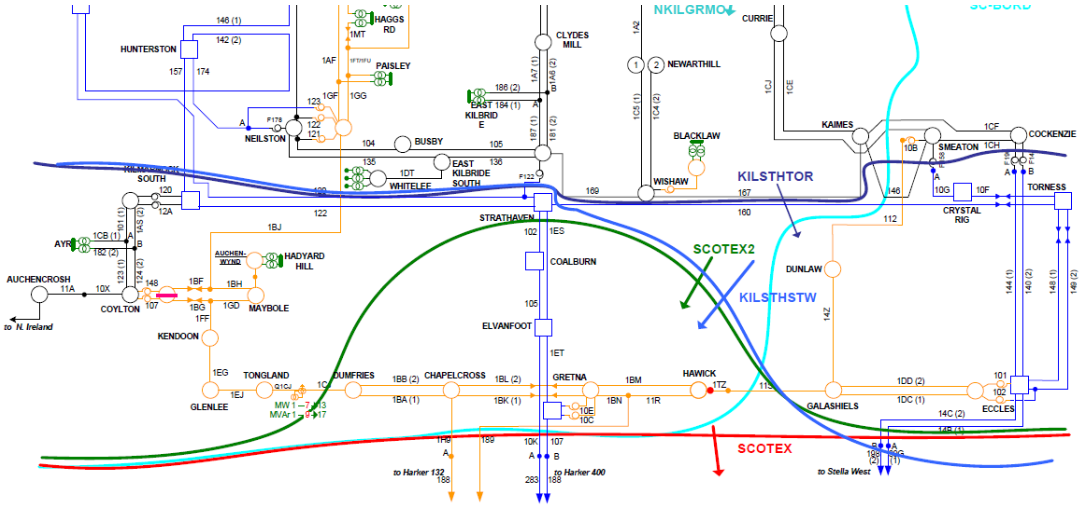
SC-BORD



148. When there is insufficient generation synchronised within Scotland to meet Scottish demand, generation on the English side of the SC BORD constraint looks to meet the demand. This

causes high transfers across the boundary as Cockenzie, Torness (and other generation in the group) generation flows North – West into Scotland rather than South to England. As such, the transfer that can be secured is dependant on the output of generation within Scotland (captured by the SSE + GRMO limit)

KILSTHTOR, KILSTHSTW and SCOTEX2 and SCOTEX

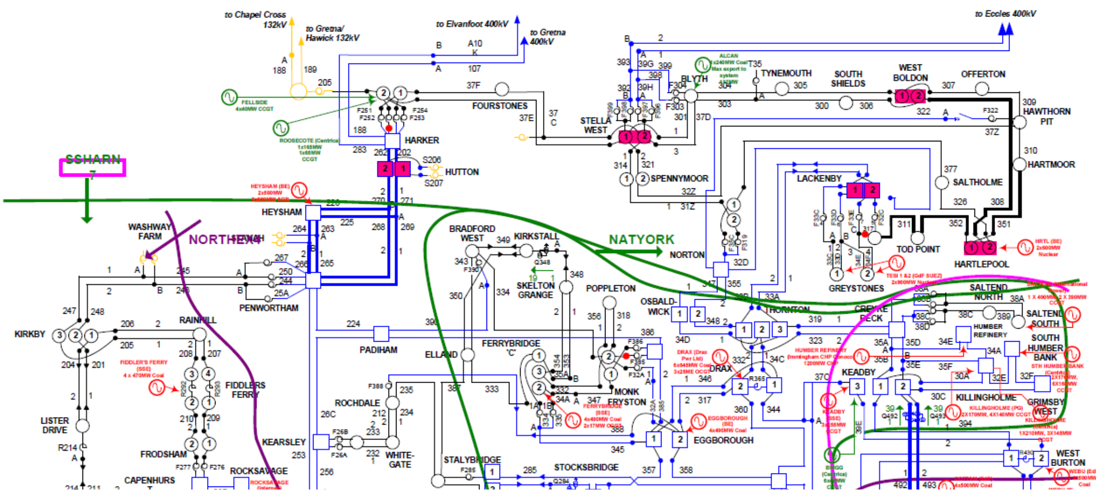


149. The transfer across these boundaries can be limited by thermal, voltage or stability issues. As the thermal capability of the boundary increases, the stability limit becomes the limiting factor on transfer across the boundary.

North of England

SSHARN7

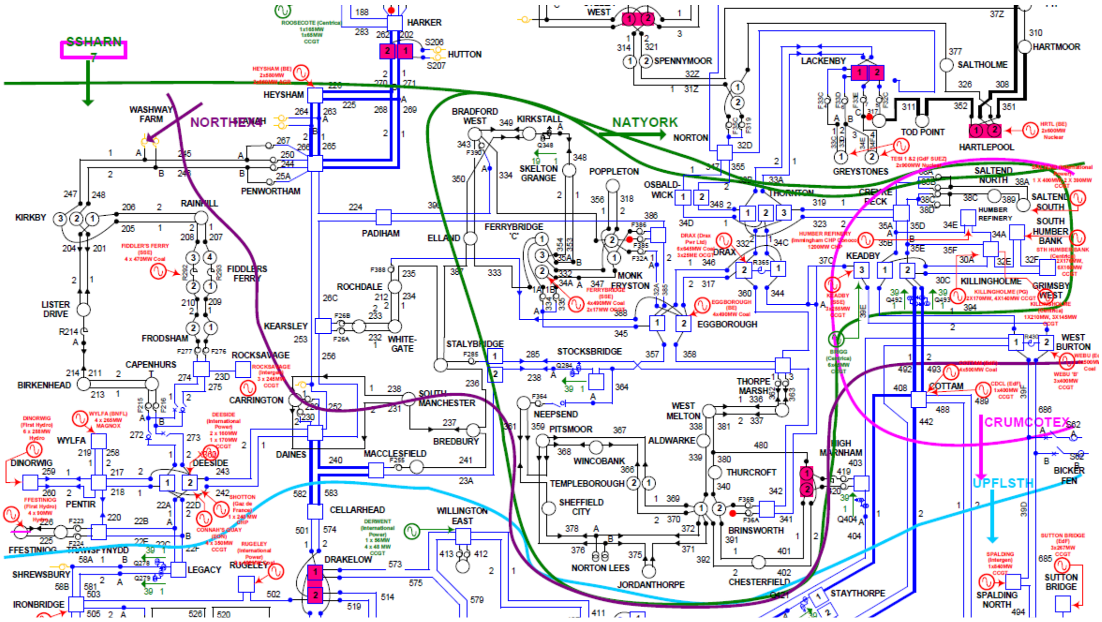
Master Picasso 2010



150. As the SCOTEX boundary capability increases and new generation connections in the North of England, high transfers may be observed across this boundary. During outages of circuits

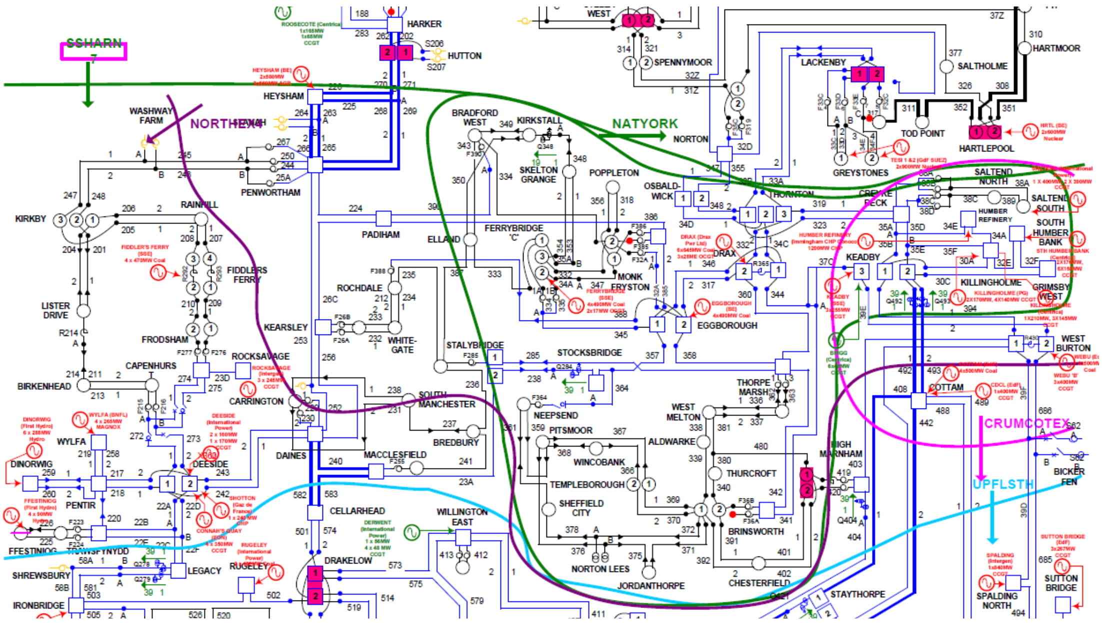
on the boundary, the loss of a circuit may lead to unacceptable loadings on the remaining circuits.

NATYORK



151. This boundary captures the thermal issues resulting from high output from Aire Valley generation, flowing South West. This issue is exacerbated overnight when Dinorwig generation switches into pump mode.

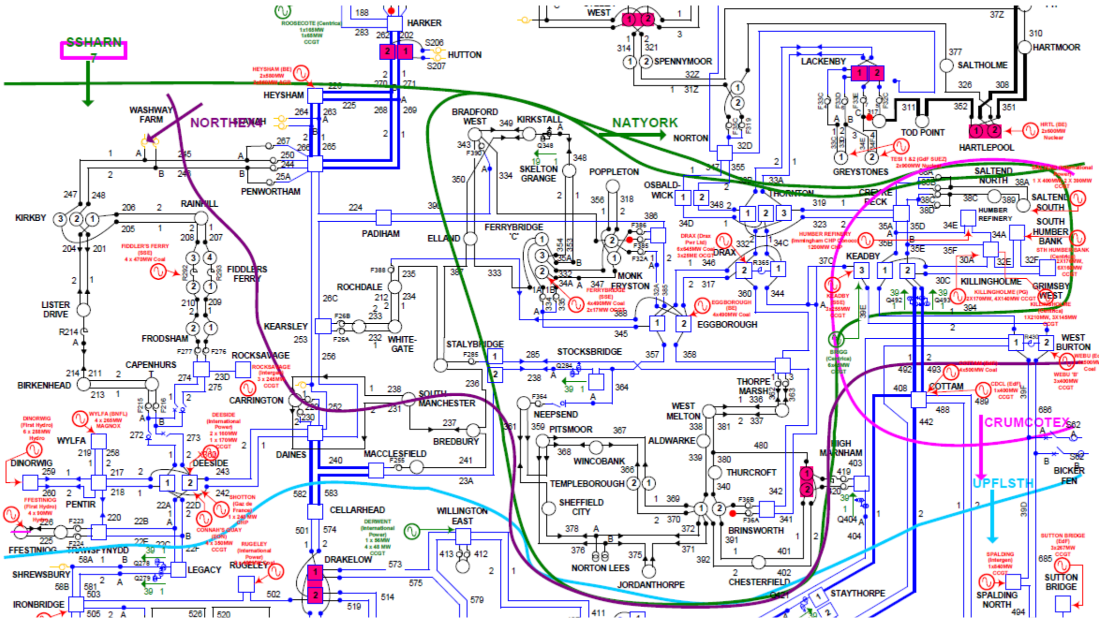
NORTHEX4



152. This boundary is active during outages of circuits along the boundary and is driven by thermal issues resulting from high transfers from Scotland combined with high output from generation

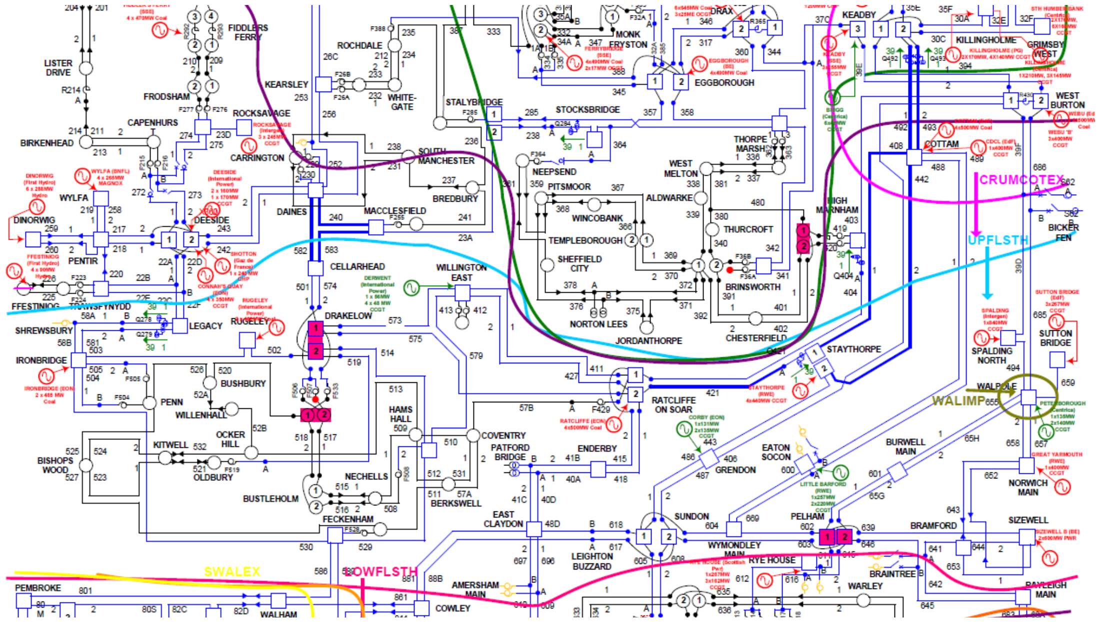
in the North of England. Low output from Cottam and West Burton generation can reduce the transfer which can be secured on this boundary.

CRUMCOTEX



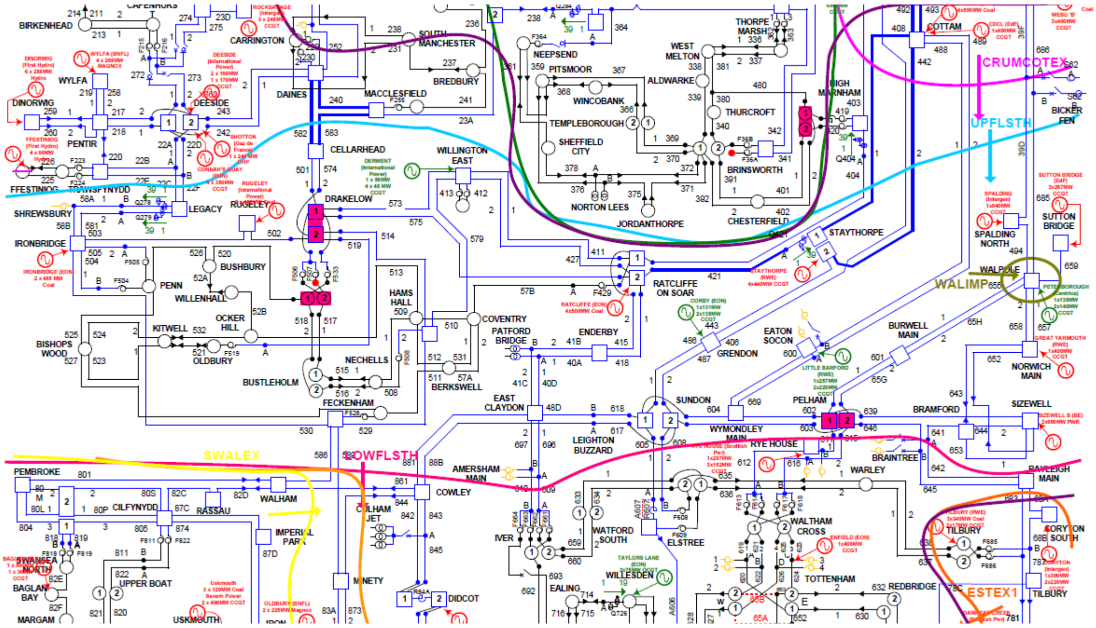
153. This limit describes thermal issues resulting from high output from Humberside generation. When limits on these three limits are active, the model will seek to take one action to resolve all three boundaries. This can mask some interacting issues between the boundary limits, however it is considered an appropriate simplification within a generic boundary based model.

UPFLSTH



154. The boundary serves to capture thermal issues resulting from the loss of a double circuit along the boundary. Within the model it will also serve to secure any voltage limitation on the FLOWSTH boundary.

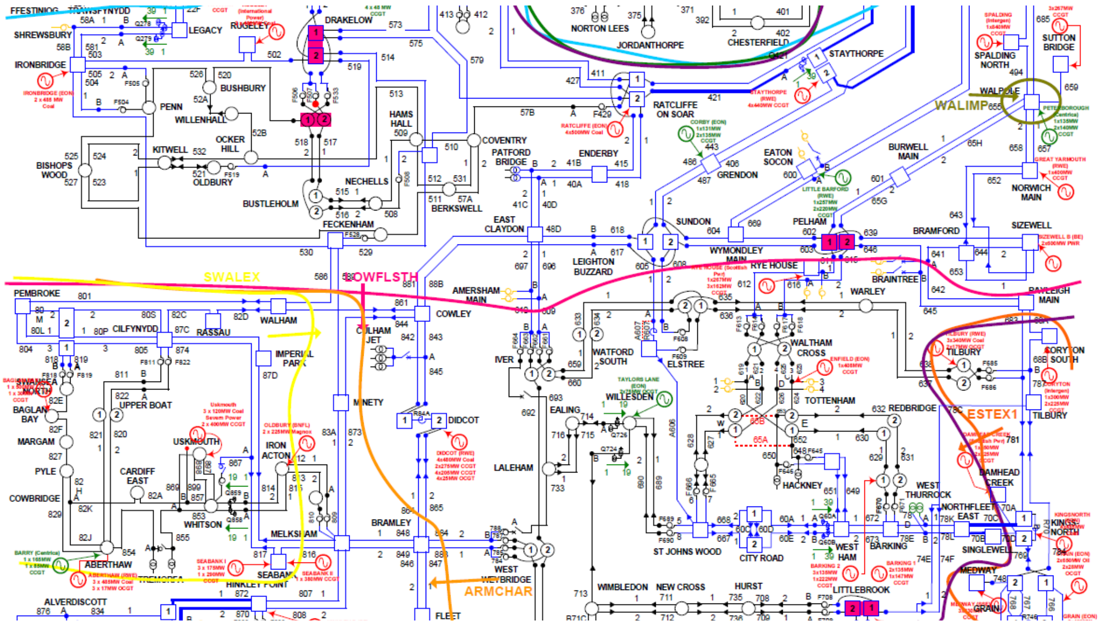
WALIMP



155. WALIMP is a thermal import constraint enclosing the demand at Walpole. Walpole has 4 off 240MVA Supergrid transformers and when one of these is on a planned outage, for the loss of a remaining transformer, the firm capacity is down to 480MVA. The demand at Walpole can exceed this level at peak periods making the WALIMP constraint active. Embedded generation at Kings Lynne/Peterborough will be constrained on to secure the local demand.

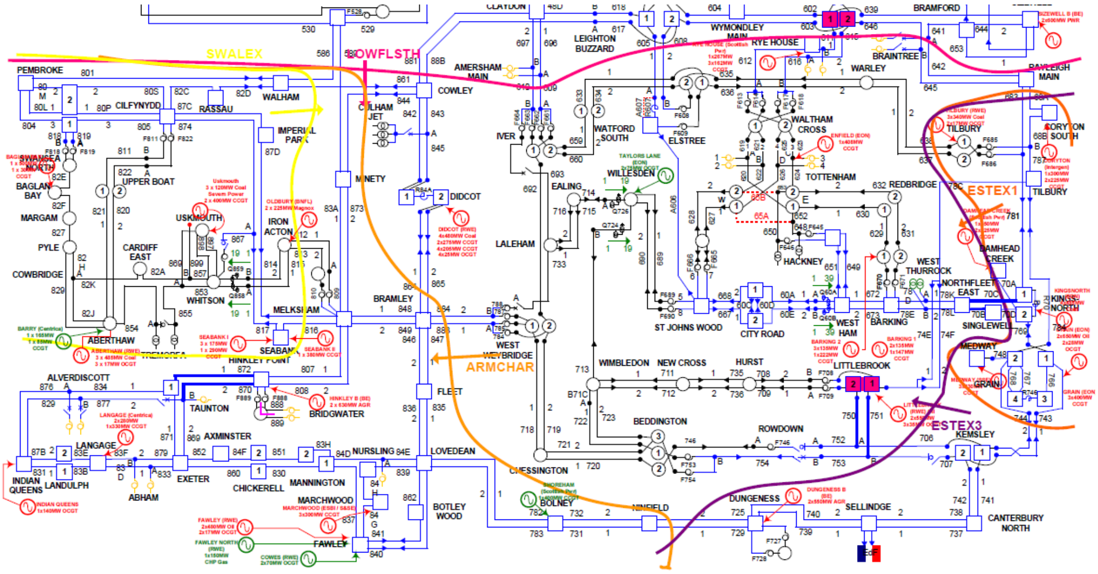
5.1.1 South of England

LOWFLSTH



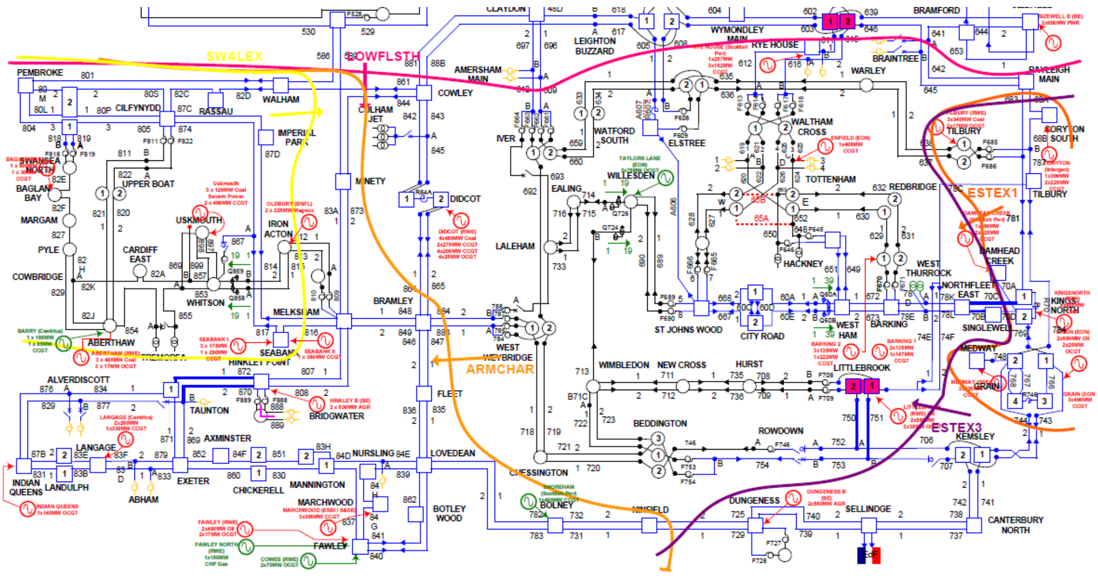
156. LOWFLSTH captures issues associated with insufficient generation across the South of England. This limit can be active under both pre and post fault conditions. This limit is typically managed by increasing generation in the South or trading to increase imports on the IFA.

SWALEX3



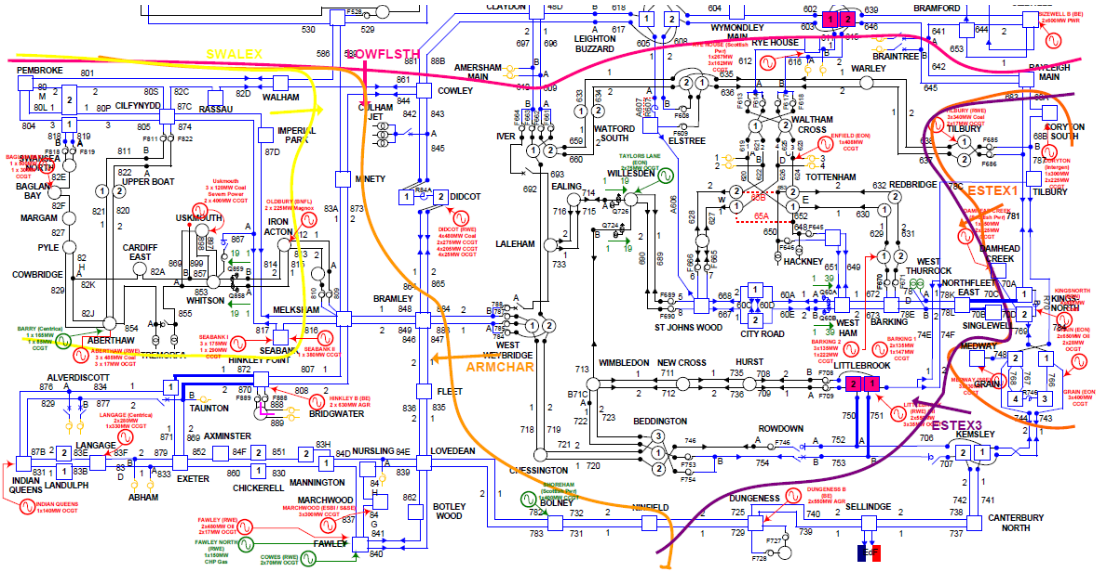
157. This boundary is one which may not be active in 11/12/13 and one which is expected to be active only under outage conditions. As new generation connects in the area, outages on several circuits in the area will be required.

ARMCHAR



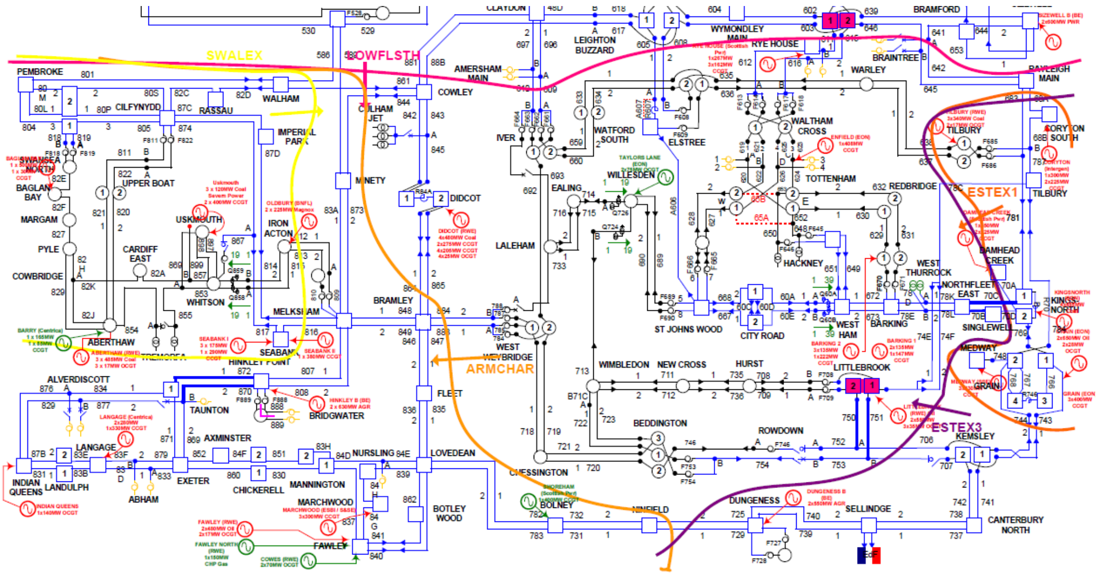
158. The ARMCHAR boundary describes an import constraint which ensures that there is sufficient generation in the South West of England to prevent unacceptable voltage conditions or loading of transmission equipment following the loss of a double circuit route into the area.

ESTEX1



159. During periods of high output from Thames Estuary generation with exports or low imports on the IFA the loss of a double circuit route from the Thames Estuary will result in unacceptable loading of the remaining circuits. Imports from Netherlands on BritNed during such periods (loop flows) would exacerbate the existing issues.

ESTEX3



160. ESTEX3 describes issues observed in the South East of England (Thames Estuary, greater London and along the South Coast) during periods of high output from Thames Estuary generation combined with imports on the IFA and/or on BritNed.

6. Appendix B: List of Questions

161. Appendix B list the questions posed in this Constraints Addendum that are additional to those relating to constraint management in the main Initial Proposals document:

Question CA1: To what extent do you agree that the way in which ex-ante inputs to the unconstrained model have been derived, as set out in paragraphs 21 to 44 above, is appropriate? Are there any further inputs you think should be considered?

Question CA2: To what extent do you consider that the approach taken to calibration of the model provides a reasonable ongoing representation of generation output for the duration of the incentive scheme?

Question CA3: To what extent do you consider the proposed approach to modelling the transmission network as a series of boundaries allows for a pragmatic representation of transmission capability for the purposes of incentivisation?

Question CA4: To what extent do you agree that the proposed approach to modelling generator effectiveness on boundaries will result in appropriate constraint volumes being determined?

Question CA5: To what extent do you consider that there exists the potential for windfall profit or loss under the scheme if an 'expert group' methodology is used to determine a year 2 outage plan as described above?

Question CA6: To what extent do you consider it possible to forecast BM price submissions ex-ante? Do you consider there to be alternative mechanisms to that considered by National Grid for determining BM Prices ex-ante?

Question CA7: To what extent do you consider that a 'discount factor' could be used in conjunction with Ex-Post BM pricing to deliver efficient incentivisation of constraint management activities?

Question CA8: To what extent do you agree with the areas of constraint incentivisation outlined in section 3? Are there other activities that you consider should be covered by constraint incentivisation?

Question CA9: To what extent do you think that National Grid's proposed approach to delivering a modelled target cost for constraints will act as an appropriate incentive to deliver cost efficiencies?